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INCORPORATING INTELLIGENT PIGGING INTO YOUR PIPELINE INTEGRITY MANAGEMENT SYSTEM

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Summary

Many operators are introducing detailed management procedures to ensure that the integrity of their pipelines is maintained at a high level.

These procedures can take the form of a 'management system', where each element of the maintenance and inspection of a pipeline is documented and formally approved at all levels.

One of the major problems faced by operators is how to include intelligent pigging into these systems, and how to measure effectiveness. This paper presents a methodology for producing pipeline integrity management systems, and shows how the usefulness of intelligent pigging can be assessed before including it in the management system.

1. What Is A Management System?

First of all, we need to know what a management system is, and what it can do. Unfortunately, management systems are often confused with management structures; they are different, although the latter is contained in the former.

A Management System is a management plan, in the form of a document, that explains to company staff, customers, regulatory authorities, etc., how the company and its assets are managed, by stating:

- who is responsible for each aspect of the asset and its management,
- what policies and processes are in place to achieve targets and goals,
- how they are implemented,
- how performance is measured, and finally ,
- how the whole system is regularly reviewed and audited.

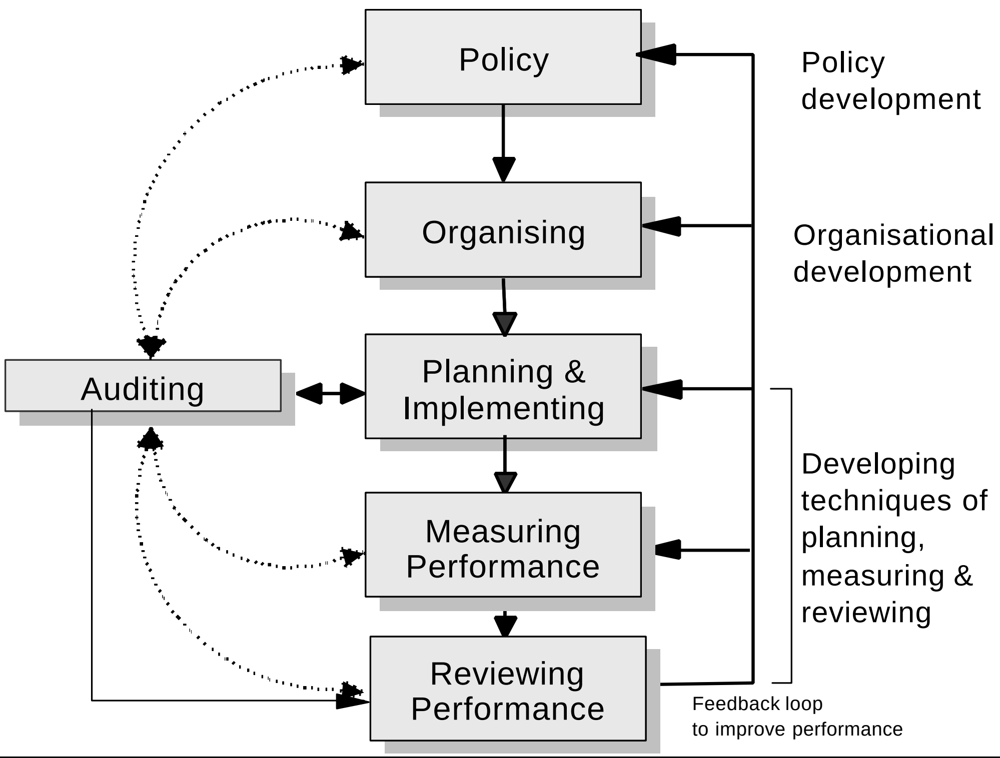
The document is agreed at board level, constantly and systematically reviewed and updated, and all levels of management comply with its contents. Many companies operate such a system in a piecemeal, or unstructured manner. It is the production of a single, detailed document that encompasses all the above aspects that creates the 'system'.

Examples of why a company needs a management systems, and the need to constantly review all management procedures, can be found in the literature (e.g. (1)). Indeed, in the UK, recent Regulations (2,3) require pipeline operators to have in place a safety management system for their pipelines.

2. Simple Management Systems

A simple management system is a safety management system. Figure 1 gives an outline of a safety management system (4). This is one part of a pipeline management system. However, it does show the components of a management system. If any of these components are missing, it is not a complete system.

Figure 1. Safety Management System (4)
Overview of Key Elements



3. Pipeline Management System

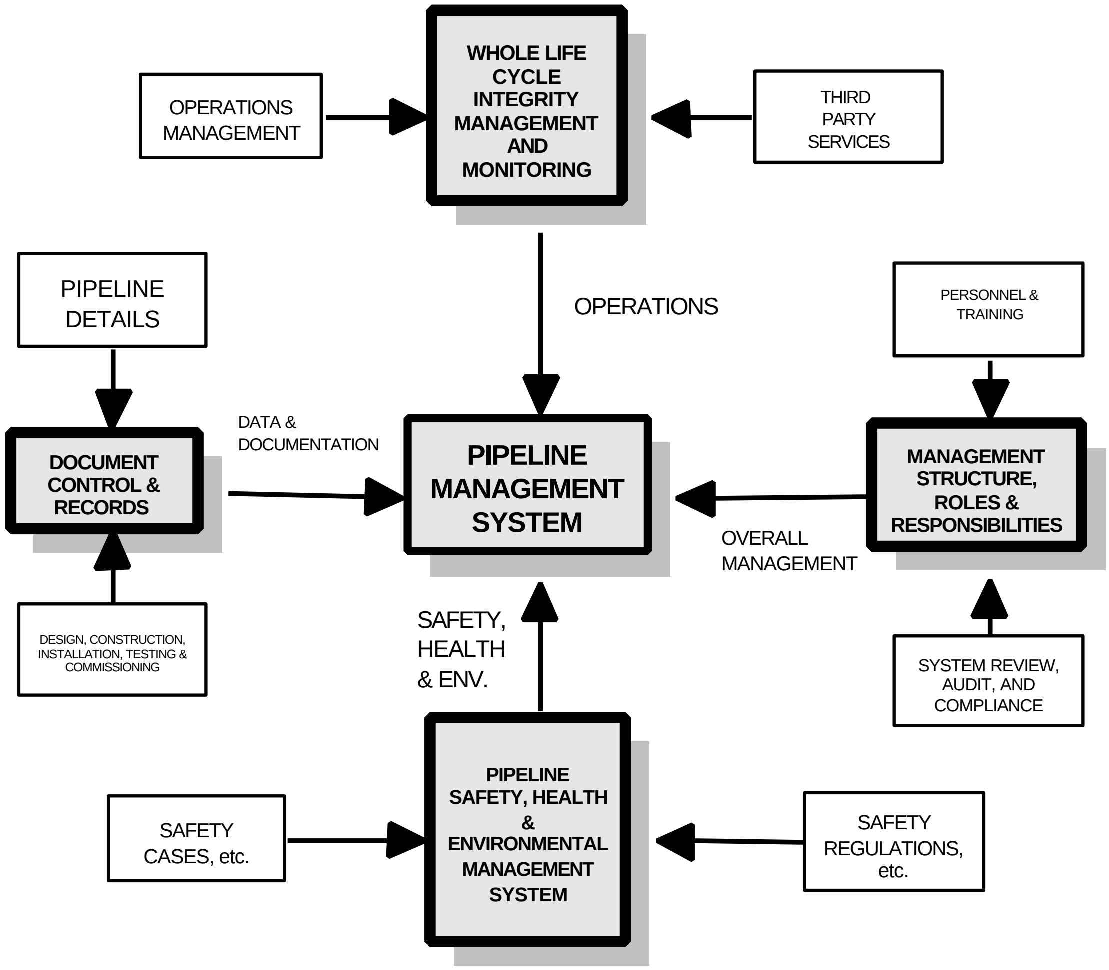
A Pipeline Management System is shown in Figure 2 (5,6). This is a suggested format; different companies require different formats, and different priorities. However, this overall format should satisfy the needs of most companies, and also satisfy requirements of Regulatory Authorities.

Each arm of the management system in Figure 2, should contain all the elements of Figure 1. Therefore, it is not sufficient to have in place an integrity monitoring programme (however good it may be); this programme must be constantly reviewed, and audited to test its adequacy, and checked that it is being applied correctly and completely.

As stated above, one of the key components of the management system is measuring performance, Figure 1. This is important in pipeline engineering, as it can allow early detection of problems, and can also allow relaxations in operational practices, that can allow reductions in operating costs. Figure 3 gives an example of how measuring performance can achieve this.

In this example, in-service inspection is reduced at the start of 1998 because the

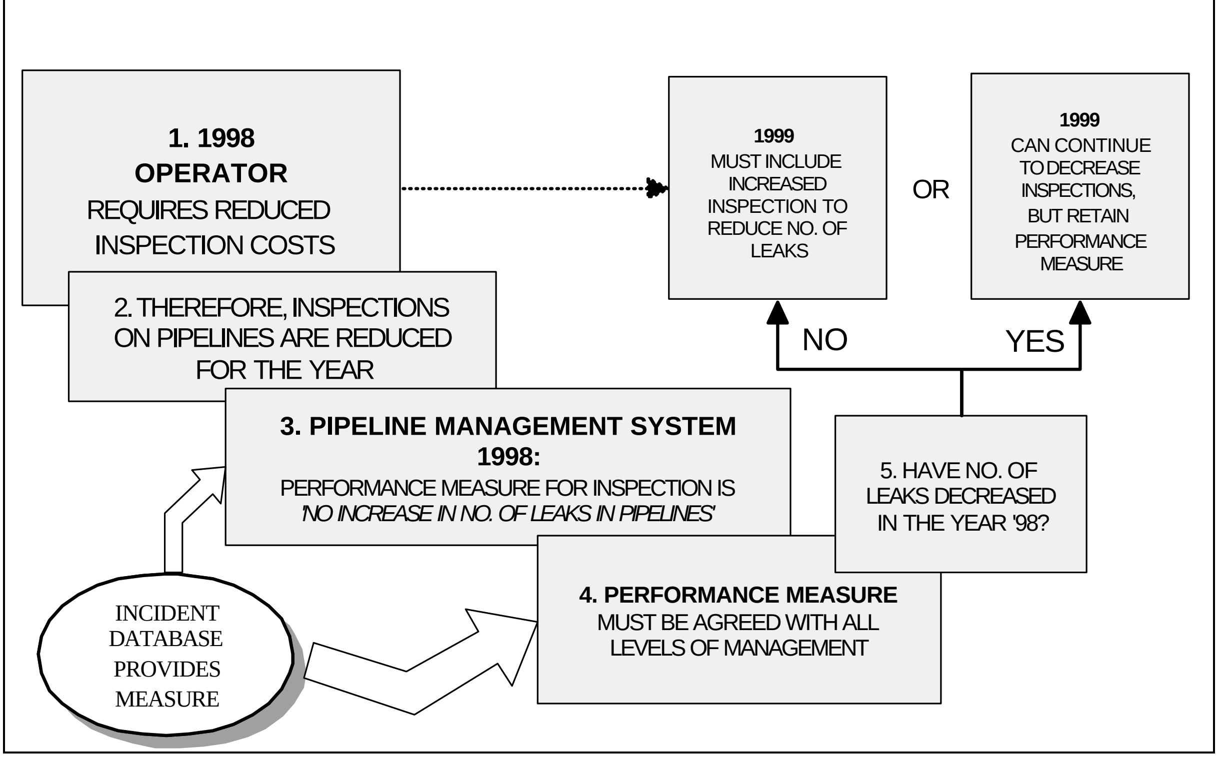
Figure 2. Pipeline Management System (5)



pipeline has a very low incidence of leakage, and the inspections in place are considered excessive.

However, as a competent operator, management sets a performance measure that insists that an increase in the number of leaks is unacceptable. Management agrees that ‘unacceptable’ will be deterioration or leaks over and above accepted or past levels (from an in-house database). During the year all pipeline incidents and leaks are monitored. If they go above the agreed levels, they have failed the performance criterion, and therefore inspections may have to be increased in the following year, to achieve the same performance criterion. This example shows the flexibility of a management system.

Figure 3. Performance Measures in a Pipeline Management System (5)



4. Pipeline Integrity Management Systems

A typical onshore Pipeline Integrity Management System could have the following content and structure (key elements in bold):

1. Introduction - *Purpose, Objectives, Goals, Company Mission Statements.*
2. **Organisation & Control - *Structure, Accountabilities and Responsibilities, Organisation, Relationships with Other Groups/Bodies, Communication Systems.***
3. Description of Pipeline Systems.
4. Legal and Statutory Duties.
5. Interfaces with Other Operators' Facilities or Pipelines.
6. Description of design, construction, etc., standards.
7. **Integrity control, maintenance, inspection & monitoring- policies, procedures & specifications:**
   i. Internal Erosion, Corrosion and External Damage - Control, Mitigation, and Monitoring,
   ii. Pipeline Geometry, Leaks, Ground Movement - Control, Mitigation and Monitoring,
   iii. Pressure and Overpressure Control - Control and Monitoring,
   iv. Definition of Reportable Incident/Damage, Incident Investigation and Analysis
   v. Full Listings Of All Integrity Monitoring Procedures, Intervals, Responsibilities, Agency Carrying Out Duties, Reporting,
   vi. Repair, Modification and Emergency Procedures and Methods,
   vii. Emergency Plans, and Liaison with Other Services,

viii. Information & Documentation Relating to Pipeline Integrity,
ix. Statement of compliance with any Pipeline Safety Regulations and Associated Laws.

8. **Performance Measures.**
9. **Pipeline Integrity Management System Review - *Responsibility and Frequency.***
10. **Management Review - *Responsibility and Frequency.***
11. **Audit of All Processes - *Feedback and Change Implementation.***

As stated above, it is the inclusion of the performance measures, review and audit sections that turn the above into a 'system'.

This system will help a company manage its pipeline system. However, how does a pipeline operator incorporate one of their foremost integrity measures - intelligent pigging? The key questions that management must ask, prior to hiring an intelligent pig, are:

i. Do I need to intelligent pig my line?
ii. When should I pig?
iii. Should I conduct a baseline pig inspection, on a new line?
iv. How often should I pig?
v. Which pig should I use?

If an operator cannot answer these questions, they will not be able to assess the benefits of using a pig (both in terms of cost, and integrity), and will not be able to set performance measures for their inspection policies.

The following Sections outline an approach for incorporating pigging into integrity management systems. First of all the reader needs to have a basic appreciation of how pipelines fail, i.e. the basic formulae that we use to calculate the significance of pipeline defects. Then we can show how these formulae can be used to select a pig, and answer the above questions.

5. Setting Defect Acceptance Levels for Inspections

5.1 Basics

Defect acceptance levels are set by using what is known as the 'Battelle' formula (7,8). This formula relates the failure stress of a defective pipeline, to the size of the defect in the pipeline. The only parameters that need to be known are: pipe outside diameter, pipe wall thickness, pipeline yield strength (or grade), defect length and defect depth.

The standard pipeline defect failure equation is:

$$\frac{\sigma_f}{\bar{\sigma}} = \frac{1-\left(\frac{d}{t}\right)}{1-\left(\frac{d}{t}\right) M^{-1}} \qquad (1)$$

$$M = \sqrt{1 + 0.4(2c/(Rt)^{0.5})^2} \qquad (2)$$

Where:

$$P_f = \sigma_f \frac{t}{R} \qquad (3)$$

$$\bar{\sigma} = 1.15 SMYS \qquad (4)$$

P_f	failure pressure
σ_f	hoop stress at failure
M	'Folias 'bulging' factor
$\bar{\sigma}$	flow strength
d	maximum depth of part wall defect
2c	defect axial length
t	pipe wall thickness
R	outside radius of pipe
SMYS	specified minimum yield strength

Notes:

1. The Folias Factor, M, determines how a through-wall defect will fail. It calculates the stress, σ_R that would cause the defect to rupture (usually called 'break), rather than a leak:

   $$\sigma_R / \bar{\sigma} = M^{-1} \qquad (5)$$

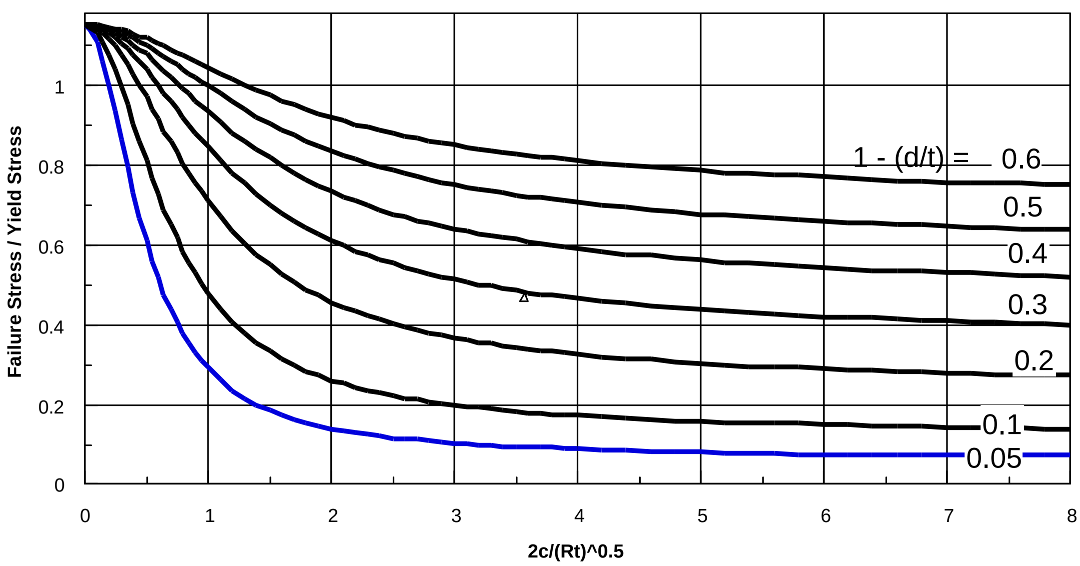
   There are various definitions of Folias (see Refs. 7 and 8, and Table 1, below)

2. There are various definitions of Flow Strength (see Refs. 7 and 8, and Table 1). The definition used here (1.15xSMYS) is reasonable.

3. You can replace 'd' with the defect area, A (i.e. the through wall cross-sectional area of the defective region), and 't' with the cross-sectional area occupied by the defect , A_o (i.e. 2c x t) in Equation 1. Therefore d/t = A/A_o

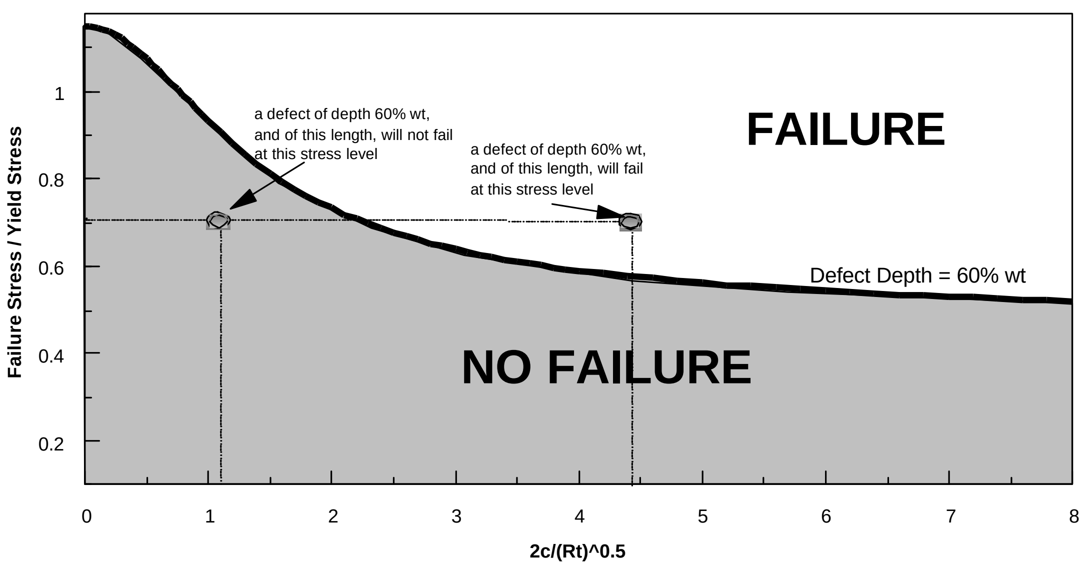
Equation 1 can be used to set defect acceptance levels. It can be represented as:

Figure 4. Failure of Partwall Defects in Linepipe



It is important to understand how the above curves work. The following example illustrates what these curves tell us. In this case, we are plotting the failure curve for a defect of depth 60% wall thickness (this gives us a remaining ligament (1 - d/t) of 0.4, see Figure 4)

Figure 5. Failure of Partwall Defect of 60% wall thickness in Linepipe



You can see that defects of constant depth, will either fail, or not fail, depending on their length, at the various stress levels.

There are various other methods and equations for determining the failure stress of pipeline corrosion defects. The following provides a summary of them and their basis. The more recent models should provide more accurate predictions, and are therefore recommended (9).

Table 1. A Summary of the Development of Corrosion Failure Equations

Method	**Basic Equation**	**Flow Strength**	**Defect Shape**	**Folias Factor**
Classic (7,8)	Eq. 1	1.1xSMYS	Defect Area	$\sqrt{1+0.8(2c/\sqrt{Dt})^2}$
B31.G (10)	Eq. 1	1.1xSMYS	Parabolic (A=0.67x(d/t))	$\sqrt{1+0.8(2c/\sqrt{Dt})^2}$
B31.G (Modified) (11, 12)	Eq. 1	SMYS + 10ksi	A=0.85(d.2c)	$\sqrt{1+0.63(2c/\sqrt{Rt})^2-0.003...}$
RSTRENG (11, 12)	Eq. 1	SMYS + 10ksi	Defect 'Profile'	$\sqrt{1+0.63(2c/\sqrt{Rt})^2-0.003...}$
The Future? (13,14)	Eq. 1	UTS	Defect 'Profile'	Parametric

5.2 Setting Defect Failure Levels at Design Pressure

When setting pig defect acceptance levels , Equation 1 needs rearranging:

$$\frac{d}{t} = (1-\frac{s_f}{s})/(1-\frac{s_f}{s}M^{-1}) \qquad (6)$$

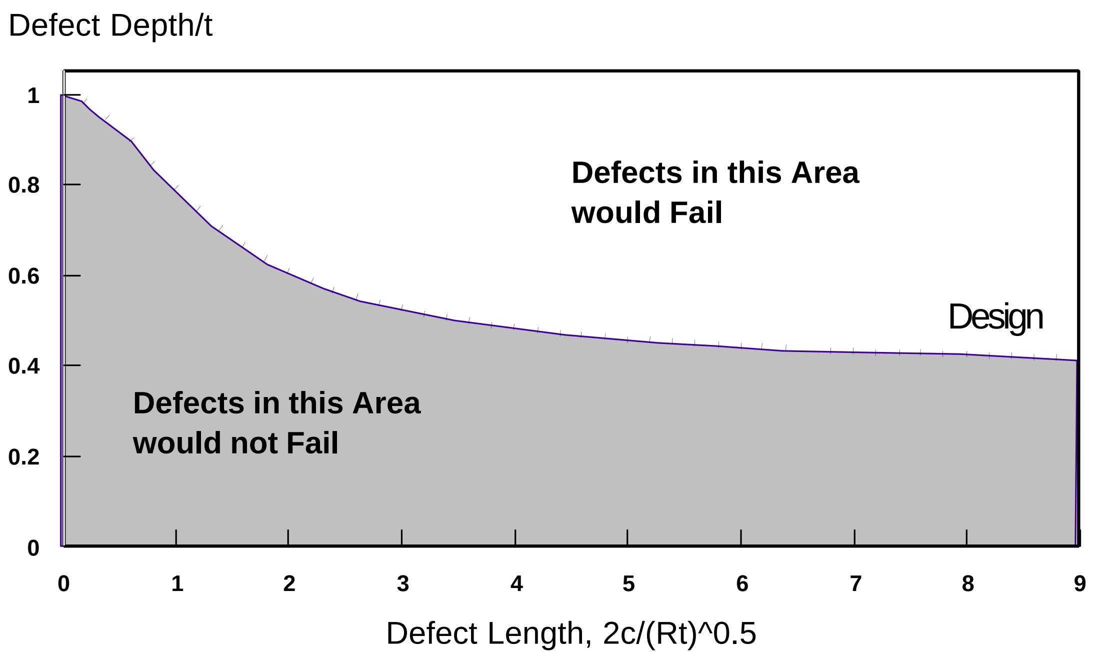
We will know our design pressure P_d, and therefore we will know our 'failure' pressure, P_f as we will be assuming that $P_d = P_f$

$$P_d = P_f = s_f\frac{t}{R} \qquad (7)$$

$$P_d\frac{R}{t} = s_f$$

We can now plot our defect acceptance curves, as defect depth (divided by wall thickness), versus defect length. Figure 6 uses a design stress of 72% SMYS to illustrate these curves.

Figure 6. Critical Defect Sizes - 72% SMYS
No Safety Margin



5.3. Setting Defect failure Levels at Hydrotest Pressure

The defect acceptance levels we have set in Section 5.2 are failure levels at the design pressure. Obviously, we now want to add a safety factor to these calculations to account for uncertainties in the input data (e.g. yield strength), uncertainties in the equations we are using (they are not precise), etc..

We can incorporate a safety factor reasonably easily, by calculating the defect sizes that would cause failure at a hydrotest level. This is done by inputting the stress at hydrotest into Equation 1. The defect sizes we calculate are then our 'acceptable' defects.

The rationale behind using the hydrotest defect acceptance levels as our safety factor is that defect sizes in excess of these sizes would not survive a hydrotest, and so we are only accepting defects that would have survived the hydrotest (10).

We will set a minimum hydrotest level of 100% SMYS. However, if lower level hydrotests have been used on pipelines, these may be used by an expert and with caution, as they can produce very large 'acceptable' defects.

When setting defect acceptance levels at the hydrotest level, we again have to rearrange Equation 1, to obtain Equation 6.

We will know our hydrotest pressure P_h. Assuming $P_h = P_f$

$$P_h = P_f = s_f \frac{t}{R} \qquad (8)$$

$$P_h \frac{R}{t} = s_f$$

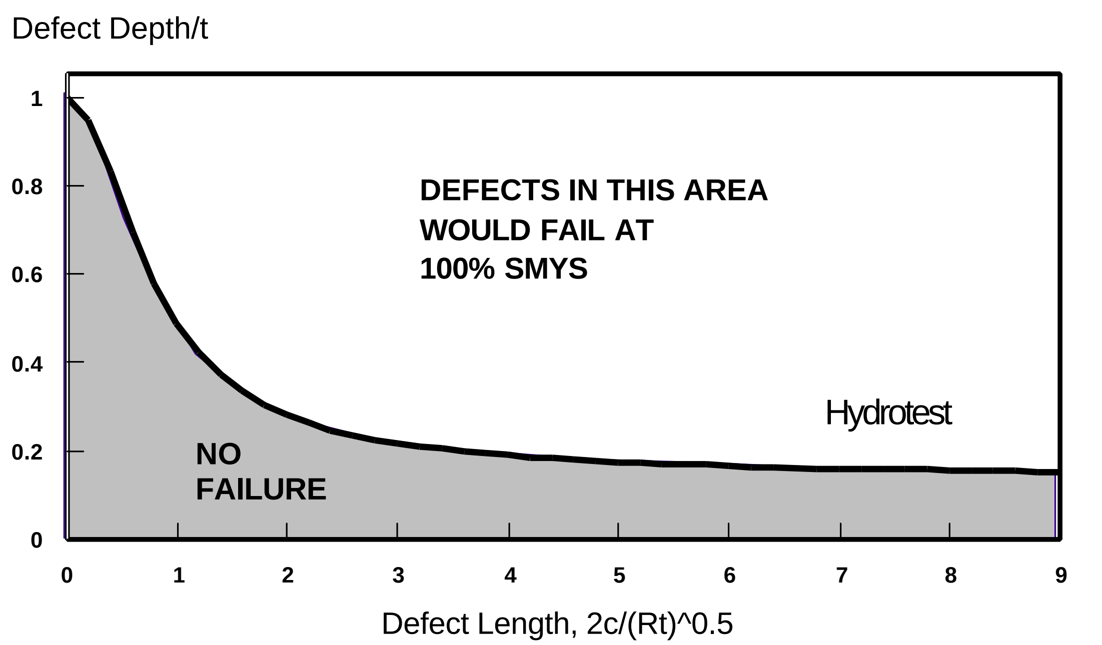
Because we are setting our hydrotest level to 100% SMYS, we can say:

$$s_f = s_y$$

We can now plot our defect acceptance curves, as defect depth (divided by wall thickness), versus defect length.

<u>Figure 7. Critical Defect Sizes - 100% SMYS (Hydrotest)</u>

NO SAFETY MARGIN

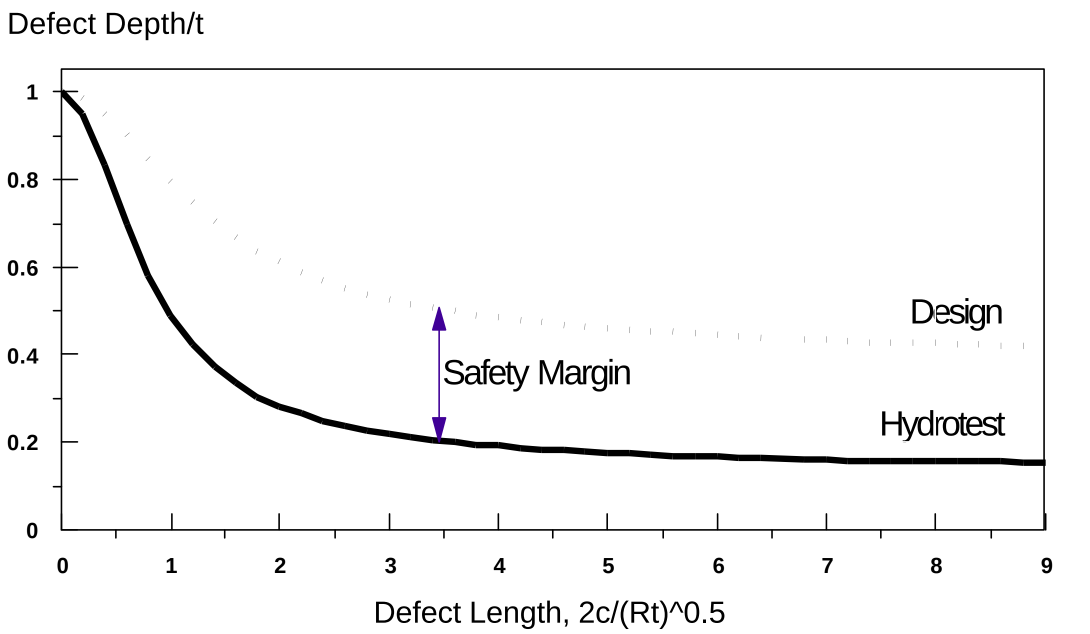


<u>5.4 Plotting Defect Acceptance Charts and Incorporating a Safety Margin</u>

We have now calculated the defect acceptance levels at both our design pressures (assuming 72% SMYS) and our (100% SMYS) hydrotest pressures. We now plot these values on a single plot:

These curves allow us to categorise any defect we find in our pipeline, following a pig run.

Figure 8. Defect Acceptance Charts for a 72% SMYS Line
Hydrotested to 100% SMY



6. Using Defect Acceptance Charts to Determine Pigging Frequency and Levels

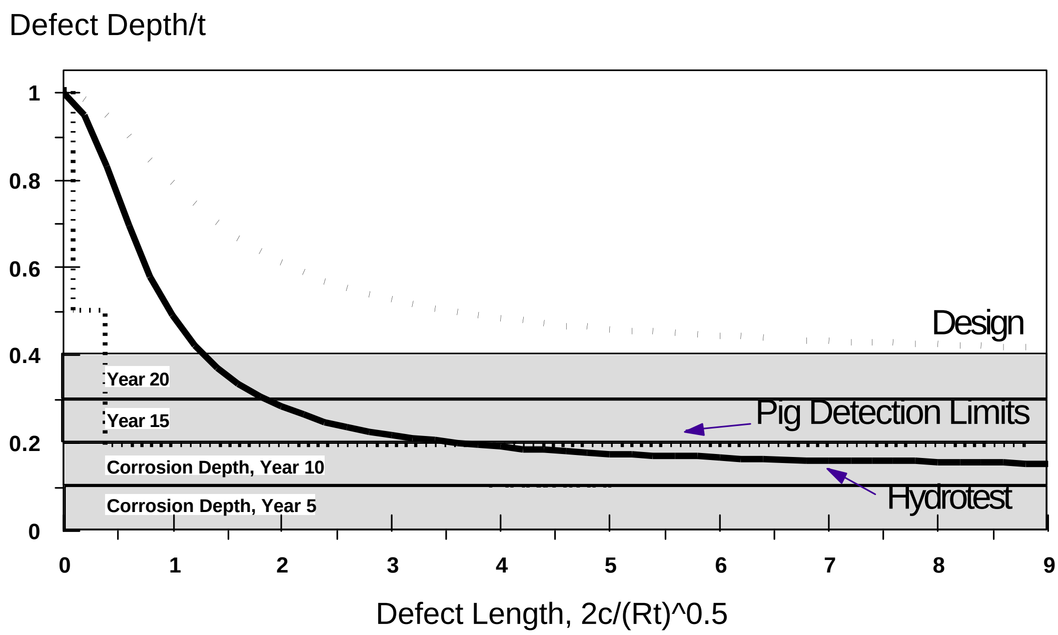
The pig you use for an inspection needs to be both reliable (able to *detect* all defects) and accurate (able to *size* the detected defects). The pig operator will usually specify a minimum defect depth it can detect (e.g. 20% wall thickness) and the minimum length of defect (e.g. 3 x wall thickness). Clearly, if the defect sizes you are interested in are less than these tolerances, a pig run is of little use.

Figure 9 shows how an operator can select a pig, and a pig interval. In this example, an operator has a definable corrosion problem. An internal corrosion mechanism is causing corrosion of about 0. 02% of wall thickness/annum. This means that every 5 years there may be cumulative corrosion of depths of 10% wall thickness present in the pipeline

The pig operator decides that the maximum corrosion depth they will accept is 20% wall thickness - the ‘hydrotest’ level. Therefore, an inspection after 10 years will allow early detection of these corrosion sizes. However, if the operator wanted an early indication of this corrosion growth, they would need to use a more accurate pig (a pig that can detect, say, 10% wall thickness depths).

Also, the tolerance in the pig measurements must be taken into account. If the pig operator specifies a tolerance on corrosion depth measurement of +/-10% wall thickness, this uncertainty needs to be added to Figure 9; the effect would be that (assuming the minimum depth detectable is 20% wall thickness) you could not reliably detect the corrosion sizes you are interested in. Another pig, with a superior minimum depth measurement, or better tolerances, is needed.

Figure 9. Defect Acceptance Charts for a 72% SMYS Line
Effect of Corrosion



7. Incorporating Pig Specifications into a Pipeline Management System

Figure 9 presents a simple illustration of how these methods in Section 5 can be used to calculate the best time to inspect (in this case, after 10 years), and it also shows how they can be contained in a pipeline management system.

For this pipeline example with a corrosion rate of 0.02mm/year, and acceptance curves as specified in Figure 9, we conclude:

Policy/Process - Pipeline Inspection and Controlling Corrosion using Fitness-for-Purpose Methods.

Organising -

i. Appoint project manager with understanding of fitness-for-purpose methods, and intelligent pigging.
ii. Hire organisation that can conduct fitness-for-purpose calculations.
iii. Establish communication channels, authorities, and documentation system.

Planning & Implementation -

i. Establish the need for a baseline survey by reference to the appropriate pipeline design code, or by the calculations detailed in Section 8.3 (later), or by the considerations detailed in Figure 13 (later).

ii. Conduct deterministic calculations to determine inspection level and frequency, as shown above.
iii. Hire a pig (using the above example) that can detect a minimum corrosion defect depth of 10% wall thickness, with a maximum tolerance of +/- 10% wall thickness, or another pig that can reliably detect a corrosion depth of 20% wall thickness.
iv. Inspect (in the above example) after 10 years of operation.

Measuring Performance - Analyse pig report, and determine if corrosion is present, and if it is within acceptable levels. Excessive corrosion will require appraisal of corrosion inhibition, protection ,etc..

Review and Audit - if corrosion is above the acceptable (i.e. expected) levels, determine cause, and implement remedial measures. Review next inspection interval, and consider extra corrosion mitigation measures if corrosion is excessive. If corrosion is below expected levels, reconsider predicted corrosion growth, and future inspection requirements.

This is a simple deterministic approach; a more thorough and reliable approach is to use probabilistic methods (see Section 9, later).

8. Assessing the Value of a 'Baseline' Survey

Increasingly, operators are conducting intelligent pig runs immediately upon operating the pipeline (15-18) but some operators do not consider them necessary, although they acknowledge that an early inspection (e.g. after one year service) should be considered for pipelines where corrosion is a risk, or corrosion control is difficult (19). The arguments for and against the baseline survey can be summarised as follows:

8.1 Benefits of a Baseline Survey

1. The baseline (or 'fingerprint') inspection allows an operator to perform a final check on the construction quality of the pipeline, and can be used as the basis for poor construction practice claims by the operator under any pipeline warranty.

2. The baseline is certainly a good quality assurance tool, as it will provide a searching inspection for a variety of possible defects.

3. It also allows an operator to log defects reported during the inspection. These defects can be assessed, but as they have passed the pre-service hydrotest they are not significant, and are likely to be pipeline material defects, or minor damage. On subsequent in-service inspections these defects can be ignored (provided they have not grown during the interim period), and the operator is in no doubt that any other defect reported has been caused in-service. This can prevent extensive excavations of defects that are innocuous (16).

4. A limitation of the hydrotest is that it will only impose a pressure load on the pipeline; it will not be a searching test for circumferentially orientated defects

(that may cause problems under external loads at spans). A pig can detect a variety of different defects in different orientations.

5. Another limitation of the hydrotest is that there can be a long delay between testing and commissioning. This increases the risk of corrosion being present in the pipeline at the start of operation. A baseline survey, conducted soon after commissioning, would detect any serious corrosion.

6. The Norwegian Petroleum Directorate (NPD) considers information about the initial condition of the pipeline as ‘very important’, as it provides ‘absolute necessary reference values for future condition control’ (20). Knowledge of defects at the start of a pipeline’s life will ‘disclose possible damage or failures originated from the fabrication, transportation, installation and commissioning phase’ (20). NPD gives four ‘operational’ reasons for a baseline (20):

   i. When a pipeline is internally inspected during operation, and it has not received a baseline survey, there is a possibility of unnecessary and dangerous repairs to innocuous defects.
   ii. Damage originating in the operating phase risks being explained away and dismissed as having been present from commissioning.
   iii. In the Norwegian continental shelf there have been cases of debates and uncertainty as to the origins of wall thickness reductions detected during operation.
   iv. It has been shown that if no baseline survey is carried out, then it is very difficult to establish any corrosion rate that is active during operation.

<u>8.2 Drawbacks of the Baseline</u>

1. The above four reasons could be argued against as:

   a. *Don’t repair them*. Any defect that is found during operation, will be assessed for the full remnant life of the pipeline, and only be repaired if it is shown to be a failure threat.
   b. *Don’t dismiss them*. Damage detected during inspection will not be assumed to have been caused before the pipeline entered service.
   c. *There will always be uncertainty, regardless of a baseline survey*. Any wall thickness reductions detected during service will be assessed using fitness for purpose methods, and their significance determined quantitatively.
   d. *Corrosion rate of defects is difficult to establish, regardless of a baseline survey.* Any defect detected in service can be assumed to have started corroding immediately after commissioning.

   It is difficult to see how the four reasons for a baseline (quoted in Section 8.1) given by NPD are ‘operational’. They are reasonable, but appear to be mainly anecdotal, and as such do not constitute a technical basis for the baseline.

2. It should always be remembered that no intelligent pig is 100% reliable (i.e. it will not detect all defects), or 100% accurate. A pig can miss defects, or incorrectly size them. Similarly, the idea of ‘comparing’ the results of a baseline survey with

a later in-service inspection is very attractive, but how practical is it? It should be emphasised that a pig does not report a defect, it reports an electronic signal of some description. Later pig runs (say, 15 years in the future) will not use the same pig, and even if the same pig supplier is used, it is highly unlikely that they will be using the same technology. Hence, comparisons will not be between identical signals. However, the more sophisticated intelligent pig operators are understood to be able to make these comparisons, providing the two runs use their pigs on both occasions.

3. Certainly, a baseline survey would allow an operator to log defects that have been detected, but these defects would still require assessment, and an explanation of their origins. Later inspections of the line would allow these defects to be dismissed as (e.g.) fabrication defects. However, it is difficult to quantify such a benefit; all that can be said is that these defects have survived the pre-service hydrotest, and are unlikely to pose an integrity threat to the line.

4. A limitation of the hydrotest is that it will only impose a pressure load on the pipeline; it will not be a searching test for circumferentially-orientated defects (that may cause problems under external loads at spans). A pig can detect a variety of different defects in different orientations. However, the probability of these defects, and resulting failures, occurring are difficult to quantify, and hence any benefit is difficult to quantify.

5. The only practical way (and the only impartial way) that the value of a baseline inspection can be quantified is to assess its effect on the integrity of the pipeline. This can be done by assessing precisely what the baseline inspection will and will not detect, and also comparing the defects that the baseline would detect, to those that would be detected (i.e. failed) by the pre-service hydrotest (see Section 9 and Figure 13, later).

The following Section uses the results from Section 5 to present a fitness-for-purpose assessment to determine if the baseline survey is of value.

8.3 Quantifying the Benefits of a Baseline Inspection (Versus a Pre-Service Hydrotest at a Similar Time)

Sections 8.1 and 8.2 have shown that their are both potential advantages and disadvantages in a baseline survey. Clearly, an operator must consider all the listed points and make a decision for their pipeline. This Section attempts to provide further guidance on this decision making process.

Pipelines are invariably hydrotested prior to service. If an operator is also contemplating a baseline pig survey, then the baseline must be shown to give the operator information that would not be obtained from the hydrotest, and also enhance the integrity of the pipeline throughout its life.

The sole intent of a baseline survey, and a major intent of a hydrotest, is to detect defects in the pipeline that may cause failure during service. The size of defects that a baseline survey can detect is governed by the accuracy and reliability of the pig. The size of defect ‘detected’ (i.e. that would fail) on a hydrotest can be calculated using fitness-for-purpose methods in this Section (see Figures 7, 8).

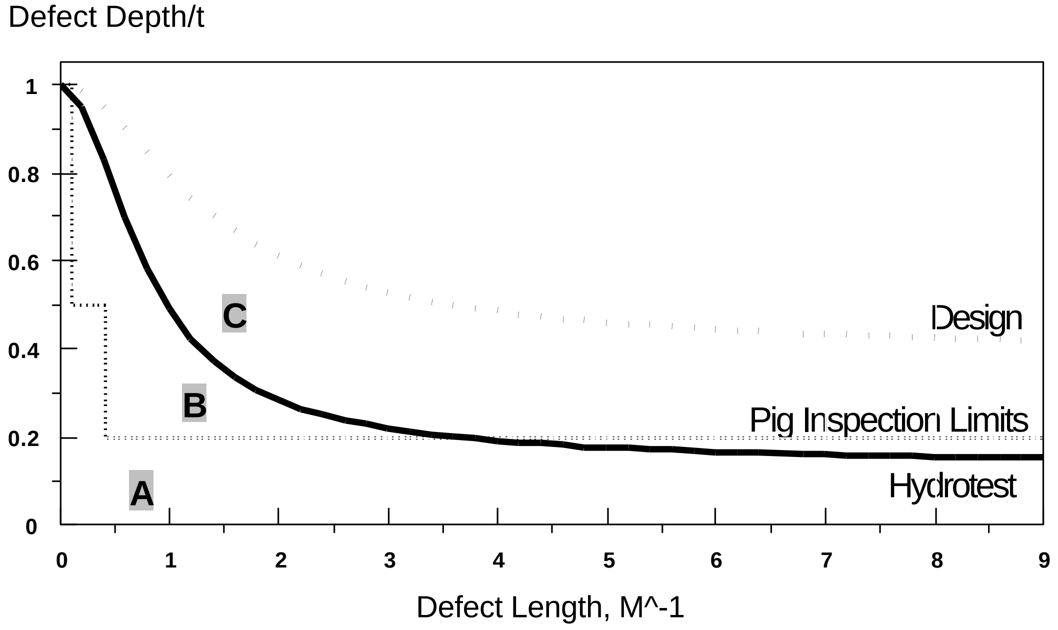
Figure 10 shows the defect sizes that would fail during a hydrotest on an offshore pipeline, and compares these defect sizes to those that would be detected by a typical high resolution intelligent pig, during a baseline survey.

The following points should be noted from Figure 10:

i. Any defects within Area A will not be detected by either the hydrotest or the baseline survey.
ii. In the unlikely event that defects exist within the area labelled ‘C’ on the chart, the pipeline will fail during the hydrotest.

Therefore, if a baseline survey is performed, the only potential benefit (over the hydrotest) will be the detection of defects which lie within Area B.

Figure 10. Defect Acceptance Charts for a 72% SMYS Line
Hydrotested to 100% SMYS



The probability of defects in area B being present in the pipeline at start-of-life needs to be evaluated. Certainly, some of the defects in this area in Figure 10 are very large, and considered ‘incredible’.

For the case given in Figure 10, the baseline inspection will detect some defects of a certain size, that the hydrotest would not ‘detect’ (i.e. fail), but these are considered incredible start-of-life defects. Therefore, for this case, there is little difference between the baseline survey and the hydrotest in terms of defects they will detect.

This conclusion, and Figure 10, will vary with different pipelines, and different pig limits, but the methodology behind it, with the reasoning given in this Section, can be used to determine if a baseline survey is needed.

9. Introducing Probabilistic Considerations

The previous Sections have used simplistic, deterministic considerations to determine pig inspection levels and frequencies, and also to assess the need for baseline inspections.

Obviously, the situation is not that simple, as there is considerable uncertainty in the calculations, their inputs, and the accuracy and reliability of the pig.

The best approach to assessing the benefits of a pig run is to use probabilistic methods that accommodate these uncertainties.

This approach requires the operator to maintain the pipeline below a specified failure probability, i.e. the pipeline failure probability is not allowed to exceed a certain level throughout the design life. Therefore, inspections are only undertaken when the failure probability approaches this specified level, and the accuracy and reliability of the pig is included in the calculations, as it will affect failure probability.

The mathematics behind this probabilistic approach is beyond the scope of this paper, but an example of the type of relationship can be illustrated on a pipeline with corrosion problems when its fluid is both flowing, and stagnant.

$$P_f\left(Pipeline\right) = \left[1-\left(1-P_{i\_flowing}\right)^{N_{flowing}}\right] + \left[1-\left(1-P_{i\_stagnant}\right)^{N_{stagnant}}\right] \qquad (9)$$

where:-

- P_f(Pipeline) = probability, either Serviceability or Ultimate, of the failure of the pipeline.
- $P_{i\_flowing}$ = probability, either Serviceability or Ultimate, for individual defect failing under flowing conditions.
- $N_{flowing}$ = Number of individual defects under flowing conditions.
- $P_{i\_stagnant}$ = probability, either Serviceability or Ultimate, for individual defect failing under Stagnant conditions.
- $N_{stagnant}$ = Number of individual defects under Stagnant conditions.

In this example, an oil pipeline is being assessed for corrosion failure, under both flowing and stagnant conditions. Two types of possible ‘failures’ are considered; an ‘ultimate’ failure where the pipeline reaches some condition where it is unsafe e.g. a rupture causes a loss of containment of the fluid, or a ‘serviceability’ failure, where the pipeline reaches a condition where it cannot be operated effectively, e.g. stressing above the pipeline’s yield strength.

The information needed for this calculation needs an estimate of the defects expected, which will require both estimation and expert judgement.

When the effect of a pig inspection is included in Equation 9, it is essential to have both an estimate of the expected defect lengths and depths (so that an inspection is not undertaken when these defects may fall below the threshold limit of the inspection tool), and the inspection tools threshold limits, and tolerances on readings.

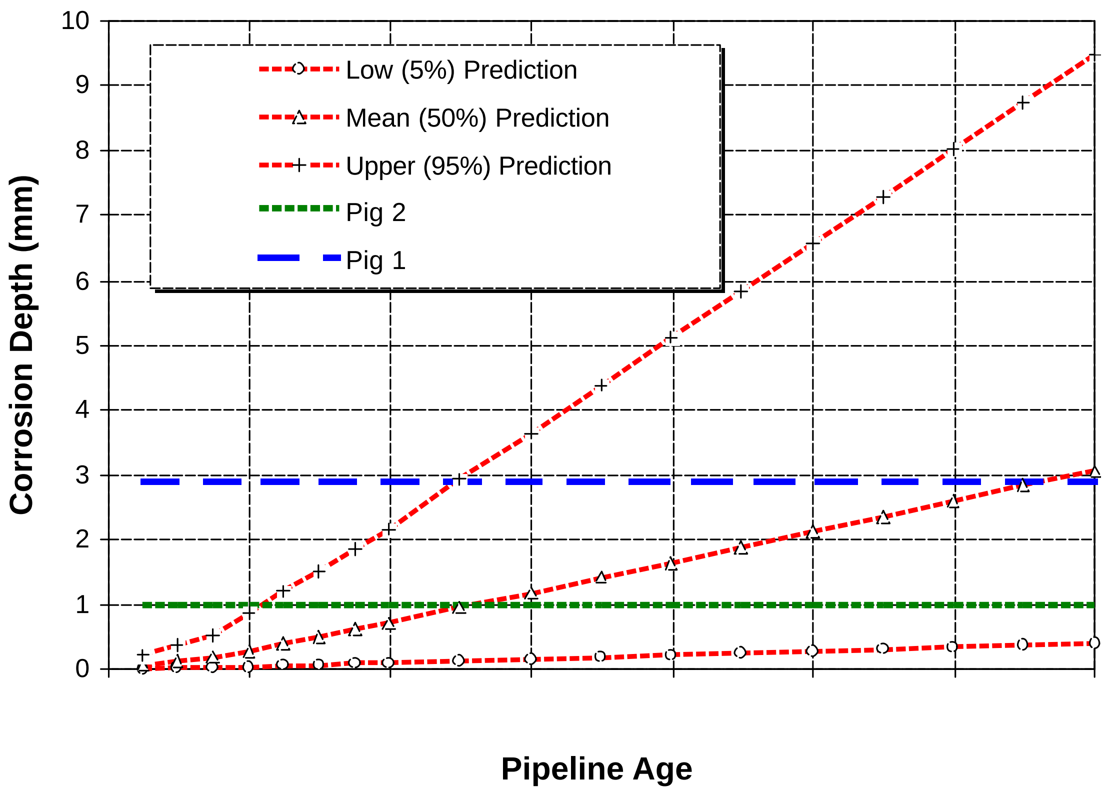
9.1 Using Probabilistic Methods to Determine Which Pig to Use

We can again illustrate the effect of differing pigs, using this probabilistic approach.

We assume two different pigs, and want to evaluate which of these pigs to use on our pipeline, which has an active corrosion mechanism. The two pigs are:

1. **Pig 1**. The detection threshold of corrosion depth of this tool for general corrosion defects is quoted as 0.1t, where t is the nominal wall thickness. These correspond to ~2.9 mm for any defect ≥ 86.1mm in length in this particular pipeline. The accuracy of this tool is quoted as ± 0.1t, corresponding to ± 2.9mm.
2. **Pig 2**. This tool has a quoted standard detection threshold depth of 1 mm, and a quoted accuracy of ± 0.5 mm.

Figure 11. Selecting the Most Suitable Intelligent Pig Using Probabilistic Methods



It is important to note that the above detection and accuracy limits are based on present inspection technology. Over time, inspection technology will be expected to increase resulting in lower threshold limits and greater accuracy. There is also the possibility that new inspection methods may be developed.

Figure 11 shows the time dependency of a predicted corrosion depth over time on the sensitivity of the two intelligent inspection tools. Three corrosion probability levels are presented in this example: 5%, 50%, and 95% percentiles. These predictions span the likely corrosion rates, and resulting depths. The 'mean' predicted corrosion growth is given by the 50% percentile

Pig 2 has a higher probability of detecting defects earlier, than Pig 1, due to its smaller detection threshold. It can be seen that Pig 2 will detect corrosion very early, and there is little likelihood of Pig 1 detecting any corrosion in this pipeline until well into the life of the pipeline.

This difference can be quantified by analysing the probabilities calculated using Equations such as Equation 9. Figure 11 does not show the results of this calculation, but Pig 2 is nearly 30 times more likely to detect corrosion early in the life of this pipeline, and then about 2 times more likely as the pipeline ages.

Figure 11 is purely an assessment of the pigs' capabilities, in terms of detectability. Operators have also to consider the 'track record' of a pig company; does the company have a good record for conducting the surveys on time, to cost, and do they deliver the results to the specified times and quality.

9.2 Using Probabilistic Methods to Set An Inspection Interval

Section 6 used deterministic methods to set inspection intervals. The inspection interval is set when a defect depth reaches a level determined using failure calculations (Section 5). The input into these calculations are usually lower bounds, or conservative estimates, with a suitable safety margin on the final calculation of failure. This means that we have a simple 'go/no go' situation, and the inspection interval is set deterministically, when the predicted defect depth exceeds a predicted 'acceptable' defect size. When using probabilistic methods, we use the same failure equations, but we input distributions for corrosion rates, etc.. Consequently, we obtain a failure probability from our calculations. This means that we need to inspect when the predicted failure probability, exceeds a predicted 'acceptable' failure probability.

Table 2. Acceptable Failure Probabilities (21, 22)

OFFSHORE	**ACCEPTABLE FAILURE PROBABILITIES (per year)**	
Limit States	**SAFETY ZONE**	**OPEN WATER**
Ultimate	10^{-5} - 10^{-6}	10^{-3} - 10^{-4}
Serviceability	10^{-1} - 10^{-2}	10^{-1} - 10^{-2}

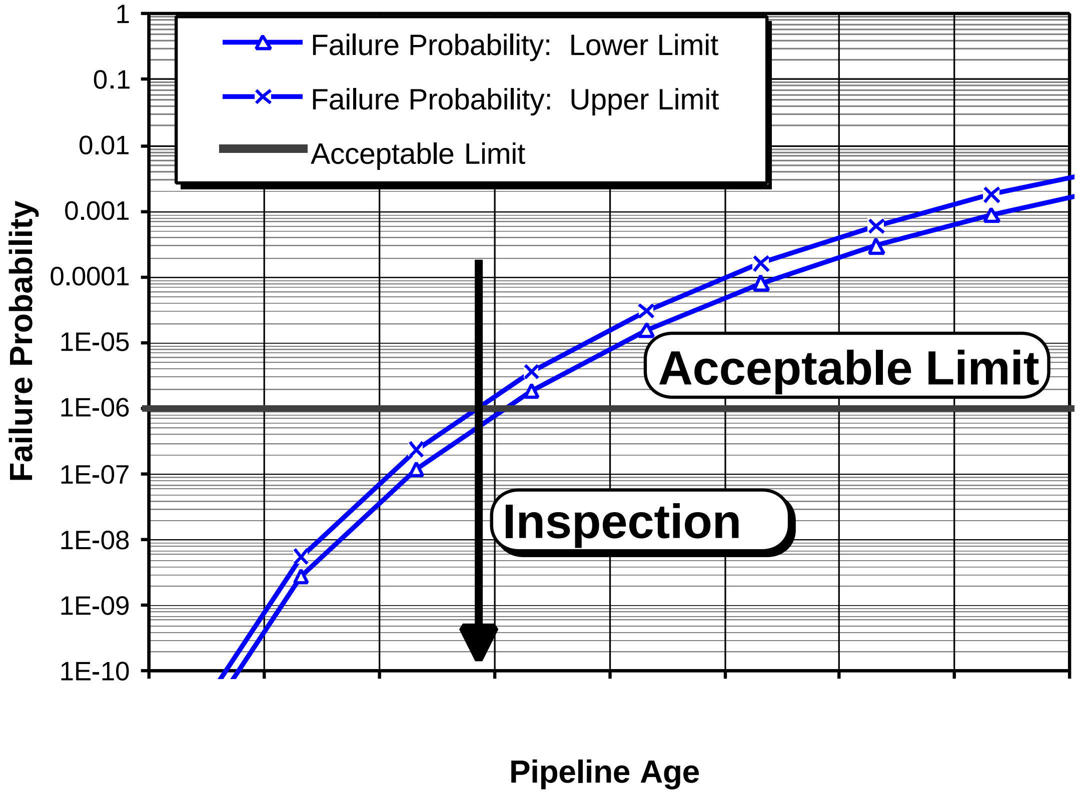
ONSHORE	**TARGET FAILURE PROBABILITIES (per km)**		
Limit States	**MORE SERIOUS (Urban)**	**LESS SERIOUS (Remote)**	**SERVICEABILITY**
Ultimate	10^{-7}	10^{-4}	
Serviceability			10^{-3}

The concept of "acceptable" failure probability is a complex issue, and deals with many aspects. It has received some attention in the literature, but much more work needs to be undertaken in this area. Table 2 shows some proposed acceptable corrosion failure probabilities, published for offshore pipelines (21), by the 'SUPERB' project (which formed the basis of the DNV 1996 Rules), and onshore pipelines for an onshore Canadian pipeline code (22).

The consequences of failure are controlled in the above table by introducing 'zones' in offshore pipelines, and 'areas' in onshore pipelines. These have the effect of limiting the number of people in the vicinity of the pipeline, and hence reducing the number of people effected by a possible failure. This gives a measure of an acceptable *qualitative* risk level. 'Acceptable' *quantitative* risk levels are used on onshore pipelines in certain countries in Europe. These risk levels (which accommodate both the failure probability and consequences of failure) can also be used to set an acceptable failure probability.

Using these type (Table 2) of acceptable failure probabilities, we can calculate the most suitable time to inspect. Figure 12 shows an example of this calculation, using the pipeline from Figure 11, and an acceptable or target failure probability of 10^{-6}.

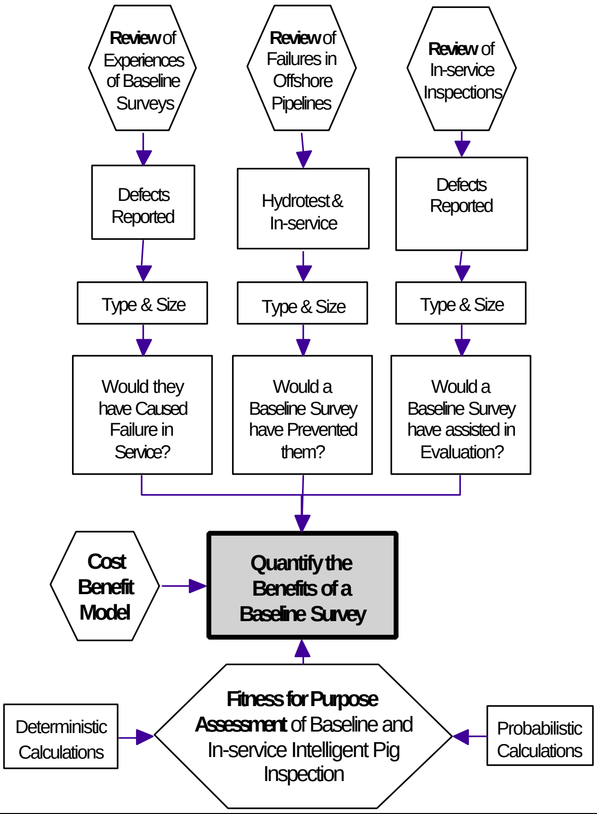
Figure 12. Setting the Time of Your First Intelligent Pig Inspection Using Probabilistic Methods



It is not usually appropriate to set the timing of a second inspection, because of the necessity to include the findings of this first inspection in the calculation of the second inspection timing.

Probabilistic methods can also be used to determine the usefulness of a baseline survey. However, further information is needed before a robust assessment can be conducted. Figure 13 illustrates the type of work needed, if the usefulness of a baseline survey is to be quantified.

Figure 13. An Evaluation of the Benefits of a Baseline Intelligent Pig Survey



9.3 Incorporating Probabilistic Methods for Setting Pig Inspection Limits and Frequencies into a Pipeline Management System

The above probabilistic calculations can be incorporated into a pipeline management system as follows:

Policy/Process - Pipeline Inspection and Controlling Corrosion using Probabilistic Methods

Organising -

i. Establish the need for a baseline survey by reference to the appropriate pipeline design code, or by the calculations detailed in Section 8.3, or by the considerations detailed in Figure 13.
ii. Establish that your Regulatory Authority will accept probabilistic methods, and agree target or acceptable failure probabilities, or an appropriate code to work to.
iii. Hire a specialist in probabilistic analytical methods, fitness-for-purpose calculations, and pipeline engineering.
iv. Appoint project manager with understanding of fitness-for-purpose methods, and intelligent pigging. Ensure an in-house engineer or manager understands the probabilistic methods used, or the implications of the results.
v. Agree expected corrosion levels and growth laws with Regulatory Authority
vi. Obtain tolerances and reporting levels from selected intelligent pig operators.
vii. Establish communication channels, authorities, and documentation system.

Planning & Implementation -

i. Conduct probabilistic calculations to determine inspection level and frequency, as shown above.
ii. Determine which pig meets your requirements in terms of accuracy and frequency.
iii. Conduct inspection at the time calculated. After this inspection, repeat calculations with any new data, to determine second inspection timing.

Measuring Performance -

i. Analyse pig report from first inspection, and determine if corrosion is present, and if it is within acceptable levels.
ii. Assess performance of intelligent pig, and ensure that it meets or exceeds specification.
iii. Assess performance of corrosion inhibition, protection, etc., systems.
iv. Assess performance of probabilistic calculations - are they predicting realistic conditions?

Review and Audit - If corrosion is above the acceptable (i.e. expected) levels, determine cause, and implement remedial measures. Review next inspection interval, and consider extra corrosion mitigation measures if corrosion is excessive. If corrosion is below expected levels, reconsider predicted corrosion growth, and future inspection requirements.

10. Conclusions

1. Pipeline Management Systems, and Pipeline Integrity Management Systems can be produced to help an operator to systematically manage and control their pipeline.
2. A Management System is a management plan, in the form of a document, that explains to company staff, customers, regulatory authorities, etc., how the company and its assets are managed.
3. A key part of these type of systems is the incorporation of intelligent pig inspection levels and frequencies. The need for, type of, and frequency of, intelligent pig inspection can be determined using fitness-for-purpose methods. These methods can use either deterministic or probabilistic methods.
4. The deterministic methods are simplistic, and it is more appropriate to use probabilistic methods, which model uncertainty in both input parameters (such as corrosion growth rates), and the pig's reporting accuracies.
5. The role of the baseline survey, and the need for such a survey, can be assessed using these methods, although its usefulness will vary between pipelines.
6. The probabilistic methods require specialists to conduct them, and it is necessary to agree 'target' or 'acceptable' failure probabilities with Regulatory Authorities.

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