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PIPELINE INTERNAL INSPECTION - WHAT A PIPELINE OPERATOR NEEDS TO KNOW.[1]

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1. INTRODUCTION

Pipelines are recognised as the safest method of delivering energy (Ref.1). However, pipelines, like all engineering plant can, and do, fail. A number of transmission pipelines have failed recently, with both tragic and spectacular effect (Ref. 2). For example in Venezuela in 1993, 51 people were burnt to death when a gas pipeline failed and the escaping gas ignited. More recently (1994), a pipeline failed in New Jersey, USA, and the resulting fireball killed one person, and injured 58 others. There have been other recent reports of pipeline failures in Russia, Pakistan, Argentina, Canada and Britain.

Pipeline failures rarely cause fatalities to the public (Ref. 1), but they can disrupt an operator's business, either by loss of supply, or by necessary remedial work. They can be extremely costly in terms of replacement and repair. For example, the BP Forties oil pipeline in the UK North Sea has had to be replaced due to internal corrosion at a cost of $250 million, and a single pipeline failure can cost tens of millions of dollars if it occurs in an environmentally-sensitive area (Ref. 3).

An operator needs to maintain a safe pipeline, and ensure it has a long and profitable life. Consequently, he must consider maintenance measures that are both cost effective, and prevent failures or large repair bills.

Internal inspection of a transmission pipeline using intelligent pigs is increasingly being used by pipeline operators as a means of both maintaining their pipelines and ensuring that their major asset has a long and efficient life. British Gas has internally inspected most of its 18,000 km high pressure pipeline system, and is now able to reduce maintenance bills. This company can now look to the future with confidence in the knowledge that it knows the condition of its (mainly 25 year old system) pipelines, and can demonstrate to Regulatory Authorities their safety, potential for uprating, and potential for an infinite design life.
This Section of the Workshop is aimed at answering the type of questions a pipeline operator should ask himself before he considers an internal inspection. The paper starts by covering maintenance and inspection methods in general.

[1] Taken from D G Jones, P Hopkins, '**PIPELINE INTERNAL INSPECTION - WHAT A PIPELINE OPERATOR NEEDS TO KNOW**', The Sixth European And Middle Eastern Pipeline Rehabilitation And Maintenance Seminar And Exhibition

2. WHY MAINTAIN AND INSPECT A PIPELINE?

Engineering plant follow a 'bath tub' type failure probability curve, Figure 1. This curve shows that during a structure's design life the highest failure probability is when the structure is new, or when it is old. This curve applies to automobiles, aircraft, etc., and pipeline operators will identify with it; pipelines have high failure rates early in life (e.g. hydrotest) and later in life (due to corrosion). An inspection of a pipeline will help to extend the low probability portion of Figure 1 - the goal for the pipeline operator being to extend the design life of his pipeline to 80 or even a 100 years, Figure 1.

3. HOW TO MAINTAIN A SAFE PIPELINE

3.1 What Methods are Available, and What do they Prevent/Detect?

Pipelines can be, and are, routinely inspected and monitored using many direct and indirect techniques. The methods are well-documented (Refs. 4-6) and aim to ensure that:
a. pipelines do not become defective or damaged ('proactive' methods),
b. damage or defects are detected before they cause serious problems ('reactive' methods).
An operator should assess the greatest damage/defect risk to his/her pipeline, then select a monitoring/inspection method to reduce that risk:

TABLE 1 : Pipeline Inspection and Monitoring Methods

DEFECTS/ DAMAGE	**MONITORING/INSPECTION METHOD (P = PROACTIVE METHODS, R = REACTIVE METHODS)**						
	AERIAL/ GROUND PATROLS	***INTELL-IGENT PIGS***	***PRODUCT QUALITY***	***LEAK SURVEYS***	***GEOTECH SURVEYS & S. GAUGES***	***CP & COATING SURVEYS***	***HYDRO-TEST***
3rd Party Damage	P	R					R
Ext. Corrosion		R				P	R
Int. Corrosion		R	P				R
Fatigue/Cracks		R					R
Coatings						P	
Materials/Construct Defects		R					R
Ground Movement					R		
Leakage	R	P		R			R
Sabotage/Pilfering	P						

(Visual examinations are not included)

3.2 Which Methods should an Operator Use and How Should they be Optimised?

A method for determining which method to use, and on which pipeline, is a 'Prioritisation Scheme'. These type of schemes (Refs. 5,7-10) are increasingly being used to guide operators on the optimum use of maintenance and inspection methods. For example, if a pipeline's major cause of damage is third party interference, increased surveillance or the introduction of a One-Call System may be appropriate preventative maintenance methods. However, if a pipeline is failing due to internal corrosion, then an internal inspection using an intelligent pig would be appropriate.

A Prioritisation Scheme considers the probability and consequences of failure within a group of pipelines (or sections of a single pipeline) by systematically assessing the pipelines' design, operation and failure history. Points are allocated for design, operation and failure history. High points indicate high risks. For example, the probability of failure due to external corrosion is evaluated by considering the quality of the pipe coating, CP system, etc., and the consequences of failure are considered by estimating the density of surrounding population, security of supply, etc.

The great advantage of this scheme is that it can:

i. rank all the pipelines within a group (or sections of a pipeline) in terms of probability of failure, and consequences of failure,
ii. determine which pipeline (or section of a pipeline) is most in need of some type of maintenance measure,
iii. determine which maintenance measure to use.

There is now no need for a pipeline operator to 'guess' which part of his system needs maintenance, and he now does not to have wait for a section of his system to show signs of deterioration. The Priority Scheme is a proactive method of setting maintenance and inspection schedules. Figure 2a shows a readout of one particular scheme. This scheme has been used to rank seven pipelines. Clearly pipeline number seven is the highest risk pipeline. Figure 2b shows the second analysis the Scheme conducts on pipeline number seven.

Figure 2b shows that this pipeline is most at risk from internal corrosion, therefore an internal inspection is necessary. Figure 3a shows the results of a re-run of the Prioritisation Scheme to quantify the effect of the internal inspection on pipeline number seven. Now, pipeline two is the highest risk, and Figure 3b shows third party interference to be the major risk to pipeline two. The operator can now consider increasing surveillance to reduce this risk.

4. IN LINE INSPECTION OF TRANSMISSION PIPELINES

4.1 What Type of Pigs Are Available?

Instrumented pigs have been in use for the internal inspection of transmission pipelines for over 20 years. They can be classified as (Ref. 11):

Utility pigs are used to assist in the operation and maintenance of the pipeline. For example cleaning pigs are used to clear wax from inside oil lines, and batching pigs are used to separate different fluids. There are a variety of 'smart' or 'intelligent' pigs that measure and retain pipeline data. Configuration and mapping pigs are used to check the geometry and location of a pipeline, but the most recent advances have produced smart pigs that can detect and measure pipe wall defects such as corrosion and cracks.

4.2 How do the Intelligent Pigs Work?

These intelligent pigs use a variety of technologies (Ref. 12), and these will be covered later in the Conference by other authors:

TABLE 2 : Technologies Used in Intelligent Pigs

Type of Intelligent Pig	Technologies Used	Function
Caliper Pig	Mechanical, Induction	Dents, Ovalities, etc.
Inertia (Mapping) Pig	Gyroscope (Inertial Navigation)	Route Surveying, Route Profile and Bends
Leak Detection Pig	Pressure Difference, Ultrasound	Detection/Location of Leaks
Burial and Coating Pig	Radiation (Neutron Irradiation)	Loss of Coating, cover and detection of free spans
Crack Detection Pig	Eddy Current, Pulsed Eddy Current, Ultrasound	Detection and sizing of cracks
Metal Loss Pig	Magnetic Flux Leakage, Ultrasound	Detection and sizing of metal loss defects

The most commonly used intelligent pigs for detecting metal loss defects use magnetic flux leakage techniques to detect defects such as corrosion pits. MFL pigs detect metal loss defects, but are unlikely to detect axially-orientated, planar defects such as cracks. However, they can, and have, detected circumferentially-orientated cracks in both oil and gas pipelines.

Other intelligent pigs use conventional ultrasonics to measure pipewall thickness. They require a liquid coupling between their transducers and the pipewall, which prohibits their use in gas lines, unless they are run in a slug of liquid (see Section 4.12) or the coupling has been attached by other means.

4.3 Can I Use an Intelligent Pig in my Pipeline?

Not always. Your pipeline must have launch and receive facilities, and the pipeline must allow free passage of the pig.

In the USA, 42% of natural gas lines and 11% of liquid lines cannot accommodate pigs because of physical limitations such as no pig traps or reduced-bore valves or other fittings (Ref. 13). An operator must consider the design of his pipeline to determine whether or not a pig can be used.

4.4 Can I continue to operate my Pipeline during the Inspection Operation?

An intelligent pig is intended to be run in an operating pipeline, therefore the pipeline need not be de-commissioned. However, most intelligent pigs are designed to operate at speeds of 3-7 mph , where pig motion is stable and onboard instrumentation can operate efficiently and safely (Ref.14). A speed of 3-7 mph is an average flow rate in liquid lines, but gas lines can operate at much higher speeds. Some pigs can operate at higher (9 mph) and lower (1.5 mph) speeds, but inspections of some gas lines may well require a reduction of pressure (unless a specially-designed high by-pass pig can be used), and are usually conducted outside peak demand periods (Ref. 14). Additionally, a pig operator will usually require a minimum pressure in the line to ensure pig passage and stability.

The use of intelligent pigs which use ultrasonics technology to detect wall thickness variations will require the use of a liquid slug to inspect a gas pipeline. This may involve de-commissioning the line, or a sophisticated procedure to introduce the slug, pass it along the line, dispose of it, and then clean the line.

4.5 When do I need to Use an Intelligent Pig?

The USA Dept of Transportation (Ref. 13) consider the following safety-related factors as criteria to decide when to conduct instrumented pig surveys: Population Density, Location relative to Ground Movement, Leak History, Type and Quality of Pipeline Coating, Known Corrosion, Age of Pipeline (including type of seam), Security of Throughput, Pipe Wall Thickness, Time from Last Hydrotest, and Time from latest Instrumented Pig Survey. USA pipeline operators have ranked (and added to) this listing (Ref. 13). In order of importance:

TABLE 3 : Reasons for Conducting an Intelligent Pig Run

CRITERIA
Leak History
Known Corrosion
Cathodic Protection History
Population Density
Type/Quality of Coating
Age of Pipe/Type of Seam
Product Transported
Environmental Sensitivity
Pipewall Thickness
Location Relative to Ground Movement
Security of Throughput
Time from Last Instrumented Pig Survey
Time from Last Hydrotest

An operator should consider all these factors, to determine the need for an inspection. These factors would automatically be included in the Priority Schemes mentioned above. Therefore, the use of a Priority Scheme is recommended.

4.6 What should I do before asking for Inspection Prices?

Inspections may at first seem costly, but they can also be very cost beneficial and improve the safety and security of a pipeline. Therefore an operator must consider a number of factors before selecting an inspection company.
An operator should have first assessed the condition of his pipeline via a Prioritisation Scheme to determine which of his pipelines needs what type of maintenance or inspection. The lines selected for internal inspection need further consideration. These considerations are detailed on Figure 4, and an operator must address and answer all these questions before asking inspection companies to quote.

4.7 How Much will an Inspection Cost ?

The price of an inspection will depend on many things ranging from pipeline design and product type, to the type of intelligent pig selected.

A general figure for a magnetic flux leakage inspection has been quoted in Reference 13 at $2,839/mile (1992 Prices). A more recent survey (Ref.14) has quoted (1992) prices for American pigging companies ranging between $650 to $2,400 per mile, with non-USA inspection companies quoting higher figures ($1,200 to $4,000 per mile). These figures hide an important difference. Intelligent pigs can be considered to be of two types (Ref. 15): First Generation or Low Resolution (able to locate defects) and Second Generation or High Resolution (able to locate and size defects).

The cost of these differing tools is given as (1992 prices):

Low Resolution - $600 to $1,200/mile
High Resolution - $1,500 to $4,000/mile

Reference 16 quotes (1991 prices):

Geometry ILI - $100 to $200/mile
Low Resolution - $450 to $1,320/mile
High Resolution - $3,000 to $5,000/mile

A pipeline operator should NEVER assume that the price quoted for an inspection is the total price of the exercise. Many inspection companies charge extra for additional analysis of defects or will recommend 'calibration digs' to check the accuracy of their pig. Additionally, an operator must take into account the cost of any expert defect assessments that might be needed, repairs to defects and associated excavation costs, etc.

Figure 5 summarises the total cost of an inspection. The cost of each exercise will depend on the pipeline, the inspection, the pig's accuracy and reliability, and the detected defects. The total cost of the inspection can be far greater than the
inspection price because of unnecessary excavations, etc. caused by inaccuracies in the older type of ('low resolution') pig (Ref. 15), or extra costs associated with the inspection method used (see Sections 4.9 & 4.12, below).

<u>4.8 Which Intelligent Pig Should I Use?</u>

The answer to this question is widely accepted as 'it depends' (Refs. 16,17). Certainly operators must be cautious of basing judgements on experiences over two years old, because the inspection industry is constantly improving (Ref. 16).

There are no obvious answers to this question. The best advice is given by Cordell (Ref. 16): '... *call suppliers and talk to other operators with similar experience, especially those who have used ILI tools within the past two years'.*

An operator can also refer to the available literature, much of which is reported in Sections 4.9 to 4.13 below, to discover the experiences of other operators.

<u>4.9 How should I choose Between Low Resolution (1st Generation) and High Resolution (2nd Generation) MFL Pigs?</u>

Low resolution MFL pigs have been available for many years and are considered to be able to locate defects and defective areas, although they have limited sensitivity to lower levels of corrosion, and usually cannot discriminate between internal and external corrosion. However, the high resolution pigs can both accurately locate and size defects (Ref. 15), and can discriminate between internal and external defects.

Reference 15 compares the total cost of low and high resolution inspections, Figure 6. These are true figures from Chevron. They show quite clearly that the reliability of the high resolution pig ensures that all defects are located and sized, allowing sensible and safe repair assessments of the defects. However, the uncertainty with defect sizing, etc. with the low resolution pig meant additional analysis and exploratory excavations. The effect was to increase the total cost when compared with the high resolution inspection.

Reference 15 gives the following advice on choosing between low and high resolution inspection:

Choose low resolution if:
- you are required to inspect frequently,
- you have a strong background in using and interpreting these tools,
- you do not plan to make repairs,
- your costs per repair are very low,
- you only need to locate and not size defects.

Choose high resolution if:
- you want to obtain an accurate baseline condition of your system,
- your lines lie in areas that would be difficult/costly to repair,
- your lines lie in environmentally-sensitive areas,
- you want to make as few repairs as possible,
- you need to be able to accurately size and locate defects before excavating.

It is necessary to emphasise that following the low resolution inspection (Ref. 15) *'the risk is that there is a distinct possibility that even with the utmost care, some severe defects could be left in the ground due to the inherent weakness of the reporting format'.*

And finally to reinforce the potential high total costs of a low resolution inspection, the experience of a Canadian company of using a low resolution pig to inspect a 179 mile pipeline (Ref. 18) in 1989 should be noted. The tool reported 1809 defects requiring excavation to validate the pig inspection. Rather than make these excavations, the company re-inspected using a high resolution pig, which showed that only 3 excavations were required.

4.10 How Reliable are Intelligent Pigs?

Reliability is defined here as the ability to *detect* defects.

Both low and high resolution pigs appear to be able to locate defects reliably, although there is some doubt about the low resolution tools (Ref. 15). However, this can be misleading. A low resolution tool may record all the defects in the pipeline, but it may also report 'false' defects, or spurious indications not worthy of investigation. This can be expensive in terms of excavations to the pipeline operator. Ref. 18 quotes an example of a low resolution tool giving 1809 defect locations, whereas a high resolution tool indicated only three.

The literature does not contain extensive data to determine the most reliable pig available, but the Danish pipeline operator, DONG, considers the British Gas intelligent pig to obtain the best inspection results on the basis of their own and other European gas companies experience (Ref. 19). Their evaluation took into account reliability.

4.11 How Accurate are Intelligent Pigs?

Accuracy is defined here as the ability to *size* defects.

The British Gas MFL intelligent pig has consistently been quoted in the literature as the most accurate and reliable tool in the market:

i. Reference 20 quotes an Italian company with experience of using a number of intelligent pigs as considering only the British Gas tool to have proven '*capability, while running through the pipeline, of precisely detecting, locating and sizing almost all the anomalies and defects which could impair the structural integrity and safety of the line'.*

ii. Reference 14 quotes a Canadian company as stating (in 1989) that only the British Gas tool can measure the depth and length of detected corrosion damage with the accuracy that meets the company's requirements, and allows the company to conduct engineering critical assessments. The same reference states that one USA operator considers the British Gas tool superior to a rival.

iii. Reference 21 states that an Australian operator in 1993 perceived the British Gas tool to be the most advanced tool with superior defect, recognition and sizing. However, even the British Gas tool, described by Shell as '*the world's most intelligent pig*' (Ref. 22) has experienced wear and tear problems in some difficult pipelines, although modifications allowed successful inspections without delaying the operator's timescales (Ref. 23).

4.12 Are Pigs Based on Ultrasonics better than the High Resolution MFL Pigs?

Some operators believe that pigs which use ultrasonics will have a superior accuracy than those which use MFL (Ref. 24). However, the literature provides conflicting data with studies showing ultrasonic pig accuracy to be greater than MFL, while other studies show MFL pigs to give equivalent or superior accuracy (Ref. 25).

Both types of pig can distinguish between internal and external defects in a pipeline but the ultrasonic tool usually requires a liquid couplant between its sensors and the pipewall. Consequently, to run this pig in a gas line would require two conventional pigs at either end of a liquid slug, usually a gel (Ref. 16). This can be a significant limitation of ultrasonic pigs, as launching and receiving these pigs, with the intelligent pig, can be difficult. More importantly, the cost of this slug is dependent on many things, but a cost quoted in the literature (for the slug alone) is $300,000 (Ref. 28).

Reference 25 reports the experiences of an operator using an ultrasonic pig in three pipelines in 1991. The operator concluded that the pig grossly overestimated internal corrosion at 100 selected locations, and concluded that *'Ultrasonic pigs require further refinement before they can be used reliably to inspect pipelines in which internal corrosion is predominant, such as lines employed in petroleum production'*. However, some operators have had good experiences with ultrasonic pigs, and recommend their use in certain situations (Ref. 17).

4.13 Can Intelligent Pigs Detect Cracks in my Pipeline?

Yes, the technology exists to detect cracks (e.g. fatigue cracks at longitudinal seam welds, or stress corrosion cracks) in pipelines.

To the authors' knowledge only British Gas has a proven intelligent pig, capable of detecting and sizing cracks. Their pig uses ultrasonic transducers in liquid filled wheels to inspect both oil and gas pipelines for cracks. This pig has run successfully in oil and gas pipelines in North America, and has a proven record of detecting a variety of cracks. It and has been described by pipeline operators (IPL and Colonial in North America) as '*an industry first which would ultimately lead to diminishing reliance on costly hydrotesting'*. The pig is fully employed during 1995, as operators increasingly become aware (through failures) of the importance of detecting cracks.

4.14 Is it Better/Cheaper to use Intelligent Pigs, rather than an In-Service Hydrotest?

Pre-service hydrotesting has been used for many years to 'prove' a pipeline's integrity. However, the in-service hydrotest only gives a demonstration of the pipeline's integrity on the day of the test. If there is an active deterioration mechanism operating (e.g. corrosion or fatigue) it cannot guarantee long term integrity, and also some defects that survive the hydrotest can fail at lower pressures at a later date. This phenomenon is known as 'pressure reversals' (Ref. 26).

The hydrotest is generally acknowledged as expensive and requires the shut-down of the pipeline for as much as several weeks (Refs. 14,17). There are many issues to be addressed before a hydrotest is conducted, Figure 7, and the total cost is far in excess of the cost of the test itself, Figure 8.

Figure 9 compares the cost of an onshore intelligent pig inspection, and a hydrotest (Ref. 14). Even when compared to the highest priced intelligent inspection pig, a hydrotest is 2.64 times higher than an inspection for an onshore line, and can be even higher for an offshore line (see Section 5.4).

4.15 Should I conduct a 'Fingerprint' ('baseline') Inspection Immediately Upon Operating the Pipeline?

Increasingly, operators are conducting intelligent pig runs immediately upon operating the pipeline (Ref. 19,24,27) but some operators do not consider them necessary, although they acknowledge an early inspection (e.g. after one year service) should be considered on pipelines where corrosion is a risk, or corrosion control is difficult (Ref. 17).

The 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. 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, 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 (Ref. 19).

4.16. When, and how often, should I Inspect?.

One of the most difficult questions faced by an operator is when to start to inspect his lines, and how often to inspect.

British Gas traditionally inspected their lines using intelligent pigs at periods ranging from 2 to 10 years, depending on the pipeline's condition, strategic value, and risk to surrounding population, and based on a Prioritisation Scheme (see above). They now assess each of their pipelines, using information from previous inspections, and calculate when next to inspect.

Methods exist that allow an operator to determine when and how often to inspect. Figure 10 outlines these methods. In the first instance, an operator assesses the cost of an inspection (See Section 4.7), and compares this cost with the cost of not inspecting (costs of failures, loss of supply, costs of repairs, etc.). Obviously, these latter costs will vary throughout the pipeline's age, and therefore, the operator should attempt to calculate the risk of failure as the pipeline ages. This requires knowledge of the failure rates of pipelines, which can be found in the literature (e.g. Ref. 2).

Inspection frequencies can also be based on recorded corrosion rates (Ref. 2,10), which many operators have for both external and internal corrosion, and Figure 10b can be re-plotted for differing corrosion rates.

Regardless of the method used to calculate inspection frequencies, it requires expert methods and staff. However, the cost savings on optimised inspections offset this additional cost.

5. AFTER THE INSPECTION - DEFECT ASSESSMENT AND REPAIR

5.1 After the inspection - what do I do next?

Inspection can reveal defects in the pipeline, and the operator needs to assess the significance of any detected defect. There is guidance in national codes (Refs. 29-31). However, only "small" (10%-12½% wt deep) gouges/grooves and plain dents (2%-6% of diameter depth) in the pipe body are allowed. Allowable corrosion is limited to localised areas in buried straight pipe. Cut-outs, or major repairs, are required for all other defects. Furthermore:

i. After a high resolution internal inspection an operator needs to determine future safe operating conditions and the remaining life of his pipeline.

ii. If an internal inspection discovers corrosion in a pipeline and it cannot be eliminated, an operator needs to decide what to do next, knowing that the pipeline will continue to deteriorate (i.e. corrode).

iii. During service, operation at an increased pressure (uprating) or an extension to the operating life can be required. An operator can inspect his pipeline to determine its condition and subsequently he needs to know its suitability for uprating or life extension.
Fitness-for-purpose methods are now available which allow the operator to relate the severity of any defect to the pipeline operating conditions. The combination of an accurate inspection and a reliable fitness-for-purpose assessment can:

i. prevent failures, loss of product and casualties,
ii. avoid unnecessary and expensive repair, de-rating or replacement,

iii. allow early low cost remedial action.

Therefore after an inspection, an expert fitness-for-purpose assessment should be conducted to allow the definition of future safe operating strategies (Ref. 32).

Generally, a strategy of repeat high resolution inspection, fitness-for-purpose assessment and repair (i.e. a turnkey operation) is highly cost effective. Reference 33 gives an example of 800 km of pipeline containing extensive external corrosion. The accurate sizing of the corrosion by high resolution inspection followed by a rigorous fitness-for-purpose assessment confirmed that less than 10 repairs, and no cut-outs or re-coating, were required. The above strategy was 40 times more cost-effective than the alternatives which were considered (complete replacement of the pipeline, repair/re-coating "as necessary").

5.2 What is a defect assessment?

A fitness-for-purpose assessment quantitatively relates the severity of a defect to the pipeline operating conditions, by rigorously evaluating brittle and ductile fracture, defect growth and crack propagation behaviour using fracture mechanics. Consequently, a fitness-for-purpose assessment may allow larger defects beyond those permitted by the (qualitative) good workmanship requirements of the fabrication code with no reduction in the safety or integrity of the pipeline. It can involve more than a few calculations. Below, we highlight three examples of pipeline defect assessments conducted by British Gas (Ref. 32):

(1) After inspection of the Total 175km, 32 inch, Frigg Line 1 South gas offshore pipeline in the North Sea, 11 external metal loss features were investigated (Ref. 24). All the features were similar (and of depths to a maximum of 48% wall thickness) and all within 400mm of a girth weld. Total established that the features were associated with the cutting-off of the field applied concrete at double-joints before replacing with stronger re-inforced concrete. The fitness-for-purpose calculations: (i) confirmed the above (all the features were predicted to survive the pipe laying stresses and pre-service hydrotest), and, (ii) confirmed that all the features were insignificant with respect to the current operating conditions, and no repair was necessary. The studies benefited from Total's excellent pipeline records (indeed, the pipe mill certificate was provided for each pipe containing a feature).

(2) After inspection of the Phillips Petroleum Company Norway (PPCoN) 442km, 36 inch Ekofisk to Emden gas pipeline in the North Sea, five cracked girth welds were reported. The largest crack was reported onshore, and was removed to confirm the presence and reported size of the crack (Figure 11). The subsequent fitness-for-purpose assessment included (i) extensive calculations (ii) extensive mechanical and toughness testing to confirm: (i) that other than the crack, there was no evidence that the weld was sub-standard, and, (ii) devising and conducting a programme of four full scale tests. This programme involved designing and constructing a test rig and conducting the world's first full scale tests of a defective girth weld subjected to internal pressure, external bending and low temperature (Figure 11). It was concluded that the remaining four sub-sea cracked girth welds have no effect on the integrity of the pipeline and that no repairs were necessary (Refs. 34-37).

(3) After inspection of an offshore pipeline, British Gas was involved in the assessment of a cracked tie-in weld in the expansion pipework at the bottom of a riser. A fitness-for-purpose assessment could not be conducted immediately because there was no information relating to the static and environmental stresses, or to the toughness of the weld. Consequently, the following was recommended and carried out: (i) a finite element stress analysis (ii) a simulated weld to be manufactured under saturation diving conditions in a hyperbaric chamber, and subsequent CTOD toughness testing conducted. A subsequent fracture and fatigue assessment was conducted to confirm the defect's insignificance.

British Gas has also fully assisted and represented Clients in discussions and presentations to their Regulatory Authorities to justify that detected defects do not require any repair or remedial action.

5.3. What should I do with a corroding pipeline?

Both deterministic (Ref. 38) and probabilistic (Ref. 39) procedures are available which provide the operator with advice on (see above):

i. the significance of the corrosion; when will it fail?
ii. when, and how often, to inspect the pipeline?
iii. is it more cost effective to recoat/repair/replace sections of the pipeline?

Deterministic procedures have been applied to the BP 169 km, 32 inch Forties oil pipeline in the North Sea (Ref. 40). The original pipeline contained corrosion and whilst fit for its original purpose, would not enable the system to operate economically as future oil demands increased. Three intelligent pig inspections and fitness-for-purpose assessments allowed a de-rating schedule to be defined which would have an impact on the pipeline capacity within three years. Consequently a new 36 inch pipeline was planned, designed, procured, constructed and commenced full production within this three year period.

Onshore pipelines with external corrosion have also been assessed on the basis of defining a future safe operating strategy. This provided the operator with: (i) a list of the corrosion which required immediate repair, and, (ii) a schedule for repairing the pipe coating at other less severe corrosion, and, (iii) a re-inspection schedule.

Deterministic methods generally use lower bound data (e.g. peak depth of corrosion and minimum wall thickness). Figure 10b shows typical results of a probabilistic assessment (Ref. 39) of a pipeline containing extensive internal corrosion. The probabilistic assessment accounts for the variation in pipe wall thicknesses and yield strengths in the pipes in a pipeline, the sizing accuracy of the inspection, the variation in corrosion rates (e.g. British Gas has assessed pipelines where the measured corrosion rates varied from 0.1 to 1 mm/year). The probability of failure increases as the pipelines ages (i.e. the corrosion increases in size). Figure 10b can be used as the basis for scheduling further inspections. There is a significant, rapid increase in the probability of failure at 20 years; clearly the pipeline should be re-inspected within 20 years.

5.4 How can I uprate my pipeline?

British Gas has developed a procedure for determining a pipeline's fitness-for-purpose for operation at an uprated (increased) pressure (Ref. 41).

It has been applied to the Phillips Petroleum Company Norway (PPCoN) 440 km, 36 inch North Sea gas pipeline from Ekofisk to Emden (Ref. 34-37) . The pipeline was commissioned in 1977. To increase the capacity of the pipeline to meet the demands of the 1990's it was necessary to uprate the operating pressure capability from 134 to 145 bar.
It was impractical to uprate on the basis of a hydrostatic re-test, as required by the pipeline code, because it is costly (63 days plus contingency shutdown), difficult, and has severe technical limitations. An alternative approach based on an internal inspection and subsequent fitness-for-purpose was proposed. This approach is not only a cheaper option, but also provides a better knowledge of the pipeline than would be possible from a hydrostatic re-test. In particular, the fitness-for-purpose assessment provides a quantitative knowledge of defect safety margins, defect growth, conceivable cracks and long running fractures. It was concluded that the pipeline could be uprated to 148 bar (higher than the proposed 145 bar).

PPCoN obtained agreement in principle from their Regulatory Authorities that the pipeline could be uprated on the basis of an inspection and subsequent fitness-for-purpose. In addition, this procedure for uprating was discussed with the ANSI/ASME B31.8 code committee and efforts are underway to allow the use of fitness-for-purpose in their revised code (anticipated in 1996). Similar code revisions are also being considered by the International Standards Organisation (ISO) for inclusion in their pipeline code (Ref. 37).

The above procedure was also applied to the Petroleum Authority of Thailand's (PTT) 425 km, 34 inch offshore gas pipeline in the Gulf of Thailand. The pipeline is successfully uprated and delivery of natural gas has reached an all-time high of 800 million standard cubic feet per day and a further increase of 5-10% anticipated (Ref. 42).

5.5 How can I extend the life of my pipeline?

A topical concern is life extension of older pipeline systems. For example, many pipelines in the North Sea and the Middle East are approaching their notional design life; operators in the North Sea are considering the abandonment of their platforms, whilst retaining their pipeline systems to service other field developments (Ref. 43). The procedure above (inspection, followed by fitness-for-purpose assessment) for uprating in-service pipelines is also the recommended method of extending the life of older pipelines. Indeed, UK. Health and Safety Executive supports this approach (Ref. 43). The above procedure should also be adopted for determining future safe operating conditions for pipelines inspected during their design life.

5.6 Do I need more than an assessment of my inspection findings?

It is not sufficient to solely assess the defects reported by a high resolution internal inspection as the basis for uprating, life extension or continued safe operation at current operating conditions (Ref. 32). All other relevant aspects must be considered and examples are:
.
-is the toughness of a gas pipeline high enough to prevent long running cracks at an uprated pressure?
-will there be a change in the design operating conditions (e.g. pipeline designed for sweet gas/oil will be required to transmit sour gas/oil in the future and an inhibitor study required)?
-is there any other conceivable future cracking mechanism?
-has an offshore pipeline been subjected to free-spans, and what is the remaining fatigue life?
-what is the remaining fatigue life of seam welds which have been subjected to internal pressure cycling?

5.7 Pipeline Repair

Pipeline repairs can be very expensive, particularly to offshore pipelines. Repairs should be both cost-effective and return the pipeline to its original (construction) condition.

Many pipeline repair methods are available to pipeline operators. However, a technically-validated repair method, and probably the strongest pipeline repair, is rapidly becoming popular around the world - this is the epoxy-filled shell repair (Ref. 44).

The epoxy-filled shell repair comprises two half shells which are joined to encircle the damage, leaving an annular gap of between 3 and 40mm. The gap is then filled with a high stiffness grout. The half shells can be either welded together, or flanged.

The repaired pipeline is extremely strong, resistant to cyclic loadings, and reduces rupture risk, because the shells prevent radial bulging (necessary for the defect in the pipeline to fail), and some stress is transferred from the defective region into the shells.

The repair is cheap - it uses shells the same thickness as the pipeline, and a simple, cheap, low pressure epoxy grout injection. The use of flanged shells obviates the need for welding, and the repair can be used to repair defects (such as cracks in girth welds) that can be subjected to high axial loads.

Full scale evaluations of the repair on a variety of geometries of pipelines and defect sizes, have demonstrated excellent static and cyclic strength (Ref. 44). It has been used for over 10 years in British Gas, and has been applied many times to oil and petroleum product pipelines in Europe, and over 90 have been applied to pipelines in the Middle East. Furthermore, versions of the epoxy-filled shell repair method for leaking defects, and defects in offshore pipelines has been developed.

5.8. Is Periodic Inspection, combined with Defect Assessment, and Selective Repairs, Cost-Effective?

NOVA, Canada have published (Ref. 45) the following data comparing three methods of rehabilitating a pipeline (1980s Prices):

TABLE 4 : The Cost of Rehabilitation

METHOD TO PROVIDE RELIABLE ASSET	**COST ($/Km)**
Pipeline Replacement	1,000,000
Repair as Necessary, Recoating	500,000
Periodic Intelligent Pigging, Defect Assessments & Repair	12,600

Therefore, periodic inspection, defect assessments based on fitness-for-purpose methods, and repair is more than one order of magnitude more cost-effective than other rehabilitation alternatives.

6. SUMMARY AND CONCLUSIONS

6.1. A pipeline operator needs to ask the following questions **before** considering an inspection:

- When, and which parts of my pipeline system, do I need to inspect?
- Why am I inspecting, and what do I want to demonstrate?
- Which intelligent pig will give me the data I need, with the right levels of quality, reliability and cost?
- What will the true inspection cost be, and will I need further services afterwards?
- Will it be cost-effective?

6.2. Pipeline maintenance prioritisation schemes are available that can assist an operator in determining which maintenance method to use, on which pipelines, and how often (e.g. Refs. 5,7-10,39).

6.3. Internal inspection of pipelines using intelligent pigs, is now a mature maintenance procedure. The MFL pig ('*the most trusted method of surveying pipelines'* (Ref. 46)) is being used in major pipeline rehabilitation projects, re-certification strategies, and safety assessments by major oil and gas pipeline operators (e.g. Refs 45, 47). The use of a high resolution MFL pig can be very cost-effective (Ref. 49) and operators have had good experience of this type of pig (Ref. 48) in finding internal and external corrosion, pitting, gouges, dents and mill defects. However, it is important to use high resolution (sometimes called 'advanced' or '2nd generation') MFL pigs, otherwise significant defects can be missed (Ref. 49).

6.4. An operator should view inspection as part of an overall pipeline integrity strategy.
A combination of internal inspection, followed by defect assessments using fitness-for-purpose criteria and selective repair, is the most cost beneficial way of rehabilitating a pipeline (Ref. 45).

6.5. Operators now recognise that the in-service hydrostatic test *'provides a limited amount of information about the condition of the pipeline at the time of test',* whereas the MFL pig provides, '*needed information about sub-critical defects presently existing on the pipeline*' (Ref. 50). A Canadian operator has reported that the use of a high resolution MFL system has saved an estimated $2.6 million (1987 prices) over hydrostatically testing a 914mm diameter pipeline (Ref. 51).

6.6. Intelligent pigging of transmission pipelines is a method of ensuring a safe pipeline, and a means of protecting your largest asset. The availability and use of intelligent pigs now means that no operator need have doubts about the condition of his pipeline.

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FIGURE 1 : 'BATH TUB' FAILURE CURVE
and extending pipelines' lives

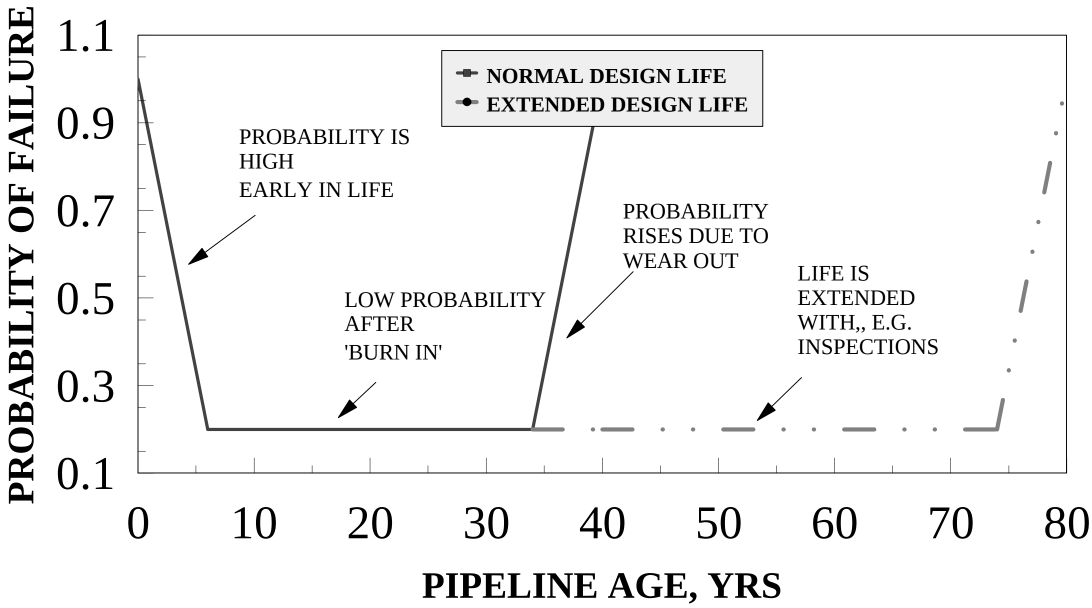


FIGURE 2a : PIPELINE RISK SCORES

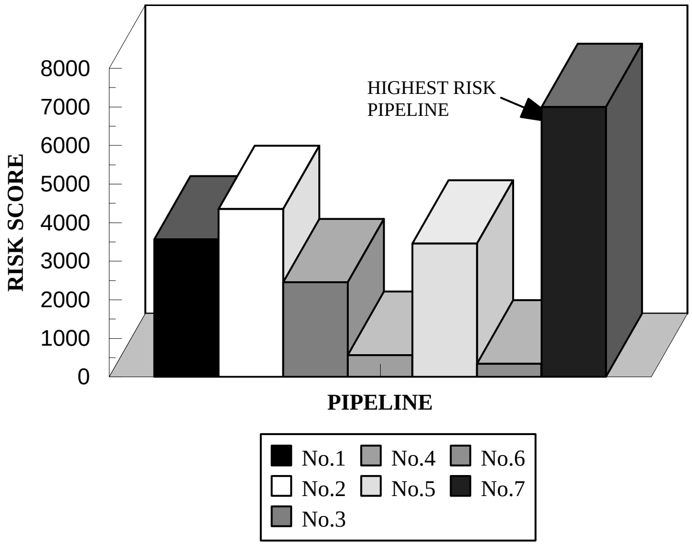


FIGURE 2b : DAMAGE/DEFECT RISK ASSESSMENT
FOR PIPELINE NUMBER 7

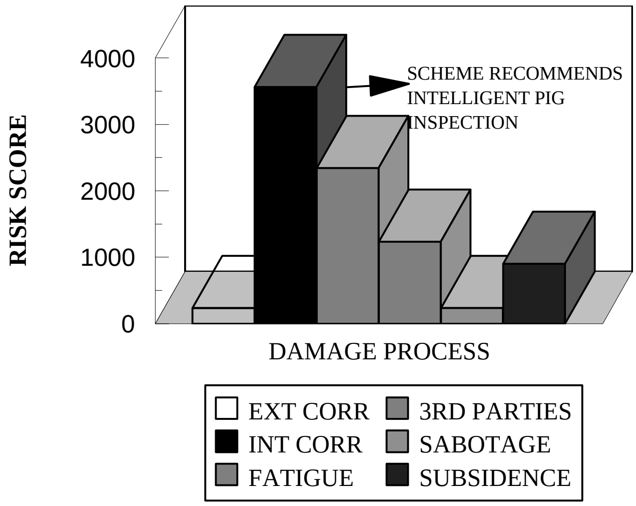


FIGURE 3a : PIPELINE RISK SCORES

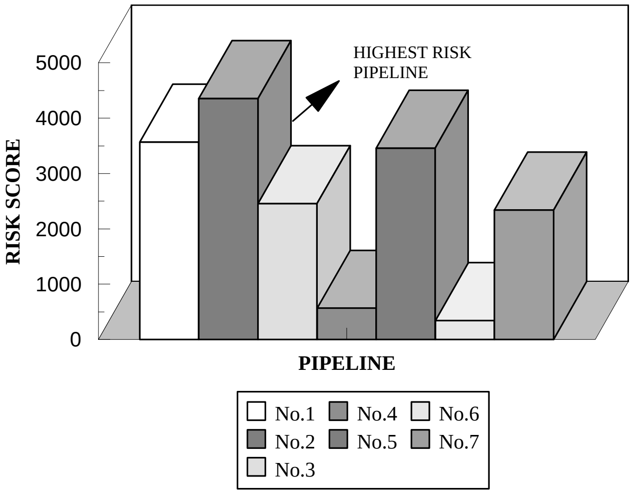


FIGURE 3b : DAMAGE/DEFECT RISK ASSESSMENT

FOR PIPELINE NUMBER 2

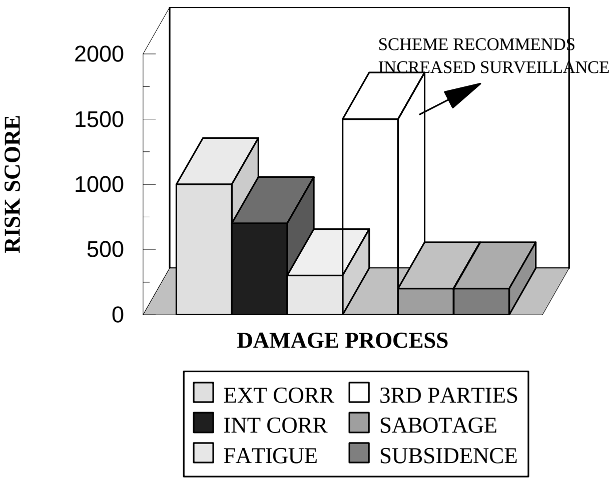


FIGURE 4 : IN-LINE INSPECTION - KEY DECISIONS AND FOLLOW-UP SERVICES

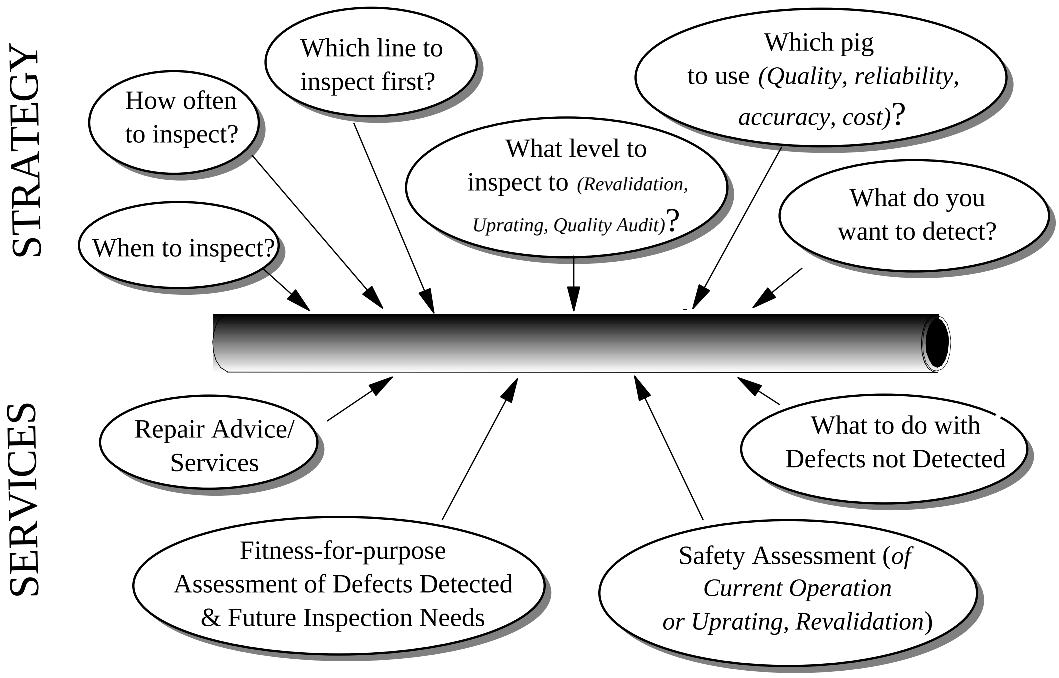


FIGURE 5 : TRUE COST OF IN-LINE INSPECTION:
MORE THAN A QUOTE

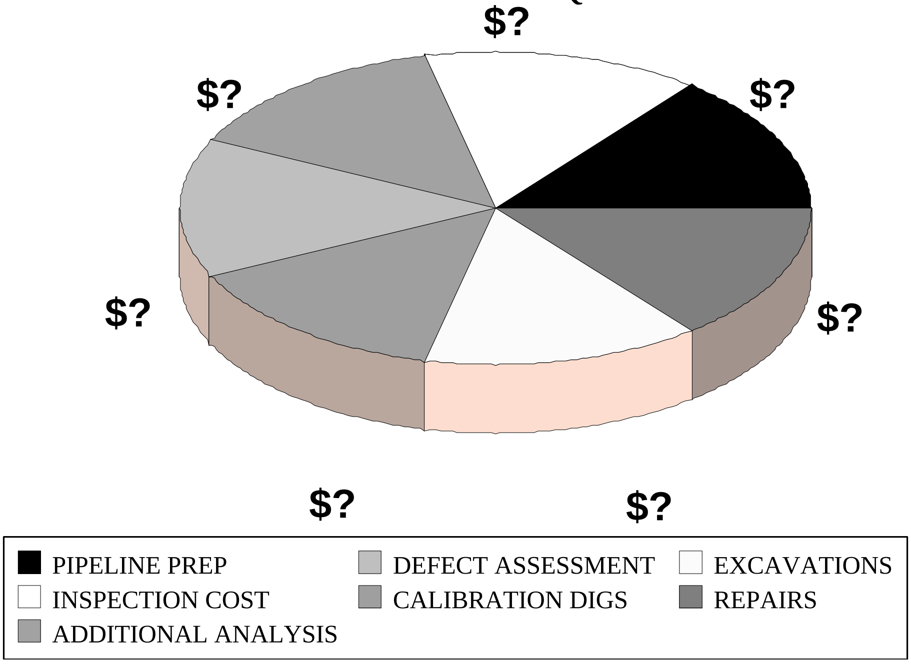
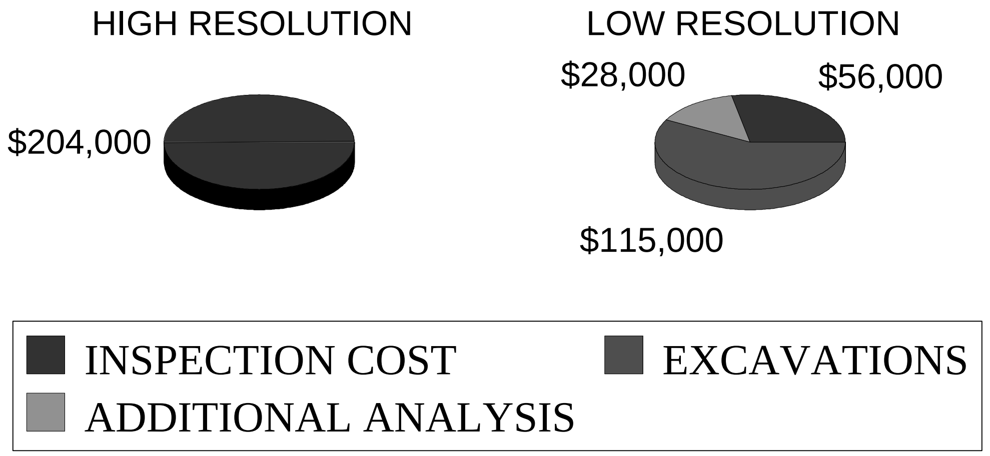


FIGURE 6 : THE TRUE COST OF INSPECTION:

HIGH Vs LOW RESOLUTION MFL



Total Cost of HR Run = $204,000. Total cost of LR Run = $199,000

FIGURE 7 : THE IN-SERVICE HYDROTEST: KEY DECISIONS AND FOLLOW-UP SERVICES

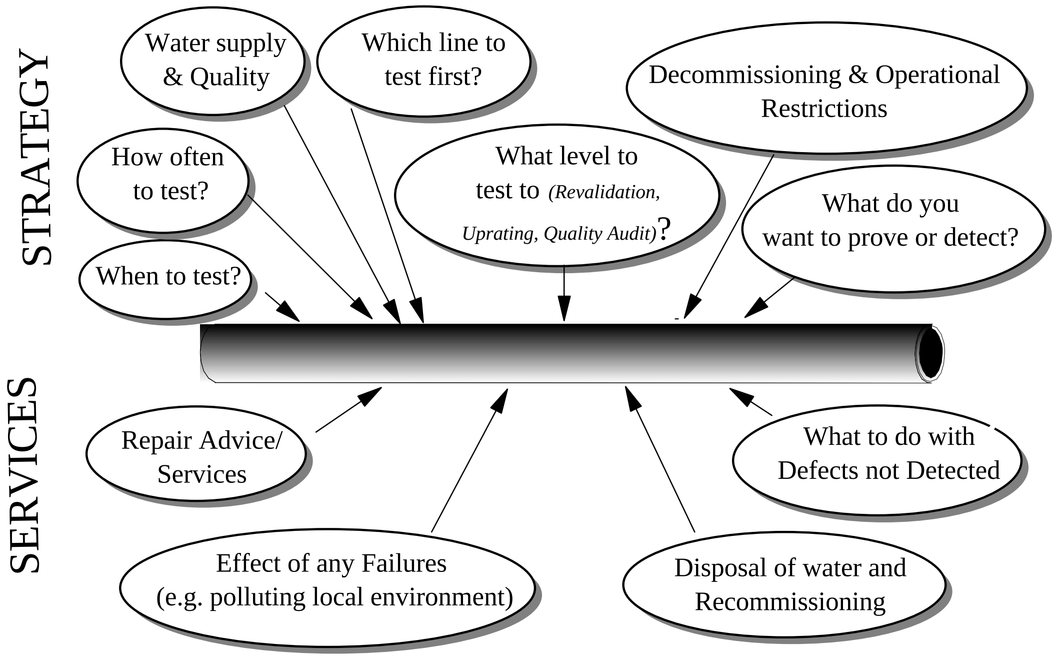


FIGURE 8 : TRUE COST OF A HYDROTEST:

MORE THAN A TEST QUOTE

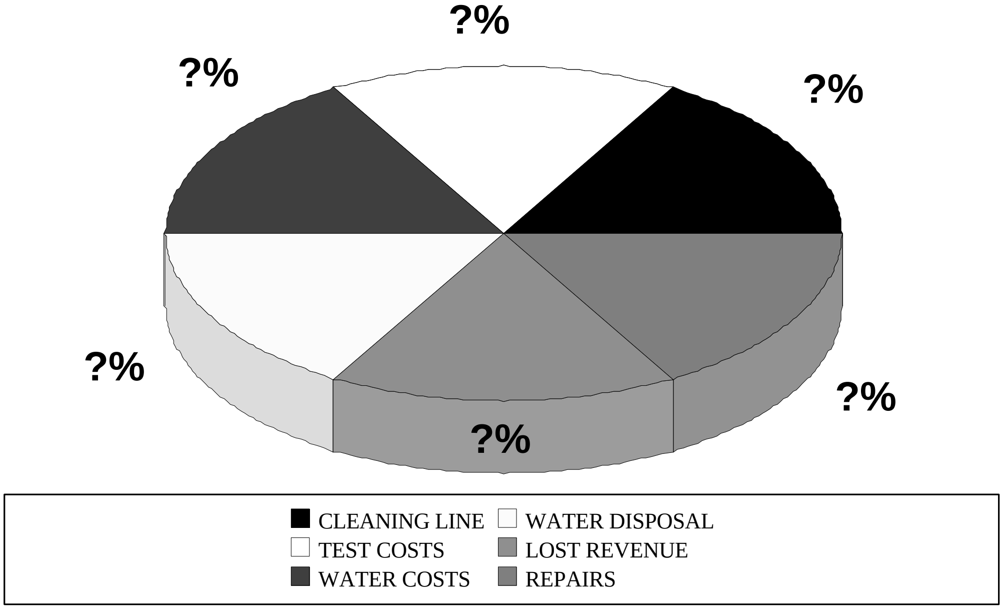


FIGURE 9 : HYDROTESTING COSTS Vs INSPECTION COST

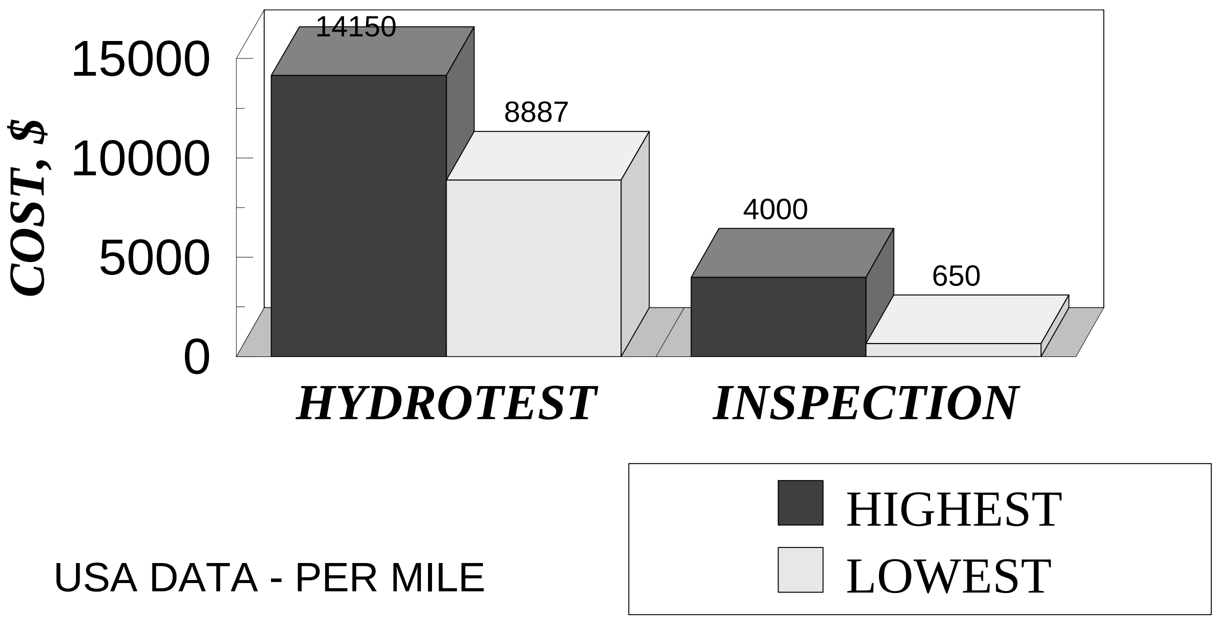


FIGURE 10a : SHOULD I INSPECT?
THE COST BENEFIT APPROACH

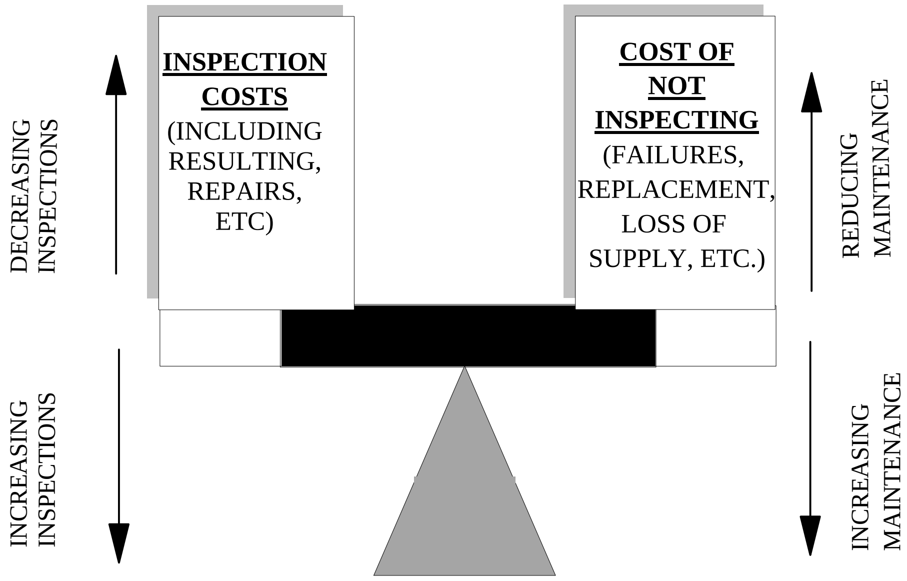


FIGURE 10b : HOW OFTEN TO INSPECT?
THE FAILURE PROBABILITY APPROACH