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Executive Summary

Offshore pipelines are an important component of the offshore energy industry that require special techniques and methods to be maintained. Offshore pipelines many times are difficult to maintain and inspect due to accessibility reasons, which hinder inspection and maintenance operations. Therefore, to be able to maintain the offshore pipeline infrastructure many energy companies are looking to develop new techniques for the maintenance of their aging pipeline infrastructure. This thesis analyzes the problem of maintaining offshore pipelines, and develops a quantitative and qualitative methodology for maintenance.

Section number one analyzes the general risk factors associated with offshore pipelines and weighs each risk factor according to probability of occurrence and also according to risk. In this first section it is ascertained that the largest cause of offshore pipeline failure is that of corrosion, and then the rest of the thesis develops methods to attack the corrosion problem.

Section two of this thesis develops a qualitative methodology for predicting corrosion loss in a pipeline, and addresses the issue of various corrosion causing mechanisms like pH and fluid flow in a pipeline.

In section three a quantitative method of analysis is developed, realizing that a lot of pipelines have similar operating and physical characteristics, and therefore data from piggable pipelines should be utilized to gain more understanding about unpiggable pipelines.

Section four of the thesis finally implements the theory behind the various maintenance techniques in an Access 97 database format. The theory explained in the previous sections is further developed and refined in order that it may be implemented into the Access platform.

Section I: Overview of Risk Assessment and Management for Offshore Pipelines

Introduction

Risk management of pipelines is becoming more advanced, and many operating and inspection companies are following the trend of computerization to assist efforts of risk assessment and management. The main task however, before any risk assessment or management model can be implemented, is to identify the failure influencing mechanisms affecting a pipeline. Once the outline of the model is known it is recommended that further subdivisions be performed in order to arrive at a more accurate picture of the risks associated with the pipeline.

It is important to note that ultimately, failures are caused either by a weakening of the system, which occurs due to flaws that are present in the system, or by too large of a force that acts on the system for which no precautionary measures have been taken. Both mechanisms can bring the system to an ultimate state. These types of failures can be safeguarded against by over-design of the system. In general this is either uneconomical or the probability of failure due to a large natural force or material failure is acceptable. Usually the acceptability of failure is dependent upon cost, and a decision is usually made after an analysis of the situation is completed.

Sometimes however the design of the system is not carried out with enough diligence, therefore leading to premature failures and weakening of the system. How well the design steps are executed and how dedicated the owner is to maintenance directly impacts the probability of failure of the system. For this reason the best way to prevent system failures is to have a checklist for design requirements that have to be met every time a new system is designed. The same rule also applies to construction and operations.

Before moving on, it is also important to have a clear definition of what failure is. Failure can be defined as having various different impacts. Some failures are catastrophic, while others are the kind where small inconveniences occur, but the costs of which add up over a long period of time. Human nature is such that it tends to focus on the short term and catastrophic failures, but not on the long-term or small failures, because these are not as obvious when a strict economic analysis has not been performed. It is important to observe all types of failure types, at least in a general sense, because both can result in significant costs to the owner. Limits should be set however, because overanalyzing the problem is uneconomical, not to mention impractical when the coefficient of variation of the data used is greater than 20%.

1.0 Risk Contributing Factors

It is important to point out that failure can occur due to either Type I errors or Type II errors. Type I errors result from a demand on the structure which exceeds the design resistance, causing the failure of the structure. In other words, these failures are the type where if a hurricane or a mudslide occurs, the force on the pipeline is greater than that for which it was originally designed, given that the design was performed correctly. Type II errors on the other hand are the type of errors where a mistake is made in the design or construction method and the mistake results in failure of the pipeline. In the example of a 10-year return period hurricane descending upon a pipeline, failure may occur due to the fact that the pipeline was accidentally designed for the 5-year storm instead of the 50-year or 100-year storm. Type II errors result from human and organizational factors and are responsible for about 80% of all failures of engineered systems. For the purpose of constructing an outline for risk factors on an engineered system, first the Type I failure-causing factors are analyzed and then the Type II failure-causing factors are incorporated into the outline. Type II failure-causing factors are predominant at every stage of design and operation, and can be summed up in one outline, which can then be applied to every Type I activity.

The major divisions into which risk factors can be divided are ***design, construction, operation,*** and ***maintenance***. These four areas are associated with the lifecycle of most engineered systems. The design of the system is carried out first, and then construction. Next, once the construction is finished, the system has to be operated and maintained. Errors in any of the four areas may lead to the failure of the system, which may occur instantly or cause slow degradation of the system. Towards the end of the system's life more and more failures start occurring, as it nears decommissioning. Figure 1.1 illustrates the hazard function of a typical engineered system, labeled BT (bathtub). Increasing and decreasing hazard functions are also illustrated, labeled IFR (increasing failure rate) and DFR (decreasing failure rate) respectively.

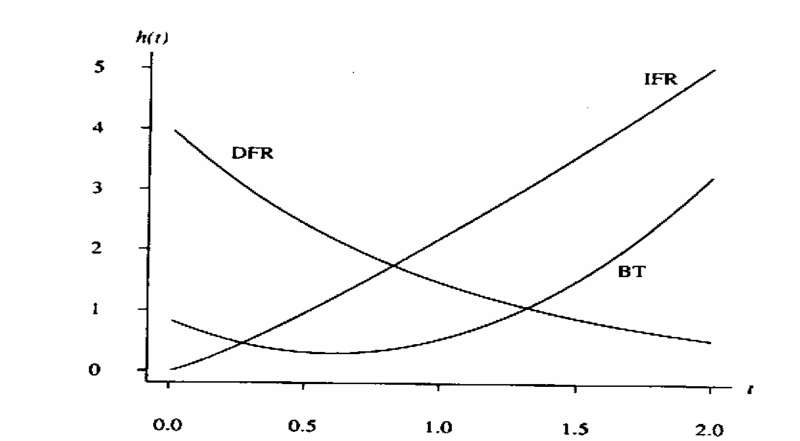

Figure 1.1: Various hazard functions.

The hazard function illustrates the amount of risk associated with an item at time t. In the case of manufactured items like pipelines the hazard function takes on a bathtub-shaped form like that in Figure 1.1, where the hazard function decreases initially and then increases as items age. Often manufacturing, design or component defects cause early failures. The period in which these failures occur is called the **burn-in period**. Once items pass through this early part of their lifetime, they have a fairly constant hazard function, and failures are equally likely to occur at any point in time. Finally, as items continue to age, the hazard function increases without limit, resulting in **wear-out** failures. For pipelines, the burn-in period is highly influenced by construction and design errors, while the wear-out period is dependent on maintenance, operation and again, design. The reliability of a pipeline is constantly dependent on how accurate the design is, therefore the greatest care should be practiced when designing the system.

2.0 Risk Contributing Factors due to Design Errors

The first step in the design of any structure, including pipelines, is determining the demand or the loading that will act upon the system. Many errors occur in the design stage due to either the inexperience of the engineer or accidental omission of certain load combinations that might affect the structure. Load combinations on any structure can become very complex due to the fact that many different mechanisms can act on the structure and each can act from a number of directions.

Design for a typical pipeline can be divided into the following major components: structural, geotechnical, material, mechanical, and hydraulic. Table 2.1 illustrates the various topics that each division of design deals with.

Design Component of Pipeline	Details
Materials Engineering	*fatigue design* (stress reversals, Miner's rule, cracking) *corrosion design* (galvanic action, stress corrosion, fretting corrosion, cavitation, coating selection) *toughness* (ability of material to withstand occasional high stresses without fracturing) *resilience* (ability to absorb and release strain energy without permanent deformation) *ductility* (material has ability to deform and elongate great deal before failure)
Hydraulic Engineering	*flow analysis* (energy losses due to friction, minor losses, energy and hydraulic grade lines, flow measurement in networks, analysis of multiphase flow)
Mechanical Engineering	*pumping power and efficiency* (brake pump power, friction power, hydraulic power) *system curves* (a plot of the static and friction energy losses experienced by the fluid for different flow rates) *valve design* (systems control issues)
Structural Engineering	*pressure vessel design* (pipe thickness required for a safe operation) *bending strength design* (free span stresses, buoyancy) *dynamic analysis* (vibration analysis due to vortex shedding from currents, earthquakes, wave action)
Geotechnical/Ocean Engineering	*sea bed mechanics and pipeline stability* (fluidization of sea-bed due to wave action, scouring, forces on bodies near sea bed, sediment transport)

Table 2.1: Major components of pipeline design. [1]

All of the design components of a pipeline listed in Table 2.1, are not equally influential on failure. Usually, the probability of failure will be highly dependent upon certain factors like complex design guidelines or unusual loading. The factors influencing the occurrence of design malfunctions are listed in Table 2.2.

Factors Influencing the Occurrence of Design Malfunctions
new or complex design guidelines and specifications
new or unusual materials
new or unusual types of loading
new or unusual types of structures
new or complex computer programs
limited qualifications and experience of engineering personnel
poor organization and management of engineering personnel
insufficient research, development and testing background
major extrapolations of past engineering experience
poor financial climate, initial cost cutting
poor quality incentives and quality control procedures
insufficient time, materials, procedures and hardware

Table 2.2: Factors influencing the occurrence of design malfunctions.[1]

Therefore knowing the design steps from Table 2.1, and knowing the factors that might cause failure in the design steps from Table 2.2, guidelines can be set up to prevent errors. Basically the questions of what, when, how, and who to check become the primary tools of finding occurrences of error in the design step. This step is called quality assurance or quality control. Table 2.3 lists some of the criteria used for quality control.

Design Quality Control Criteria	
WHAT TO CHECK?	• High likelihood of error part (e.g. assumptions, loading, documentation) • High consequence of error parts
WHEN TO CHECK?	• Before design starts (verify process, qualify team • During concept development • Periodically during remainder of process • After design documentation completed
HOW TO CHECK?	• Direct toward the important part of the structure (error intolerant) • Be independent from circumstances which lead to generation of the design • Use qualified and experienced engineers • Provide sufficient quality control resources • Assure constructability, inspection, maintenance and repair.
WHO TO CHECK?	• The organizations most prone to malfunctions • The design teams most prone to malfunctions • The individuals most prone to malfunctions

Table 2.3: Design quality control strategies. [1]

Quality control and assurance is the single most important concept exercised to keep failures from occurring. The truth is we are all human and we err, so it is infinitely important to humble ourselves and to accept this fact. This keeps the engineer honest.

3.0 Risk Contributing Factors due to Construction and Related Processes

Reverting back to the bathtub shaped hazard function, it can be noted that at the beginning of operating a system, higher probabilities of failure will be present than during the regular life of the system. For a pipeline system, a large portion of the failures early on will be the cause of incorrect design and construction. Construction, especially, is a high risk cycle in the life of the system, due to the fact that a lot of human errors can be introduced.

In the same way that the system has to be engineered, so does the construction process. However, even if the construction is engineered properly, human factors during the pipeline installation have a large effect upon the reliability of the system. During the time that a pipe design leaves the drawing board up to the point to when it is installed, several different mechanisms can act upon it that will decrease its reliability. These factors that influence reliability fall under two headings, one, shipment and manufacture, and two, poor quality control and an inexperienced work force.

3.1 Risk Contributing Factors due to Manufacture and Shipping

The manufacturing of pipes has become very refined over the years thanks to the process and quality engineers working in the manufacturing industry. Manufacturing plants today are mostly automated, which greatly increase productivity, but at the same time quality is not compromised. Robots and specially made machines perform such processes as welding and roll forming. Seamless pipe on the other hand is manufactured by heating a solid round bar known as a billet to forging temperatures (2000-2300 ^{0}F for steel) and piercing it with a mandrel, but again through the process of automation minimizing human error in the process. Subsequent operations with rollers strengthen, size and finish the pipe. Butt welding and seamless pipe manufacture is shown in Figure 3.1. [2]

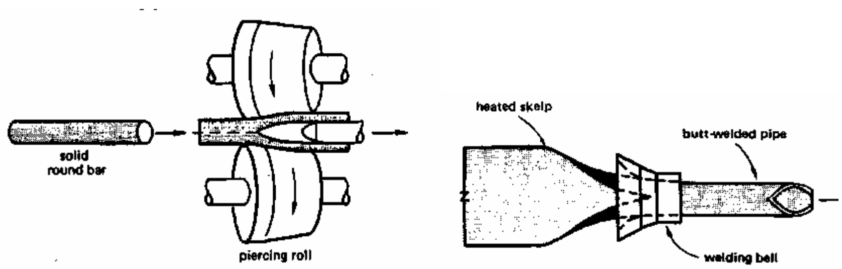

Figure 3.1: Seamless pipe and welded pipe manufacture. [2]

Most manufacturers have refined their processes and usually even introduce a bias into the reported pipe strength. Usually this bias is 2 standard deviations from the reported strength. Therefore if the reported yield strength of the steel is 60,000 psi and the coefficient of variation is 8%, the standard deviation of the steel strength is 60,000 x 0.05 which is equal to 4,800 psi. Therefore the true yield strength is equal to 60,000 + 2 x 4,800 or 69,600 psi. Manufacturers in the United States are held responsible for their product, and have a responsibility to be honest with the public. Therefore the proper regulations and methods are in place when items are manufactured in the factory, but when the welding has to be performed on a barge, a lot of new variables are introduced.

Mistakes also occur when a shipment has to be delivered. The process of shipping usually involves two major activities where a potential exists for risk. First, after being manufactured, pipe is loaded onto truck beds, a process during which it can be damaged or dented. If the pipe is manufactured as one piece and wound upon a reel that stores the pipe until it is unfurled and ready to be installed, then the risk of damage is greatly reduced. The bottom line is that at the shipping stage, if the manufacturer is not careful enough, dents and scratches may be introduced onto the pipe surface, altering the structural properties of the pipe before it is installed. If there is a special coating requirement on the pipe, inside or outside, care should be taken at this point not to damage it.

Once the pipes are delivered to the pipe-laying barge, it is handled once again by a crane to load it onto the barge. Usually, problems are more prevalent due to handling when the pipeline consists of individual pieces, rather than of one whole reel. The point is that if handling of the pipes is not done carefully enough, then there is a potential for future problems during the life of the pipeline.

Risks Due to Manufacturing	**Risks Due to Shipping**
Using wrong manufacturing process	Incorrect handling of material
Using different type of alloying than required by specs	Exposure to harmful conditions

Table 3.1: Risk contributing factors due to manufacturing and shipping.

3.2 Risk Contributing Factors due to Construction

Once the decision has been made to build a new pipeline, and the design has been completed, the next step is to construct the pipeline. Due to the fact that construction also introduces large forces into the pipeline system, it is also important to design for construction stresses.

A differentiation between shallow and deep water has to be made, but even at depths of 150 to 200 feet (referred to as shallow water), considerable problems during construction can occur. Lately there has been a shift of production from shallow to deep water, therefore the need to have more and more flexible pipeline systems is on the rise. The increase in flexibility producing large displacements leads to higher non-linear behavior in the pipelines. There are various types of externally applied loads on the pipe during construction : 1) their own weight including the weight of coatings and the weight of the liquid in the pipeline, if any; 2) the tension force applied to the pipeline at the barge; 3) the interaction forces developed between the pipe and the stinger while the pipeline slides freely on the stinger; 4) the buoyancy forces depending on the depth of the water between a point on the pipe and the free surface of the water; 5) the forces due to the winds, waves and currents; 6) the reaction of the soil to the pipe at the sea floor beyond the touchdown point of the pipelines.[3]

The loads acting on a submarine pipeline are more numerous than those acting on many other structural systems as can be seen from the list above. The motion of the lay barge due to sea waves produces additional dynamic loads to those produced on the pipeline by direct wave interaction and it has been shown that the motion of the barge has a measurable effect on pipes especially pipes with a large diameter. The rigidity, buoyancy and the length of the stinger along with proper tensioning are very important to the protection of the pipeline from overstressing or breaking. The sea floor does not provide a solid stable support for the pipeline, and the forces exerted on the pipeline through scour, wave induced soil instabilities create undesirable stresses in the pipes. A typical pipeline laying process is depicted in Figure 3.2.[3]

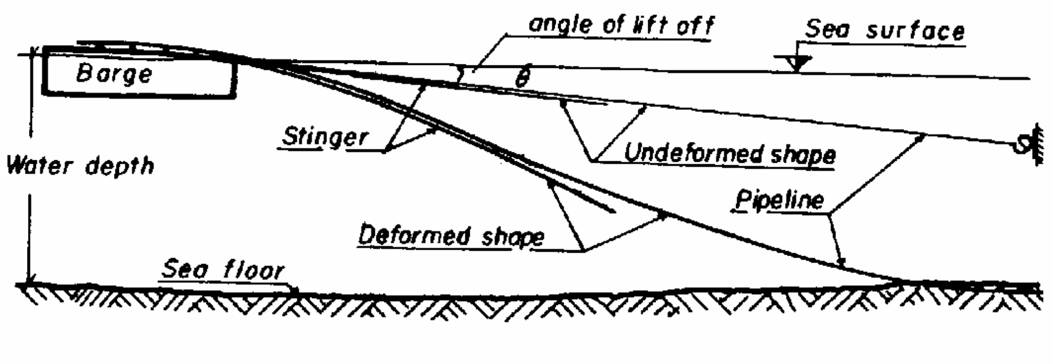

Figure 3.2: Typical pipeline laying process.[3]

During construction the pipe rolls on the guidance tracks freely, a specific lift off angle is required otherwise too high stresses in the pipe result, and the pipe slides freely on the stinger. Lengthy separation of the pipe from the stinger can produce undesirable additional stresses in the pipes, therefore it is important that the ratio of the rigidity of the stinger to the pipe is adjusted correctly. This enables the pipe to slide continuously on the stinger without lifting off the stinger along one or more intermediate intervals. Also, the pipe must separate tangentially from the stinger before or almost at the end of the stinger in order to prevent an excessive shearing force reaction exerted to the pipe by the stinger. Figure 3.3 illustrates the variation in shape of a pipeline with different tension forces applied to it during construction.[3]

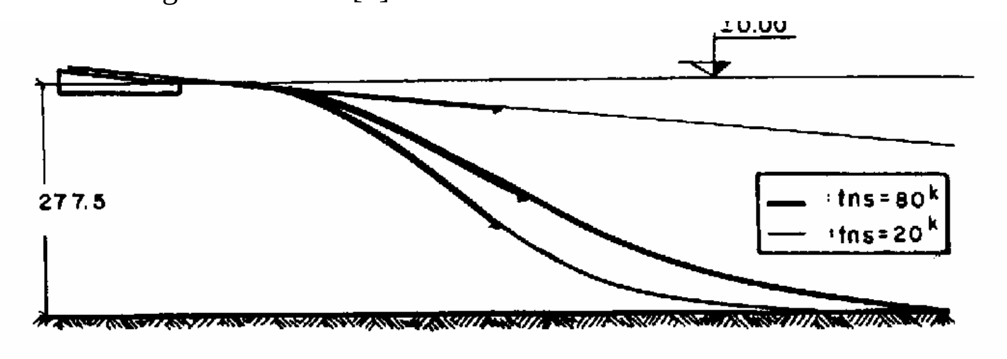

Figure 3.3: The deformed configuration of a pipeline during construction.[3]

By increasing the tension at the barge the curvature of the pipeline is reduced, and thus the magnitude of the bending moments along the suspended part of the pipeline is also reduced. The variation of the moment diagram with the variation of the tension applied to a 20 inch pipeline being constructed in 278 feet of water is shown in Figure 3.4. The increase in the tension applied to the pipeline at the barge reduces the magnitude of the maximum and minimum normal stresses in the pipes as long as the bending moment is the governing factor. Beyond a limiting magnitude of the applied tension, the tension force becomes the governing factor and the tensile stresses increase with the tension applied at the barge.

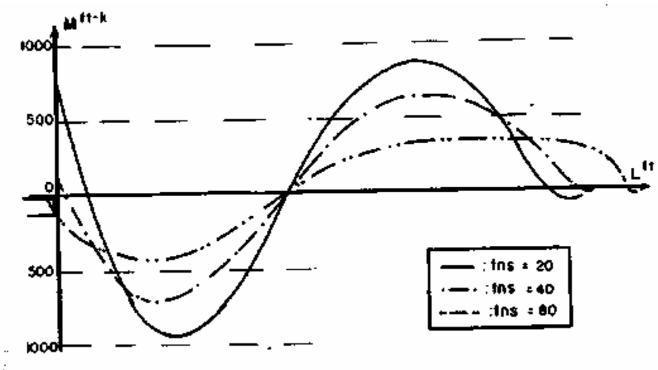

Figure 3.4: Moment diagram along the length of a pipe during construction.

During construction there are many human factor that also come into play. It is quite difficult to keep a barge steady especially in the ocean, and many times welding has to be performed under adverse conditions therefore compromising the weld strength. Welding is either performed by machines, or the pipe is seamless pipe that is unwound from a reel. It should also be noted that many of the techniques used to construct pipelines have been engineered by engineers who are subject to the risk contributing factors listed in chapter 2.

Therefore, during construction a pipeline can have various stresses introduced into it that might cause it to deform plastically or change its structural characteristics. Small flaws might develop at this time, which in the future might grow into a problem. Quality control and inspection are the two most important risk reduction factors at this stage, which highly depend upon how well the contractor has planned ahead and cares to deliver a quality product for the owner.

<u>4.0 Risk Contributing Factors due to Operation Malfunctions</u> [4]

Having considered design and construction, the third phase, operations, is perhaps the most critical from a human error standpoint. This is a phase where an error can produce an immediate failure. Emphasis therefore is on error prevention rather than error detection. To reduce the likelihood of failure due to operation malfunctions the following areas have to be evaluated.

1. Operating procedures
2. Supervisory Control And Data Acquisition (SCADA) / Communications systems
3. Drug testing
4. Safety programs
5. Surveys
6. Training
7. Mechanical devices

In each of these areas a sense of professionalism in the way operations are conducted should be evident. Also, it is also possible in this phase to practice controllability and observability to their maximum. This means observing the daily operations and improving on them as it is seen fit.

4.1 Operating Procedures

For each pipeline, it is necessary to have written procedures on how the pipeline should be operated. It is however not enough to only write procedures down, but to also practice these procedures, review and revise them in order to reduce the probability of failure. This in essence will provide a feedback loop to the operator and will function as a proactive-reactive tool for improving operations. Ideally the use of procedures and checklists reduces variability. Some examples of checklists are:

- Valve maintenance
- Safety device inspection and calibration
- Pipeline shutdown and start-up
- Pump operations
- Product movement changes
- ROW maintenance
- Flow meter calibrations
- Instrument maintenance
- Management of change

This list of course goes on and many times includes items that are not on the line but have an influence on the pipeline. The procedures for the most critical items should be developed first, and then moving to the less critical items. Procedures in cases of emergencies should also be developed to handle crisis situations.

4.2 SCADA and Communications

Part of operations consists of obtaining feedback from the pipeline. For this task supervisory control and data acquisition (SCADA) tools need to be developed. SCADA systems usually are designed to provide an overall view of the pipeline from one location. The main contribution of SCADA to human error prevention is the fact that another set of eyes is watching the pipeline operations and is hopefully consulted prior to field operations. More human involvement though, even from a control room, increases the probability of human error. The key therefore is to have effective communication between the control room and the field and to constantly check the effectiveness.

4.3 Drug Testing

From a risk standpoint, finding and eliminating substance abuse in the pipeline workplace reduces the potential for substance related human errors. Government regulations in the U.S. currently require drug testing programs for certain classes of employees in the transportation industry. This aspect of operations and the need for drug testing is self explanatory.

4.4 Safety Programs

A safety program is one of the nearly intangible factors in the risk equation. It is believed that a company-wide commitment to safety reduces the human error potential. Judging the level of commitment is however difficult. The following items can help to identify whether a company has an adequate safety program.

- Written statement of safety philosophy
- Safety program designed with high level of employee participation
- Strong safety performance record
- Housekeeping
- Signs, slogans
- Full time safety personnel

4.5 Surveys

Surveys are intended to identify areas of risk, and a formal program of surveying, including proper documentation, implies a professional operation and a measure of risk reduction. Routine surveying indicates a more proactive than reactive, approach to the operation. Examples of some surveys are:

- Close interval surveys
- Coating condition survey
- Deformation detection by pigging
- Depth of cover surveys
- Sonar surveys
- Thermographic surveys
- Leak detection

Surveys are used to collect information about the pipeline and to help management make a better decision when it comes to a certain action. Feedback of the condition of the pipeline is one of the most crucial pieces of information that an owner can acquire.

4.6 Training

Training is the first line of defense against human error and accidents. For purposes of risk reduction, training that concentrates on avoiding any failure is the most vital. The focus is on avoiding any failure of the pipeline system that may threaten life or property. This is in contrast to training that emphasizes protective equipment, first aid, injury prevention, and even emergency response. An effective training program, will have several key aspects, including common topics in which all pipeline employees should be trained.

Some aspects of training include:

- Documentation of minimum requirements
- Testing
- Topics
  - Product characteristics
  - Pipeline material stresses
  - Pipeline corrosion
  - Control and operations
  - Maintenance
  - Emergency drills
- Job procedures
- Scheduled re-training

4.7 Mechanical Error Preventers

Installing mechanical devices that prevent operator error has proven time and time again in the past to be effective in reducing risk. The premise is that even if an operator is properly trained, he might have attention lapses. Mechanical devices, such as computer logic programs, can prevent certain actions from being performed out of sequence. Other devices that can be considered as mechanical error preventers are:

- Three way valves with dual instrumentation
- Lock-out devices
- Key-lock sequence programs
- Computer permissives
- Highlighting of critical instruments

With this the discussion on risk contributing factors due to operating errors is concluded and the next topic, maintenance is summarized. It should be noted again, that most of the errors in these chapters can be attributed to human and organizational factors, which tend to be the most elusive to correct. This is highly due to the fact that individuals are unique and each will have their own special way of approaching life. Nonetheless, by proper analysis of the system, high-risk areas can be identified and errors arising from these areas can be reduced. Many times, implementation of techniques is the hardest tasks when it comes to eliminating human error. Old paradigms are difficult to break and unfortunately don’t happen overnight, but there has to be a place to start. Usually educating the operator and his crew are the best approaches to preventing errors.

5.0 Risk Contributing Factors Due to Lack of Maintenance [4]

Improper maintenance is a type of error that can occur at several levels in the operation. Lack of management attention to maintenance, incorrect maintenance requirements or procedures, and mistakes made during the actual maintenance activities are all errors that may directly or indirectly lead to a pipeline failure. It should be noted that maintenance does not command a large portion of the risk as one an independent entity, but many items in the overall pipeline risk assessment are dependent upon this factor. Therefore risk due to improper maintenance is distributed over all risk contributing factors.

Routine maintenance should include procedures and schedules for operating valves, inspecting cathodic protection equipment, testing/calibrating instrumentation and safety devices, corrosion inspections, painting, component replacement, lubrication of all moving parts, engine/pump/compressor maintenance, tank testing, etc. Maintenance must also be done in a timely fashion. Maintenance frequency should be consistent with regulatory requirements and industry standards as a minimum. There is nothing that says though that individual companies can't elect to use higher standards if they can harvest savings from their actions.

The strength of a maintenance program can be judged according to the following criteria:

1. Documentation
2. Schedule
3. Procedures

The criteria listed are in increasing importance, with procedures being the most important aspect of maintenance.

5.1 Documentation

To reduce risk a formal program retaining all papers or a databases dealing with all aspects of maintenance must exists. This may include a file system or a computer database in active use. Any serious maintenance effort will have associated documentation. The ideal program will constantly adjust its maintenance practices based on accurate data collection.

A large problem with the data collection though is that false information can be collected and false assurance of accuracy will be given. Many times, upon failure, data is obtained as to the cause of the failure, but without appropriate analysis, an initial guess might not pinpoint the cause of failure. Therefore it is important to have material testing performed upon the pipeline, from which the information can be used to improve operations.

5.2 Schedule

A formal schedule for routine maintenance based upon operating history, government regulations, and accepted industry practices should also exist in order to reduce failure risk. Again this schedule will ideally reflect actual operating history, and within acceptable guidelines, be adjusted in response to that history.

5.3 Procedures

Written procedures dealing with repairs and routine maintenance must be readily available. Not only should these exist, it should also be clear that they are in active use by the maintenance personnel. Checklists, revision dates and other such items should be looked for when evidence is sought about maintenance procedures. Procedures are necessary to ensure consistency and to help facilitate the maintenance flow. Specialized procedures are required to ensure that original design factors are still considered long after the designers are gone. A prime example is welding where material changes such as hardness, fracture toughness, and corrosion resistance can be seriously affected by the welding process.

Therefore it is important for the owner to be aware of the major risk contributing factors related to his pipeline in order that he may concentrate most of his effort in the areas where the likelihood for failure is significant. Again it is important to notice that certain paradigms are present in the industry and many individuals are not willing to change old habits. Therefore it is crucial that the benefits of a good maintenance program are demonstrated to management in order that they may leave their paradigms behind and bring innovation to the business. As Peter Drucker says, those who can't leave old paradigms behind and innovate will soon find themselves out of business.

6.0 Conclusions

After analyzing the four major areas that influence pipeline failure, Table 6.1 was constructed, based on a similar one constructed by William J. Funge in the 1979 Proceedings of the ASCE Pipeline Division Specialty Conference. Table 6.1 summarizes the major areas of risk and breaks them down according to natural or man-made. The potential damage incurred from each risk factor is analyzed and compared to its expected occurrence probability. It is important to realize that both probability and damage due to failure has to be analyzed in order to arrive at an expected cost for damage.

	Potential Hazard	Damage Potential			Probability of Occurance		
		Extensive	Moderate	Minor	Most Probable	Expected Occurance	Least Probable
Natural Hazards	External Corrosion	■			■		
	Internal Corrosion	■				■	
	Water Depth		■				■
	Waves		■				■
	Currents		■				■
	Tide & Surge		■				■
	Wind		■				■
	Marine Fouling			■			■
	Thermal Effects & Ice			■			■
	Abrasion & Chaffing			■			■
	Hurricanes	■					■
	Severe Storms	■					■
	Earthquakes	■					■
	Soil Transport			■		■	
	Erosion			■		■	
	Bottom Phenomena			■		■	
Man-Made Hazards	Ship Accidents	■			■		
	Anchor Dragging	■			■		
	Fishing	■					■
	Dredging		■				■
	Debris Discharge		■				■
	Operator Errors			■		■	
	Equipment Inadequacies	■				■	
	Equipment Malfunction	■				■	
	Sabotage	■					■
	Vandalism	■					■
	Explosion	■					■
	Fire	■					■
	Unnoticed Damage During Construction		■			■	
	Material Deficiencies		■				■
	Poor Quality Control		■				■
	Design Deficiencies			■			■

Table 6.1: Summary of risk contributing factors and their damage potential.[5]

From the natural hazards, corrosion and hurricanes and earthquakes score the highest for damage potential, but out of these two corrosion has a higher probability of occurrence, therefore warranting greater attention from the operator. On the man-made hazards side of the table, anchor dragging, ship accidents, equipment failures and sabotage score the highest as far as hazard potential is concerned, but from all these factors the most probable incidents are ship accidents and anchor dragging. Usually failures occurring from ships and their anchors are very serious and there are some guidelines that help the designer assess what type of damage can be expected on a certain pipeline due to anchors of varying sizes. Figure 6.1 depicts the effect of anchor size on ground penetration in differing soil types, which can assist the engineer in recommending how deep the pipeline should be buried. The type of traffic in the area is also important in considering the type of precautions that should be followed to reduce damage to the pipeline.

Also, from the man-made hazards side of the table, poor quality control commands a moderate damage potential, along with material deficiencies and unnoticed damage during construction, but the likelihood of these occurring are moderate to low. Usually within the system there are adequate checks to prevent errors from occurring, but of course they can always be improved, depending upon the owners choice and knowledge of each problem.

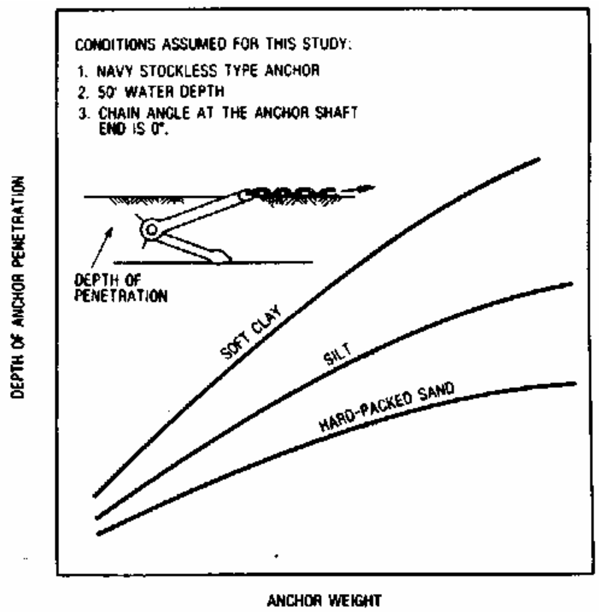

Figure 6.1: Depth of penetration v. anchor weight.

It is important to also realize that risk cannot be completely eliminated, but its frequency of occurrence can be reduced, as well as its damage potential. Also, since usually 80% of errors are human and organizational, it is important to improve operating and maintenance techniques so that these errors can be minimized.

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Section II: Development of a Qualitative Methodology for Predicting Corrosion Loss in Unpiggable Pipelines

Introduction

Corrosion of pipelines in the offshore oil industry has been a major problem for years, and many industry leaders have tried to tackle the problem from various angles. One way corrosion can be arrested is through the application of a barrier like paint or a plastic lining, that is able to separate the corroding surface from the corrosive environment, thus reducing the potential for corrosion. Corrosion inhibition can also be accomplished through the use of cathodic protection, through the use of corrosion resistant materials, or through the conditioning of the environment in which the corroding material is to be placed. Often, these solutions lose their effectiveness with time, and then the pipelines have to be inspected.

The major problem with the inspection of pipelines is that some are difficult to access, and therefore to obtain any useful information about the state of the pipeline, expensive diving operations are needed. Some pipelines can be accessed through the use of “intelligent pigs”, that are able to use magnetic flux leakage sensors to gather information about the state of the pipeline. Other pipelines are too small for the pigs, or they have such a geometry that pigs can’t maneuver easily along the pipeline’s length.

Therefore to save money, and to reduce the risk of accidents caused by the failure of corroded pipelines, it is important to be able to predict the extent of corrosion in any specific pipeline without having to inspect the pipeline manually. For pipelines that can be pigged, the task of determining the reliability of the system is straightforward, while the task of determining the reliability of an unpiggable pipeline runs into several obstacles.

This report will focus on obtaining the reliability of both piggable and unpiggable pipelines, as well as on obtaining the burst pressure of a corroded pipe. By knowing the capacity, the demand and the standard deviation of the capacity and the demand, the reliability of a pipeline system can be found. The key component for assessing the pipeline’s reliability is to correctly determine the corrosion loss in the pipeline, and then calculate the capacity of the pipeline.

Throughout the course of the research a continuing effort will be made to correctly assess the corrosion problem of ferrous compounds in various environments. As additional information is obtained, the model will be updated periodically. By correctly determining the corrosion rate in a pipeline, along with the allowable pressure that the pipeline can be operated at, accidents can be avoided, and pipelines can be kept in service longer through the application of preventive maintenance.

1.0 Corrosion Rate

Corrosion is a major problem for the engineering industry, and the potential for savings that corrosion control can provide is constantly on the rise. Industries are realizing that by controlling the corrosion problem through practicing preventive maintenance, more can be gained than by neglect of the problem.

The key to understanding the corrosion problem is to be able to accurately predict the nature of the reaction taking place at the interface of the corroding material and the environment. Careful experiments and meticulous records of the results of these experiments have to be made. An empirical process would result in the best solution to the corrosion problem, but the experiments would have to be case specific. Also, enough of these experiments have to be performed to build up a significant population, which could provide a reasonable confidence limit. This approach is both time and labor intensive, and costs money. Therefore the method used to derive a representative formula for the corrosion rate of ferrous compounds, was to fit a curve to existing data and then to calibrate the equation of the curve for various environments. As more and more data is gathered, the equation can be calibrated better and better.

1.1 Derivation of the Corrosion Loss Equation

According to various published sources, the corrosion loss with time in ferrous compounds takes the shape represented in Figure 1. This curve is similar to an n^{th} degree polynomial, and the equation of the curve can be derived through the process of curve fitting. The problem with a polynomial equation though is that it is case specific, unless the constants and the powers are left as variables. Also, the more degrees the polynomial has the more accurate it is, but this would result in more terms. When the variables are introduced into the problem, the task of how to chose the variables becomes the main concern. The selection of the variables will highly depend upon the environment where the metal is placed. This requires the individual applying the equation to know a lot about where the corrosion loss is to be evaluated, sometimes know more than is humanly possible.

Therefore the polynomial solution was rejected and a different approach was used. It can be seen in Figure 2 that a polynomial solution can be approximated by the combination of a logarithmic function and a linear function. After some trial and error, Equation 1 was derived. This equation has a component that is logarithmic, along with a power function, which provide

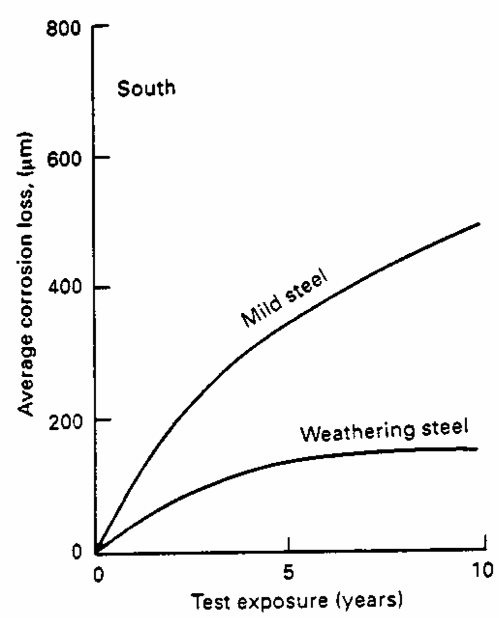

Figure 1: Typical corrosion loss curve. [8]

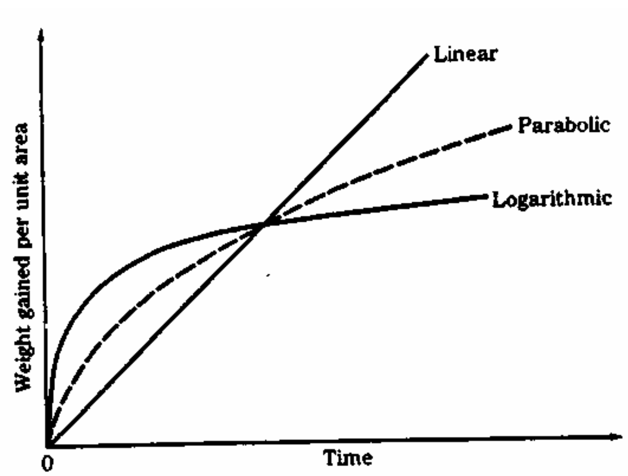

Figure 2: Oxidation rate laws. [9]

the general shape of the corrosion loss curve. The exponential term and the inverse t term in the equation only control the corrosion loss for the first couple of years and then the terms decay to a value of 1 with higher values of t.

$$CorrosionLoss = \left[1 + e^{(1-Nt)}\right]\left[\log(1+t)^{P}\right]\left[1 + \frac{1}{(1+t)}\right]\left[t^{\frac{1}{3}}\right] \qquad \textbf{EQ. 1}$$

In Equation 1, the variables N and P serve as shaping parameters, and depend upon the type of environment where the corrosion loss is being calculated. The variable t in the equation is measured in years.

Once the general form of the corrosion loss is known, the equation has to be calibrated in order that it may be applied to any specific case. The goal of this research however was to obtain a bound on the corrosion problem in pipelines and risers, therefore the effort of calibrating the equation was focused around this area.

1.2 Calibration of the Corrosion Loss Equation

To calibrate the corrosion loss equation, several references [6, 8] were used to supply corrosion loss data. The collection of data from these sources has been tabulated and is included in Appendix A. Most of the data available is for a limited number of metals, therefore the effort of calibration was focused around the type of metals on which there is considerable information. These metals include iron, mild steel or carbon steel, low alloy steels, stainless steels, and nickel iron alloys.

One drawback of using the existing data is that not only is this data for atmospheric corrosion, but the numbers supplied are for various environments, various exposure times, and sometimes values of either corrosion loss or corrosion rate are given. For the corrosion loss data, Equation 1 was applied, and a fit of the curve for the value provided was accomplished through trial and error. Sometimes more than one value of P and N were able to fit the curve for the existing point, therefore all possible combinations of P and N were calculated and then averaged.

For the corrosion rate data, the same approach was used as with the corrosion loss, but first the equation for the corrosion rate was calculated. The corrosion rate equation is simply the derivative of the corrosion loss equation, and takes the following form:

$$CorrosionRate = \left[1+e^{(1-Nt)}\right]\left[\log(1+t)^{P}\right]\left[1+\frac{1}{(1+t)}\right]\left[t^{\frac{1}{3}}\right]\left\{\frac{1}{3t} - \frac{1}{(1+t)^{2}+(1+t)} + \frac{\log(e)}{\left[\log(1+t)\right](1+t)} - N\frac{e^{(1-Nt)}}{1+e^{(1-Nt)}}\right\}$$

EQ. 2

Again, for various values of the corrosion rate corresponding to certain exposure times, the curve was calibrated to fit the data point available, and when all the possible combinations of P and N were obtained, the mean was calculated. The results for the various mean values of P and N are tabulated in Table 1.

*VALUES FOR ATMOSPHERIC CORROSION	IRON	MILD CARBON STEEL	LOW ALLOY STEELS	STAINLESS STEELS	NICKEL IRON ALLOYS
Mean "P"	7.48	15.03	9.38	0.47	16.90
Mean "N"	3.00	3.48	1.90	~	~
Coefficient of Variation of "P"	32%	103%	81%	67%	88%
Coefficient of Variation of "N"	94%	124%	75%	~	~

Table 1: Results of statistical analysis performed on fitting parameters P and N.

Due to the fact that only a limited population was available to obtain the results tabulated in Table 1, several adjustments to the values of P and N for the various metals was needed. With increasing values of P, the corrosion loss or rate increases, but it is well known that nickel iron alloys have a lower potential to corrode than mild steels, therefore the value of P for nickel iron alloys in Table 1 can't be correct. Very little data was available for all the metals except mild steels, therefore the value of P for mild steel was retained, while the values for the other metals were adjusted around this value.

The value of N does not influence the corrosion rate or loss at large time values, therefore this parameter does not play an important part in the result of long term analysis. The value N however is important if only the short-term corrosion effects have to be calculated. In this case larger values of N tend to reduce the corrosion loss at the early stages of corrosion, while lower values of N result in a sharp rise in the corrosion loss. An illustration of how values of N influence corrosion loss can be seen in Figure 3.

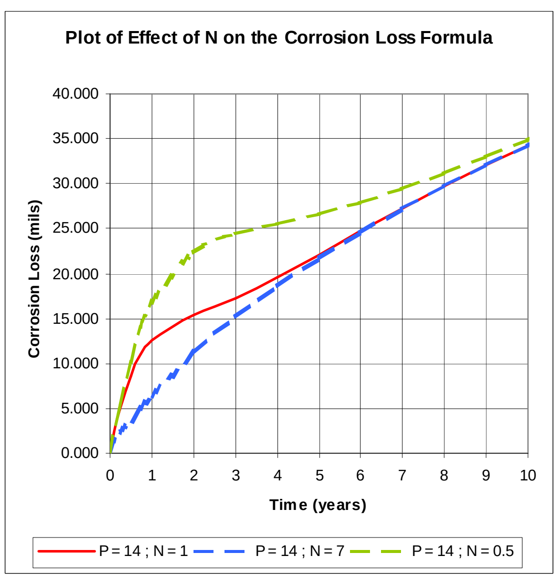

Figure 3: Effect of N on corrosion loss.

To finalize the standard values of P and N for various metals, intuitive judgement and general knowledge of the metals was used. These final values can be seen in Table 2, but it must be kept in mind that the representative values in the table are for corrosion in an atmospheric environment. In a pipeline however, localized pH values can drop as low as one, and in this case the values of P and N have to be adjusted accordingly.

*VALUES FOR ATMOSPHERIC CORROSION	**P**	**N**
Mild Steel	14	1.5
Low Alloy Steel	10	2
Nickel Iron Alloys	5	3.5
Stainless Steel	1.5	7
Titanium	0.25	10

Table 2: Typical values of N and P for various materials

The graphical representation of corrosion loss for the values shown in Table 2 can be seen in Figure 4.

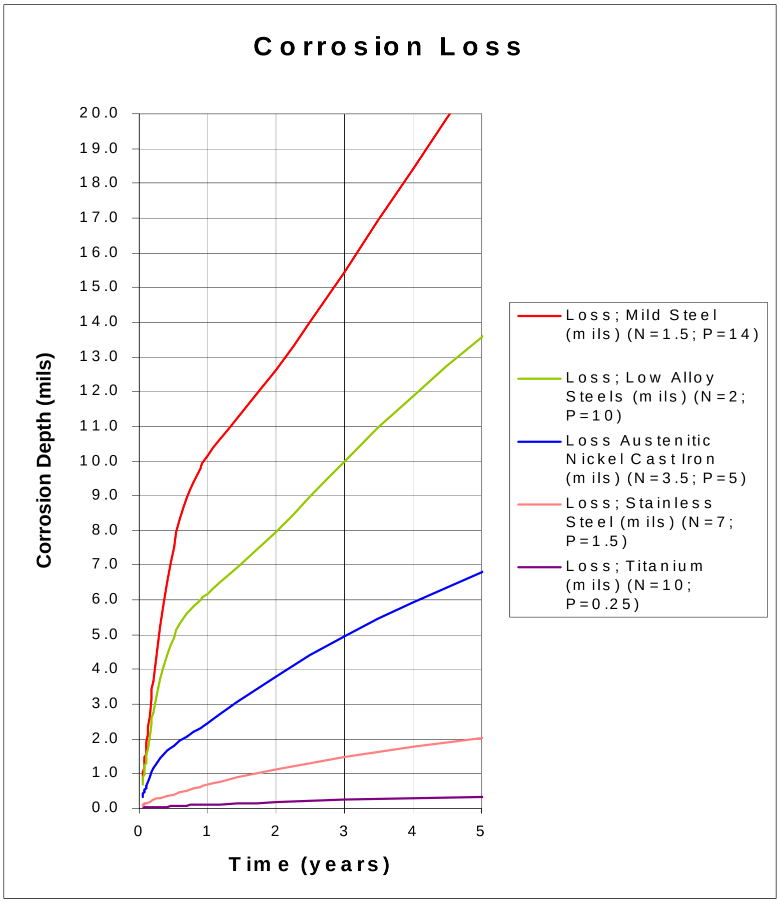

Figure 4: Theoretical corrosion loss experienced by various materials due to average atmospheric conditions.

The next step in calibrating the equation for corrosion loss is to analyze the specific environment where it is to be applied. Since there are many specific environments where the equation can be utilized, to keep the problem reasonably simple one such environment was chosen. The specific environment chosen was that in which oil and gas is transported over long distances, and where secondary recovery techniques like pumping water into the wells are utilized.

2.0 Calibration of the Corrosion Loss Equation for Unpiggable Pipelines

2.1 Biocorrosion

Before further calibration of the corrosion loss equation is possible, the major causes of corrosion in pipelines have to be examined. It has been stated earlier that corrosion is a problem in pipelines in the United States due to the fact that many of the wells are of a sour nature.

Souring of the wells can be largely attributed to microbial activity, where through the aid of bacteria, hydrogen sulfide is produced. Other sulfur compounds will also be present and all these compounds react with iron or steel when contact is made. When exposed to sulfur species, iron and steel first develop a weak protective film of mackinawite (an iron sulfide rich in iron) that later changes through different chemical and electrochemical paths to more stable iron sulfides. [7]

In all cases iron sulfides are characterized by their marked cathodic effects on the hydrogen reduction reaction, which leads to an increase in the corrosion rate. In many cases the biocorrosion process is related to the passivity breakdown by metabolic products having aggressive characteristics which are introduced into the medium by the activity of sulfate reducing bacteria (SRB). Also, other anions able to facilitate localized corrosion are frequently present in the environment, such as the widely distributed chlorides that enhance the aggressiveness of sulfur compounds. [7]

The biocorrosion attack can be attributed to the capacity of the bacteria to uptake hydrogen by the means of their enzymatic systems (hydrogenase), which in turn produces ferrous sulfide and ferrous hydroxide, corrosion byproducts. The three elements of biocorrosion are illustrated in Figure 5.

It has been noticed however by certain researchers that the settlement of a bacterial film on a carbon steel surface previously coated with an iron sulfide film can diminish the spalling of this film, but cannot avoid the localized corrosion hazard. Usually corrosion affects areas where there are defects in the iron sulfide film or metal matrix. Hence, the role of environmental conditions are very important in determining the chemical structure and physical form of the iron sulfides that, in turn, condition the rate and extent of the corrosion. [7]

Overall reaction	$4 Fe + SO_4^{2-} + 4 H_2O \longrightarrow 3 Fe (OH)_2 + FeS + 2 OH^-$		
Metal	$4 Fe \longrightarrow 4 Fe^{2+} + 8e^-$	Anode	Electro-chemical cell
	$8 H^+ + 8e^- \longrightarrow 8H_{ad}$	Cathode	
Solution	$8 H_2O \longrightarrow 8 H^+ + 8 OH^-$		Electrolyte
Microorganism	$SO_4^{2-} + 8 H \longrightarrow S^{2-} + 4 H_2O$		Microbial depolarization
Corrosion products	$Fe + S^{2-} \longrightarrow FeS$	$3Fe^{2+} + 6 OH^- \longrightarrow 3 Fe (OH)$	

Figure 5: The three elements of biocorrosion.[7]

The rate of corrosion is also affected by the presence of oxygen, therefore the less oxygen present in the system the better are the chances of the metal not corroding. As a biofilm attaches to the surface of the metal, with time it grows and after a certain time period it becomes thick enough to prevent the efficient diffusion of oxygen to the metal-biofilm interface. When this occurs, at the bottom of the biofilm there are strictly anaerobic bacteria. The bacterial deposits therefore create a differential availability of oxygen at the metal surface. Note however, that sulfate can also act as a terminal electron acceptor, instead of oxygen, so eliminating oxygen from the system might not necessarily stop the corrosion process. [7] A differential aeration cell can be seen in Figure 6.

In Figure 6 the area with the lowest oxygen availability (under the deposit) is forced to become the anode in the reaction, while the area outside the deposit acts as the cathode (in this case through the microbial mucilage). The explanation of the previous statement is the following. On a microscopic scale, a metal is rarely uniform and each grain will have slightly different surface characteristics and oxygen availability from its neighbors. At any time, some of the grains will be acting as anodes while others will be acting as cathodes. A fraction of a second later, the conditions may be reversed, and these constantly changing anodic and cathodic sites explain why a metal shows uniform rusting over its entire surface. In the case of bicorrosion however, the area under the biofilm has no access to oxygen, therefore it becomes the anode. [7]

It is evident therefore that sulfate reducing bacteria act on corrosion in an indirect way, due to their ability to produce hydrogen sulfide that could be used as a cathodic reactant (removes electrons from metal). This in turn determines whether an area on a metal surface will be anodic or cathodic.[1] [7]

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[1] Cathode: site on metal surface where electrons are removed

Anode: site on metal surface where metal ions go into solution

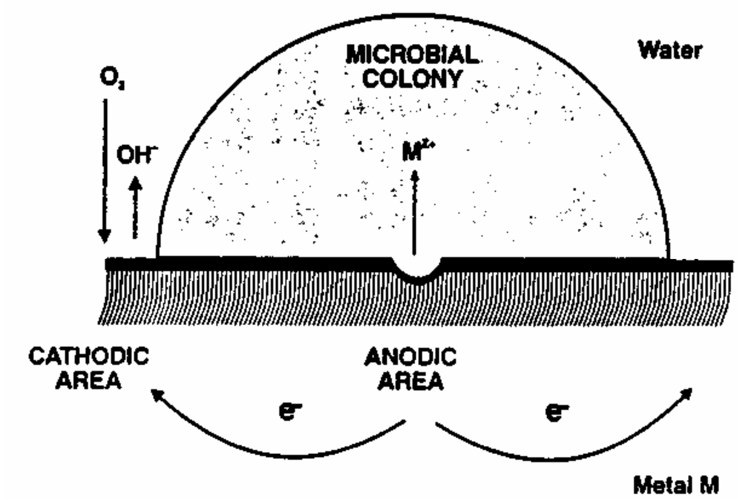


Figure 6: Simplified scheme of biocorrosion beneath a bacterial colony.[7]

2.2 Types of Bacteria Associated with Sulfate Reduction

Sulfate reducing bacteria (SRB) are prokaryotic microorganisms, which means that they lack a definite nucleus, and reproduce through binary fission. These bacteria are also heterotrophes, therefore an external source of carbon is required for their growth. Some recent studies have suggested that there is a wide range of carbon sources that these bacteria can use for their growth. Several species are able to use acetate as the sole carbon source, and in the case of marine SRB, the limiting factor for growth is not the sulfate ion but the concentration of the carbon source available in the seawater.

A list of sulfate reducing bacteria and their characteristics can be found in Table 3.

Table 3

Prokaryotic Microorganisms

Thiobacillus	Aerobic; use carbon dioxide as their main carbon source; rate of sulfur oxidation depends on the type of sulfur compound used; Need an average sodium chloride concentration of ca. 0.5 M. Frequently its aggressiveness is enhanced through the formation of microbial consortia with anaerobic SRB, or in certain environments called "sulphuretum" in which part or whole of the sulfur cycle takes place.
Thiobacillus Denitrificans	able to grow anaerobically by using nitrates as the final electron acceptor
Thiobacillus Thiooxidans	Ability to oxidize 31 g of sulfur per gram of carbon; pH on the order of 0.50 Able to produce an important amount of sulfur ot decrease the environmental pH to 0.50
Thiobacillus Thioparus	Sulfur oxidizing bacteria, generally short, thick rods ranging from 0.5 to 3.0 μm; Being aerobic and autotrophic, they are able to synthesize complex organic compounds They do not use organic compunds as nutrients; Optimal temperature for growth is 25 - 30 deg Celsius; Oxidizes thiosulfate to sulfate and sulfur; This species also oxidizes elemental sulfur to sulfate, although it is not able to oxidize sulfide. Oxidation reactions begin at pH ~ 7.8, and after completing their growth they can reach values of 4.5
Thiobacillus Concretivorus	Oxidizes thiosulfate using tetrathionate as an intermediate reaction compound and also oxidizes elemental sulfur and sulfide. The optimal pH range for growth is 1 - 4.
Thiobacillus Ferrooxidans	generally related to the iron oxidizing bacteria through its ability to oxidize inorganic ferrous compounds; It also obtains energy from thioulfate oxidation. Its natural habitats are acidic waters with high iron content, and much of the literature on this bacterium is related to the bioleaching process. It is an obligate autotroph that grows within an optimal pH range of 2.5 - 5.8 During oil recovery operations, iron oxidizing bacteria can diminish the permeability of rock-formations, and their elimination or control from injection water should be mandatory.
Desulfovibrium (non-sporulated)	Strict anaerobes growing between 25 - 44 degrees Celsius and within a pH range of 5.5 - 9.0 (optimum pH = 7.2); Approximate dimensions: 0.5 - 1.0 μm diameter and 3.0 - 5.0 μm long. Some species as *D. salexigens* require a concentration of 2.5% sodium chloride in the medium.
Desulfotomaculum (sporulated)	Strict anaerobes, and can exist as singel cells or short chains. One of the species, *Desulfotòmaculum nigrifican*, is thermophilic with an optimal temperature for growth of 55 degrees Celsius. The upper temperature range for growth is 65 - 70 degrees Celsius, they can be adapted to grow at 30 - 37 degrees Celsius. The existence for these thermophilic strains is important to the injection waters used for secondary oil recovery, where planktonic and sessile SRB are frequently found at temperatures of 70 degrees Celsius and higher. These microorganisms can cause serious problems of biofouling and corrosion in the water injection lines.

The pH range that is optimal for the different bacteria listed in Table 3, varies between a value of 0.5 to 9. The temperature range also varies from a low of 25^{o} C (77^{o} F) to a high of 70^{o} C (158^{o} F). All the bacteria represented in Table 3 can be found in the marine environment, and can be responsible for the souring of oil wells, or the pitting of steel.

The corrosion of pipelines therefore is dependent upon what type of bacteria is present in the system. According to a study performed on the producing wells of 24 oil fields it was concluded that as the temperature and the salinity of a well increases, the bacterial count in the well decreases. In Figure 7 a plot of bacterial count versus the temperature of each well from the study can be seen. [39]

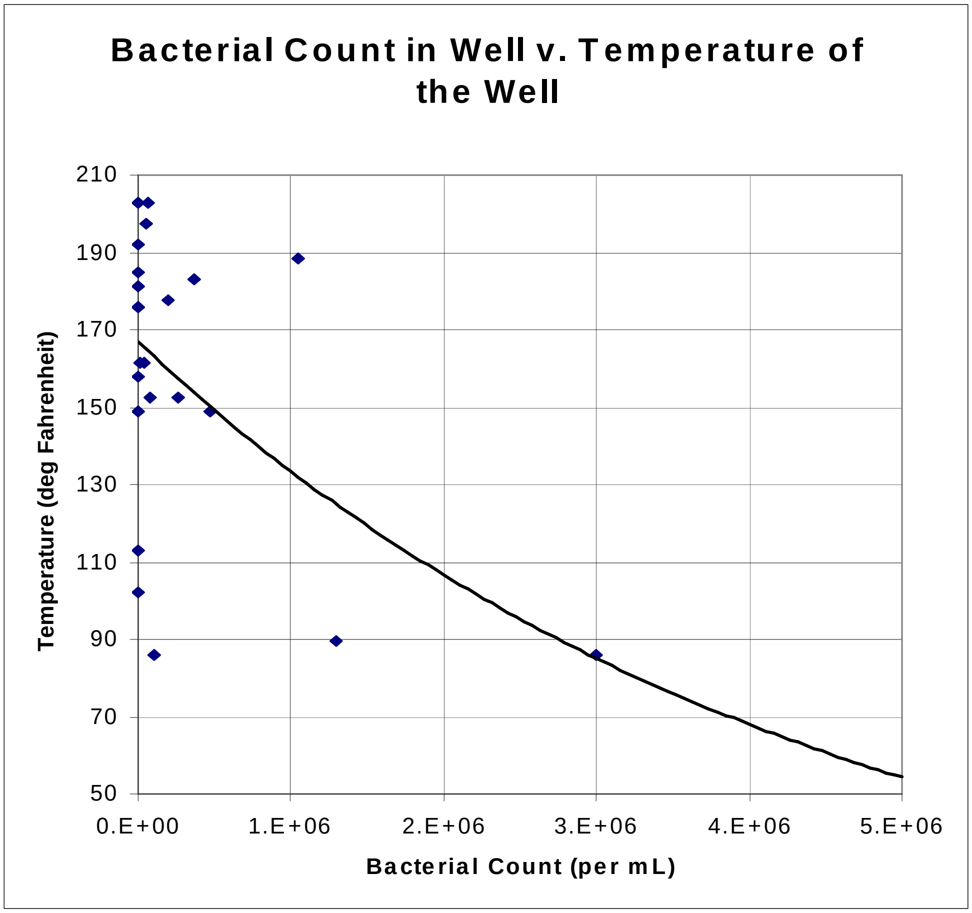


Figure 7: Plot of bacterial count versus well temperature. [39]

The conclusion from the study was that it is more likely for a low temperature well to be sour, due to the fact that it provides a more suitable environment for bacterial growth. There are two hypotheses as to how a well can become sour. The first hypothesis states that as water is pumped into the oil wells during secondary recovery techniques, the indigenous bacteria present in the well are provided with nutrients, which in turn stimulates them to grow. The second hypothesis states that since ocean water contains many types of bacteria, these bacteria when introduced into the oil well, use the nutrients in the well and flourish.

Oil wells often contain connate water that was trapped during the geological formation of the wells, and many times the water supports indigenous bacteria. When the connate water in oil wells are sampled, new species of bacteria are always found, especially in the lower temperature oil wells. This implies that life in the wells is able to flourish, therefore when water is pumped in from the ocean, the sulfate reducing bacteria in the water are able to flourish unimpeded. The question however is which bacteria are more likely to flourish?

Returning to Table 3, it can be seen that certain bacterial types have an optimum temperature and pH range where they are able to grow and flourish at an optimum rate. Most however can evolve and assimilate to their new environment. In Table 4, a list of temperature ranges corresponding to possible localized pH ranges at the surface of the metal can be seen. At the lower temperatures, the possible pH range has lower values, while at the higher temperatures, the pH ranges are near neutral. The explanation for lower temperature ranges having lower possible pH ranges is that sulfate reducing bacteria are more likely to survive at lower temperature. Therefore the more species that survive, the more likely it is that hydrogen sulfide will be produced, and the possible pH therefore will be lower.

TEMPERATURE RANGE OF WELL (^{O}C)	TEMPERATURE RANGE OF WELL (^{O}F)	POSSIBLE pH RANGE
30 – 50	86 – 122	0.5 – 5.0+
50 – 70	122 – 158	2.0 – 6.0+
70 – 90	158 – 194	4.0 – 7.0+
90 – 110	194 – 230	5.0 – 8.0
110 – 140	230 – 284	7.0 – 9.0

Table 4: Possible localized pH ranges on the surface of the metal for various well temperatures.

It is important to note however that for localized pH values to be on the order of 1 and 2, there has to be a biofilm present on the surface of the metal, under which sulfate reducing bacteria are active. Due to the effect of shear stress at the wall of the pipe this might not be possible along certain sections of the pipe, therefore pH ranges at these pipe sections would have to be adjusted.

2.3 Effect of pH on P and N

From the previous section it was ascertained how sulfate reducing bacteria might affect the value of pH at the liquid metal interface, but the question still remains as to how can the effect of pH be manifested in the values of P and N in the corrosion loss equation.

According to various sources, as the pH of a solution decreases, the corrosion rate tends to increase exponentially. A plot of the effect of pH on the corrosion rate for zinc can be seen in Figure 8.

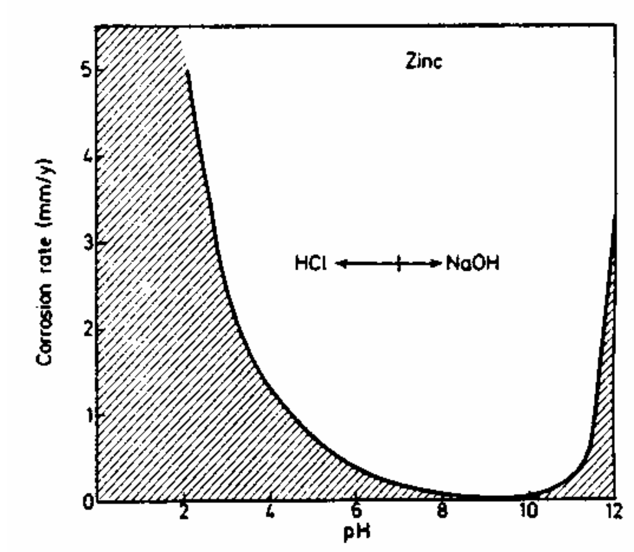


Figure 8: Effect of pH on metals relying on passive films for protection. [8]

The above depiction of the effect of pH on the corrosion rate was used as the basis for developing a rule as to how P and N are affected with decreasing pH. Since P affects the corrosion process directly the following relationship was developed: Corrosion Loss is directly proportional to P. The rule for N is the opposite, where with increasing pH, N decreases.

The key to developing a rule for exactly how pH and P and N are linked together, is to first set a limit on the corrosion loss possible during the first year that the pipe is in service. The limit set on the corrosion loss was 1.3 inches in one year. This value for the corrosion loss was then assigned as the worst corrosion loss possible after one year, for the steel with the highest value of P, mild steel (P = 14). Next the value of P needed to have a corrosion loss of 1.3 inches after one year was determined. The corresponding value of P is 1619.

Since the rule between pH and corrosion rate is exponential, the question becomes, what power does P have to be raised to, to obtain a value of 1619. The answer is 2.8. 2.8 therefore becomes the upper limit for the exponent and now the value of the lower limit must be found. According to Figure 8, the corrosion rate attains its lowest value around a pH of 9, therefore it was decided that at this pH the values of P and N would not change from their original values corresponding to atmospheric corrosion. Equations 3 and 4 illustrate the relationship between pH and the exponent to which P and N are raised.

$$\text{Exponent}_P = \frac{2.80}{pH^n}$$

EQ. 3

$$\text{Exponent}_N = \left[\frac{2.80}{pH^n}\right]^{-1}$$

EQ. 4

In Equations 3 and 4, n is equal to 0.47, and is the fitting parameter that controls what value the exponent takes at a pH of 9. For n = 0.47, the value of the exponent for P and N at a pH of 9 has the value of 1. Figure 9 shows a graphical representation of the relationship between pH and P and N.

Knowing the effect of pH on P and N, the next task is to determine how the flow regime affects P and N. If the flow in a pipe is turbulent, then there is low probability of a biofilm attaching to the sides of the pipe. Therefore the pH would not be as low as if there were sulfate reducing bacteria growing on the side of the pipe. On the other hand as the flow becomes less and less turbulent, the biofilm has a larger probability of being able to attach itself to the sides of the pipe.

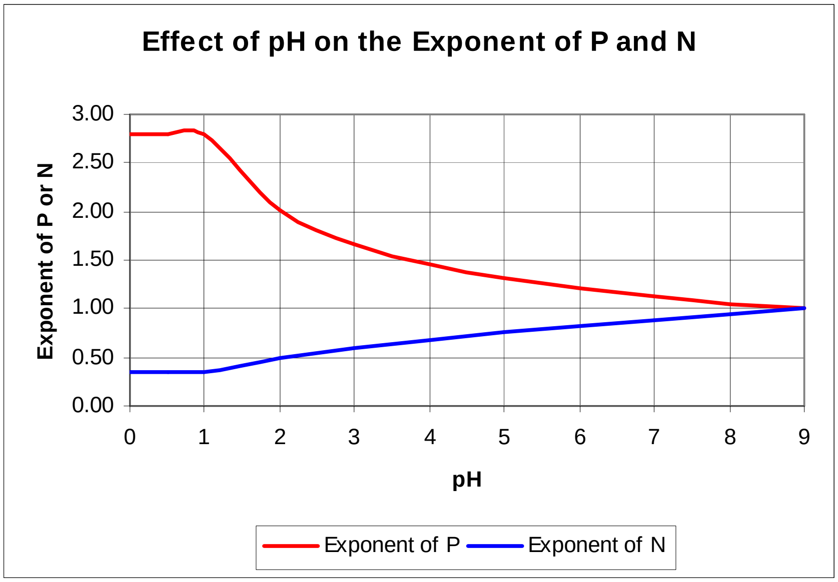


Figure 9: Illustration of the effect of pH on the power to which P or N is raised.

2.4 Effect of Flow Regime on the Value of P and N

Flow in a multiphase carrying pipe can be difficult to classify, due to several reasons. One reason is that there are at least three major types of fluids present in the pipeline. A multiphase pipeline may carry a certain percentage of oil, gas and water, each of which has a different viscosity, density, and therefore tends to move with a different velocity in the pipe. The rate of the corrosion in the pipeline is directly related however to the velocity of the media within the pipeline.

The corrosion processes in oil and gas production pipelines involve the interaction between metal wall and the flowing fluids. Relative motion between fluid and the metal surface will in general affect the rate of the corrosion. Three theories have been proposed as to how flow affects corrosion. The three ways in which flow can affect corrosion rate are, through convective mass transfer, phase transport, and erosion. For convective mass transfer controlled corrosion, the corrosion rate is affected by either the convective transport of corrosive material to the metal surface or the rate of dissolved corrosion products away from the surface. The phase transport corrosion depends on the wetting of the metal surface by the phase containing corrosive material.

The phase distribution is strongly affected by the multiphase flow. Erosion corrosion occurs when high velocity, high turbulence fluid flow and/or flow of abrasive material prevents the formation of a protective film, allowing fresh material to be continuously exposed to the corrosive environment. The multiphase flow conditions in oil and gas pipelines are also important factors influencing the corrosion and the inhibitor effectiveness. A strong relationship has been found between field measurement of corrosion rate and flow regime.[42]

Figure 10 illustrates the typical flow patterns observed in oil/water/gas flow. At low liquid and gas flow rates, the three phases flow in a smooth stratified pattern. As the gas flow rate is increased, the interface between the oil and gas becomes wavy. If the liquid flows are increased, plug flow is reached.[17]

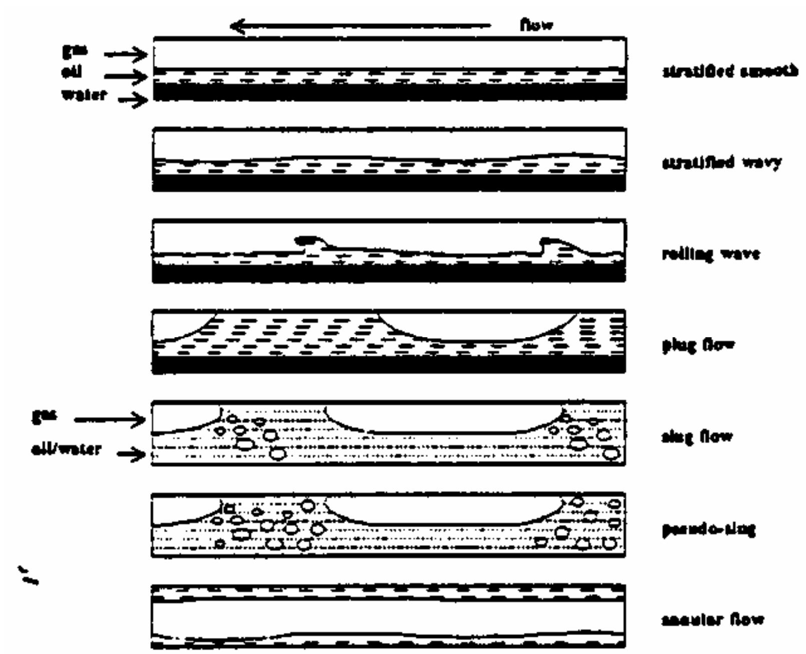


Figure 10: Flow patterns observed in a multiphase pipeline.[17]

In three-phase plug flow, the oil/water interface remains stratified while intermittent gas pockets remove the oil from the top of the pipe. If the gas flow rate is increased from plug flow, slug flow regime is reached. Characteristics of this slug flow include mixing of the oil and water layers, gas pockets of increased length, and gas bubble entrainment in the front of the slug, commonly referred to as the mixing zone. An additional increase in the gas velocity creates a flow pattern termed pseudo slug flow. Pseudo slugs have the same characteristics as slugs, but the mixing zone extends through the slug length allowing occasional gas blow through to occur. At even higher gas flow rates, annular flow is reached. Annular flow exists when the less dense fluid, the gas, flows in a core along the center of the pipe, while the more dense fluid, the oil/water mixture, flows as an annular ring around the pipe wall.[17]

A study performed at the University of Ohio on multiphase flow in high-pressure horizontal and +5 degree inclined pipelines had the following conclusion:[17]

- The slug frequency increases with increasing liquid flow rate, regardless of liquid composition, inclination and pressure.
- The slug frequency was not variant with pressure.
- Increasing the pressure has no effect upon the stratified/intermittent boundary.
- Increasing the pressure causes pseudo-slug flow to dominate the slug flow regime.
- Increasing the inclination forces the stratified/intermittent boundary to occur at lower liquid flow rates.

Another study performed at the University of Ohio by the same group of researchers, had the following conclusions regarding wall shear stress and flow turbulent intensity near the wall:[42]

- The wall shear stress changes substantially across the front of the slug. The greatest changes occur at high Froude numbers.
- The wall shear stress is always greatest at the bottom of the pipe and decreases towards the top.
- Both the wall shear stress and turbulent intensity increase with an increase in Froude number.
- Adding the oil phase into the flow system increases the wall shear stress but decreases the turbulent intensity.

According to the previous conclusions, several hypotheses can be brought forth. One is that near the well, the velocities in the pipe are large and there is a high probability that there is a lot of turbulence, and also that the shear stress is high. As the flow is examined further down the pipeline, due to head loss in the pipe, the flow velocity decreases due to friction losses. Therefore the second hypothesis states that as the velocity in the pipe decreases the flow regime shifts away from slug flow to plug flow or to stratified flow. The conclusions then are that near the well it is more likely that erosion corrosion along with convective mass transfer corrosion are controlling, but due to the high turbulence bacterial colonies are not able to attach themselves to the pipe walls. As the flow regime changes down the line however, water separates from the oil and the flow becomes stratified. This enables the bacteria to find suitable conditions to thrive and the water at the bottom of the pipeline is where bacterial colonies tend to be found, which also explains why internal corrosion is predominantly found along the bottom of pipelines.

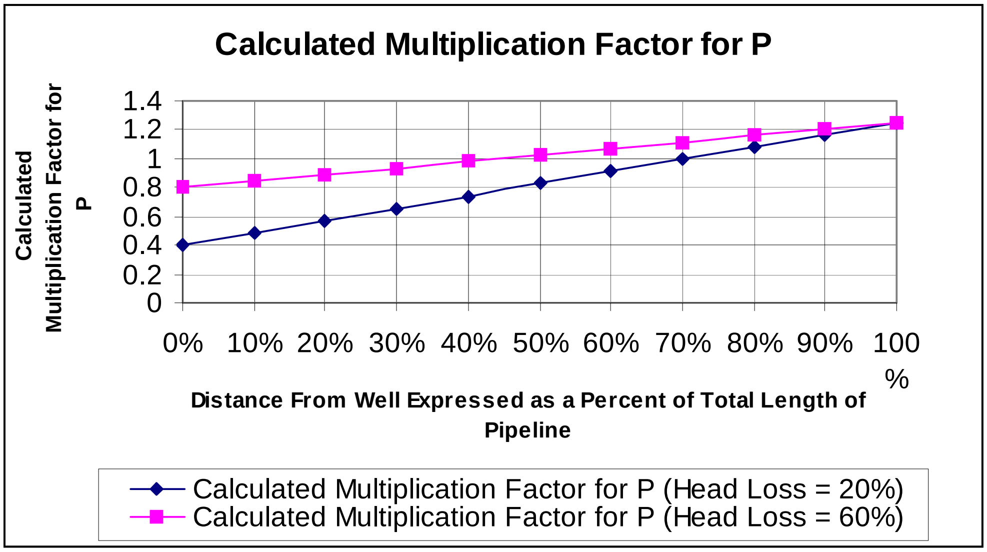
A theoretical equation was derived based on the previous assumptions, which can be seen in Equation 5.

$$MultiplicationFactorForP = \left(1.05 - \frac{PercentHeadLoss_{OverTotalLength}}{100}\right)\frac{PercentLength_{OfTotalLength}}{100} + \left(\frac{PercentHeadLoss_{OverTotalLength}}{100} + 0.20\right)$$

EQ. 5

According to Equation 5, the corrosion rate will depend upon how much head loss there is in the pipeline. The head loss in Equation 5 is taken to be uniform over the length of the pipeline for simplicity. The multiplication factor for P depends upon which point along the line is being examined, and reaches a maximum value of 1.05 at the end of the pipeline. At the front end of the pipeline, the multiplication factor is equal to 0.20 plus the head loss over the total length of the pipeline. The multiplication factor for N on the other hand can be ignored, because N does not have a significant role in the corrosion loss. Figure 11 illustrates the change in the multiplication factor for different values of head loss.

Figure 11: Illustration of how the multiplication factor changes with total head loss.



To use the diagram in Figure 11, the head loss over the length of the pipeline must be known and the user must decide where the corrosion loss in the pipe is to be calculated: at 50% of the total length or at 75% of the total length. Once the foregoing parameters are known, Equation 5 can be used, or if a set of curves have been developed for various head losses, then the multiplication factor for P can be read directly off of the graph. The value obtained from the graph then can be applied to P, and a correction can be made to the corrosion rate, but this correction factor only applies to a specific section of pipe.

If the pipe is divided into sections for analysis, then the average distance of that section from the well can be used to obtain a value from the graph.

Given that all the above parameters can be determined, the calculation of the reliability is performed in the following manner:

1. **Choose type of material (i.e. Mild Steel, Diameter, Yield Strength, Thickness)**
   - **P and N are determined**
2. **Determine temperature range of well**
   - **Possible pH is calculated (pH = 0.034Temp(F) + 0.757)**
3. **Adjust P and N according to pH value (Eqs. 3 & 4)**

4. **Where is the probability of failure to be calculated? (i.e. at 50% total length)**
5. **What is the total head loss in pipeline due to friction and appurtenances?**
   - **Calculate multiplication factor for P (Eq. 5)**
6. **Are there any inhibitors in use? How effective are they?**
   - **Adjust P accordingly (i.e. 50% effective = 0.5P)**
7. **How old is the pipeline (years)**
8. **Calculate corrosion loss (Eq. 1)**
   - **Is the corrosion loss less than 20% ⇒ Continue Operation (Make sure operating pressure is at least 1/2 to 2/3 that of design)**
   - **Is the corrosion loss greater than 80% ⇒ Inspect/Replace Section**
9. **Calculate burst pressure (Eq. 10)**
10. **Determine operating pressure**
11. **Calculate the safety index, β (Eq. 12)**
12. **Calculate probability of failure (Eq. 11)**
13. **Is the probability of failure too high? Too low?**
    - **Can decrease or increase operating pressure**

3.0 Conclusion

Determining the reliability of a pipeline is a straightforward process if all the components of the reliability model are known. The developed model, tries to capture the relevant details of the corrosion problem faced by the offshore oil industry, where corrosion due to souring is a major problem.

The souring of wells is caused by bacterial intervention, where sulfate reducing bacteria act to produce hydrogen sulfide and other sulfur compounds that have corrosive characteristics. Wells with lower temperatures, on the order of 100^{o} F, have more potential to sour due to the fact that they offer a good environment for bacteria to grow. Souring of wells is usually accelerated by new recovery techniques, like the pumping of steam or seawater into the well, which either introduces new organisms into the well or provides nutrients for bacteria already present in the connate water of the well.

As the oil, gas and water mixture is recovered, it is transported along the pipeline, where certain flow conditions influence the corrosion process. Due to the fact that a multiphase flow exists in the pipe, under certain conditions high shear stress can develop between the media and the pipe, therefore making it difficult for bacteria or for inhibitors to attach to the side of the pipe. This usually occurs near the well due to the fact that the head loss in the pipe is still minimal, not allowing the oil, gas and water mixture to become fully stratified. As the multiphase mixture travels along the pipe, due to head loss, the velocity decreases, allowing the water to settle out and the mixture stratifies according to density. The water, being the most dense, settles to the bottom and in certain locations stagnates, enabling bacteria to attach to the pipe and to thrive. This is also the reason why most corrosion in pipes is found along the bottom of the pipe.

As bacteria attach to the sides of the pipe, localized pH values may become very low, where in any one bacterial colony there might be several prospering bacterial species. Species that are able to metabolize high amounts of sulfur tend to produce very low pH values, on the order of 2, and tend to cause a lot of damage.

Capturing all the previously mentioned characteristics of a pipeline system, the reliability of the pipeline can be calculated. The model however has to be calibrated for the specific field conditions and the type of metal that the pipeline consists of, in order for it to be more accurate.

It must also be realized that the model was developed through the aid of several references, but actual tests have not been performed to validate the findings. This will have to be done in order for the model to be more reliable. One way to do this is to utilize the databases available through the Minerals Management Service, or to develop new databases that are well organized and maintained.

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Section III: Development of Quantitative Theory for Risk Assessment of Unpiggable Pipelines

Introduction

Many pipeline operating companies are moving towards the direction of risk management, and therefore are looking to develop systems that will be able to perform the task of risk management. However, there are several obstacles that have to be overcome before such a risk management system can be effectively implemented. One of the major obstacles that have to be overcome is the lack of data available on pipelines.

For a risk management program, statistical variables have to be defined, values of which are usually provided for the reliability engineer in the form of data collected about the pipeline. In the case of pipelines however, there is very limited data available and therefore for the initial distribution of failure rates, only a sample from the whole population can be taken. There is hope however, because once the relevant variables are identified, data about these variables can be collected, and failure rate distributions can be fitted with increasing accuracy as more and more data is collected.

This report will focus on failure due to corrosion and managing the risk associated with corrosion. Corrosion is only one failure mechanism associated with a pipeline. The major categories of failure modes are design related failures, third party damage failures, corrosion failures, and incorrect operation failures. These categories can then be subdivided further, depending upon the accuracy desired. If it is desired that these competing risks be included in the model, then certain statistical and probabilistic methods have to be employed which tend to get very convoluted. Modeling for competing risks will be left out of this report. Caution must be practiced however due to the fact that there will be less and less data available about more finely divided categories and it might not be practical to even model some categories of failures because the coefficient of variation associated with these mechanisms would be very high.

Corrosion failures in pipelines are very prevalent, but in most cases they are not catastrophic. As a pipeline ages, more and more corrosion associated flaws will develop on it’s internal and external face, and each section of pipeline will have a distribution of flaws associated with it. If the distribution of flaws is known, along with the operating conditions, the probability of failure can be calculated for one flaw and then a series system model can be utilized to find the probability of failure for the whole section.

Once the probability of failure for each section of pipeline has been calculated, the next step is to determine the impact of failure associated with the section. Larger flaws will influence failure in a more detrimental way than smaller flaws, so they have to be watched more closely. The model can be set up to find the probability of failure of the whole section, taking into account all the flaws at once, or flaw sizes can be divided into ranges and for each range a probability of failure can be calculated. In the latter method, different flaw sizes can be analyzed for their relative impact and a lot of the detail about the failure probability will be retained as opposed to the former method, where all flaws are grouped together.

All failure probabilities, as calculated above, are done so for a given point in time, but it has to be kept in mind that with corrosion, flaw size distributions grow and they will be also time dependent. Therefore for every section of pipe, the flaw size distribution has to be determined relative to time. This in essence is a three dimensional distribution where one axis has the flaw sizes as a label, and the other axis would have time as an axis label. The third axis would of course be the frequency or the probability of failure associated with each flaw size.

This report will develop a comprehensive way in which the reliability of a given pipeline can be calculated, and will develop a guideline that can be used to approximate the distribution of flaw sizes in a section of pipe relative to time.

1.0 Theory

There are many different distributions available for the modeling of lifetime distributions, but each has its pros and cons. The exponential distribution is the simplest of distributions, but its applicability is limited. Unfortunately, the exponential distribution has a property called the memoryless property, meaning that the lifetime distribution of a new and used object modeled by the exponential distribution would be identical. In other words a used object would be as good as a new one. This of course is not the case for a pipeline.

Another distribution, the Weibull distribution, is a generalization of the exponential distribution that is appropriate for modeling lifetimes having constant, strictly increasing, and strictly decreasing hazard functions. Before going any further however, several definitions will be given about distributions in general to aid the reader.

1.1 Definitions

When discussing any type of distribution, there are five major functions that can be used to describe the distribution. The five functions define the distribution of a continuous, nonnegative random variable T, associated with a given system. There are also other methods to describe the distribution of T, but these other methods, like the moment generating function, the characteristic function, and the Mellin transform are not as popular and do not have intuitive appeal.

The five different functions that can be used to describe a distribution are the survivor function, the probability density function, the hazard function, the cumulative hazard function, and the residual life function. These five functions are briefly described in the next five sections.

1.1.1 Survivor Function

The survivor function S(t), is a generalization of reliability. There are two interpretations of the survivor function; one: S(t) is the probability that an individual item is functioning at time t, and two: if there is a large population of items with identically distributed lifetimes, S(t) is the expected fraction of the population that is functioning at time t. The survivor function can also be described as the complement of the cumulative distribution function.

$$S(t) = P[T \geq t] \quad \mathrm{t} \geq 0 \qquad \textbf{EQ. 1}$$

$$F(t) = P[T \leq t] \qquad \textbf{EQ. 2}$$

$$\therefore \mathrm{S(t)} = 1 - F(t) \qquad \textbf{EQ. 3}$$

1.1.2 Probability Density Function

The probability density function is defined by f(t) = -S’(t), where the derivative exists, and has the probabilistic interpretation

$$f(t)\Delta t = P[t \le T \le t + \Delta t] \qquad \textbf{EQ. 4}$$

This equation is valid for small Δt. The probability of failure between times a and b is calculated by an integral:

$$P[a \le T \le b] = \int_a^b f(t)dt \qquad \textbf{EQ. 5}$$

1.1.3 Hazard Function

The hazard function, h(t), is perhaps the most popular of the five representations for lifetime modeling due to its intuitive interpretation as the amount of risk associated with an item at time t. A second reason for its popularity is its usefulness in comparing the way risks change over time for several populations of items by plotting their hazard functions on a single axis.

$$h(t) = \frac{f(t)}{S(t)} \quad t \ge 0 \qquad \textbf{EQ. 6}$$

Thus the hazard function is the ratio of the probability density function to the survivor function. The probabilistic interpretation of the hazard function is

$$h(t)\Delta t = P[t \le T \le t + \Delta t | T \ge t] \qquad \textbf{EQ. 7}$$

for small values of Δt.

The shape of the hazard function indicates how an item ages. The intuitive interpretation as the amount of risk an item is subjected to at time t indicates that when the hazard function is large the item is under great risk, and when the hazard function is small the item is under less risk. The three hazard functions in Figure 1.1 correspond to an increasing hazard function (labeled IFR for increasing failure rate), a decreasing hazard function (labeled DFR for decreasing failure rate), and a bathtub shaped hazard function (labeled BT for bathtub-shaped failure rate).

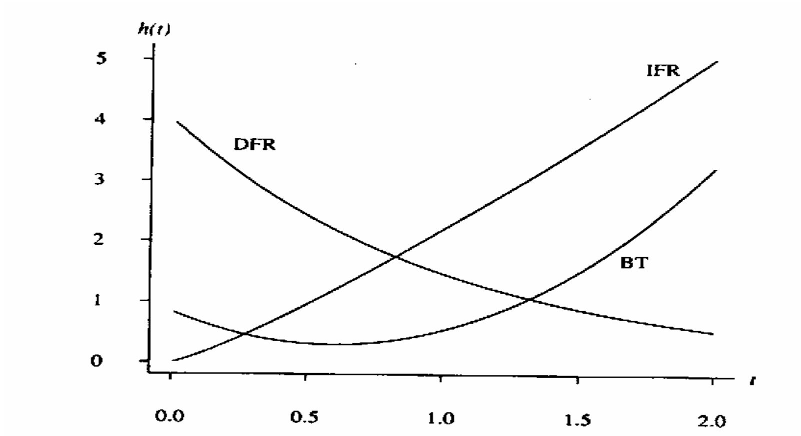

Figure 1.1: Illustration of various hazard functions.

1.1.4 Cumulative Hazard Function

The cumulative hazard function, H(t), can be defined by

$$H(t) = \int_0^t h(\tau)d\tau \quad t \geq 0 \qquad \textbf{EQ. 8}$$

The cumulative hazard function is valuable for variate generation in Monte Carlo simulation, implementing certain procedures in statistical inference, and defining certain distribution classes.

1.1.5 Mean Residual Life Function

The mean residual life function, L(t), is the expected remaining life, T-t, given that the item has survived to time t. The mean residual life function can be represented by

The five distribution representations are equivalent in the sense that each completely

$$L(t) = E[T - t | T \geq t] = \frac{1}{S(t)} \int_t^\infty \tau f(\tau) d\tau - t \qquad \textbf{EQ. 9}$$

specifies a lifetime distribution. Any one lifetime distribution representation implies the other four. Algebra and calculus can be used to find one lifetime distribution given that another is known. Table 1.1 illustrates the relationship between the various lifetime distributions.

	$f(t)$	$S(t)$	$h(t)$	$H(t)$	$L(t)$
$f(t)$	•	$\int_t^\infty f(\tau)d\tau$	$\frac{f(t)}{\int_t^\infty f(\tau)d\tau}$	$-\log\left[\int_t^\infty f(\tau)d\tau\right]$	$\frac{\int_t^\infty \tau f(\tau)d\tau}{\int_t^\infty f(\tau)d\tau} - t$
$S(t)$	$-S'(t)$	•	$\frac{-S'(t)}{S(t)}$	$-\log S(t)$	$\frac{1}{S(t)}\int_t^\infty S(\tau)d\tau$
$h(t)$	$h(t)e^{-\int_0^t h(\tau)d\tau}$	$e^{-\int_0^t h(\tau)d\tau}$	•	$\int_0^t h(\tau)d\tau$	$\frac{\int_t^\infty e^{-\int_0^\tau h(y)dy}d\tau}{e^{-\int_0^t h(\tau)d\tau}}$
$H(t)$	$H'(t)e^{-H(t)}$	$e^{-H(t)}$	$H'(t)$	•	$e^{H(t)}\int_t^\infty e^{-H(\tau)}d\tau$
$L(t)$	$\frac{1+L'(t)}{L(t)}e^{-\int_0^t \frac{1+L'(\tau)}{L(\tau)}d\tau}$	$e^{-\int_0^t \frac{1+L'(\tau)}{L(\tau)}d\tau}$	$\frac{1+L'(t)}{L(t)}$	$\int_0^t \frac{1+L'(\tau)}{L(\tau)}d\tau$	•

Table 1.1: Relationship between lifetime distributions.

1.2 The Weibull Distribution

Now that the five various function used to describe a distribution have been introduced, they can be applied to the Weibull distribution. The first four lifetime distribution representations for the Weibull distribution are

$$S(t) = e^{-(\lambda t)^{\kappa}} \quad f(t) = \kappa\lambda^{\kappa} t^{\kappa-1} e^{-(\lambda t)^{\kappa}} \quad h(t) = \kappa\lambda^{\kappa} t^{\kappa-1} \quad H(t) = (\lambda t)^{\kappa}$$

EQ. 10 **EQ. 11** **EQ. 12** **EQ. 13**

for all $t \geq 0$, where $\lambda > 0$ and $\kappa > 0$ are the scale and shape parameters for the distribution.

1.3 Problem Set Up

Before the parameters for the distribution are determined, the problem will be set up in its entirety. Since the shape parameter can only have units of a certain number of flaw size per time, or number of flaws for a given flaw size, we need to have two separate types of distributions. One distribution will give the number of flaws of *a certain* size for a given section of pipe relative to time, while another distribution will give the flaw size distribution for a section of pipe relative to time. In other words, in order to calculate the probability of failure for a section of pipe, we need to know the size range of the flaws in a pipe, and then we can calculate the probability of failure associated with each flaw range. Once the probability of failure due to a certain sized flaw is determined, the next step is to take into account the number of flaws there are of this certain size.

The best way to model the failure of a section of pipe, or in this case a pipeline system, is to set up a series system. In a series system if one flaw results in failure, then the whole system fails and the pipeline is taken out of operation. This can be represented in the following way

$$P_{fSystem} = 1 - \prod_{i=1}^{n}\left(1 - P_{f_i}\right) \qquad \textbf{EQ. 14}$$

Where P_{fi} is the probability of failure associated with a certain sized flaw. In the case of equal probabilities of failure, as would be associated with a certain number of equivalent sized flaws the previous equation would reduce to

$$P_{fSystem} = 1 - \left(1 - P_{fIndividual}\right)^{n} \qquad \textbf{EQ. 15}$$

where n is the number of flaws of a certain size that are present in the system.

Another important consideration is accounting for the periodic repair of the system. Usually, in the case of pipelines, the smaller sized flaws are disregarded because they are numerous and are difficult to fix individually unless the whole section of pipe is removed. Also in the case of a series system, components that have very low reliabilities should be removed, because they decrease the reliability of the whole system extensively. Therefore usually the larger flaws are fixed and therefore the reliability of the system greatly improves, given that there aren't a significant number of smaller flaws in the system. A plot of system reliability versus component reliability is shown in Figure 1.2. The most important concept that this graph shows is that a small increase in component reliability nets a substantial increase in system reliability for a system with a large number of components.

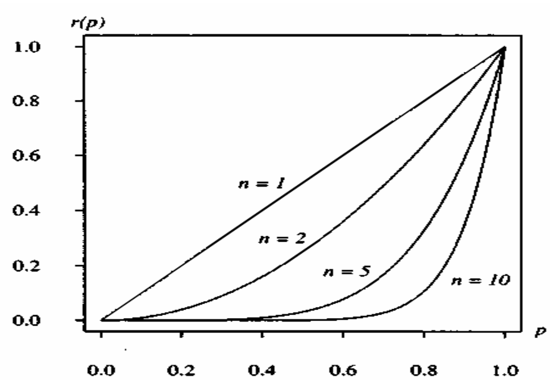

Figure 1.2: Component reliability versus system reliability for a series system.

Once the reliability of the system is known, the next question is when to inspect the pipeline and to order periodic maintenance measures. Maintenance models are used when both preventive and corrective maintenance is applied to a system. Preventive maintenance is action taken on a system before it fails, while corrective maintenance is action taken on a system upon failure. One popular question concerning a maintenance model is the optimal time for preventive maintenance to be performed. The question of optimal time will be discussed later, and for now the discussion will be focused upon maintenance. The repair of the system and the updating of the reliability of the system is described in section 1.3.1.

1.3.1 Point Processes

When the time to repair or replace an item is negligible, point processes, are appropriate for modeling the failure times. The lifetimes of non-repairable items are described by the distribution of a single nonnegative random variable. On the contrary, a repairable item, such as a pipeline, has several points in time where it may fail. In many situations, the intensity function, $\lambda(t)$, of a nonhomogeneous Poisson process may be the appropriate probabilistic mechanism for modeling the failure history of the item. The intensity function is analogous to the hazard function in the respect that higher levels of $\lambda(t)$ indicate an increased probability of failure. The term improvement is used if the intensity function is decreasing, and the term deteriorating is used if the intensity function is increasing.

For the case of the reliability of pipelines, the nonhomogeneous Poisson process is chosen, due to its ability of modeling improving and deteriorating systems. The occurrence of flaw sizes, λ, varies over time according to $\lambda(t)$, which is often called the intensity function. The cumulative intensity function is defined by

$$\Lambda(t) = \int_0^t \lambda(\tau)\,d\tau \qquad \textbf{EQ. 16}$$

and is interpreted as the expected number of flaws by time t. These two functions are generally used to describe the probabilistic mechanism for the failure times of an item, as opposed to the five distribution representations for non-repairable items.

A counting process is a nonhomogeneous Poisson process (NHPP) with intensity function $\lambda(t) \geq 0$ if $N(0) = 0$ (the number of failures or flaws at time = 0 is 0), the process has independent increments, and the probability of exactly n events occuring in the interval (a,b] is given by

$$P\left[N(b) - N(a) = n\right] = \frac{\left[\int_a^b \lambda(t)dt\right] e^{-\int_a^b \lambda(t)dt}}{n!} \qquad \textbf{EQ. 17}$$

for n = 0, 1,…

For NHPPs, the times between events are neither independent nor identically distributed. The time to the first event in an NHPP has the same distribution as the time to the first event of a single nonrepairable item with a hazard function λ(t). The times between these subsequent events do not necessarily follow distributions like the Weibull distribution.

The next step in the risk management of pipelines is to obtain the parameters necessary to develop an appropriate distribution for various flaw sizes over a given time period.

1.4 Parametric Estimation for the Weibull Distribution

To estimate the scale and shape parameters of a Weibull distribution two different methods can be used. One method utilizes mathematical formulas and becomes very cumbersome when only limited calculation abilities are available. The reason for this is that the Weibull distribution does not have a closed form maximum likelihood estimator for its parameters.

The second method of solving for the fitting parameters of the Weibull distribution is to use graphing techniques. Prior to the widespread use of computers for reliability analysis, "Weibull paper" was used to determine if the Weibull distribution was an appropriate model for a data set. To apply the Weibull distribution to estimate the number of flaws in a pipeline distributed according to time, data must be available, but usually in the beginning there is little if any data that can be fitted. Therefore, for the initial estimate some common sense and expert knowledge should be utilized. It should be noted however that the Weibull distribution was chosen because it is a relatively simple distribution to use for our purpose, but if in the future it is discovered that another distribution better answers our purpose then a switch can be made. For the time being however, we will work with the Weibull distribution.

Previously the survivor function was defined as

$$S(t) = e^{-(\lambda t)^{\kappa}} \qquad \textbf{EQ. 18}$$

which can be transformed into the cumulative distribution function by subtracting the survivor function from 1

$$F(t) = 1 - e^{-(\lambda t)^{\kappa}} \qquad \textbf{EQ. 19}$$

At this point the scale parameter, λ, is rewritten as 1/σ, in order that the calculations are more easily performed. Now the equation for the cumulative distribution function can be rewritten in the form

$$\frac{1}{1 - F(t)} = e^{\left(\frac{t}{\sigma}\right)^{\kappa}} \qquad \textbf{EQ. 20}$$

After taking the natural logarithm of the function twice, this new equation can now be rewritten as

$$\ln\ln\left[\frac{1}{1 - F(t)}\right] = \kappa \ln(t) - \kappa \ln(\sigma) \qquad \textbf{EQ. 21}$$

Thus for any Weibull variate the above function will plot as a straight line against the natural logarithms of the observations. To make the plotting of the above equation easier, Weibull probability paper can be used, which will reduce the amount of work needed to determine the fitting parameters. If Weibull probability paper is used the above equation may be rewritten as

$$W = a + bz \qquad \textbf{EQ. 22}$$

where

$$W = \ln\ln\left[\frac{1}{1-F(t)}\right] \quad z = \ln(t) \quad b = \kappa \qquad \textbf{EQ. 23}$$
$$and \quad a = -\kappa \ln(\sigma)$$

The plot then can be used to find the scale and shape parameters.

2.0 Application of the Theory to Pipelines

Before any answers can be obtained using the above outlined theory, it is necessary to divide the problem into relevant parts. This is necessary due to the fact that this reduces the amount of computation needed, and makes the whole problem more manageable.

To make the problem easier to handle, the first step will be to decide what ranges for the flaw sizes should be used. Instead of obtaining distributions for an infinite number of flaw sizes, the effort will be concentrated on obtaining distributions for various categories of flaw sizes. The obtained distributions will then try to compensate for a certain range of flaw sizes below and above a certain value of the flaw size. For example if one distribution is obtained for ¼ inch flaws and another for 1 inch flaws, then the 1 inch distribution can be designed to compensate for flaws ranging from ¾ inches to 1 ¼ inches.

Depending on the accuracy desired, distributions can also be calculated for various sections of the pipeline. Of course this requires more work and depending on how accurately corrosion can be predicted in the pipeline, it might not even be worth the effort since the confidence level of the output would be very low. If the pipeline can be pigged however, this would be an ideal task to perform in order that a better understanding is achieved of the corrosion risk management of the pipeline.

For the purpose of this report only certain general categories of flaw sizes and corrosion magnitudes will be considered, in order that the procedure can be demonstrated. To apply the risk management technique to a specific pipeline, several characteristics of the pipeline would have to be considered, and the corrosion rate calculated using the many available corrosion loss formulas. Once the corrosion rate and loss is calculated for a pipeline, the distribution of flaws can be determined and the appropriate fitting distribution chosen.

2.1 Range of Flaw Sizes

As was mentioned earlier, this report will only address a certain range of flaw sizes, due to the fact that pipelines can have various diameters, which in turn result in various sized flaws. The pipe diameter that will be used throughout this report will be 8 inches. This value will represent the outside diameter of the pipeline. Once the diameter of the pipeline is known so is the size of the largest flaw.

Next, various ranges of flaw sizes will be chosen below 8 inches, for which distributions will be determined. The midpoint of these various ranges can be represented by 5 inches, 2 inches, 1 inch, and ¼ inches. It is important to note however that when that probability of failure is calculated the depth of each of these flaws also needs to be known. The above values only represent lengths for the flaws, which will later be related to the impact that the failure might have. For instance a longer flaw will spill more barrels of oil if failure occurs at that flaw, then would a ¼ inch flaw. To make the problem easier, it will be presumed that corrosion loss for all flaw sizes will more or less take place at the calculated general rate, as obtained through the use of the pipeline characteristics.

To obtain an appropriate distribution for the flaw sizes in a pipeline, it is also necessary that the type of service be determined. As the product that is being transported in the pipeline becomes more corrosive, or abrasive if sand is present, then chances are that there will be more and more flaws with increasing detrimental environmental conditions.

Environmental conditions therefore are designated for a pipeline, for which the flaw size distribution is calculated. These various environments can be described as very corrosive, mildly corrosive, and not corrosive. Each of these descriptors will play an important part in determining the amount of flaws present in the pipe. It should be noted however that the designator "not corrosive" does not imply that there will be absolutely no corrosion loss, but rather corrosion loss in this environment will be very minute.

The pipeline will also be divided into three parts, which will be labeled as the first 1/3, the middle 1/3 and the end 1/3. Again due to the various flow conditions present in the various sections, different flaw size distributions can be expected. Of course as more accuracy is desired, the pipeline can be divided into finer and finer sections, but for the purposes of this report we will deal with just these three divisions.

2.2 Pipeline Environment Descriptors

As was mentioned in the previous section, different corrosive conditions will have different effects on flaw sizes. In this section, each environmental descriptor, very corrosive to not corrosive, is described in more detail and examples are given as to where each descriptor is applicable. This method then can be used to develop an initial estimate of the distribution of flaw sizes in the pipeline, where a hypothetical distribution is provided for each type of environment.

The first descriptor, very corrosive, is designated for all sour pipelines, and multiphase pipelines where the water cut in the pipeline is over 30%. Pipelines where the temperature of the effluent is relatively high, above 100^0 F, can also be described as having a very corrosive environment, especially if the product in the pipeline has an acidic pH. The important point is to identify which parameters are important in influencing corrosion, and then quantify their effect on the pipeline. Depending on how the parameters affecting the corrosion rate in the pipeline are defined, the environment will be influenced accordingly.

In order to ease the process of determining which type of environment is present in a pipeline, a table has been set up that can be used as an aid. The table is presented below.

	VERY CORROSIVE	MILDLY CORROSIVE	NOT CORROSIVE
Temperature Range	150^0-100^0 F or greater	100^0-70^0 F	<70^0 F
Amount of Oxygen in System	1 to 10 ppm	500 to 900 ppb	<300 ppb
Amount of Hydrogen Sulfide in System	50 to 200 ppm	1 to 40 ppm	<1 ppm
Type of Flow in System	Pseudo Slug / Slug Flow	Plug Flow	Stratified Smooth Flow
Amount of Water Present in System	>15%	14 to 5%	<1%
Particles Present in System (Significant Concentrations)	D > 50 mils	10 < D < 50 mils	D < 10 mils
Coating Lifetime	1 to 5 years	6 to 14 years	>15 years
Inhibitor Effectiveness	10 to 30%	30 to 70%	>70%

Table 2.1: Evaluation of environmental descriptor.

Next, an indexing technique is used to calculate a score for each type of pipeline that is being evaluated. For each category, very corrosive to not corrosive a range of index values must be assigned. In this case, the range chosen is from 1 to 3, where the lower scores indicate unfavorable conditions and the higher scores are reserved for pipelines that are in a relatively non-corrosive environment. So the value of 1 corresponds to very corrosive, 2 corresponds to mildly corrosive, and 3 corresponds to not corrosive. Once all the above parameters have been scored the total score must be tallied up. The total score is calculated by adding all the values obtained for the various parameters.

Once the total score is known, it is necessary to know what ranges correspond to a specific environment. The table below shows how the ranges can be evaluated.

	VERY CORROSIVE	MILDLY CORROSIVE	NOT CORROSIVE
Cumulative Score	8 to 13	14 to 21	22 to 24

Table 2.2: Evaluation of cumulative score for environmental descriptors.

2.2.1 Coating Effectiveness

At this point a short chapter is dedicated to coating effectiveness, due to the fact that many times it will be difficult to evaluate how effective a coating really is. Therefore several criteria are listed here that should be looked at when evaluating coating effectiveness.

How effective a coating is strongly affects the corrosion rate in a pipeline, but when the coating is being evaluated, several factors must be kept in mind. Usually coatings are applied for external corrosion, but there are instances where internal coatings are applied to the inside of pipelines. Usually if a pipeline is submerged in seawater, coatings are used along with cathodic protection devices. If there is no solution present that can support the migration of ions for the purposes of cathodic protection, then a coating must be applied to the pipeline.

Coatings in the past were mainly in the form of bitumastic and thin film epoxy paints. Many pipelines in service today still utilize the same mechanism for external protection, but these mechanisms do not provide adequate corrosion prevention because of unavoidable holes in practical coatings. Corrosion is usually concentrated in the cracks or holes of the coating, causing premature perforations, sometimes earlier than on the equivalent bare pipeline. Also, as corrosion develops under the paint, it may cause a thinning of the coating schedule, making the pipeline more vulnerable to further damage by corrosion. If the coating is durable and has been applied according to the proper specifications, it will probably perform up to expectations. Usually a couple of localized corrosion attacks will develop however, because there isn't a coating that is perfect.

Organic damage to the coating of a pipeline can occur as barnacles and various other marine organisms make their home in and around the shelter of a newly laid unburied pipeline. The concrete weight coating which is usually required on marine pipelines for negative buoyancy protects the coating from damage due to marine life and provides some corrosion protection as well, due to reduced moisture penetration and raised pH. However, cathodic protection is normally applied to provide corrosion protection to the holes and areas of accidental coating damage.

The most severe conditions of external corrosion exist in the splash zones of offshore structures. This hazard is especially critical for risers because they are often hot, and because the consequences of safety are much more important than on the supporting structure. Usually corrosion is initiated at coating defects which trap water and aggravate the corrosion problem.

Therefore the criteria that are important in evaluating coatings are: 1) is the coating under a lot of stress which might cause cracking; 2) is the coating elastic and durable; 3) how does the coating perform under hot temperatures; and 4) what were the specifications for applying the coating and what are the "as-built" conditions of the pipeline.

2.3 Calculation of Flaw Size Distribution

In this section of the report it will be demonstrated how the initial distribution of flaw sizes can be calculated with respect to time for various flaw sizes. The calculation will be carried out for 1 inch sized flaws in a hypothetical "very corrosive environment, meanwhile for the other flaw sizes a summary will be presented. The calculations for other flaw sizes, in a hypothetical mildly corrosive environment, can be found in Appendix B. It should also be remembered that the calculations are based on the premise that the pipeline is constructed of mild steel.

It was mentioned before that larger flaw sizes will be less frequent than smaller flaw sizes, therefore the distribution for 1 inch sized flaws should fall between the ¼ inch and the 2 inch flaw size distributions. Due to the fact that there is no real data available for the calculations, a limit will be set as to how many flaws can develop in an 8 inch diameter pipe over a certain period of time given that the environment is very corrosive. For this task an educated guess will be made, but it must be kept in mind that when the calculations are applied to an existing pipeline the flaw size distribution can be estimated from a small section of the pipeline, which will be representative of the whole population. Also operators who have been working in the field for extend periods of time, will be able to make educated guesses about the flaw size distribution in a pipe even if there isn't much data available.

For this example calculation the following data, presented in Table 2.3 was collected about 1 inch flaw sizes in an 8 inch diameter mild steel pipe that was in service in a very corrosive environment:

OBSERVATION NUMBER	DURATION TO DEVELOP 2000 1 INCH FLAWS PER MILE (DAYS)
1	730
2	912
3	1000
4	1130
5	1250
6	1345

Table 2.3: Sample data.

The next step is to see if the Weibull distribution is an appropriate distribution for the obtained values. In order to determine this, a plot of lnln(1/1-F(t)) versus ln(t) has to be constructed. If the data follows the trend of a line, then the Weibull distribution is an appropriate distribution for the obtained numbers, and the shape and scale parameters can be determined from the plot. The plot of the values in Table 2.3 can be seen in Figure 2.1.

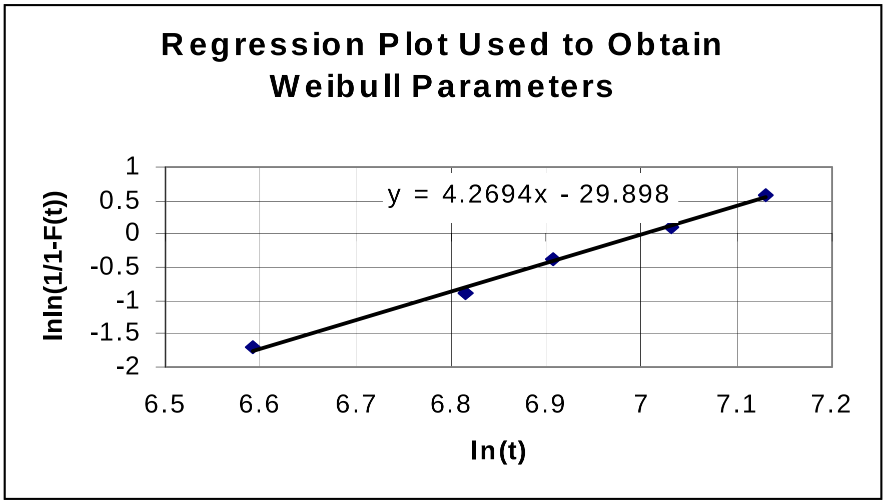

Figure 2.1: Linear regression used to find fitting parameters.

The scale and shape parameters for the distribution are 0.00091 and 4.27 respectively. The distribution can be seen in Figure 2.2.

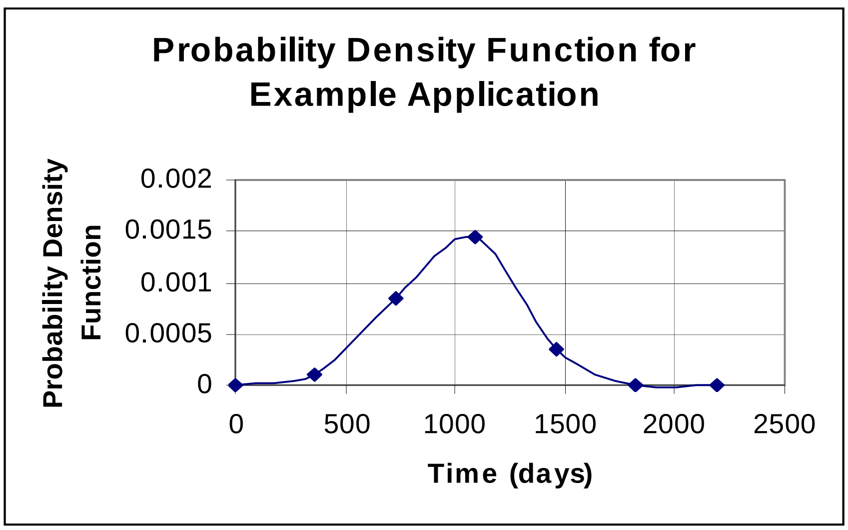

Figure 2.2: Probability density function for example application.

Once the scale and shape parameters are known, the distribution can be applied to calculate the probability of failure associated with flaws 1 inch in size. Later, the probability of failure, as calculated for flaw sizes ranging from ¼ inches to 8 inches can be combined to obtain a total for the probability of failure for the whole pipeline.

Next, the probability of failure has to be calculated for an individual flaw size.

2.4 Calculating the Probability of Failure for a 1 inch Flaw Size

To calculate the probability of failure for a 1 inch flaw size the classic demand-resistance model will be used, where the demand will signify the operating pressure, and the resistance will be the burst pressure of the pipe, given that there is a 1 inch flaw present. It should be noted here that to make the calculations easier, corrosion for all flaw sizes can be taken as uniform, meaning that a flaw size that is 1 inch long and a flaw size that is 8 inches long will have the same amount of corrosion loss. Therefore after the corrosion loss in the pipeline for a particular year has been calculated, the value obtained can be applied to all flaw sizes.

To continue the example, it will be presumed that in this "very corrosive" environment the corrosion rate is 50 mils per year, and we wish to calculate the probability of failure due to 1 inch flaws in the pipe after a time of 2 years. We will take the pipe wall thickness to be 0.30 inches. The operating pressure will be taken as 1500 psi.

Therefore after 3 years, the pipe wall thickness is expected to be 0.30 – 3(0.05) inches, which is equal to 0.15 inches. The next step is to calculate the burst strength of the pipe, which can be done using the following equation

$$P_{burst} = f_{wl} \frac{t^*}{R}\left[\frac{1}{2}+\frac{1}{\sqrt{3}}\right]^{n+1} \sigma_{uts} \qquad \textbf{EQ. 24}$$

In the above equation f_{wl} accounts for the increase in strength provided that the wall loss only occurs around the 1 inch flaw. n is the strain hardening index of the steel, usually on the order of 0.05 to 0.15, t* is the corroded pipe wall thickness, R is the mean radius, and σ_{uts} is the ultimate tensile strength of the pipe. The value of f_{wl} is given by the following formula

where ϕ is the fraction of the pipe wall that has corroded, mainly the 1 inch flaw length. In this case ϕ is equal to $1/[(8-0.6)\pi]$ or 0.043 (4.3% circumferential wall loss). If n has a value of 0.15 then f_{wl} equals 1.10. If the ultimate tensile strength of the pipe steel is

$$f_{wl} = \left(\frac{2}{1+\phi}\right)^n \qquad \textbf{EQ. 25}$$

100,000 psi, then the burst pressure when a 1 inch flaw present is 2334 psi.

The probability of failure now can be calculated using the following equation

$$p_f = 1 - \Phi\left(\frac{\ln\left(P_{burst}/P_{operating}\right)}{\sqrt{\sigma^2_{\ln_b} + \sigma^2_{\ln_o}}}\right) \qquad \textbf{EQ. 26}$$

This equation takes advantage of the assumption that the distribution of pressures is lognormal and the correlation between the burst pressure and the operating pressure is zero. Φ is the cumulative normal distribution function, and σ_{lnb} and σ_{lno} are the lognormal standard deviations of the burst and operating pressures. Usually σ_{lno} is on the order of 0.20 and σ_{lnb} is usually on the order of the value of

the amount of corrosion loss that the pipe experienced. In this case σ_{lnb} is on the order of 0.50, because there exists a 50% wall loss. At this point a safety factor of 0.20 is added to the value of 0.50, making σ_{lnb} equal to 0.70. Knowing all the relevant values to apply into the equation, the value of the probability of failure becomes

$$p_f = 1 - \Phi\left(\frac{\ln\left(2334/1500\right)}{\sqrt{0.70^2 + 0.20^2}}\right) = 1 - \Phi(0.607) = 1 - 0.728 = 0.272 \qquad \textbf{EQ. 27}$$

At this point the probability of failure for the mile long section of the pipe can be calculated, taking into account all the 1 inch flaws present in the section. Previously the limit for the number of flaws was set at 2000, and if the theory of a series system is applied, then the probability of failure will be 1, due to the fact that there are so many flaws. At this point though, it has to be calculated what the probability is for having 2000 one inch flaws in the pipeline after 3 years. From the previously obtained distribution, the probability of having 2000 flaws after 3 years is

$$p_{2000} = 1 - e^{-(0.00091*1095)^{4.27}} = 0.627 \qquad \textbf{EQ. 28}$$

Therefore the probability of failure of the pipeline after 3 years due to 1 inch flaws, for the 1 mile section of the pipeline, is equal to 1 * 0.627 or simply 62.7%. Similar procedures can be used to calculate the probability of failure associated with the other flaw sizes and then the results can be combined to obtain a total probability of failure for the pipeline. In certain cases though it is wiser not to combine the values obtained, because the impact upon failure from the various flaw sizes will be very different. Therefore each flaw size should be evaluated on its own, with the most attention going to the larger flaw sizes. Again, there are fewer larger than smaller flaws in the pipeline at any given time, but the impact due to larger flaws will tend to be more serious. Therefore a probability of failure of 62.7% for 1 inch flaws might mean that there will be some minor leaks along the length of the pipeline that will need some attention. The amount of fluid that might be lost through a 1 inch hole can be calculated from Bernoulli’s equation and then the impact assessed.

In the next section of this report the impact due to failure of a 1 inch flaw is going to be evaluated, and it will be demonstrated how a decision can be made concerning the risk management of the pipeline.

3.0 Impact Assessment

The ultimate goal of risk management is to reduce the risk associated with an operation. Usually an engineer will describe the risk in terms of dollar values, due to the fact that these type of units are more meaningful to management. Of course though, each dollar value is associated with an impact, which in turn is related to the type of failure that the pipe will experience. Failure of large flaws, even though less prevalent in the system will tend to have a greater impact than smaller flaws. The gravity of the impact is also directly related to what type of area the pipe is located in. For example, if failure of a pipeline occurs in an area where some sensitive animal species are present, or where people can get hurt, the impact in terms of dollars experienced by the owner of the pipeline will be considerably higher than if the failure occurred in a remote unpopulated area.

Therefore to be able to make the appropriate decision as to how to manage a pipeline it is crucial that the impact associated with a certain type of failure be known. The expected cost of the failure can then be calculated by multiplying the probability of failure by the cost of failure. Again it is crucial that the impact due to various failure types be distinguished. The type of mitigation chosen also has a cost associated with it, therefore this cost also has to be considered before an action is taken.

It is also important to take note of the type of detection and isolation systems that are present on the system because how early the leak is detected and isolated directly influences the magnitude of the impact due to the leak. In this section an indexing method is going to be developed for the impact assessment due to the failure of pipelines, where three major categories of impact will be distinguished. One category will be high impact, another moderate impact and a third, low impact. High impact for example will be associated with failure of pipelines that carry hazardous materials that are in close vicinity to populated areas, or whose failures can have a detrimental effect on the surrounding environment.

3.1 Impact Influencing Operational Characteristics

In this section several characteristics of the pipeline are going to be listed and ranked according to the impact that they are expected to have. This is going to be performed for a 1 inch flaw size which can later be adjusted to compensate for other flaw sizes. To accomplish this, several important questions need to be asked:

- Are there people in the area?
- Is the area rural or urban?
- What is the leak detection method and threshold?
- How do you stop the leak?
- What will the product do when it leaks?
- What are the properties of the product?
- How do you clean up the product?
- How will the leak spread or disperse?

The next step is to determine the index range associated with each question according to whether the impact will be high, moderate or low. Again this is done for a 1 inch flaw size.

3.1.1 Influence of Population upon Impact

The vicinity of the failure of a pipeline to people is considered one of the major impact influencing criteria. Usually when more and more people are present near a pipeline, its failure will tend to have higher impacts. This is especially true if the failure is catastrophic, where an explosion might develop, or a pool fire might develop for example.

Before it can be decided how many people need to be in a certain area for a failure to be considered high impact, it has to be decided what the influencing area is for a specific pipeline. For example, an 8 inch diameter pipeline will have a larger influencing area associated with it, than a 2 inch diameter pipeline that carries the same type of material.

In general, the impact criteria is defined by placing limits on the low and high ranges and then using these values to define the intermediate range. In this case, a low impact is defined as when 1 or 0 persons are present in the vicinity of the pipeline, and a high impact is defined as when 5 or more people are affected by a failure. Anything in between is considered moderate. An alternate method is to use DOT classifications like Class 1 through 4.

3.1.2 Property Damage

In this criteria for assessing the impact of failure, the amount of property in the vicinity of the pipeline is analyzed. Usually in a rural environment, pipelines may have a lot of property in their vicinity for a certain section, but none whatsoever for another section. The same can be said for people being near the pipeline, therefore it is important to divide the pipeline into relevant sections that are analyzed individually, and the section with the highest risk is given priority.

For assessing the impact on property when failure occurs, a low impact will be defined as property damage totaling $10,000 while a high impact is defined as a loss of property totaling $50,000 or more. Anything in between is considered moderate. These dollar value ranges are dependent on the operating company's willingness to accept damages totaling a certain amount. Some companies of course will define these ranges differently, according to the amount of monetary damages they think they can absorb. The DOT classifications can also be used here.

3.1.3 Leak Detection Methods

According to how fast a leak is detected, the amount of damage can decrease or increase. The best detection systems are ones that use instrumentation to detect changes in operating conditions, after which come suitably located detectors that determine when material is leaking, and finally the least efficient method of detection is visual detection or detectors with marginal coverage.

3.1.4 Leak Isolation Methods

Just like leak detection systems, leak isolations systems can also be grouped into three different categories. The most efficient isolation system is one where isolation or shutdown systems are activated without operator intervention, and there are detectors and instrumentation present. Next in efficiency are isolation or shutdown systems that are activated by operators from a control room and finally the worst case scenario is when isolation is dependent on manually operated valves.

3.1.5 Product Characteristics Upon Release

There are many different types of materials that can be transported by pipelines, and when failure occurs and the product is released, not all materials will behave equally.

Therefore it is crucial to determine the effect that release will have upon the material. For example, certain liquids when released might turn into gas, or they may just form a liquid pool. Depending upon the characteristics upon release, the product may also be more likely to ignite and cause further damage. For gases ignition would mean an explosion would occur. In general, gas lines and highly flammable fuel lines are considered high impact, meanwhile oil and multiphase pipelines having a high liquid to gas ratio (> 2:1) are considered to be in the moderate impact category. The low impact rating is reserved for pipelines that carry water.

3.1.6 Product Hazard Rating

If pipelines carry very hazardous materials like hydrogen sulfide gas, which is very toxic, consideration must be given to the impact of such a highly toxic gas. Oil on the other hand will not be as toxic to humans, but if it is in the ocean, a lot of wildlife may be affected in a negative manner. For the sake of simplicity most materials carried by pipelines, especially from offshore, will have a hazard rating that brings about a moderate to high impact upon release. For example gas pipelines are considered high impact on land and offshore, but oil pipelines can be classified as having a moderate to high impact depending on whether the shoreline is sensitive or not.

For example, failure of many offshore pipelines can seriously impact the shoreline and animals living in the water. On land however, the same failure will only have a moderate impact, depending on the viscosity of the fluid and the permeability of the soil.

3.1.7 Product Clean-Up

The cleanup of an oil spill can usually cause a lot of headache, due to the fact that special environmental considerations have to be followed. This of course is the risk that companies accept when they chose to operate in a certain environmental area. Therefore to avoid the risk of heavy environmental cleanup costs, it is wise to know before hand how sensitive a certain beach type actually is and what the cost of cleanup in the specific area is expected to be. Table 3.1 lists the sensitivity of various shore types, where the higher the index the more sensitive the shore is.

Table 3.1: Sensitivity index of shores.

SENSIT. INDEX	SHORELINE TYPE	COMMENTS
1	Exposed rocky headlands	Wave reflection keeps most of the oil offshore. No cleanup necessary.
2	Eroding wave-cut platf.	Wave-swept. Most oil removed by natural processes within weeks.
3	Fine-grained sand beaches	Oil does not penetrate into the sediment, facilitating mechanical removal if necessary. Otherwise oil may persist several months.
4	Coarse-grained beaches	Oil may sink and/or be buried rapidly making cleanup difficult. Under moderate to high energy conditions, oil will be removed naturally from most of the beaches.
5	Exposed compacted tidal flats	Most oil will not adhere to, nor penetrate into, the compacted tidal flat. Cleaning is usually unnecessary.
6	Mixed sand and gravel	Oil may undergo rapid penetration and burial. Under moderate to low energy conditions, oil may persist for years.
7	Gravel beaches	Same as above. Cleanup should concentrate on high-tide/swash areas. A solid asphalt pavement may form under heavy oil spill.
8	Sheltered beaches	Areas of reduced wave action. Oil may persist for many years. Cleanup is not recommended unless the oil concentration is heavy.
9	Sheltered tidal flats	Areas of great biological activity. Oil may persist for years. These areas should receive priority protection by using booms or oil sorbent materials. Cleanup avoided.
10	Salt marshes and mangroves	Most productive of aquatic environments. Oil may persist for years. Protection of these environments should receive priority. Burning or cutting to be avoided.

Many oil spills on the open sea cause pollution of the shorelines despite efforts to combat oil at sea and to save the coastline from any damage. The cleanup is usually straightforward, but it is very labor intensive. Inadequate organization and resources as well as adverse weather conditions may increase the damage caused by oil. Fog may severely restrict skimming operations and at times prevent overflights to locate oil concentrations and to direct the necessary equipment.

The cleanup might be complicated by oil lying submerged in the nearshore surf zones, adjacent to the areas most heavily affected. New impacts from the submerged oil might become a daily occurrence thus repeated beach cleanings are necessary.

To obtain a bound on the impact of the oil spill and the effort associated with the cleanup, the sensitivity indexes will be utilized. For example, a sensitivity index of 1 or 2 will be considered a low impact while, sensitivity indexes ranging from 6 to 10 are considered high impact. Moderate impact coincides with sensitivity indexes of 3, 4 or 5.

3.1.8 Product Dispersion

The dispersion of the product upon release strongly affects the impact that the failure has upon the surrounding environment. Gases are usually dispersed into the air, and the greatest concern is whether the wind will carry it to a certain site where a lot of people might be affected, or will the gas just diffuse and have a very low impact.

Of course the impact of the gas release is strongly related to the amount of gas released, which is usually large when a rupture occurs, and there is a sudden release. High-pressure lines are prone to ruptures, and should be given extra special care. The type of material and the line pressure both are important factors relating to the dispersion of the material. Oil on the other hand will tend to pool or run off, depending on the terrain, and if it is in the ocean then it will tend to form a sheen on the surface of the water.

To categorize the impact due to dispersion, surface area amounts were chosen to represent low, moderate and high impacts. For a low impact rating an affected area of 5000 square feet or less was designated, and for a high impact rating an affected area of 1 square mile or greater was designated. The moderate impact value lies between the value of the low and high impact.

The dispersion of the material can be ascertained from the Bernoulli equation and through the application of fluid and gas dynamics. These methods will not be discussed here, but are only mentioned as a reference.

Table 3.2 has been developed to ease the decision-making procedure and summarizes all of the previously derived rating criteria.

Table 3.2: Impact scoring summary.

	LOW IMPACT SCORE: 1-10	MODERATE IMPACT SCORE: 11-20	HIGH IMPACT SCORE: 21-30
Number of people in area	1 or less	1 < # < 5	5 or more
Amount of private property damaged	$10,000	$10,000 < $ < $50,000	$50,000 or more
Leak detection method	Instrumentation	Detectors with Marginal Coverage	Visual Detection
Leak isolation method	Automated Valves without Operator Intervention	Valves Activated by Operator from a Control Room	Manually Operated Valves
Product characteristics upon release	Water Lines	Oil and Multiphase Pipelines with liquid to gas ratios of 2:1	Gas and Multiphase Pipelines with liquid to gas ratios of 1:2
Product's hazard rating	Water Lines	Oil Pipelines on Land	Gas Pipelines / Oil Pipelines Offshore
Product clean up	Sensitivity Index 1, 2	Sensitivity Index 3, 4, 5	Sensitivity Index 6, 7, 8, 9, 10
Product dispersion	$<5,000$ ft^2	5,000 ft^2 $<X<$ 1 mi^2	>1 mi^2

3.2 Impact Scoring

Once the rating of the impact potential has been finished, the next step is to designate the relative score as low, moderate, or high in nature. The minimum score that is possible is 8, while the maximum is 240. All scores therefore falling between 8 and 110 will be considered low impact, while all scores falling in the range of 111 and 200 will be considered as moderate impact failures. Scores of 201 to 240 will be considered high impact.

Depending upon the impact rating, an appropriate safety class is associated with the structure, which will result in the most economical maintenance action. For a more in depth rating of impact however, indexing methods are not as effective as concrete numbers obtained through long years of pipeline operation. Due to the fact that sometimes data is not available, or that it is too costly to analyze a large set of numbers, indexing methods are very effective tools to fall back on. The target probability of failure associated with each index is listed in Table 3.3.

Table 3.3: Table of target probability of failure

	LOW IMPACT	MEDIUM IMPACT	HIGH IMPACT
Impact Score	8 to 110	111 to 200	201 to 240
Target Probability of Failure	$< 5 \times 10^{-2}$	$< 8 \times 10^{-3}$	$< 1 \times 10^{-3}$

Again it is emphasized that the target probabilities are not the bottom line, and may be increased or decreased according to the choice of the owner. The probability of failure of a pipeline can be most easily decreased through the reduction of the operating pressure. Once flaws are present in a pipe, it is hard to decrease the probability of failure without decreasing the operating pressure. On the other hand future deterioration of the pipeline can be inhibited through the use of corrosion inhibitors and periodic cleaning of the pipe. Sections where larger flaws exist in the pipeline, specific repair options are usually available. The pipeline can be repaired at these locations by either replacing the old section or through hot tapping or patching the pipeline at the specific location of the flaw.

The key of course is to correctly assess the corrosion mechanism present in the system, and therefore have a reliable method of predicting failure probabilities for the pipeline. Only then can a decision be made with confidence.

4.0 Example

In this section a set of distributions is going to be developed for a mildly corrosive environment, and the various lifetime distributions plotted for each. It is also going to be discussed how these distributions can be easily adjusted to fit very corrosive to non corrosive environments.

In Appendix B, several hypothetical distributions were calculated for flaw sizes ranging from ¼ inches to 8 inches. The ranges for which calculations were performed were for ¼ inch flaws, 1 inch flaws, 2 inch flaws, 5 inch flaws and 8 inch flaws. Table 4.1 shows the assumptions used to develop the distributions.

	¼ inch	1 inch	2 inch	5 inch	8 inch
Number of Flaws upon which Distribution is Based	300	150	75	25	5

Table 4.1: Number of flaws upon which distributions were based.

The number of flaws were chosen randomly for this example, but when this technique is being applied to an actual pipeline, it is best to examine samples of failed pipe sections, and try to derive a representative number of flaws for which the distribution can be calculated for. Of course a more exact answer can be obtained by continuously observing the growth of flaws and each time an inspection is done to record the number of flaws present in the pipe. If in depth measurements can not be made then an upper limit for the flaw sizes can be chosen and a distribution calculated for the chosen number of flaw sizes. It should also be kept in mind that the distribution will partially correct for the fact that only the upper limit of flaw sizes was chosen. This is true because the probability of finding 75, 2 inch flaws before 5 years will be smaller than finding 20, 2 inch flaw sizes before 5 years. Due to the increased number of flaws though, when calculations are being carried out for the series of 75 flaws a higher probability of failure is going to be obtained. Table 4.2 illustrates the example.

	Probability of Failure (series system)	Likelihood of x Number of Flaws
20, 2 inch flaws	Lower	Higher
75, 2 inch flaws	Higher	Lower

Table 4.2: Self correcting tendency of model.

Of course it should be noted that it does not mean that the two calculations for different flaw sizes will be the same, but the answer should not be vastly different.

The lifetime distributions for the flaw sizes and numbers can be seen in Figures 4.1 through 4.4.

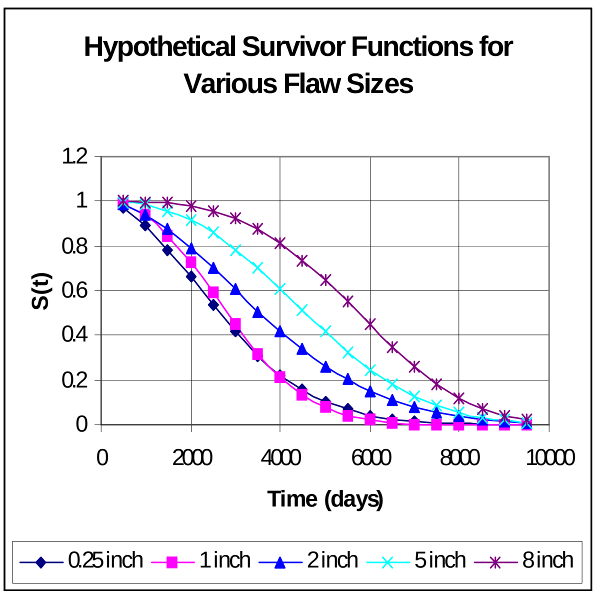

Figure 4.1: Hypothetical survivor functions.

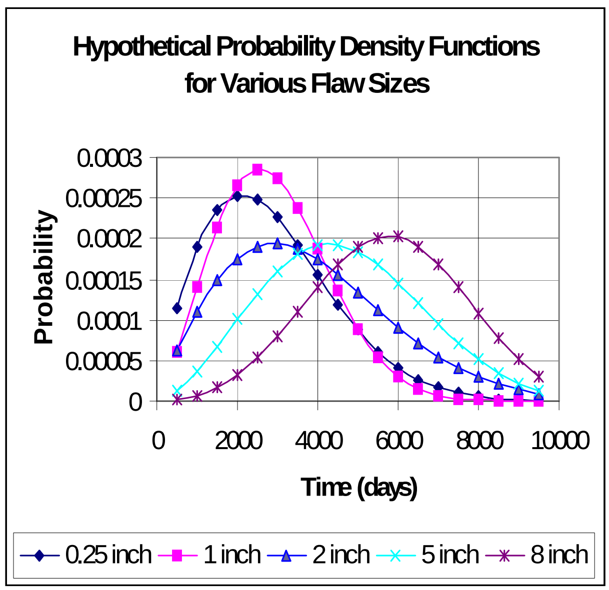

Figure 4.2: Hypothetical distribution functions.

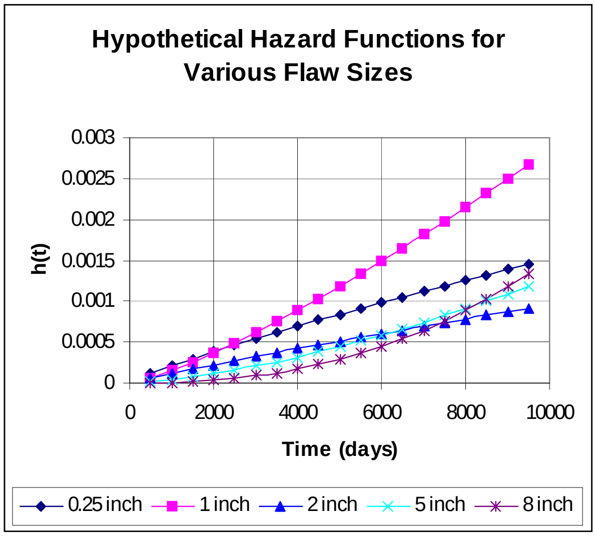

Figure 4.3: Hypothetical hazard functions.

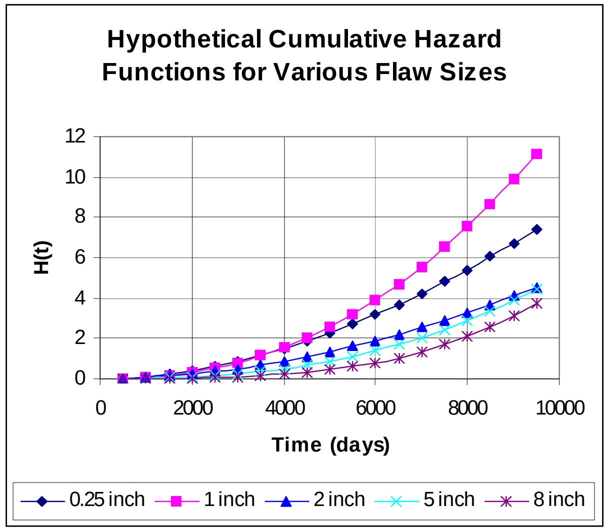

Figure 4.4: Hypothetical cum. hazard functions.

As can be seen from figures 4.3 and 4.4 the hazard function for the flaws is an increasing one which means that as time elapses the state of the pipeline becomes worse and worse.

At this point it is desired to know when an inspection can be scheduled. Due to the fact that there are a lot of small flaws present, it is uneconomical to replace all sections of pipes where small flaws are present, therefore the effort will be concentrated on large flaws. In this case 8 inch

$$h(t) = 5.1E - 13(t)^{2.37} \qquad \textbf{EQ. 29}$$

flaws are inspected, and it is found that the shape and scale parameters of the Weibull distribution are 3.37 and 1.56x10-4 respectively. Therefore the corresponding hazard function is

When the hazard function is integrated the cumulative hazard function is obtained, which gives the information: how many flaws may be expect by a certain time t. For example, looking at Figure 4.4 for 8 inch flaw sizes, at time 8000 (~22 years) the cumulative hazard function is about 2, which means that at this time the hazard has doubled, and there might be 10 instead of 5, 8 inch flaws present in the system.

After the first 5, 8 inch flaws are found, the occurrence of the next 5 can be calculated from the following equation given that the intensity function for the failures can be determined.

$$P\left[N(b) - N(a) = n\right] = \frac{\left[\int_a^b \lambda(t)dt\right] e^{-\int_a^b \lambda(t)dt}}{n!} \qquad \textbf{EQ. 30}$$

The hazard function previously calculated can be substituted for the intensity function and the value of the above equation will give the probability of the next 5, 8 inch flaws (n =1). This value of course will be somewhat different from that obtained by using strictly the cumulative hazard function. The value that is obtained of course depends upon the time interval being analyzed. Before a decision is made, the depth of the corrosion must also be taken into account.

5.0 Conclusions

The technique developed gives a rough estimate for the probability of failure of pipelines and can be utilized with effectiveness if some general knowledge is available about the pipeline. The two key components in obtaining the probability of failure is to one determine the amount of corrosion loss that the pipe has experienced or will experience, and two, determining the distribution of flaws in the pipeline. For simplicity, the pipeline can be treated as a one-piece system or if more accuracy is desired, then it can be divided into sections.

When the impact due to failure is calculated, it is crucial to divide the pipeline into sections, in order to differentiate between certain impact areas. The purpose of the process is to save money for the operating company through the application of a responsible system, but if vast generalizations are made the whole purpose can be defeated.

After developing the theory for the risk analysis for the corrosion failures of pipelines the next step is to implement the system on a database and automate the process. By doing this large amount of information can be processed quickly and a database is created for various pipelines and their characteristics. This will help future builders of pipelines to assess the risk associated with their venture, by analyzing old data for pipelines similar to theirs. Also, owners who can't pig their lines and do not have enough data on their pipeline can access the database and find pipelines similar to the ones they have, which will help them make better management decisions. This can be true for an operator who is taking over an old pipeline that has little or no information on it.

The database can be set up just like outlined in this report, but when there is a requirement for more accuracy and the data is there to provide the accuracy desired, then the database can be customized.

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Section IV: Design of Database for Performing Qualitative and Quantitative Risk Assessment of Unpiggable Pipelines

Acknowledgement

I would like to thank James Choo for providing me with the visual basic programming expertise that brought this database to reality. Without his expert knowledge and experience, it would not have been feasible to implement my theory to the fullest. James performed all the programming on this database, while I developed the theory and the structure for the database.

I also want to thank Professor Bea for trusting me to work out the problems associated with the database on my own and for encouraging me to find a solution. Many times, I thought that this project would be difficult to manage in the last semester of school, but the perpetual support of Professor Bea reassured me that a solution was at hand.

Introduction

The industrial world is leveraging the use of information technology for managing operations, and companies are developing integrated systems that are able to better handle operations. The first such use of computers by corporations has been to collect information about internal operations, but more and more the focus is switching to external data collection to assist strategic decision-makers.

The energy industry is also riding the wave of computer technology, and has been integrating computer systems into their operations for decades. However, the novelty of the current revolution is that managers and operators are able to track systems from their desks, and if need be, even from their laptops. The technology has been developed extensively to handle computations and large amounts of data, but the connecting software still has to be developed to realize the benefits of the technology.

Currently, the hottest growing occupation is that of database manager, which further reinforces the trend that data collection and analysis is taking a center stage for a large number of companies. Energy companies are currently in the midst of developing many databases that offer real-time information along with fast and reliable results. One area where database technology is being leveraged is the pipeline inspection and maintenance field.

Each energy company manages hundreds of pipelines in any given year, and therefore they are finding that it is worth while to invest in the technology that can manage their operations better. Pipelines are one of the major components of the energy industry and focus currently is on the management of these important lifelines. In the past, when there was a profusion of money in the industry, management of pipelines was less of a priority and money was diverted into exploration and development. With the increased competition worldwide however, it is becoming evident that pipeline management is an area where much money can be saved. Previously, pigging technology was not well developed, and therefore intelligent pigging was not considered a viable method of managing pipelines. Today on the other hand, pipelines are being designed so that they may be pigged, and at the same time pigs are becoming smaller, enabling more pipelines to be inspected.

Managing unpiggable pipelines poses an even more complicated question than managing piggable ones, because only a limited amount of data is available on unpiggable pipelines. The majority of pipelines in service can not be pigged, which leaves the question of, "How can the state of an unpiggable pipeline be determined?" One method of answering this question is to utilize data from piggable pipelines.

Every pipeline has certain identifying characteristics like the operating pressure, the material being transported, or the pH of the material being transported, and these characteristics can be used to match similar pipelines with each other. It should be realized however, that approaching the analysis from an "operating characteristics" angle only addresses one failure mode. The failure mode that is addressed is that associated with corrosion and flaws developed during corrosion processes. Corrosion processes are the leading cause of failure for pipelines and therefore it is a step in the right direction to analyze failure due to flaws caused by corrosion.

The database developed during this project addresses failure of pipelines due to corrosion, and both a quantitative and qualitative methodology is developed for addressing failure of unpiggable pipelines. The fundamental theory for the analysis has been summarized in the PIMPIS spring and summer reports, 1998 [2]. The quantitative theory for the database is summarized within this report however due to its complexity and to help the reader obtain a better grasp of the theory.

List of Symbols

1. b : y intercept of regression line
2. $d_{avg.}$: average depth of flaws; unique to a flaw size; average of matched piggable records for a given time in the pipeline's history
3. e: 2.7182818…….
4. $f(t)$: probability density function; time dependent
5. $h(t)$: hazard function; time dependent
6. $H(t)$: cumulative hazard function; time dependent
7. m: slope of regression line
8. n: strain hardening index
9. $n_{avg.}$: average number of flaws; unique to a flaw size; average of matched piggable records for a given time in the pipeline's history
10. $n_{exp..}$: expected number of flaws as calculated through the use of a piggable data
11. $\bar{p}_b$: mean burst pressure
12. p_b^{wl} : burst pressure of pipe with wall loss
13. $\bar{p}_o$: mean operating pressure
14. $P_{fIndividual}$: probability of failure due to an individual flaw
15. P_{fMax}: maximum probability of failure allowed for operating pipeline
16. $P_{fSystem}$: probability of failure of system taking into account individual flaws
17. R: mean radius of pipeline
18. $S(t)$: survivor function; time dependent
19. t: time
20. $t_{init..}$: initial thickness of pipeline
21. t_{min}: corroded thickness of pipeline
22. x_i: ith abscissa value used for regression calculations
23. $\bar{x}$: mean of abscissa values
24. y_i: ith ordinate value used for regression calculations
25. $\bar{y}$: mean of ordinate values
26. β: safety index
27. ϕ : fraction of circumference that is corroded
28. $\Phi(\beta)$: standard normal cumulative function
29. κ: shape parameter for Weibull distribution
30. λ: scale parameter for Weibull distribution
31. σ_b : standard deviation of the burst pressure

32. σ_{uts}: ultimate tensile strength of pipeline material

33. σ_o : standard deviation of the operating pressure

Theory for Quantitative Analysis

Quantitative analysis is considered in many cases to be the most accurate form of analysis, because it is based upon numbers. For unpiggable pipelines it is hard to obtain estimates for flaw distributions, and therefore data pertaining to piggable pipelines is utilized as much as possible.

The theory for quantitative analysis involves matching operating characteristics belonging to unpiggable pipelines with those of piggable pipelines, and organizing the data in such a manner as to obtain an estimate for the flaw distribution in unpiggable pipelines. Therefore, the first requirement is to have enough data present to be able to perform the analysis. In this case, enough pipeline histories must be present in the database so that when a search is performed enough matches are found to perform an analysis. The next step is to analyze the data in a coherent manner to make the analysis valid.

Once a set of piggable pipelines have been matched with the unpiggable one being analyzed and the corresponding data retrieved from the database, it is necessary to also account for the age differences that might exist between pipelines. What is taking place is an averaging process of data from the piggable pipelines, and therefore it is necessary to sample the data from the same point for all the piggable pipelines for the analysis to be valid.

The two most important characteristics that are of interest are the distribution of depths and the distribution of flaws. Therefore, the trend of these two characteristics needs to be analyzed. For the reason of simplicity it is assumed that the trend of flaw growth and depth growth can be represented by a linear regression line that has a slope *m*, and a zero intercept. The slope of this line can be calculated using Equation 1.

$$m = \frac{\sum_{i=1}^{n} y_i x_i}{\sum_{i=1}^{n} x_i^2} \qquad \textbf{EQ. 1}$$

The resulting graph of the data looks like the graphs shown in Figure 1.

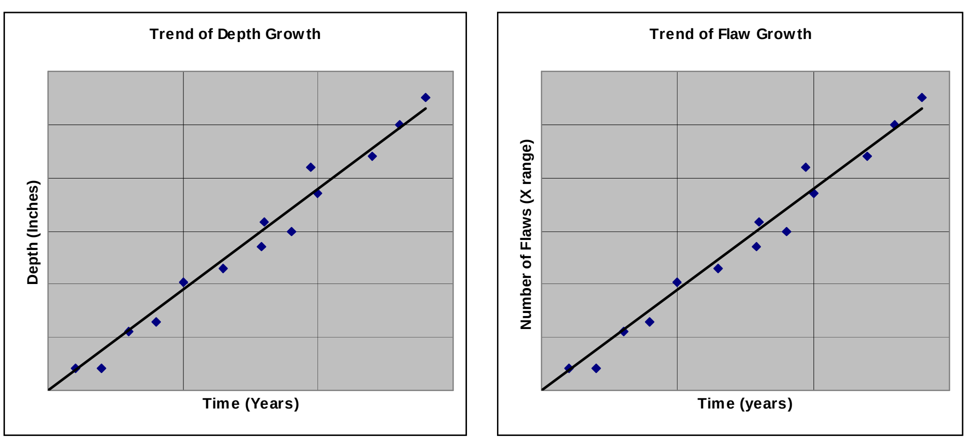

Figure 1: Trend analysis of flaws and depths for a piggable pipeline.

Next it is desired to develop a flaw and depth distribution for the unpiggable pipeline. To analyze the depth trend for an unpiggable pipeline, the first task is to "enter" the graph of each retrieved record for piggable pipelines along the time axis, where the value of time equals that of the age of the unpiggable piepline. See Figure 2.

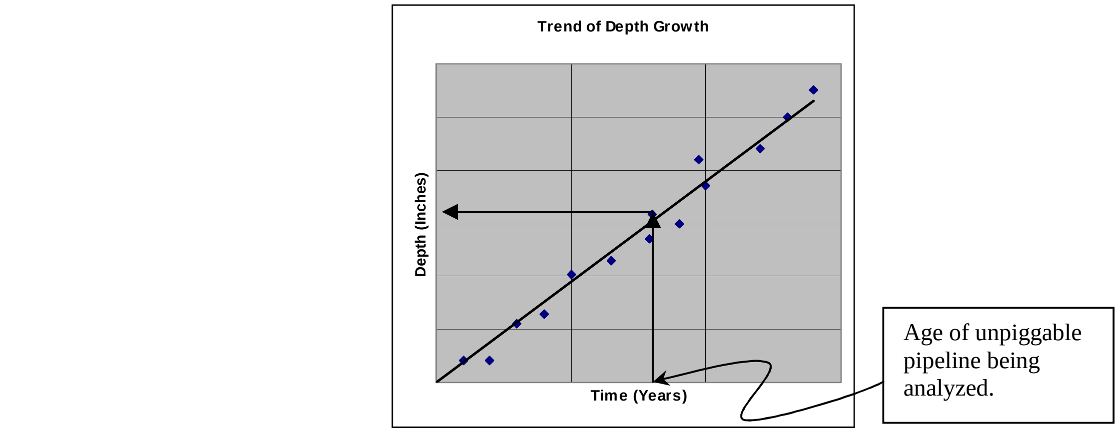

Figure 2: Determine number of flaws present, of a certain range in piggable pipeline, at time equal to age of unpiggable pipeline.

Once all the depths for the piggable pipelines have been calculated that correspond to the time equal to the age of the unpiggable pipeline, the data is collected and averaged. Therefore, now we can predict that at time *X* the unpiggable pipeline had a certain type of flaw with an average depth *Y* according to the data that is available to us. The next step is to determine the time distribution for developing *Y* depth for the flaws. For this step, the previous procedure is reversed, and the graph in Figure 2 is "entered" along the ordinate and a corresponding time is read for each piggable pipeline which in essence will provide a distribution for the unpiggable pipeline. See Figure 3.

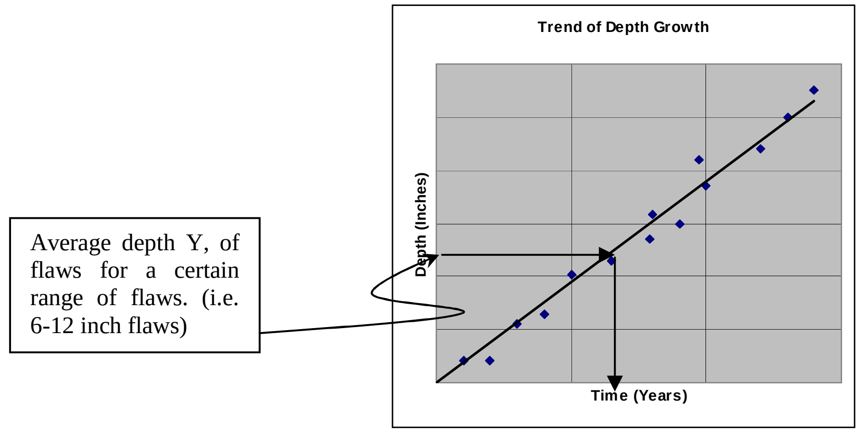

Figure 3: Time to develop *Y* depth for a certain flaw range (i.e. 6-12 inch flaws). Time value obtained from graph is subsequently used to develop a distribution for developing *Y* depth for a certain range of flaws.

Now that a range of duration to develop Y depth has been determined, the next step is to fit a distribution to these values. For our purpose the Weibull distribution was chosen due to its versatility in representing various distribution shapes. The Weibull distribution is described in Equation 2. For further details the reader is referred to the PIMPIS summer report of 1998 [2].

$$S(t) = e^{-(\lambda t)^{\kappa}} \quad f(t) = \kappa \lambda^{\kappa} t^{\kappa-1} e^{-(\lambda t)^{\kappa}} \quad h(t) = \kappa \lambda^{\kappa} t^{\kappa-1} \quad H(t) = (\lambda t)^{\kappa} \quad \textbf{E}\text{Q.2}$$

In Equation 2 for all time, t >0, $\lambda > 0$ and $\kappa > 0$ and are called the scale and shape parameters of the distribution, respectively. *S(t)* is the survivor function, *f(t)* is the probability density function, *h(t)* is the hazard function and *H(t)* is the cumulative hazard function.

To fit a set of data to the Weibull distribution, the data points first have to be arranged in ascending order. Once this has been done, each point is assigned a percentile that is respective of the order. For example, if there are 5 data points, the first point represents the 1/5 percentile (20%), the second is the 2/5 percentile and so on. This can be further expanded depending on how many points are available.

The next step is to fit the distribution, and this can most easily be performed graphically, but fundamentally it is a mathematical procedure. First the data points are plotted, as shown in Figure 4.

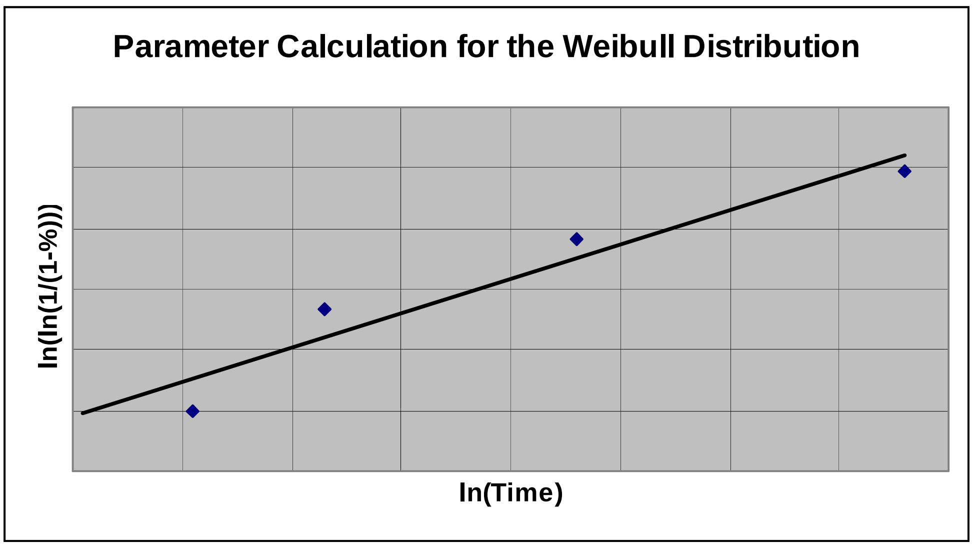

Figure 4: Calculation of the shape and scale parameter for the Weibull distribution.

A convenient feature of the Weibull distribution is that when it is plotted in the manner presented in Figure 4, the shape and scale parameters can be determined from the slope and intercept of the linear regression line. The slope of the line can be determined by using Equation 3.

$$m = \frac{\sum_{i=1}^{n} (x_i - \bar{x})(y_i - \bar{y})}{\sum_{i=1}^{n} (x_i - \bar{x})^2} \qquad \textbf{EQ. 3}$$

The intercept on the other hand can be determined by the use of Equation 4.

$$b = \bar{y} - m\bar{x} \qquad \textbf{EQ. 4}$$

Reverting back to Equation 2, the scale and shape parameters are λ and κ for the distribution respectively. The slope of the graph yields the shape parameter, and the scale parameter is equivalent to $e^{(b/m)}$. Knowing these two values, the distribution for the flaws can be plotted. The distribution therefore represents the probability of having *Y* number of flaws in the unpiggable pipeline at various times. It must also be kept in mind that the distribution is fitted according to the age of the unpiggable pipeline and therefore is most accurate at the "present time" of analysis. At any other "time" the reliability of the results tends to decrease. For a more accurate time-history analysis it is recommended that various scenarios are investigated and a trend obtained from such an analysis. Weibull distributions with various shape parameters are shown in Figure 5.

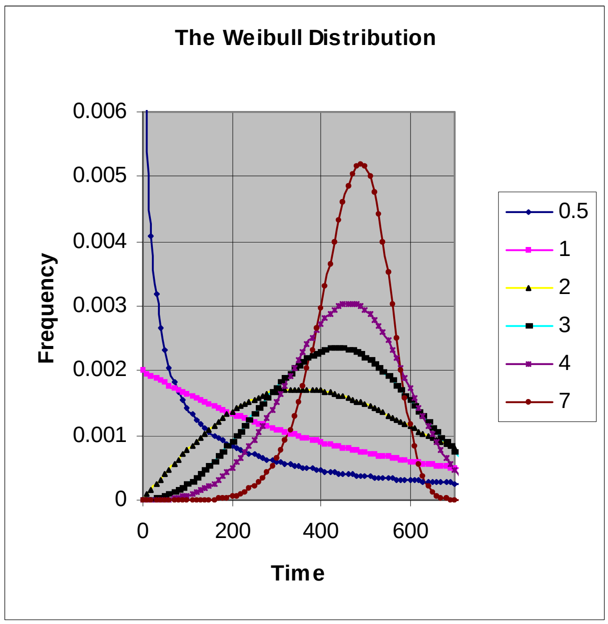

Figure 5: The varying shape of the Weibull distribution as the shape parameter changes. More peaked curves represent higher shape parameters.

Proceeding further with the analysis, the next step is to determine the burst pressure for a particular flaw type. The burst pressure equation used to calculate the burst pressure, $p^{wl}{}_{b}$, is shown in Equation 5. [5]

$$p_b^{wl} = \left(\frac{2}{1-\phi}\right)^n \frac{t_{\min}}{R}\left[\left(\frac{1}{2}\right)^{n+1} + \left(\frac{1}{\sqrt{3}}\right)^{n+1}\right]\sigma_{uts} \qquad \textbf{EQ. 5}$$

ϕ in Equation 5 represents the percentage of the circumference that has been corroded, n is the strain hardening index, $t_{\min}$ is the minimum thickness, R is the radius, and σ_{uts} is the ultimate tensile strength of the steel used for the pipe. $t_{\min}$ however is dependent on the distribution of the flaw depths, and therefore can be represented by Equation 6.

$$t_{\min} = t_{init.} - d_{avg.}\left(1 - e^{-(\lambda t)^{\kappa}}\right) \qquad \textbf{EQ. 6}$$

In Equation 6, $d_{avg.}$ is the average depth of a certain range of flaws, which was calculated using the numbers obtained from the piggable pipeline data. It is emphasized, once again that this average depth is calculated using the pipeline characteristics and the age of the unpiggable pipeline. Therefore, this is an "average depth" that is multiplied by the probability of its occurrence, and does not per se represent a depth that is changing dynamically. What is changing dynamically however is the probability that a depth equal to the average depth will occur in any given year. Performing the analysis on an unpiggable pipeline at different ages yields different results and therefore it is recommended that this analysis be performed every year.

The number of flaws also plays an important part in the calculations, and a similar analysis can be performed. The number of flaws expected at any given time can be calculated using Equation 7.

$$n_{\exp} = n_{avg}\left(1 - e^{-(\lambda t)^{\kappa}}\right) \qquad \textbf{EQ. 7}$$

Equation 7 is utilized when the total probability of failure is desired, and it is applied to Equation 7a.

$$P_{fSystem} = 1 - \left(1 - P_{fIndividual}\right)^{n_{\exp}} \leq P_{fMax} \qquad \textbf{EQ. 7a}$$

To calculate the probability of failure associated with the corroded thickness $t_{\min}$, Equation 8 can be utilized.

$$P_{fIndividual} = 1 - \Phi(\beta) \qquad \textbf{EQ. 8}$$

β is the safety index and can be evaluated through the use of Equation 9 and Φ is the standard normal cumulative function.

$$\beta = \frac{\overline{p}_b - \overline{p}_o}{\sqrt{\sigma_b^2 + \sigma_o^2}} \qquad \textbf{EQ. 9}$$

In Equation 9, σ_b is the standard deviation of the mean burst pressure, σ_o is the standard deviation of the mean operating pressure, and the terms in the numerator are the mean burst and operating pressures for the pipeline. For the calculations in Equation 9, all terms are provided for in the database, except for the standard deviation of the burst pressure. The standard deviation of the mean burst pressure is taken to be 20% of the mean burst pressure for all cases. In the future, this aspect of the calculation can be made more dynamic, but for the present time, it is deemed satisfactory for calculating the probability of failure. [6]

Due to the fact that Equation 8 can not be evaluated directly, the series in Equation 10 was utilized to obtain a value for the standard normal cumulative distribution, Φ.

$$P(\beta) = \frac{1}{2} + \frac{1}{\sqrt{2\pi}} \sum_{n=0}^{\infty} \frac{(-1)^n \beta^{2n+1}}{n! 2^n (2n+1)} \qquad \textbf{EQ. 10}$$

In Equation 10, n is the number of iterations used and β is the safety index, same as defined before. This concludes the quantitative analysis of the probability of failure for unpiggable pipelines, and next the qualitative analysis is discussed.

Theory for Qualitative Analysis

The qualitative analysis for the database was the application of the theory developed during the spring of 1998, which was also accompanied by a report. Summarizing the findings of that report briefly is Equation 11.

$$CorrosionLoss = \left[1 + e^{(1-Nt)}\right]\left[\log(1+t)\right]^{P}\left[1 + \frac{1}{(1+t)}\right]\left[t^{\frac{1}{3}}\right] \qquad \textbf{EQ. 11}$$

The corrosion loss of a metal can be estimated by Equation 11, but certain parameters like N and P must be determined first. The corrosion loss is calculated in mils and *t* has the units of years. The initial value of N and P are dependent upon the type of steel that is being used for the pipe, and Table 1 summarizes what these values are for various metals. For further details refer to the Spring 1998 PIMPIS report [1].

*VALUES FOR ATMOSPHERIC CORROSION	**P**	**N**
Mild Steel	14	1.5
Low Alloy Steel	10	2
Nickel Iron Alloys	5	3.5
Stainless Steel	1.5	7
Titanium	0.25	10

Table 1: Derived values of N and P for Equation 11.

These values, as stated in the table, have been derived for atmospheric corrosion, and therefore need to be adjusted for the specific condition that is present in the pipeline. The major characteristics that were accounted for is pH, and flow characteristics, because both play an important role in the metal's ability to develop a passive film. The relationship of pH to N and P is summarized by Equation 12.

$$P_{new} = P_{orig}^{\left(\frac{2.8}{pH^{0.47}}\right)} \qquad N_{new} = N_{orig}^{\left(\frac{2.8}{pH^{0.47}}\right)^{-1}} \qquad \textbf{EQ. 12 (a \& b)}$$

Next, the relationship between head-loss and flow characteristics is accounted for by the use of Equation 13. For a more in depth explanation of the theory for these calculations, the reader is referred to the Spring 1998 PIMPIS report.

$$P_{new}^{*} = P_{new}\left[\left(1.05 - \frac{\%HL_{TotalLength}}{100}\right)\frac{\%Length}{100} + \frac{\%HL_{TotalLength}}{100} + 0.20\right] \qquad \textbf{EQ. 13}$$

N is not affected by the flow characteristics, and therefore does not need to be adjusted. *P* on the other hand needs a multiplication factor that changes with varying head loss over the total length of the pipeline, and also according to the location of the analysis along the pipeline's length. For example if the calculation is desired at the mid point of the pipeline's length, the value of %Length would be 50% and so on. Upon entering all the relevant data into the database the probability of failure is calculated in the same manner as for the qualitative analysis. Refer to

Equations 8, 9 and 10. The standard deviation for the burst pressure however is taken to be 0.4 times the burst pressure calculated using the given data. [1]

Database Installation Instructions

The database for the PIMPIS project is in Access 97 format and is called Pipeline Management. The data that accompanies the database structure is included in the file named Pipeline Management Data. When opening the database activate the Pipeline Management file, not the data portion.

If the database is copied to another disk or hard drive, some additional steps must be performed. After copying the database it is always necessary to link tables, because the copying process eliminates the links between the data and the control module of the database. The disk that is included with this report has a fully functioning version of the database, but if a copy of the database is desired on another disk the tables have to be linked once the copying process is finished. To link the tables follow the procedure outlined below:

- Click the **Tools** button on the header
  - Then **Add-Ins** and select
    - **Linked Table Manager** - **Select all** and press **OK**
    - Select the **Pipeline Management Data** file component of the database and press **OK**

Now the database can be operated.

The disk included with this report also contains an MDE version if the database, which is a version of the database that can not be edited. All the tables can be updated with new data, tables can be modified minimally, and queries can be changed, but the forms and programmed modules can not be edited. Changes to this file might prevent the database from functioning correctly so caution must be used if editing is desired.

On the other hand, changes to the full file called Pipeline Management can be made. Changes to one part of the database might affect another part so changes to all the relevant parts of the database must be performed which the initial change affects. To do this however a complete understanding of the database structure is necessary.

Database User Interface

The interface of a database is functionally a gateway for the user to access the data in the database and to manipulate it. Users in the future might potentially use the database many times a day, and therefore it must be designed in an ergonomic fashion. The interface of the PIMPIS database still needs improvement, but the foundations have been set for future work.

Upon opening the database, the user is met with the main switchboard that contains three options. See Figure 6. The three options are labeled as "Operating Characteristics - Piggable", "Inspection Results" and "Operating Characteristics - Unpiggable".

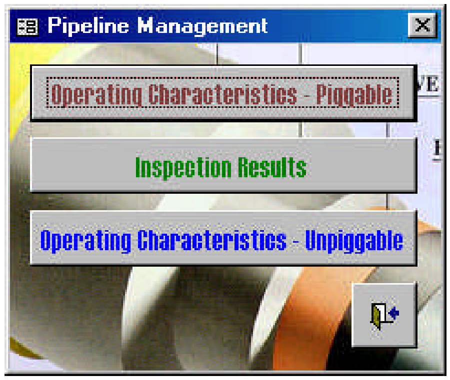

Figure 6: Main switchboard for PIMPIS.

Upon clicking on the "Operating Characteristics - Piggable" button the form in Figure 7 is activated. This form contains information on the operating characteristics of the piggable pipeline, as well as the inspection results that were done with pigs.

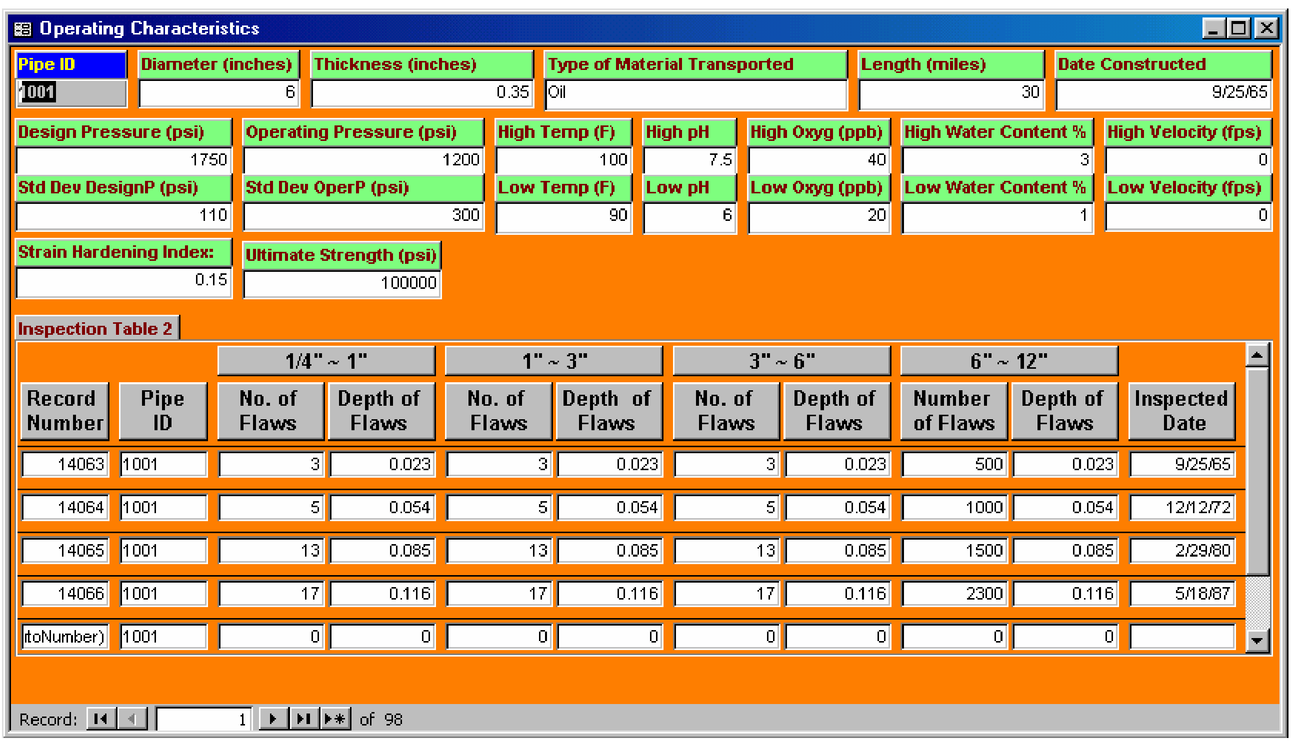

Figure 7: Operating characteristics form for piggable pipelines.

The data on the form can be organized into three different categories. The three categories are: physical characteristics, operating characteristics, and inspection results. Each of these categories is further subdivided as shown in Table 2.

Physical Characteristics	Operating Characteristics	Inspection Results
Diameter (inches)	Design Pressure	1/4"-1" No. Flaws
Thickness (inches)	Std. Dev. Design Pressure	1/4"-1" Flaw Depth
Length (miles)	Operating Pressure	1"-3" No. Flaws
Date Constructed	Std. Dev. Operating Pressure	1"-3" Flaw Depth
Strain Hardening Index	High Temperature (^{0}F)	3"-6" No. Flaws
Ultimate Tensile Strength	Low Temperature (^{0}F)	3"-6" Flaw Depth
	High pH	6"-12" No. Flaws
	Low pH	6"-12" Flaw Depth
	High Oxygen Content (ppb)	
	Low Oxygen Content (ppb)	
	High Water Content (%)	
	Low Water Content (%)	
	High Velocity (fps)	
	Low Velocity (fps)	

Table 2: List of fields on the Operating Characteristics Form.

The physical characteristics listed in the Table 2 were chosen according to how important they were in the calculation of the probability of failure. The physical characteristics represented in Table 2 are the most basic characteristics and if it is desired in the future to augment this portion of the database it can be done so without difficulty. The operating characteristics to be listed in the database were chosen as the characteristics that are most important to predicting corrosion in a pipeline. Therefore when performing searches of the database to analyze an unpiggable pipeline, it is recommended that the operating characteristics be used to search the database as much as possible.

The inspection results of the database is divided into several categories of flaw sizes and their depth. The number of flaws in each range of flaw sizes is a count of the number of flaws that are in that range per mile. Even though in a database many records can be entered, it has been designed to only store ranges of flaws to minimize the number of records in it. If the characteristic of each flaw is recorded in the database every time an inspection is performed, the memory requirements would be very large, a task for which Access is not suited for. The flaw size refers to the circumferential length of the flaw, but usually the longitudinal length is as large or larger than the circumferential length. The important concept here is to realize that for burst calculations the circumferential length of the flaw is what controls the burst pressure. Figure 8 shows the form used to enter the inspection results for piggable pipelines into the database.

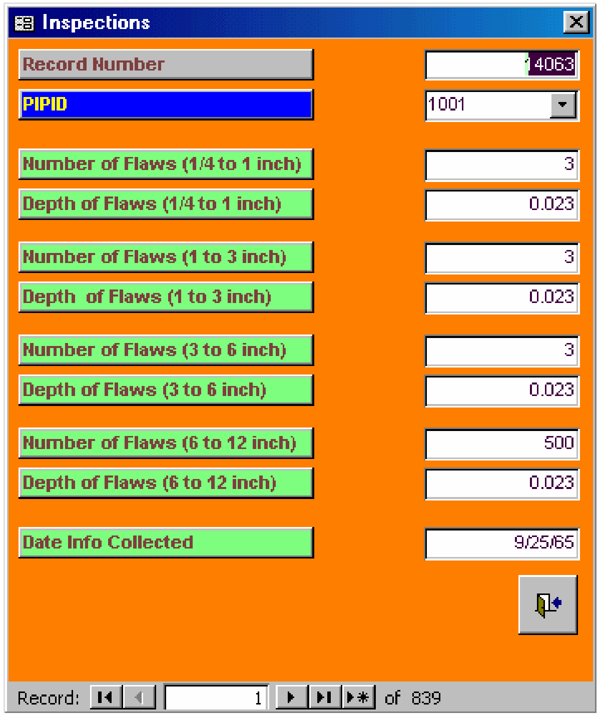

Figure 8: Inspections form for piggable pipelines.

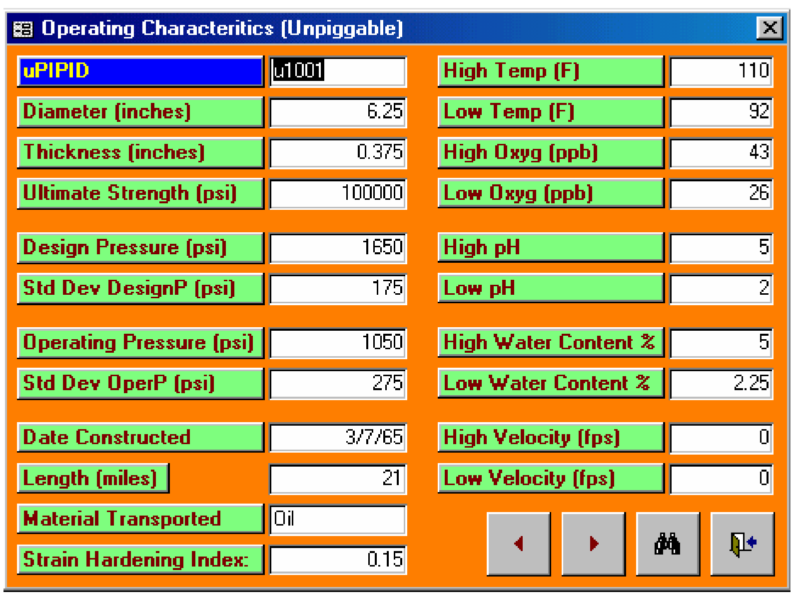

Figure 9: Operating characteristics form for unpiggable pipelines.

The operating characteristics recorded for the unpiggable pipelines are the same as those recorded for the piggable pipelines, but this is the only information that is known about these pipelines. These characteristics are used to search the piggable pipeline record set to perform any analysis on the unpiggable pipelines. The corresponding form can be found in Figure 9. To search the database, the button on the form with the binoculars is utilized. Upon pushing the button, the form in Figure 10 is activated.

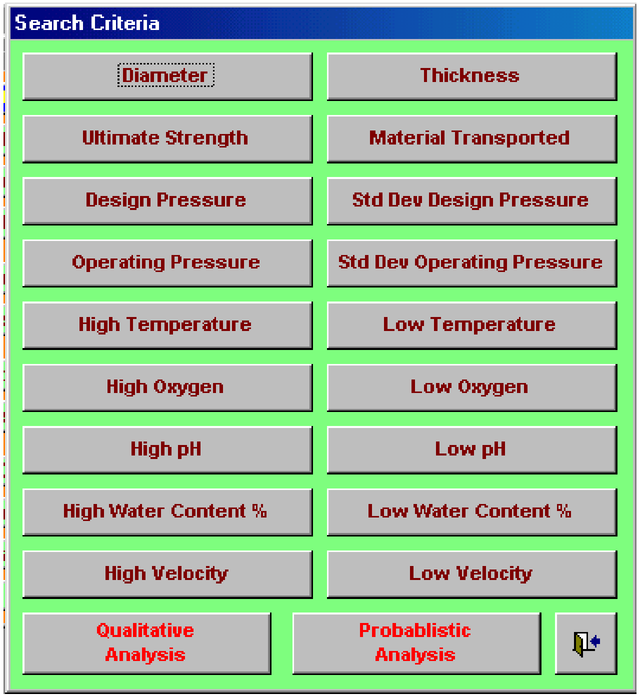

Figure 10: Search criteria form where selections are made to control the search of the database.

In the search criteria form, when a button is activated, the database is searched according to the criteria listed on the button. Operating characteristics are searched according to high and low recorded values, and physical characteristics are searched according to values that are between 25% above and below the specific physical characteristic chosen. For example, if the button with the word "Thickness" on it is activated, the database is searched for piggable pipelines that have a thickness that falls between 0.75 and 1.25 times the thickness of the unpiggable pipeline. The same is performed for the diameter, design pressure, and operating pressure characteristics. The buttons for the standard deviation are also shown, and searches for these characteristics are performed in the same manner as for the characteristics listed above.

To perform the analysis, the appropriate buttons are chosen, and the button for "Probabilistic Analysis" is activated. If matching records are found, then the form in Figure 11 is activated. The two fields on the left hand side of the form show the average number of years that the searched pipelines require to develop a certain depth or number of flaws. For a review of the theory behind the quantitative analysis the reader is referred to the quantitative analysis section of this report and to Figure 3.

The three fields to the right illustrate the expected depth and the expected number of flaws as calculated by the database for each year that the pipeline is in operation. To print reports of the probability of failure and the expected number of flaws and the expected remaining thickness of the pipeline, the buttons at the bottom of the form can be utilized.

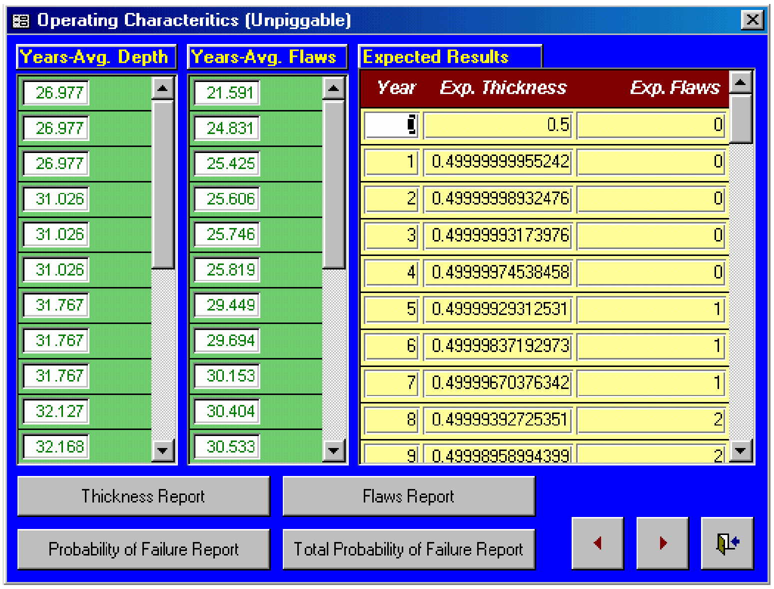

Figure 11: Form used to review the results of calculations performed by the database, according to the search criteria specified in the "Search Criteria" form.

The various reports that are capable of being produced are a thickness report, flaws report, probability of failure report and a total probability of failure report.

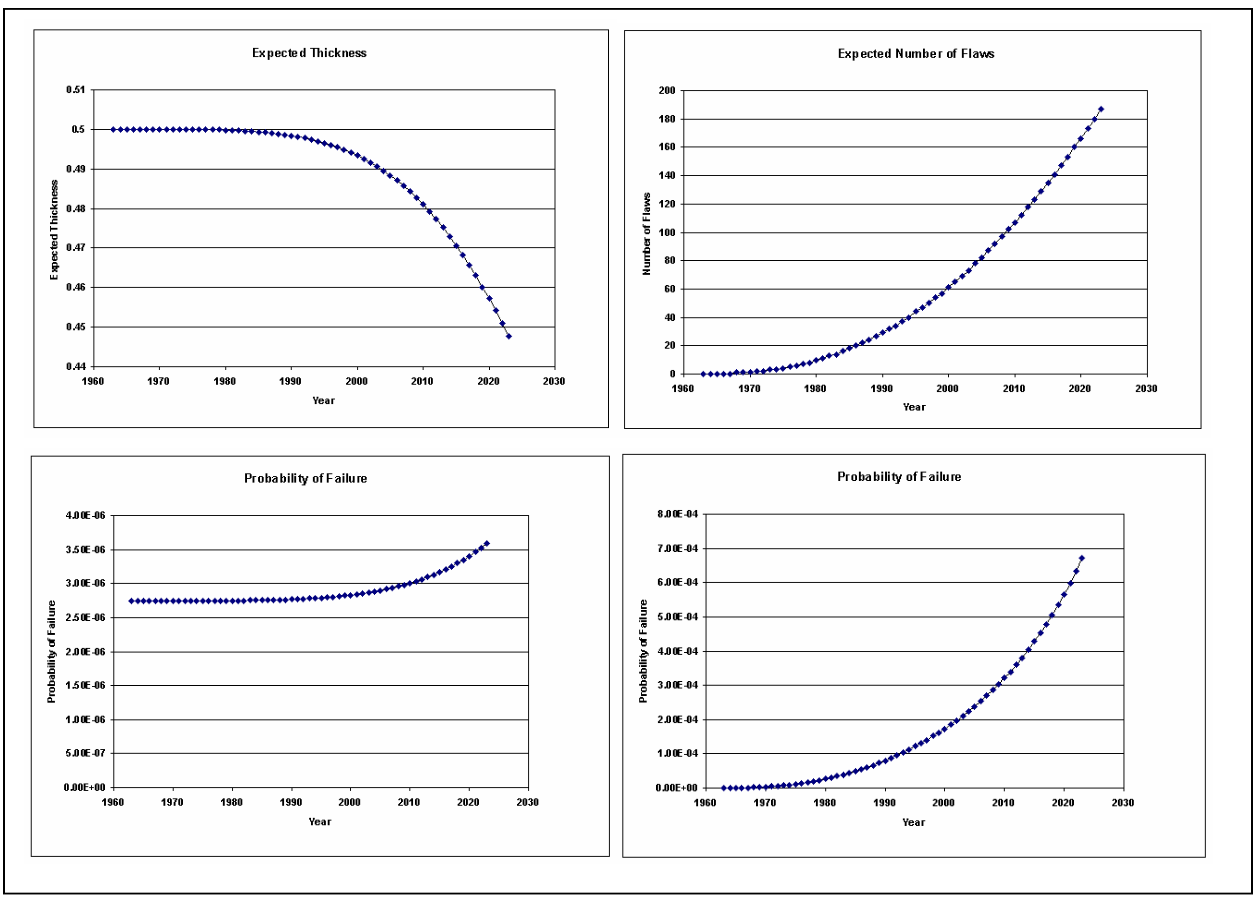

Figure 12: Various reports produced by the pipeline inspection, maintenance and performance information system.

Figure 12 shows the results of the various reports for a specific case. The difference between the two probability of failure reports is that the total probability of failure represents the probability of failure when all 6 to 12 inch flaws are accounted for. The simple probability of failure on the other hand is only dependent upon the reduced thickness of the pipeline. The total probability of failure represents the probability of failure per mile of pipeline. If the data is grouped according to some other criteria than per mile, than the new grouping controls the probability of failure.

The second type of analysis that can be performed is that of qualitative analysis. To run a qualitative analysis the "Qualitative Analysis" button is activated. The corresponding form that appears is the Qualitative Analysis form. See Figure 13. With the qualitative analysis only several criteria like the type of steel, percent head loss, and percent length where the analysis is taking place needs to be specified. For further information on this analysis the reader is referred to the Spring 98 PIMPIS report.

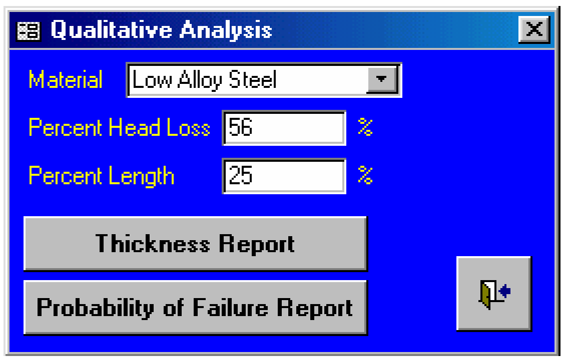

Figure 13: Qualitative analysis form.

After performing the qualitative analysis, the results shown in Figure 14 are obtained.

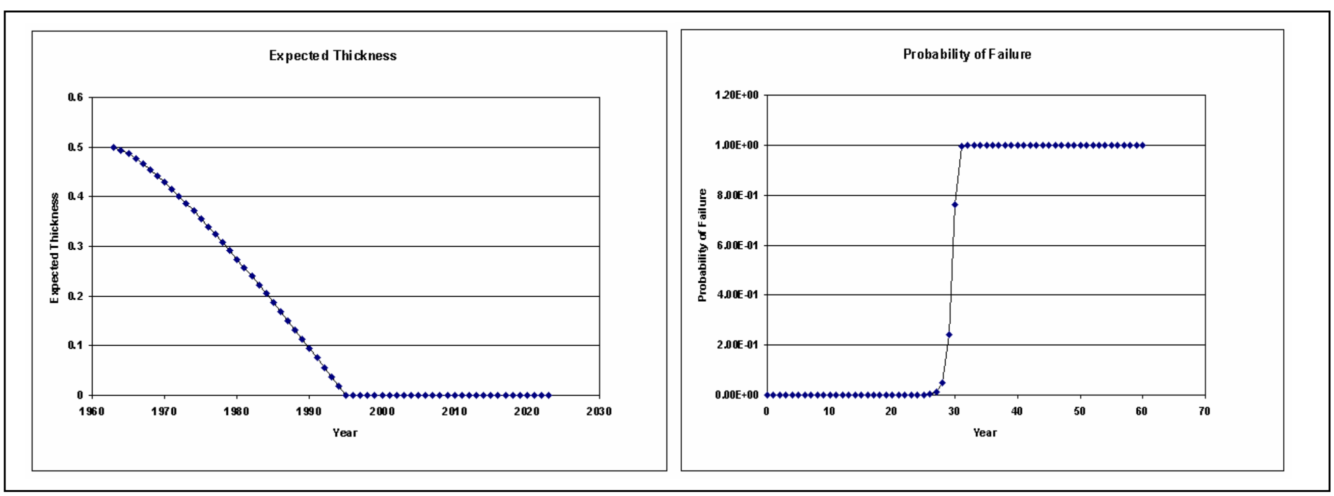

Figure 14: Expected thickness and probability of failure report for qualitative analysis.

The results of the analysis are case specific and apply to a certain section of an unpiggable pipeline only. For example the numbers in Figure 14 are representative of a pipeline that is constructed from a low alloy steel, has a head loss of 56% and the analysis is at 25% of the total length. It should also be noted that the probability of failure is calculated in the same manner as in the quantitative analysis except corrosion is assumed to be uniform over the total circumference of the pipeline. Therefore the number of flaws is irrelevant in this calculation.

This concludes the description portion of the database report. It must be kept in mind that this is an alfa version of the knowledge-based system for predicting the probability of failure of a pipeline. A much more comprehensive database system can be developed in the future, that incorporates other failure modes and analyzes the corrosion failure mode in an even more comprehensive manner.

Conclusion

The purpose of any tool is to help the user perform a function that is difficult to perform. In this case, the purpose of the database is to help pipeline management personnel make better decisions when they are dealing with unpiggable pipelines. Analysis for a piggable pipeline is only dependent upon data, and therefore as long as data is available, decisions can always be backed by data. In the case of unpiggable pipelines, data is not available so two analysis methods have been developed.

The quantitative analysis is highly dependent upon piggable pipeline data, but the main aspect of this technique is to leverage existing knowledge of piggable pipelines for analyzing unpiggable pipelines. In essence this is the most accurate method of performing an analysis for unpiggable pipelines, but the data requirements are relatively high. The analysis requires a minimum number of piggable pipeline records to be available and for these records to be similar to the unpiggable one. Searches can be limited or expanded depending upon how many search criteria are chosen, but the key is that the user has the option to choose. This flexibility in the analysis enables the user to perform either a very comprehensive analysis or a watered down analysis.

The qualitative analysis on the other hand is only dependent upon the data about the physical and operating characteristics of the unpiggable pipeline. The main portion of this analysis is dependent upon the corrosion prediction method used, and therefore the majority of potential error is rooted in this equation. The key however is that with time the equation can be refined and therefore made more accurate. It is recommended that before the system is implemented test be performed to validate the accuracy of the corrosion loss prediction equation.

If the analysis can be refined to a point where the confidence in the risk assessment due to corrosion is high, focus can be shifted to analyzing other failure mechanisms associated with pipelines. To complete the analysis, the final step is to perform a consequence analysis due to failure. For this last step, every pipeline will be unique but the factors associated with consequences need to be defined and the most influential ones highlighted.

Finally the risk assessment can be combined with the consequence assessment, and the expected cost of failure can be calculated to help owners manage their pipelines. The analysis system can also be made robust enough to handle maintenance schedules, and to analyze the pipelines in real time. The key to performing all the tasks listed above is decomposing the problem into its major components, and developing a solution that is practical and simple to implement.

References

1. Botond Farkas, Robert Bea. "Pipeline Inspection, Maintenance and Performance Information System Progress Report: Spring 1998". Marine Technology and Management Group, University of California, Berkeley.
2. Botond Farkas, Robert Bea. "Pipeline Inspection, Maintenance and Performance Information System Progress Report: Summer 1998". Marine Technology and Management Group, University of California, Berkeley.
3. Kroenke, David M. "Database Processing: Fundamentals, Design and Implementation". Sixth Edition, Prentice Hall Inc., Upper Saddle River, NJ 1998.
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5. F. J. Klever, G. Stewart. *New Developments in Burst Strength Predictions for Locally Corroded Pipes.* Shell International Research, March 1995
6. Bea, Robert. Smith, Charles. "A General Pipeline Suitability for Service Assessment System: RAM Pipe". 9th International Offshore and Polar Engineering Conference & Exhibition, May 30th - June 4th 1999.

Appendix A

Data points used in the calibration of the corrosion loss equation. The following bulleted list outlines the characteristics of the data used to calibrate the equation.

- For Steel only 10% of oxidation byproduct remains on metal when inspected
- Low Alloy Steels - Rust is darker in color and finer in grain than formed on ordinary steel
- When bacteria are present corrosion could be as high as 10 mm/year
- Atmospheric/Sea water Corrosion Usually is highest around Low Tide Line
- As one goes deeper and deeper in water the corrosion rate decreases

	8 year exposure

Type of Metal	Remarks	Location	Corrosion Loss (mm)	Corrosion Loss (mils)	Corrosion Rate (mm/yr)	Corrosion Rate (mils/yr)	Corresponding P	Corresponding N
Iron / Wrought Iron								
8 years	Atmosphere	Cristobal, Panama Canal Zone	0.559	22.000	___	___	9.7	___
8 years	In Pacific Ocean	Off Panama Canal	0.406	16.000	___	___	7.75	___
8 years	In Pacific Ocean	Off Panama Canal	___	___	___	___	___	___
8 years	In Pacific Ocean	Off Panama Canal	___	___	___	___	___	___
1 year	Ingot Iron Exposed for a Year (Salt Content of Air <0.2	Nigeria	___	___	0.044	1.73	5	5.1
Mild Steel / Carbon Steel / Cast Iron	Rural or Suburban	Godalming	___	___	0.048	1.890	5	6
1 year		Llanwrtyd Wells	0.200	7.874	0.069	2.717	7,8	6, 4.25

1 year		Teddington	___	___	0.07	2.756	7	6
1 year	Marine	Brixham	___	___	0.053	2.087	5, 6, 7	7, 4, 1.2
Great Britain		Calshot	___	___	0.079	3.110	10, 7.4	1.3, 30
1 year	Industrial	Motherwell	___	___	0.095	3.740	11, 10, 9	1, 5.5, 11
1 year		Woolwich	___	___	0.102	4.016	12, 10, 11	1, 7, 5
1 year		Sheffield	0.750	29.528	0.135	5.315	15, 14, 13	1, 5.75, 8.75
1 year		Frodingha m	___	___	0.16	6.299	15, 16, 17	1, 7, 5.3
1 year		Derby	___	___	0.17	6.693	19, 18, 17	1, 5, 5.7
1 year	Rural or Suburban	Khartoum	___	___	0.003	0.118	0.2, 0.5	1, 2
1 year		Abisko, North Sweden	___	___	0.005	0.197	0.2, 0.5	10, 0.23
1 year		Delhi	___	___	0.008	0.315	0.3, 0.5	0.25, 10
1 year		Basrah	___	___	0.015	0.591	0.5, 1	0.25, 0.7
1 year		State College, PA, USA	___	___	0.043	1.693	5, 3, 6	6, 0.67, 3
1 year		Berlin-Dahlem	___	___	0.053	2.087	5, 6, 7	7, 4, 1.2
1 year	Marine	Singapore	___	___	0.015	0.591	0.5, 1	0.25, 0.7
1 year		Apapa, Nigeria	___	___	0.028	1.102	2.9, 5	1, 1.2
1 year		Sandy Hook, NJ, USA	___	___	0.084	3.307	9.5, 12, 15	1, 3, 1.7
1 year	Marine / Industrial	Congella, South Africa	___	___	0.114	4.488	12.5, 15, 17	1, 3.2, 2.7
1 year	Industrial	Pittsburgh, Pa, USA	___	___	0.108	4.252	12.5, 15, 17	12.5, 15, 17
1 year	Marine, surf beach	Lagos	___	___	0.615	24.213	___	___
				Sum	2.072	81.575		
				Mean	0.094	3.708		
				Standard Deviation	0.126	4.965		

				COV	1.339	1.339		
0.56	Sea Water	total immersion	___	___	0.143	17.294	___	___
0.56	Sea Water	total immersion	___	___	0.143	17.272	___	___
0.56	Sea Water	total immersion	___	___	0.148	17.284	___	___
0.56	Sea Water	total immersion	___	___	0.143	17.379	___	___
0.56	Sea Water	total immersion	___	___	0.140	17.457	___	___
0.56	Sea Water	total immersion	___	___	0.140	17.517	___	___
0.56	Sea Water	total immersion	___	___	0.136	17.575	___	___
0.56	Sea Water	total immersion	___	___	0.143	17.628	___	___
0.56	Sea Water	total immersion	___	___	0.158	17.672	___	___
				Sum	1.294	17.559		
				Mean	0.144	17.410		
				Standard Deviation	0.006	0.154		
				COV	0.043	0.009		
15 years		Halifax, Nova Scotia	___	___	0.108	4.252	34	1
Mild Steel	Natural Water	Plymouth	___	___	0.065	2.559	20	1
5 years	Natural Water	Emsworth	___	___	0.065	2.559	14, 12	1, 3
15 years	Natural Water	Plymouth (reservoir)	___	___	0.043	1.693	13	___
5 years	Natural Water	La Cadene (granite bed)	___	___	0.068	2.677	14, 12	1.3
5 years	Natural Water	Dole (highly calcerous water)	___	___	0.010	0.394	2	1.25
8 years	Natural Water	Rotherham	1.000	39.370	___	___	19.3	___
15 years	Marine Atmosphe	Colombo, Ceylon	___	___	___	___	___	___

	re							
15 years	Marine Atmosphere	Auckland, New Zealand	2.430	95.669	___	___	31.5	___
15 years	Marine Atmosphere	Halifax, Nova Scotia	1.640	64.567	___	___	21.2	___
15 years	Marine Atmosphere	Plymouth , New England	1.090	42.913	___	___	14.2	___
15 years	Immersion in Sea Water	Colombo, Ceylon	2.550	100.394	___	___	33	___
15 years	Immersion in Sea Water	Auckland, New Zealand	0.036	1.417	___	___	0.5	___
15 years	Immersion in Sea Water	Halifax, Nova Scotia	2.150	84.646	___	___	27.7	___
15 years	Immersion in Sea Water	Plymouth , New England	1.580	62.205	___	___	20.5	___
15 years	In Sea Water	Colombo, Ceylon	6.500	255.906	___	___	84	___
15 years	In Sea Water	Auckland, New Zealand	2.590	101.969	___	___	33.5	___
15 years	In Sea Water	Halifax, Nova Scotia	1.230	48.425	___	___	15.9	___
15 years	In Sea Water	Plymouth , New England	2.750	108.268	___	___	35.7	___
15 years	Fresh Water		2.200	86.614	___	___	28.5	___
8 years	Atmosphere	Cristobal, Panama Canal Zone	0.254	10.000	___	___	4.9	___
8 years	In Pacific Ocean	Off Panama Canal	1.0795	42.500	___	___	20.6	___
8 years	In Pacific Ocean	Off Panama Canal	1.5748	62.000	___	___	30	___
3.3 years	In Sea Water	Harbor Island, NC	___	___	0.053	2.100	13.5, 10, 15	1, 1.33, 0.9

7.5 years	In Sea Water	Kure Beach, NC	___	___	0.102	4.000	23.7	1
8 years	In Sea Water	Kure Beach, NC	___	___	0.056	2.200	13	1
23.6 years	In Sea Water	Santa Barbara, CA	___	___	0.038	1.500	14	1
16 years	In Sea Water	Panama Canal (Pac. O.)	___	___	0.069	2.700	23	1
1.5 years	In Sea Water	San Diego (Polluted Sea-water	___	___	0.056	2.200	10, 6	1, 12
5 years	Immersed in Sea Water	Auckland, New Zealand	2.223	87.500	___	___	57	___
5 years	Immersed in Sea Water	Halifax, Nova Scotia	1.039	40.900	___	___	26.5	___
5 years	Immersed in Sea Water	Plymouth, New England	1.717	67.600	___	___	43.6	___
5 years	Immersed in Sea Water	Colombo, Ceylon	3.747	147.500	___	___	95	1
10 years	Outdoor	Sheffield	0.400	15.748	___	___	6.65	___
Low Alloy Steels		1st and 2nd years	___	___	0.077	3.031	23.5, 15, 10	1, 1.6, 4
		6th to 15th year	___	___	0.025	0.984	6.6	1
8 years	Atmosphe re	Cristobal, Panama Canal Zone	0.1905	7.5	___	___	3.65	1
8 years	In Pacific Ocean	Off Panama Canal	___	___	___	___	___	___
10 years	Outdoor	Sheffield	0.175	6.890	___	___	2.9	___
8 years		Rotherham	0.210	8.268	___	___	4	___
Stainless Steels	0.31	Heavy Industrial site	0.081	3.189	___	___	0.94	___
18 years	1.44	Heavy Industrial site	0.052	2.047	___	___	0.6	___

Atmospheric Exposure Tests	2.7	Heavy Industrial site	0.036	1.398	—	—	0.41	—
18 years	3.45	Heavy Industrial site	0.018	0.689	—	—	0.2	—
18 years	304S15	Rural	0.020	0.787	—	—	0.23	—
18 years	304S15	Semi-industrial	0.021	0.827	—	—	0.24	—
18 years	304S15	Heavy Industrial site	0.081	3.189	—	—	0.94	—
18 years	304S15	Marine	0.085	3.346	—	—	1	—
18 years	316S33	Rural	0.018	0.689	—	—	0.2	—
18 years	316S33	Semi-industrial	0.018	0.709	—	—	0.21	—
18 years	316S33	Heavy Industrial site	0.036	1.398	—	—	0.41	—
18 years	316S33	Marine	0.024	0.945	—	—	0.28	—
Maraging Steels		244m from the sea	—	—	0.005	0.197	1.21	1
8 years		in sea water flowing at 0.6 m/s	—	—	0.05	1.969	12, 21	1, 0.4
Nickel Iron Alloys	Fe36Ni	Colombo, Ceylon	0.000		—	—	—	—
Marine Atmosphere	Fe36Ni	Auckland, New Zealand	0.000	0.000	—	—	—	—
15 years	Fe36Ni	Halifax, Nova Scotia	0.100	3.937	—	—	1.3	—
15 years	Fe36Ni	Plymouth , New England	0.190	7.480	—	—	2.45	—
Immersion in Sea water	Fe36Ni	Colombo, Ceylon	1.000	39.370	—	—	12.9	—
15 years	Fe36Ni	Auckland, New Zealand	0.240	9.449	—	—	3.1	—
15 years	Fe36Ni	Halifax, Nova Scotia	2.590	101.969	—	—	33.5	—

15 years	Fe36Ni	Plymouth , New England	0.250	9.843	___	___	3.24	___
In Sea Water	Fe36Ni	Colombo, Ceylon	2.500	98.425	___	___	32.4	___
15 years	Fe36Ni	Auckland, New Zealand	1.080	42.520	___	___	14	___
15 years	Fe36Ni	Halifax, Nova Scotia	3.490	137.402	___	___	45	___
15 years	Fe36Ni	Plymouth , New England	1.820	71.654	___	___	23.5	___
Fresh Water (15 yrs)	Fe36Ni		2.000	78.740	___	___	25.8	___
Copper Steel	Atmosphere (8 years)	Cristobal, Panama Canal Zone	0.432	17.000	___	___	5.6	___

Appendix B

Example of several hypothetical distributions that were calculated for flaw sizes ranging from ¼ inches to 8 inches. The ranges for which calculations were performed were for ¼ inch flaws, 1 inch flaws, 2 inch flaws, 5 inch flaws and 8 inch flaws.

1/4 inch Flaws

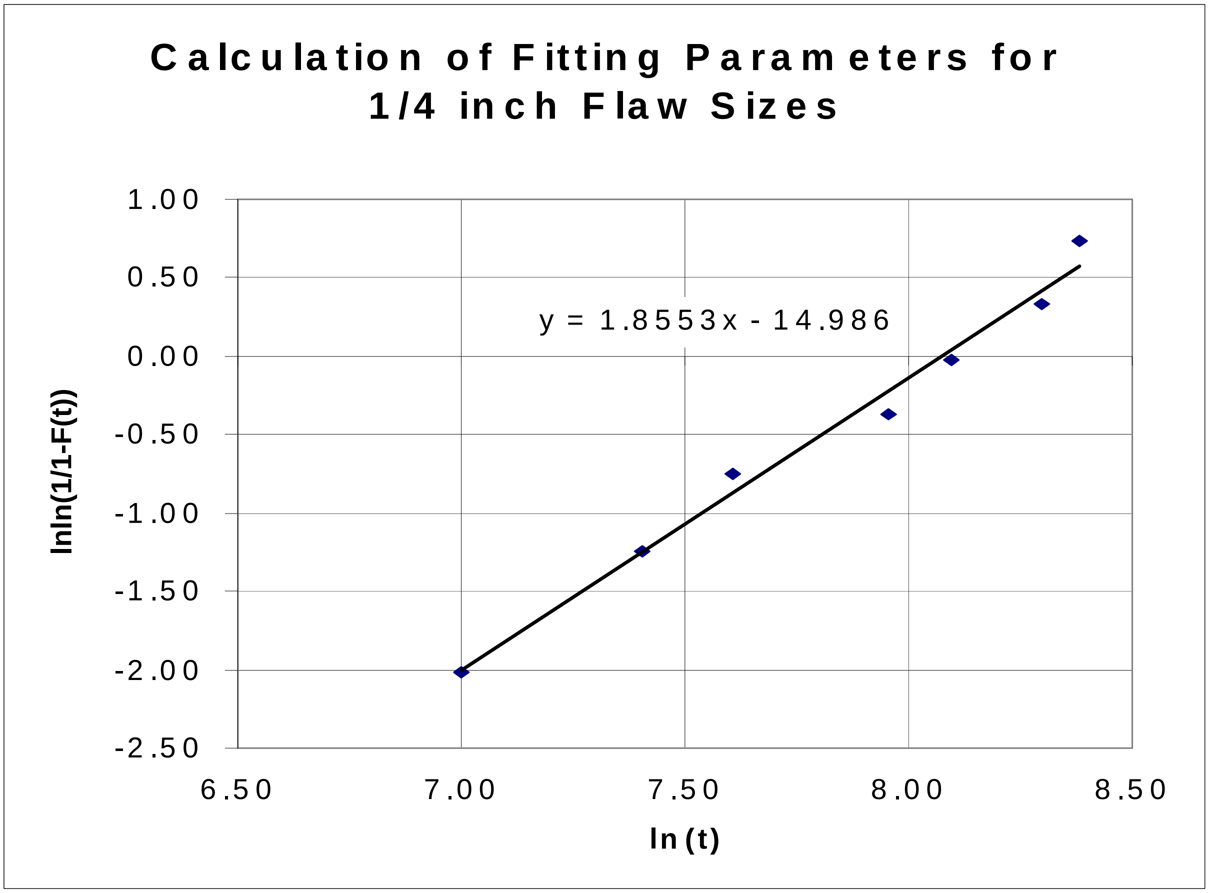
Time to develop 300, 0.25 inch flaw sizes over a length of 1 mile.

Observation Number	Time (years)	Time (days)	ln(t)	lnln(1/1-F(t))
1	3	1095	7.00	-2.01
2	4.5	1642.5	7.40	-1.25
3	5.5	2007.5	7.60	-0.76
4	7.8	2847	7.95	-0.37
5	9	3285	8.10	-0.02
6	11	4015	8.30	0.33
7	12	4380	8.38	0.73
8	13.1	4781.5	8.47	

Slope	Intercept
1.855	-14.986

κ	λ
1.855	3.10E-04

Time (Days)	S(t)	f(t)	h(t)	H(t)
500	0.969	1.13E-04	1.17E-04	0.032
1000	0.892	1.89E-04	2.12E-04	0.114
1500	0.785	2.35E-04	3.00E-04	0.242
2000	0.662	2.54E-04	3.83E-04	0.413
2500	0.535	2.48E-04	4.64E-04	0.625
3000	0.416	2.26E-04	5.42E-04	0.877
3500	0.311	1.93E-04	6.18E-04	1.167
4000	0.224	1.56E-04	6.93E-04	1.495
4500	0.156	1.19E-04	7.67E-04	1.860
5000	0.104	8.74E-05	8.39E-04	2.261
5500	0.067	6.13E-05	9.10E-04	2.699
6000	0.042	4.11E-05	9.81E-04	3.172
6500	0.025	2.65E-05	1.05E-03	3.679
7000	0.015	1.64E-05	1.12E-03	4.222
7500	0.008	9.79E-06	1.19E-03	4.798
8000	0.004	5.62E-06	1.25E-03	5.408
8500	0.002	3.11E-06	1.32E-03	6.052
9000	0.001	1.66E-06	1.39E-03	6.729
9500	0.001	8.54E-07	1.45E-03	7.439


Calculation of Fitting Parameters for
1/4 inch Flaw Sizes
y = 1.8553x - 14.986
lnln(1/1-F(t))
ln (t)
1.00
0.50
0.00
-0.50
-1.00
-1.50
-2.00
-2.50
6.50
7.00
7.50
8.00
8.50

1 inch Flaws

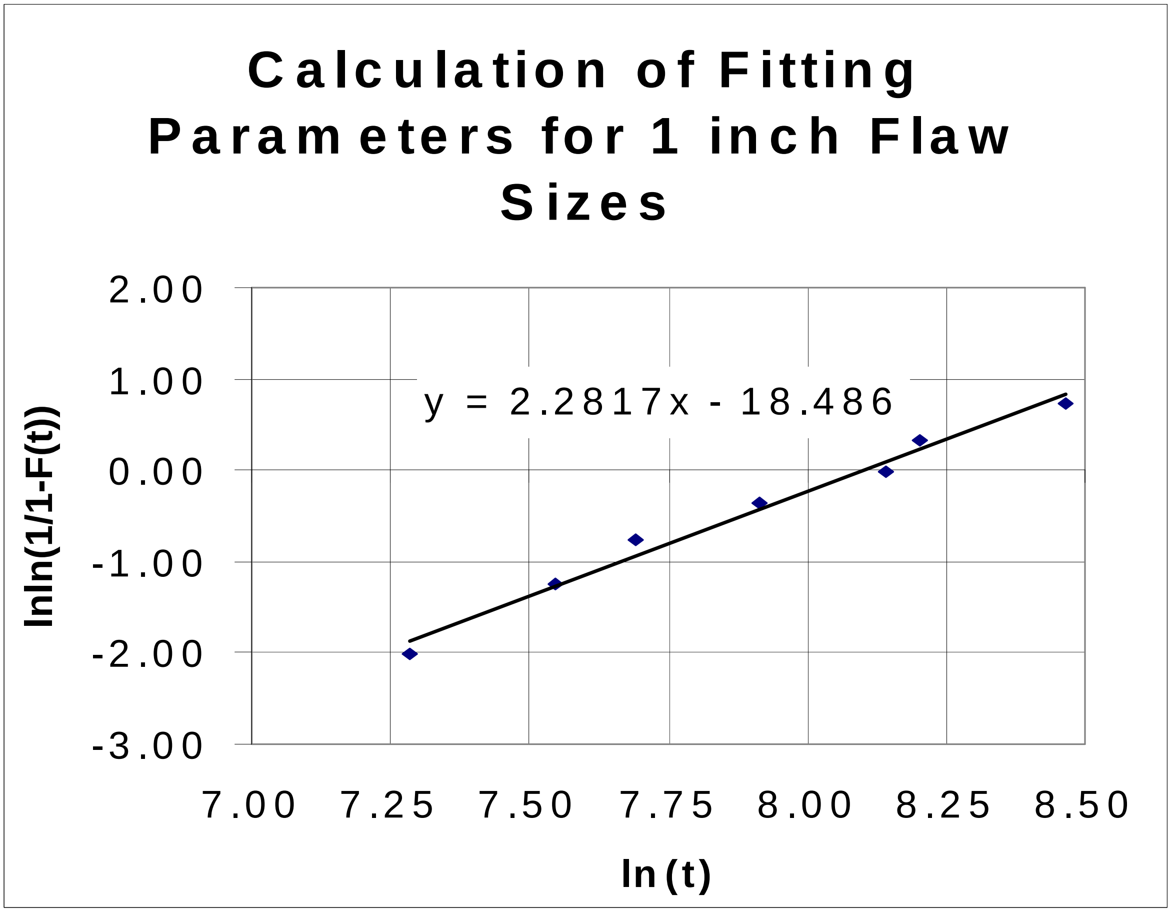
Time to develop 150, 1 inch flaw sizes over a length of 1 mile.

Observation Number	Time (years)	Time (days)	ln(t)	lnln(1/1-F(t))
1	4	1460	7.29	-2.01
2	5.2	1898	7.55	-1.25
3	6	2190	7.69	-0.76
4	7.5	2737.5	7.91	-0.37
5	9.4	3431	8.14	-0.02
6	10	3650	8.20	0.33
7	13	4745	8.46	0.73
8	16	5840	8.67	

Slope	Intercept
2.282	-18.486

κ	λ
2.282	3.03E-04

Time (Days)	S(t)	f(t)	h(t)	H(t)
500	0.987	6.07E-05	6.15E-05	0.013
1000	0.937	1.40E-04	1.50E-04	0.066
1500	0.848	2.13E-04	2.52E-04	0.165
2000	0.727	2.64E-04	3.64E-04	0.319
2500	0.588	2.85E-04	4.84E-04	0.531
3000	0.447	2.74E-04	6.12E-04	0.804
3500	0.319	2.38E-04	7.45E-04	1.143
4000	0.212	1.88E-04	8.84E-04	1.550
4500	0.132	1.35E-04	1.03E-03	2.028
5000	0.076	8.92E-05	1.18E-03	2.580
5500	0.041	5.39E-05	1.33E-03	3.206
6000	0.020	2.98E-05	1.49E-03	3.911
6500	0.009	1.51E-05	1.65E-03	4.694
7000	0.004	6.98E-06	1.81E-03	5.559
7500	0.001	2.96E-06	1.98E-03	6.507
8000	0.001	1.14E-06	2.15E-03	7.539
8500	0.000	4.04E-07	2.32E-03	8.657
9000	0.000	1.30E-07	2.50E-03	9.863
9500	0.000	3.82E-08	2.68E-03	11.158


Calculation of Fitting Parameters for 1 inch Flaw Sizes
y = 2.2817x - 18.486
2.00
1.00
0.00
-1.00
-2.00
-3.00
7.00
7.25
7.50
7.75
8.00
8.25
8.50
lnln(1/1-F(t))
ln(t)

2 inch Flaws

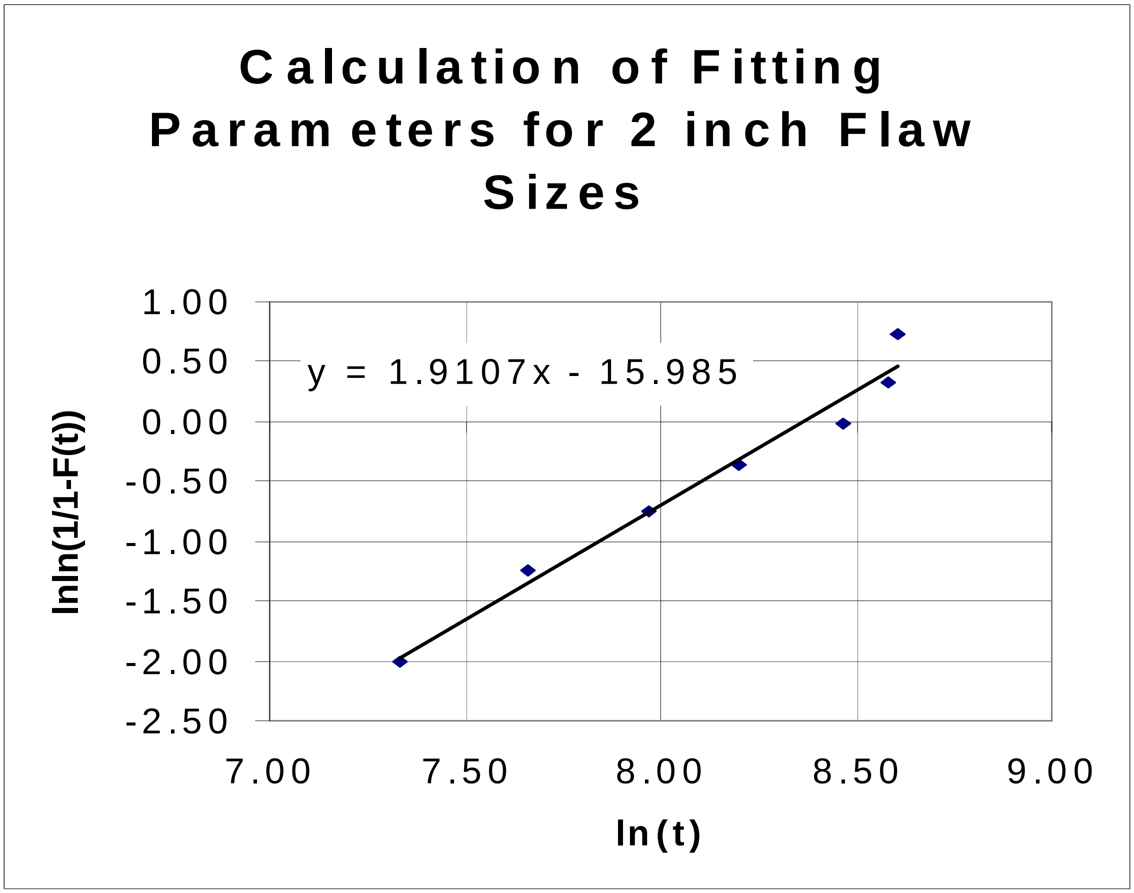
Time to develop 75, 2 inch flaw sizes over a length of 1 mile.

Observation Number	Time (years)	Time (days)	ln(t)	lnln(1/1-F(t))
1	4.2	1533	7.33	-2.01
2	5.8	2117	7.66	-1.25
3	7.9	2883.5	7.97	-0.76
4	10	3650	8.20	-0.37
5	13	4745	8.46	-0.02
6	14.6	5329	8.58	0.33
7	15	5475	8.61	0.73
8	18	6570	8.79	

Slope	Intercept
1.911	-15.985

κ	λ
1.911	2.33E-04

Time (Days)	S(t)	f(t)	h(t)	H(t)
500	0.984	6.16E-05	6.27E-05	0.016
1000	0.940	1.11E-04	1.18E-04	0.062
1500	0.875	1.49E-04	1.70E-04	0.134
2000	0.793	1.76E-04	2.21E-04	0.232
2500	0.701	1.90E-04	2.71E-04	0.355
3000	0.605	1.94E-04	3.20E-04	0.503
3500	0.509	1.88E-04	3.69E-04	0.675
4000	0.418	1.74E-04	4.16E-04	0.871
4500	0.336	1.56E-04	4.63E-04	1.091
5000	0.263	1.34E-04	5.10E-04	1.335
5500	0.202	1.12E-04	5.56E-04	1.601
6000	0.151	9.09E-05	6.02E-04	1.891
6500	0.110	7.15E-05	6.48E-04	2.204
7000	0.079	5.47E-05	6.93E-04	2.539
7500	0.055	4.07E-05	7.38E-04	2.897
8000	0.038	2.95E-05	7.83E-04	3.277
8500	0.025	2.09E-05	8.27E-04	3.679
9000	0.017	1.44E-05	8.71E-04	4.104
9500	0.011	9.67E-06	9.15E-04	4.550


Calculation of Fitting Parameters for 2 inch Flaw Sizes
y = 1.9107x - 15.985
lnln(1/1-F(t))
ln(t)
1.00
0.50
0.00
-0.50
-1.00
-1.50
-2.00
-2.50
7.00
7.50
8.00
8.50
9.00

5 inch Flaws

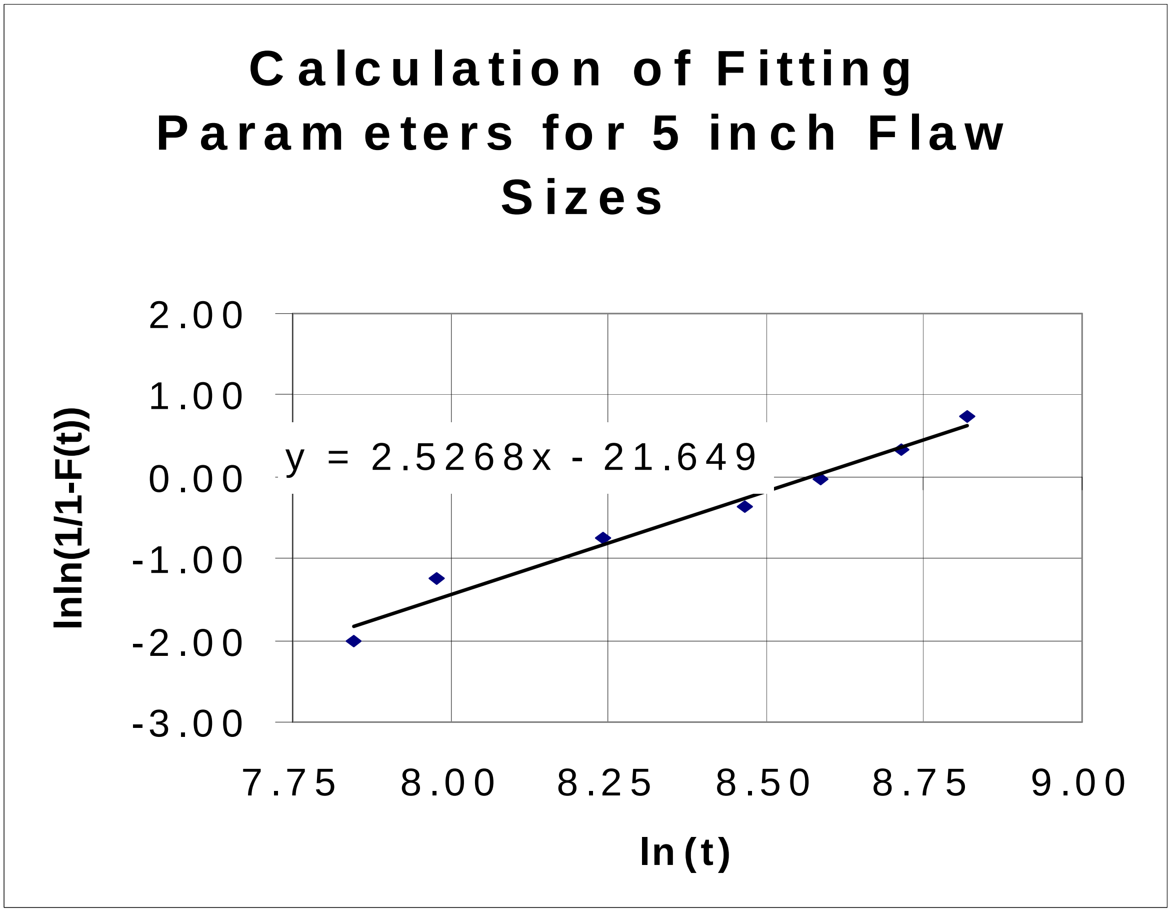
Time to develop 25, 5 inch flaw sizes over a length of 1 mile.

Observation Number	Time (years)	Time (days)	ln(t)	lnln(1/1-F(t))
1	7	2555	7.85	-2.01
2	8	2920	7.98	-1.25
3	10.4	3796	8.24	-0.76
4	13	4745	8.46	-0.37
5	14.7	5365.5	8.59	-0.02
6	16.7	6095.5	8.72	0.33
7	18.5	6752.5	8.82	0.73
8	20	7300	8.90	

Slope	Intercept
2.527	-21.649

κ	λ
2.527	1.90E-04

Time (Days)	S(t)	f(t)	h(t)	H(t)
500	0.997	1.32E-05	1.32E-05	0.003
1000	0.985	3.75E-05	3.81E-05	0.015
1500	0.959	6.78E-05	7.08E-05	0.042
2000	0.917	1.01E-04	1.10E-04	0.087
2500	0.858	1.32E-04	1.54E-04	0.153
3000	0.785	1.60E-04	2.04E-04	0.242
3500	0.700	1.80E-04	2.58E-04	0.357
4000	0.606	1.92E-04	3.16E-04	0.501
4500	0.509	1.93E-04	3.79E-04	0.674
5000	0.415	1.84E-04	4.45E-04	0.880
5500	0.326	1.68E-04	5.14E-04	1.120
6000	0.248	1.46E-04	5.88E-04	1.395
6500	0.181	1.20E-04	6.64E-04	1.708
7000	0.128	9.48E-05	7.43E-04	2.059
7500	0.086	7.12E-05	8.26E-04	2.452
8000	0.056	5.09E-05	9.12E-04	2.886
8500	0.035	3.46E-05	1.00E-03	3.364
9000	0.021	2.24E-05	1.09E-03	3.886
9500	0.012	1.38E-05	1.18E-03	4.455


Calculation of Fitting Parameters for 5 inch Flaw Sizes
lnln(1/1-F(t))
2.00
1.00
0.00
-1.00
-2.00
-3.00
y = 2.5268x - 21.649
7.75
8.00
8.25
8.50
8.75
9.00
ln(t)

<u>8 inch Flaws</u>

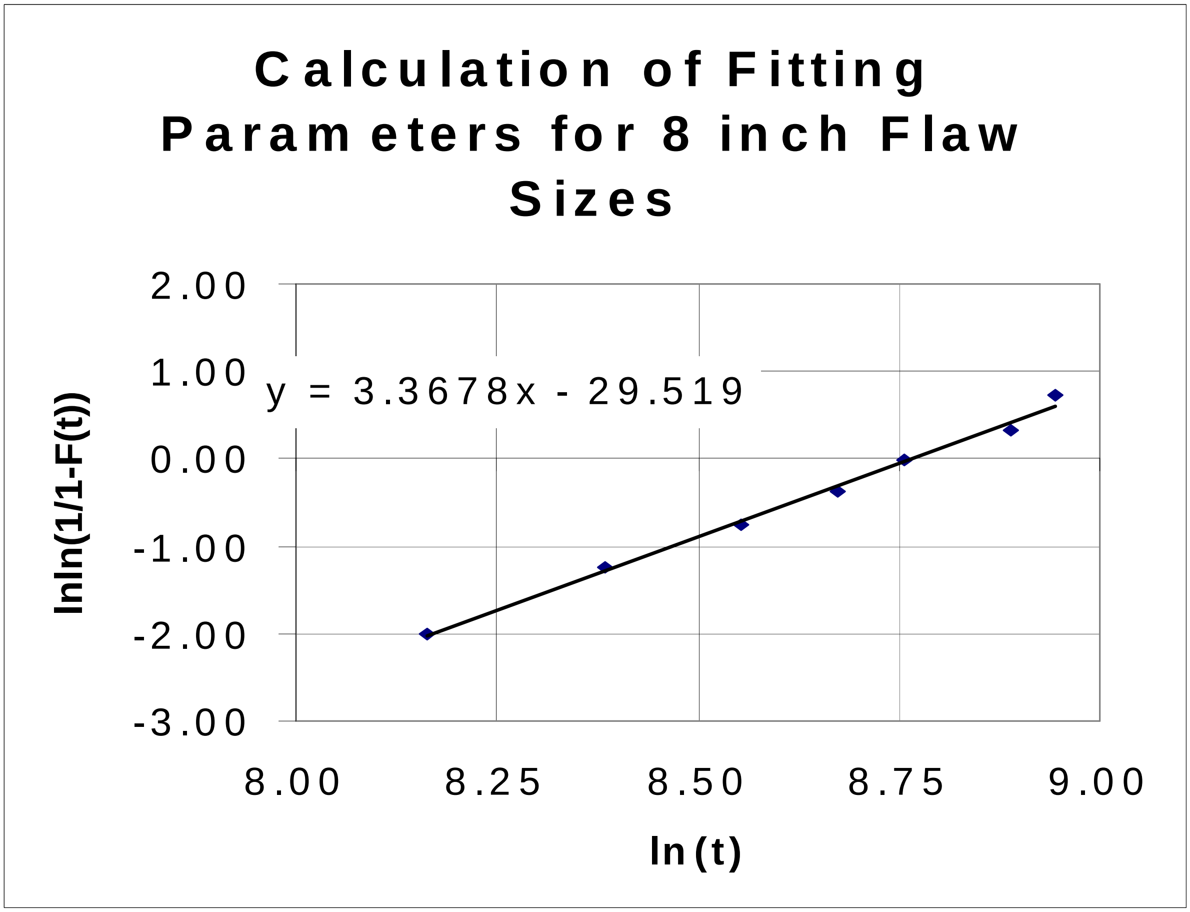
Time to develop 5, 8 inch flaw sizes over a length of 1 mile.

Observation Number	Time (years)	Time (days)	ln(t)	lnln(1/1-F(t))
1	9.6	3504	8.16	-2.01
2	12	4380	8.38	-1.25
3	14.2	5183	8.55	-0.76
4	16	5840	8.67	-0.37
5	17.4	6351	8.76	-0.02
6	19.9	7263.5	8.89	0.33
7	21	7665	8.94	0.73
8	22	8030	8.99	

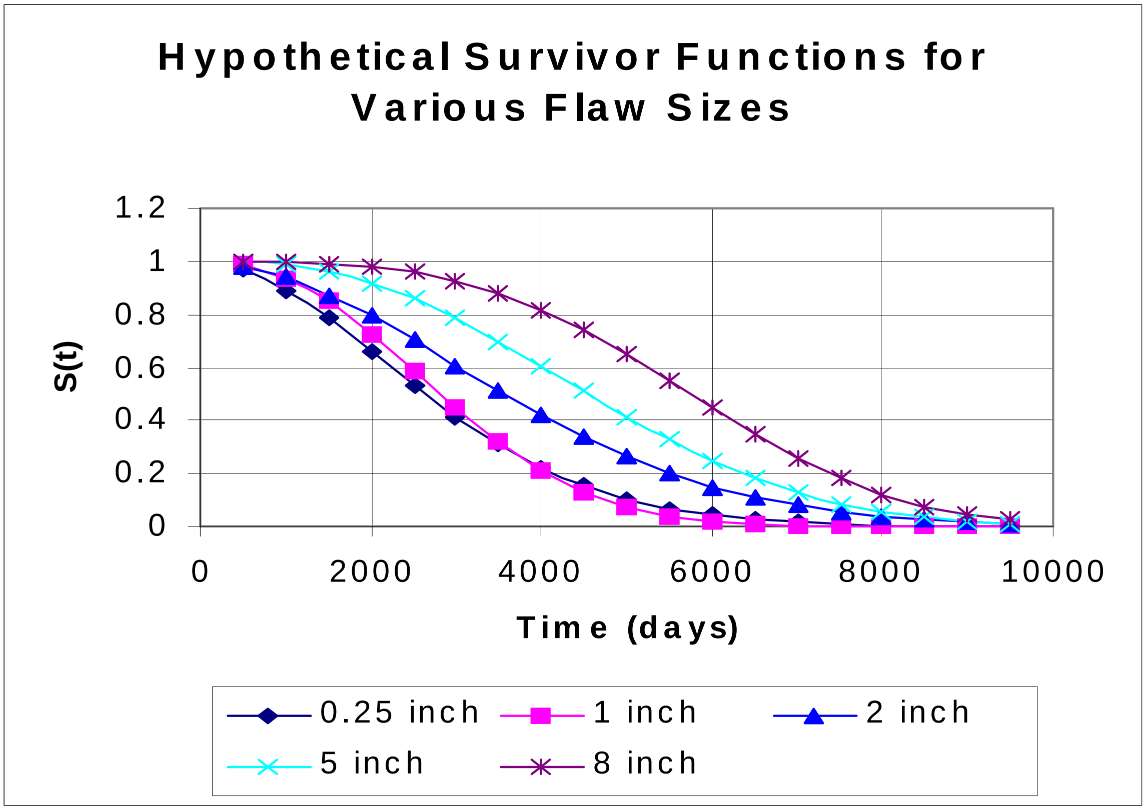
Slope	Intercept
3.368	-29.519

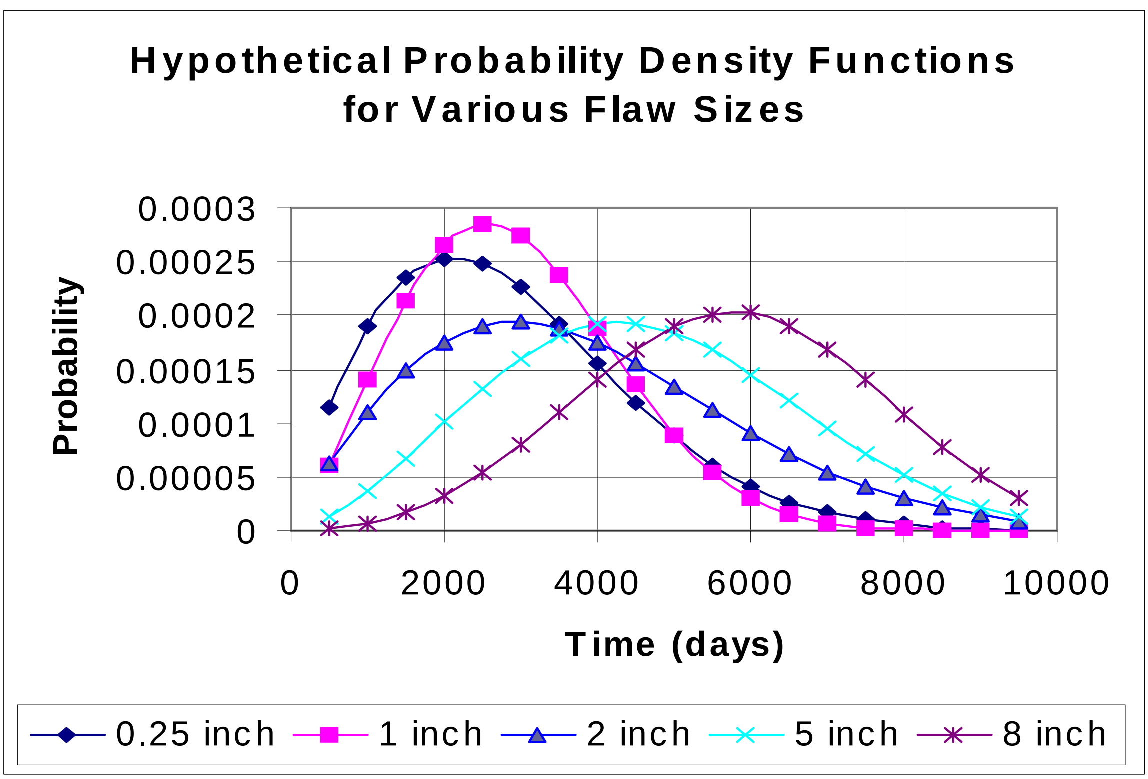
κ	λ
3.368	1.56E-04

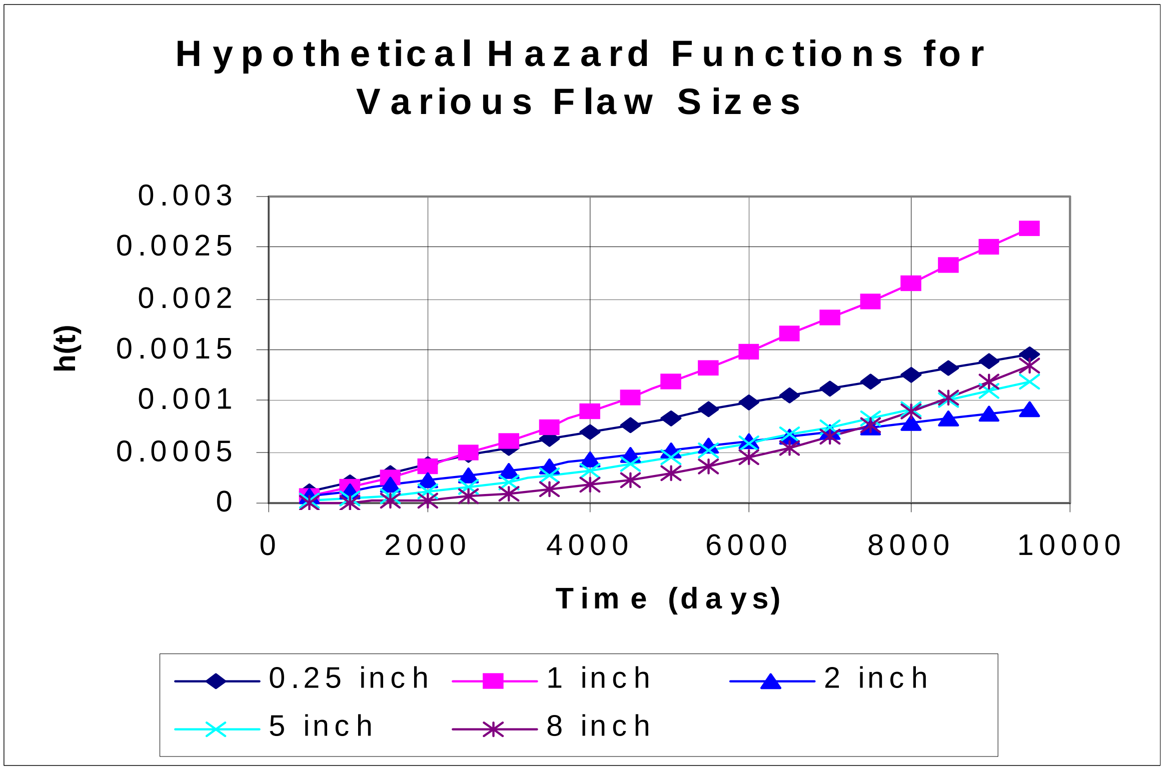
Time (Days)	S(t)	f(t)	h(t)	H(t)
500	1.000	1.25E-06	1.25E-06	0.000
1000	0.998	6.46E-06	6.47E-06	0.002
1500	0.993	1.68E-05	1.69E-05	0.008
2000	0.980	3.27E-05	3.34E-05	0.020
2500	0.959	5.43E-05	5.66E-05	0.042
3000	0.925	8.07E-05	8.72E-05	0.078
3500	0.878	1.10E-04	1.26E-04	0.131
4000	0.815	1.40E-04	1.72E-04	0.205
4500	0.738	1.68E-04	2.28E-04	0.304
5000	0.648	1.89E-04	2.92E-04	0.434
5500	0.550	2.01E-04	3.66E-04	0.598
6000	0.448	2.02E-04	4.50E-04	0.802
6500	0.350	1.90E-04	5.44E-04	1.050
7000	0.260	1.68E-04	6.48E-04	1.348
7500	0.183	1.39E-04	7.63E-04	1.700
8000	0.121	1.08E-04	8.89E-04	2.113
8500	0.075	7.69E-05	1.03E-03	2.592
9000	0.043	5.08E-05	1.18E-03	3.142
9500	0.023	3.08E-05	1.34E-03	3.769

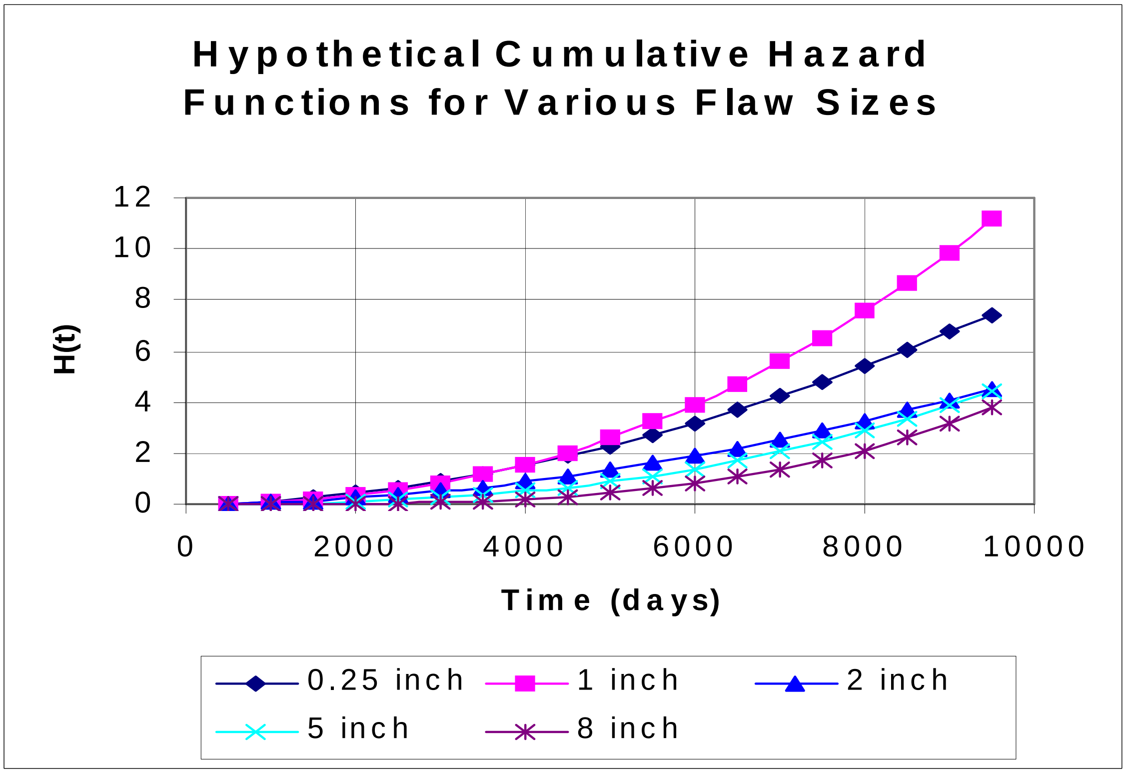


Calculation of Fitting Parameters for 8 inch Flaw Sizes
y = 3.3678x - 29.519
lnln(1/1-F(t))
2.00
1.00
0.00
-1.00
-2.00
-3.00
8.00
8.25
8.50
8.75
9.00
ln(t)


Hypothetical Survivor Functions for
Various Flaw Sizes
S(t)
1.2
1
0.8
0.6
0.4
0.2
0
0
2000
4000
6000
8000
10000
Time (days)
0.25 inch
1 inch
2 inch
5 inch
8 inch


Hypothetical Probability Density Functions
for Various Flaw Sizes
Probability
0.0003
0.00025
0.0002
0.00015
0.0001
0.00005
0
0
2000
4000
6000
8000
10000
Time (days)
0.25 inch
1 inch
2 inch
5 inch
8 inch


Hypothetical Hazard Functions for Various Flaw Sizes
0.003
0.0025
0.002
0.0015
0.001
0.0005
0
h(t)
0
2000
4000
6000
8000
10000
Time (days)
0.25 inch
1 inch
2 inch
5 inch
8 inch


Hypothetical Cumulative Hazard Functions for Various Flaw Sizes
12
10
8
6
4
2
0
H(t)
0
2000
4000
6000
8000
10000
Time (days)
0.25 inch
1 inch
2 inch
5 inch
8 inch