PIMPIS: Knowledge-Based Pipeline Inspection, Maintenance & Performance Information System

Progress Report # 1

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"PIMPIS: Knowledge-Based Pipeline Inspection, Maintenance & Performance Information System"

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Abstract

A methodology for the reliability assessment of offshore pipelines is presented. Offshore pipelines are divided into two main categories. Piggable pipes, for which internal inspection results are available and non-piggable pipes for which no inspection information is available. Reliability assessment procedures for both categories are developed. Reliability as a function of time is estimated. Also, conditional reliability, given that the pipe has survived up to time τ, is computed as a function of t. The purpose of these reliability analyses is to provide

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information to pipeline operators and owners to be used for general risk assessment relative to decisions on inspection and maintenance priorities.

1 Introduction

Integrity maintenance of aging pipeline networks is a prime concern for transmission companies. Because pipeline systems are usually large and maintenance budgets are limited by constraints of economic viability, operators must decide on how maintenance resources are best allocated. The purpose of this report is to develop a methodology for the reliability assessment of offshore pipelines.

Risk assessment techniques are often used as a means of evaluating a segment of a pipeline system for different maintenance or revalidation actions. By definition, risk assessment implies the consideration of probability. The risk related to decision making can be estimated by postulating the possible outcomes of the decision and comparing the probabilities and overall costs of the various outcomes. Risk assessment can be a valuable aid to the decision maker by indicating the most-cost effective choice.

2 Part I: Piggable Pipes

In this section a methodology for the reliability assessment of those pipes for which internal inspection information is available is presented. It should be noted that the Minerals and Management Services (MMS) has a requirement that all new built pipelines should be fitted with arrangements for pigging the pipeline. Those fittings include pig launchers and receivers and avoiding large bends in the pipe. This a recent requirement however, and it is estimated that 50% of offshore pipelines in the Gulf of Mexico are not piggable. It is that portion of pipes for which there is little available information that raises concern.

For those pipes that can be internally inspected, the pig would basically locate a corrosion defect in a particular segment of the pipe. The corroded segment is then evaluated for different inspection and maintenance alternatives using reliability and risk assessment techniques.

2.1 Model 1: Pressure-Based

In this model, the segment failure probability is formulated as a function of the pipeline operating pressure. Namely, failure occurs when the operating pressure reaches the burst pressure. This can be expressed as follows:

$$P_f = P[P_o \geq P_B] \tag{1}$$

where

P_o =Operational pressure.

P_B= Burst pressure

The burst pressure can be expressed as follows:

$$P_B = B_{Bp} 2 \frac{S_y}{D}(t-d) \tag{2}$$

where

S_y =Specified minimum yield strength of the material SMYS.

D = Pipe diameter.

d = Maximum depth of the corrosion defect.

B_{Bp}= Bias factor.

Assuming lognormal variables in equation (1), a safety index can be formulated as:

$$\beta = \frac{ln[B_{Bp} 2 \frac{S_y}{P_o D}(t-d)]}{(\sigma_{lnP_B^2} + \sigma_{lnP_o^2})^{\frac{1}{2}}} \tag{3}$$

The segment failure probability is:

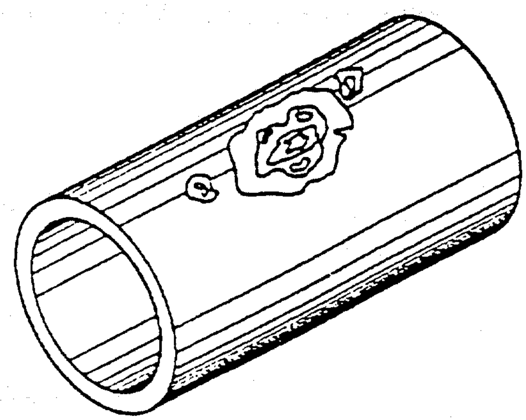
$$P_{failure} = 1 - \phi(\beta) \tag{4}$$

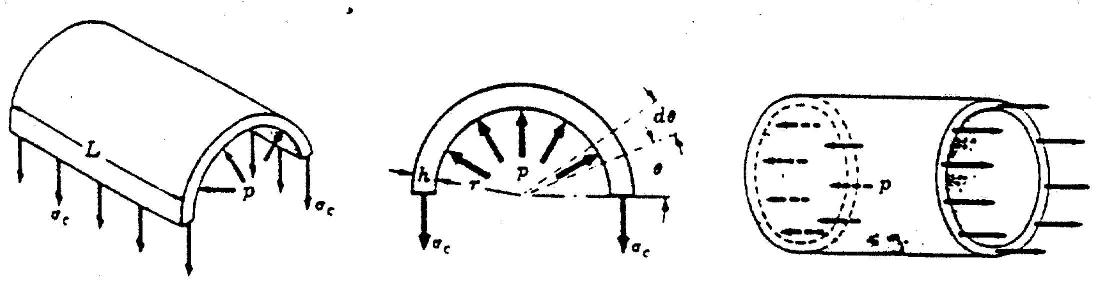
2.2 Model 2: Stress-Based

Current pipeline design procedures and codes (e.g., ASME B31.4 and B31.8) rely largely upon yield strength limits, such as the American Petroleum Institute "specified minimum yield strength" (SMYS), as their basic strength criteria for hoop stresses. Hoop stresses induced by internal pressure are primary stresses affecting the integrity of the pipeline. In the case of pressure induced hoop stress, yield strength represents a precursor to the onset of structural instability. Beyond the point of yielding, small increases in hoop stress result in relatively large increases in strain. As hoop stress is increased significantly beyond yielding, thinning of the wall occurs, which in turn leads to increased stresses and additional thinning, finally resulting in an instability failure. Fig 1 shows a segment of a corroded pipe and the resulting hoop stresses.

In contrast to primary hoop stress, most longitudinal stresses in offshore pipelines are secondary in nature. It should be noted however that in cases where the temperature difference across the pipe wall are significant, for example pipes in the North Sea, thermally induced axial stresses are significant and can result in lateral buckling.

PROBLEM DEFINITION





(a) (b) (c)

a) Hoop Stresses

c) Longitudinal Stresses

Figure 1: A Corroded Pipeline Segment,
& The Resulting Hoop & Longitudinal Stresses
Hoop Stresses are Twice The Longitudinal Stresses
i.e. Pipe will rupture along a line Running Longitudinally along its axis

Failure occurs when the operating hoop stress level reaches the "failure hoop stress level".

$$P_f = P[\sigma_{Op} \geq \sigma_f] \tag{5}$$

where

σ_{Op} =operational hoop stress level

σ_f = hoop stress level at failure

The operational hoop stress level σ_{Op} can be defined as :

$$\sigma_{Op} = \frac{PD}{2(t_o - d)} \tag{6}$$

where

D = pipe outside diameter

$P = P_i - P_{ex}$

P_i = Internal operating pressure.

P_{ex}= External pressure (Hydrostatic).

t_o = initial pipe wall thickness

d = the maximum depth of the corroded area.

The hoop stress level at failure σ_f can be calculated according to the NG-18 surface flaw equation:

$$\sigma_f = \bar{\sigma}\frac{1-\frac{A}{A_o}}{1-\frac{A}{A_o}M^{-1}} \tag{7}$$

where

$\bar{\sigma}$ =Material flow stress=1.1SMYS

$A=$ Area of a crack or defect in the longitudinal plane through the wall thickness.

$A_{\sigma}= Lt$

$L=$ Axial extent of the corrosion defect

t = Pipe wall thickness

$M=$ Folias bulging factor to account for stress concentration $\sqrt{1+\frac{0.8L^2}{Dt}}$

Equation 6 predicts the hoop stress level which will cause failure of a corroded pipe with diameter D, wall thickness, t, and minimum yield strength, SMYS, containing a longitudinally oriented crack or corrosion defect of axial length L and a maximum depth d.

Equation 6 is usually simplified by representing the area of metal loss, A, by a parabola as shown in Fig. 2.

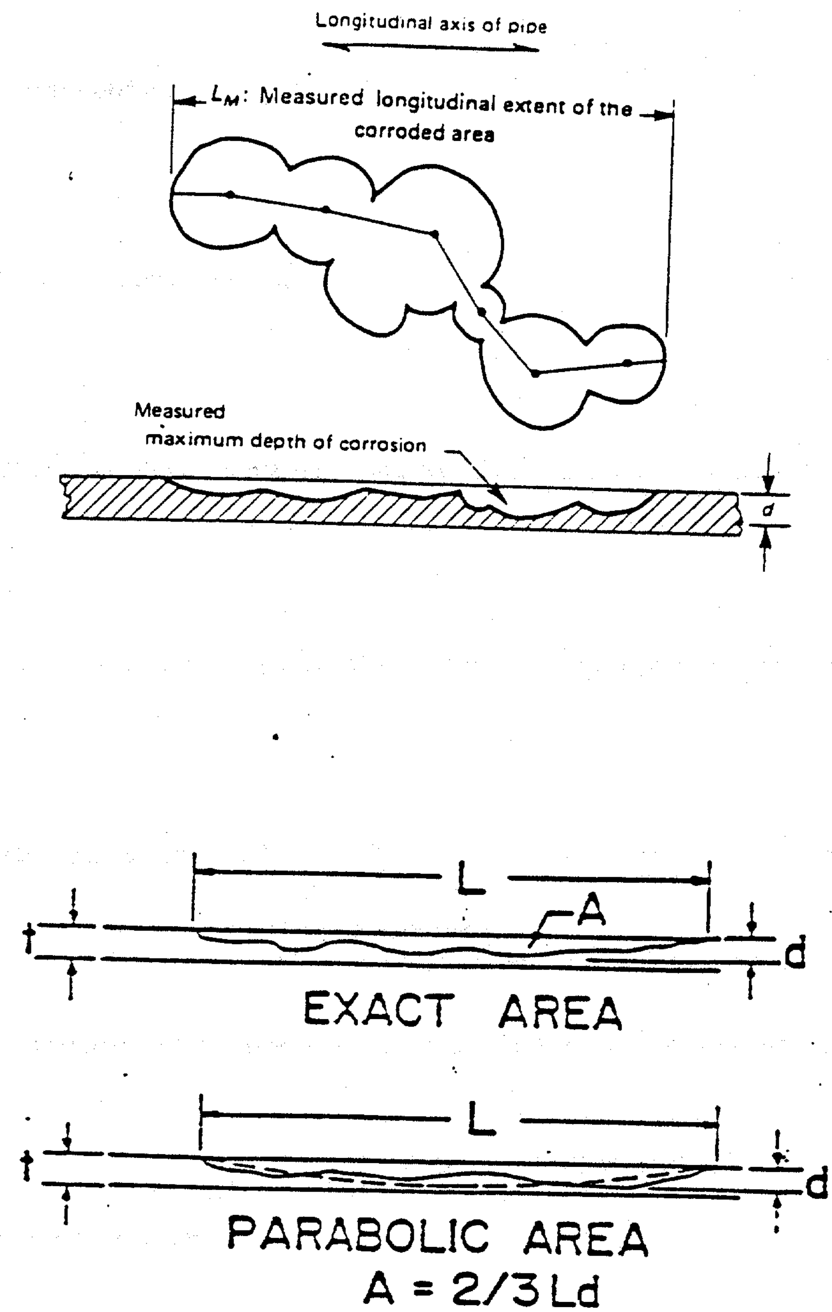


Figure 2: Parabolic Approximation of The Corroded Area, The Parabolic Representation Becomes Less and Less Accurate as The Length of The Corroded Area Increases

This permits the calculation of A on the basis of two simple parameters of the metal loss, its overall length L, and its maximum depth, d. The resulting area is equal to $\frac{2}{3}Ld$ Equation 6 then simplifies to:

$$\sigma_f = 1.1SMYS\frac{1-\frac{2d}{3t}}{1-\frac{2d}{3t}M^{-1}} \tag{8}$$

Assuming lognormal variables in equation (4), a safety index can be formulated as:

$$\beta = \frac{ln[B_{SHB}2\frac{S_y}{P_o D}(t-d)(\frac{1-\frac{2d}{3t}}{1-\frac{2d}{3t}M^{-1}})]}{(\sigma_{ln\sigma_f^2} + \sigma_{ln\sigma_{Op}^2})^{\frac{1}{2}}} \tag{9}$$

and the segment failure probability is $P_{failure} = \phi(-\beta)$

2.3 Model 3: Bai

for $\frac{L^2}{Dt} > 50$, i.e "long defect", A resistance variable can be defined as:

$$R = B_R \frac{1 - X_A}{1 - (0.032X_L + 3.3)^{-1} X_A} \tag{10}$$

where

$X_A = \frac{d}{t}$

$X_L = \frac{L^2}{Dt}$.

The demand variable, on the other hand is :

$$D = X_p = \frac{P_o D}{2S_y t} \tag{11}$$

Assuming lognormal variables, a safety index can be formulated as:

$$\beta = \frac{ln[B_R 2 \frac{S_y}{P_o D}(t - d)(\frac{1 - X_A}{1 - (0.032X_L + 3.3)^{-1} X_A})]}{(\sigma_{lnR^2} + \sigma_{lnD^2})^{\frac{1}{2}}} \tag{12}$$

$$P_{failure} = \phi(-\beta) \tag{13}$$

2.4 Generalized Model: Bea

Comparing equations, 3, 8 and 11 , a generalized model for the safety index can be expressed as:

$$\beta = \frac{ln[(\frac{2B_pS_y}{P_oD})(t-d)K_i]}{\sigma} \tag{14}$$

where $K_p = (\frac{2B_pS_y}{P_oD})$ and K_i can take the following values:

K_1 =1 for model 1.

$K_2 = \frac{1-(2d/3t)}{1-M^{-1}(2d/3t)}$ for model 2

$K_3 = \frac{1-X_A}{1-(0.032X_L+3.3)^{-1}X_A}$ for model 3

2.5 Example Application

Consider the evaluation of a 12 in schedule 40 gas pipeline for internal corrosion.

$$\beta = \frac{ln[K_pt - K_pd)}{\sigma} \tag{15}$$

$K_pt = FS_{50} = 2.4$ the median factor of safety. $d = T_c\nu$ where ν is the corrosion rate. The results of the evaluation are shown in figures 3 through 5. Sensitivity of the safety index to the relevant factors is shown figures three through 5.

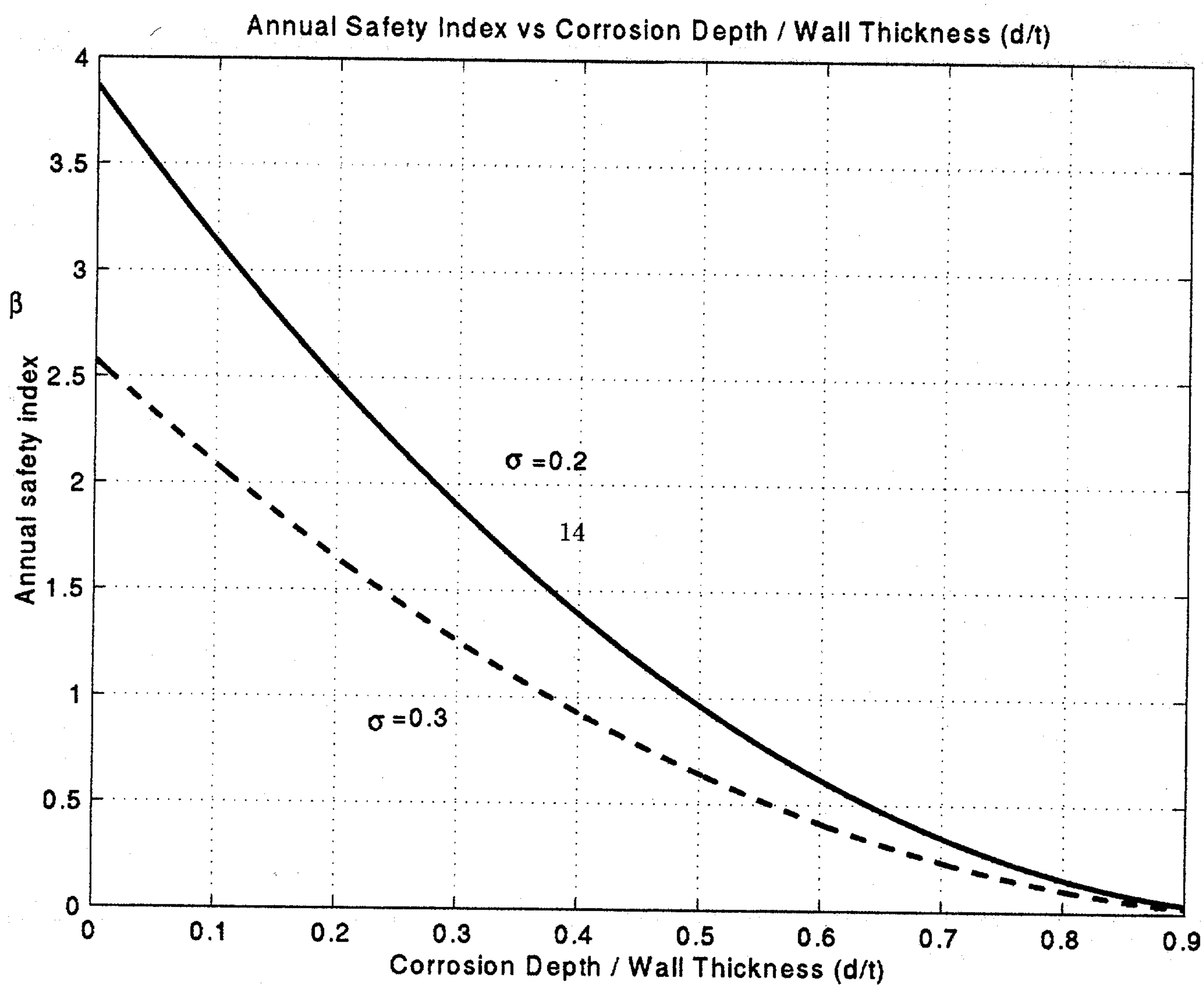


Figure 3: Annual Safety Index vs Corrosion Depth/Pipe Wall Tickness (d/t),

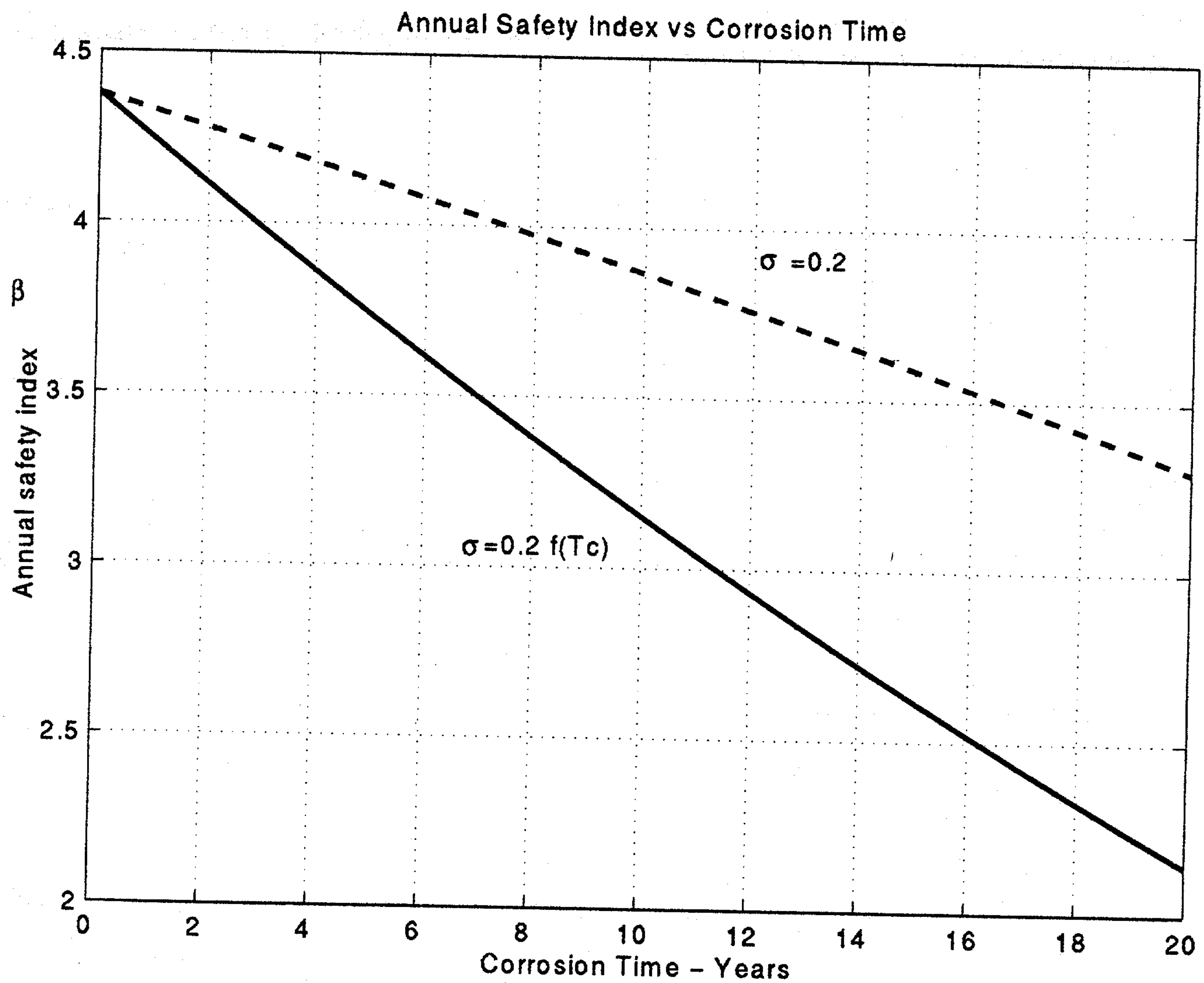


Figure 4: Annual Safety Index vs Corrosion Time (Years),
Constant Uncertainty σ=0.2
Increasing Uncertainty σ=0.2f(Tc)

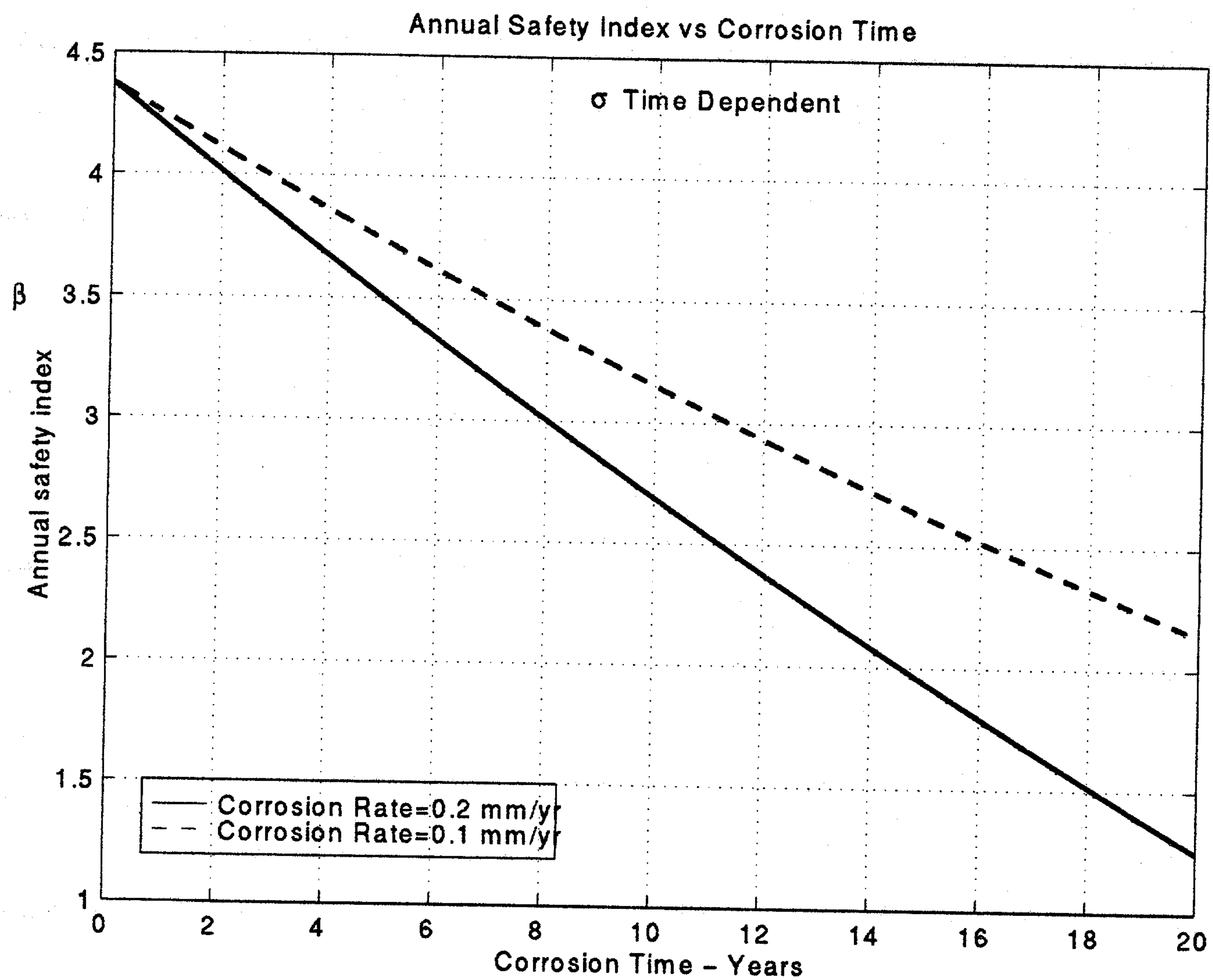


Figure 5: Annual Safety Index vs Corrosion Time (Years),
Corrosion Rate=0.2 mm/yr
Corrosion Rate=0.1 mm/yr
σ is Time Depenedent

3 Part II: Non-Piggable Pipes

In this section, a methodology for the reliability assessment for those pipes that cannot be pigged is presented. An expression to evaluate the segment failure probability under combined failure modes is developed. Another expression for computing the failure probability of the *entire pipeline* is developed. With these expressions, an evaluator can assess high risk segments on a single pipeline level as well as on a network of pipelines level.

3.1 Multiple Failure Modes

Consider a pipeline segment subject to multiple failure modes as shown in Figure 5. Let:

F_1 =Failure due to 3rd party damage

F_2 = Failure due to internal corrosion

F_3 = Failure due to external corrosion

F_4 = Failure due to a natural hazard (e.g. storms)

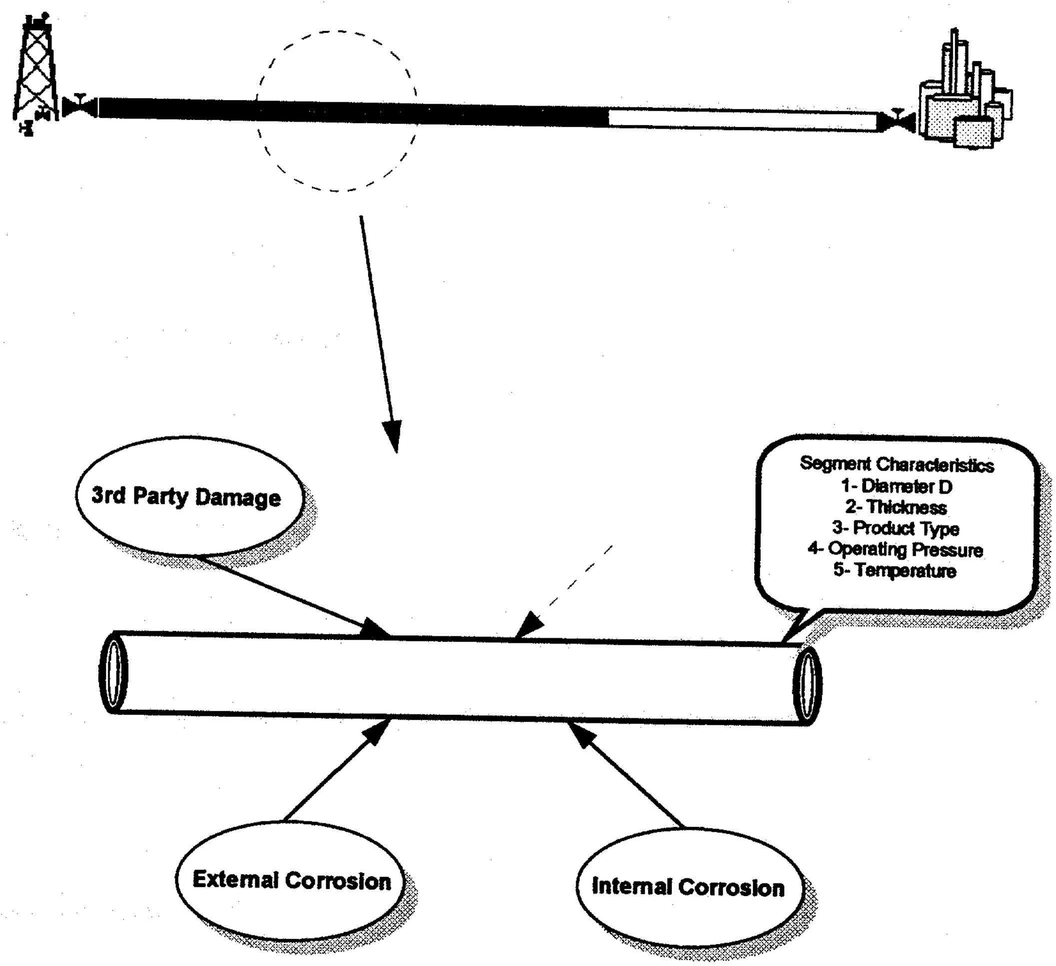


Figure 5: Segment of an Offshore Pipeline Subject to multiple Failure Modes: Internal Corrosion, External Corrosion, 3rd Party Damage, etc.

The segment probability of failure is:

$$P_{failure} = P(F_1 \cup F_2 \cup F_3 \cup F_4) \tag{16}$$

$$P_{failure} = P(F_1) + P(F_2) + P(F_3) + P(F_4) - P(F_1 \cap F_2) \tag{17}$$
$$-P(F_2 \cap F_3) \ldots + P(F_1 \cap F_2 \cap F_3 \cap F_4)$$

3.2 Probability Bounds

Evaluation of equation 14 is extremely difficult. Basically interaction terms like $P(F_2 \cap F_4)$ cannot be computed. Although in practice these terms should be maintained, since for example a pipeline weakened by corrosion would be more likely to fail in a storm, it is customary to drop these terms and substitute an upper and lower bounds for the probability of failure.

An upper bound is developed as follows.

Assuming that the failure modes are independent and $P_{F_i} \ll 1$ implies that terms like $P(F_i \cap F_j) = P(F_i)P(F_j) \approx 0$ and therefore:

$$P_{failure} = P(F_1) + P(F_2) + P(F_3) + P(F_4) \tag{18}$$

In the case where all failure modes are fully dependent, it follows directly that the weakest failure mode will always be weakest, thus a lower bound can be developed as:

$$P_{failure} = maxP(F_i) \tag{19}$$

Figure 7 shows upper and lower bounds for the segments of an offshore pipeline subject to different failure modes. Equations 15 and 16 can be combined as:

$$maxP(F_i) \leq P_{failure} \leq \sum_{i=1}^{m} P(F_i) \tag{20}$$

where m is the number of potential failure modes.

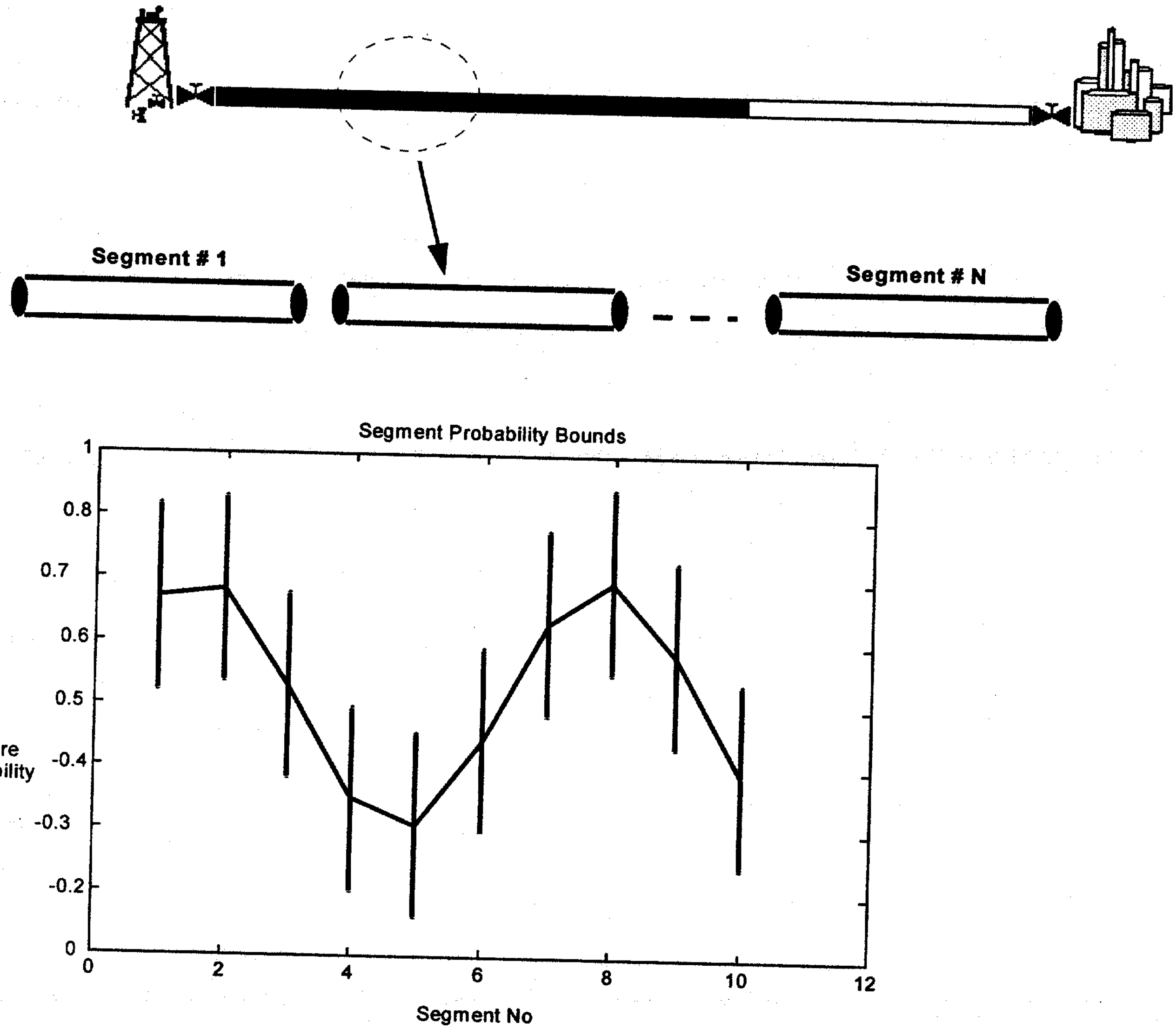


Figure 7 : Upper & Lower Bounds for the Segment Failure Probabilities

3.3 System Reliability

In general, the pipeline system is a *series system* made of n number of segments. The failure of any segment would result in disruption of service. The probability of failure of the *entire pipeline* is:

$$P_{failure} = P(F_1) + P(F_2) + P(F_3) + P(F_4) - P(F_1 \cap F_2) \tag{21}$$
$$-P(F_2 \cap F_3) \ldots + P(F_1 \cap F_2 \cap F_3 \cap F_4) + \ldots$$

where

F_1 =Failure of 1^{st} segment

F_2 = Failure of 2^{nd} segment

F_3 = Failure of 3^{3d} segment

F_n = Failure of n^{th} segment

Again with the assumption of independence and $P_{F_i} \ll 1$, we can develop an upper bound, whereas the full dependence would result in a lower bound

$$maxP(F_i) \leq P_{failure} \leq \sum_{i=1}^{n} P(F_i) \tag{22}$$

where n is the number of segments. Using equation 15 for the segment probability of failure, equation 19 can be rewritten as:

$$max\left(\sum_{i=1}^{m} P(F_i)\right) \leq P_{failure} \leq \sum_{j=1}^{n}\sum_{i=1}^{m} P(F_i) \tag{23}$$

To be conservative, the system probability of failure is:

$$P_{failure} \approx \sum_{j=1}^{n} \sum_{i=1}^{m} P(F_i) \tag{24}$$

where j is an index representing the jth segment and i represents the failure modes.

3.4 Estimation of Failure Probabilities:Historical-Data Approach

In this section a procedure for estimating the failure probabilities for different failure modes, based on offshore pipelines historical failure data, is developed. The Theoretical background is first presented, followed by an example application to illustrate the use of this procedure.

3.5 Theoretical Background

Consider the evaluation of a $16in$ gas pipeline for example. In order to use equation 15 or 16 we need to evaluate the probability that a segment of the pipe fails during the next year. Actually, we are interested in evaluating the probability of failure of the segment given that it has survived until this particular instance. To evaluate this probability, the distribution of time to failure or life length of a segment is needed.

Let T be a continuous random variable representing the time to failure or life length of a segment measured from commissioning time until it fails. T will have a probability density function $f(t)$ and a cumulative function $F(t)$. We are interested in the probability that a certain segment fails in the time interval from $T = t$ to $T = t + \Delta t$, given that it survived to time t, i.e.

$$P(t \leq T < t + \Delta t \mid T \geq t) \tag{25}$$

where Δt is taken to be one year. Equation 22 can be rearranged as:

$$\begin{aligned} \frac{P(t \leq T < t + \Delta t \cap T \geq t)}{P(T \geq t)} \\ \frac{P(t \leq T < t + \Delta t)}{P(T \geq t)} \\ \frac{F(t + \Delta t) - F(t)}{1 - F(t)} \end{aligned} \tag{26}$$

Dividing this ratio by Δt and taking the limit as $\Delta t \to 0$, we get:

$$h(t) = \frac{F'(t)}{1 - F(t)} = \frac{f(t)}{1 - F(t)} \tag{27}$$

where $h(t)$, *hazard function*, is the probability that a segment fails in a time interval, next year, given that it has survived to that time.

The hazard function therefore will provide the required conditional failure probabilities. A key issue in this development is knowing the distribution of the time to failure for different failure modes for offshore pipelines. This distribution can be estimated from the failure database maintained by the MMS. As an example application, the hazard function corresponding to the Weibull density is:

$$h(t) = \alpha\beta(\beta t)^{\alpha-1} \tag{28}$$

where

α =Weibull shape parameter

β = Weibull scale parameter

3.6 Example Application

Consider the evaluation of a $16in$ gas pipeline for internal corrosion. The pipe is 20 years old and cannot be internally inspected. The service is not sour and so the potential for internal corrosion would be due to sweet corrosion. Internal corrosion initiates at low places along the line where moisture is likely to collect and form stagnation points.

From the database, offshore gas pipelines are divided according to diameter and operating pressure. The distribution of the time to failure due to internal corrosion for this class of pipes is shown in figure 8. The corresponding hazard function as a function of time is shown in figure 9. The fact that the hazard function is increasing basically reflects the fact that the probability of failure due to internal corrosion increases with aging of the pipe. This is consistent with our intuition. From figure 9, the probability of failure due to internal corrosion can be estimated to be 0.0151. The above procedure can be repeated for different failure modes and different categories of pipelines.

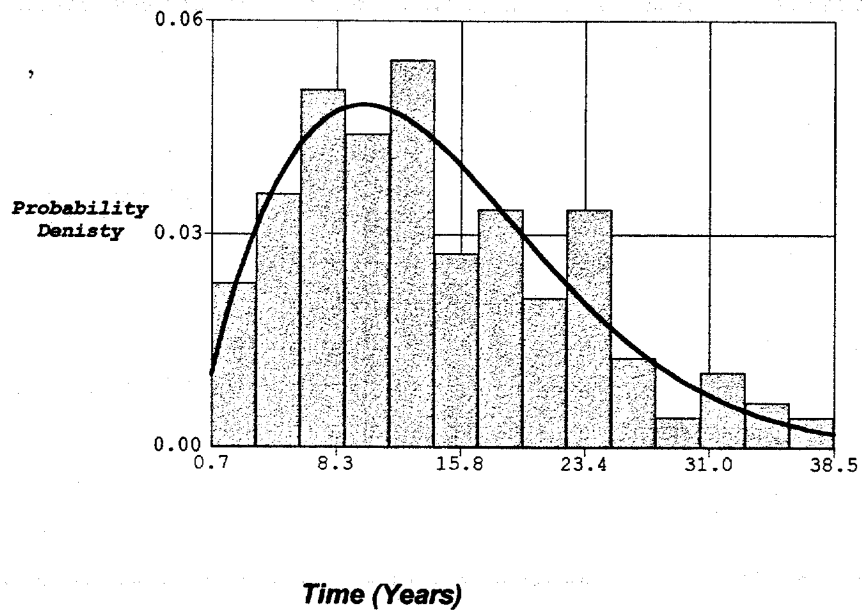


Figure 8: Distribution of Time to Failure, Life length ,Due to Internal corrosion For Gas Pipelines D>16 in: Weibull Distribution with Parameters Shape Parameter α=1.76 Scale Paramter β=16.05 Years

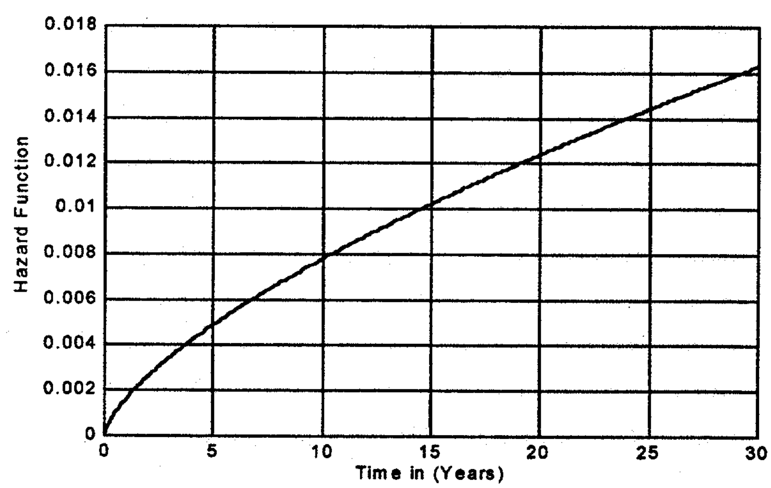


Figure 9: Hazard function (Conditional Probability of Failure) Based on the Weibull Distribution

3.7 Estimation of Failure Probabilities:Limit State Approach

In corrosion reliability, a limit state function will have the form[1]:

$$g = d - CR.t \tag{29}$$

where:

CR =Corrosion rate

d =Maximum allowable corrosion depth (appendix A)

t = Duration of wet service

The duration of wet service is assumed to equal the design life for continuos wet service (wet liquid line). For dry services (dry gas line) the duration of wet service can be calculated as follows:

$$t = n.m \tag{30}$$

where:

n =total number of upsets during lifetime

m= duration of wet service per single upset (including drying time)

In this context, an upset is defined as water or wet gas ingress into the pipeline. The duration of wet service per single upset is defined as the time

[1]Refrence 2

from the ingress start until the upset is detected and corrected and the line has returned to the dryness before the upset.

Corrosion rate is often based on the Shell model (deWaard and Milliams). This gives corrosion rate as a function of temperature, pressure and CO_2 content. In addition, effects due to pH, saturation of corrosion products, glycol content and scale formation may be accounted for. The corrosion rate is modelled as follows:

$$CR = 10^{5.8-\frac{1710}{T}+0.67.log(f_{CO_2}).x_m.i.F_{scale}.F_{pH}} \tag{31}$$

where:

F_{scale} =Correction factor for scale formation on steel surface

T =Temperature

f_{CO_2} =Fugacity of CO_2

x_m = Corrosion rate uncertainty factor.

i = Effect of Corrosion inhibitor.

F_{pH} = Correction factor for pH.

Using a MVFOSM [2] approximation a safety index can be formulated as:

$$\beta = \frac{\mu_g}{\sigma_g} \tag{32}$$

[2]Mean Value First Order Second Moment

4 Expert Assessment of Pipe Corrosion

4.1 Estimating The maximum corrosion depth d

Corrosion, unlike other pipeline failure modes, takes time to develop. Internal corrosion, for example, initiates when the product is corrosive and no barrier is present between the product and the steel.

The maximum corrosion depth can be calculated as follows:

$$d = \alpha\nu(T_s - T_i) \tag{33}$$

where:

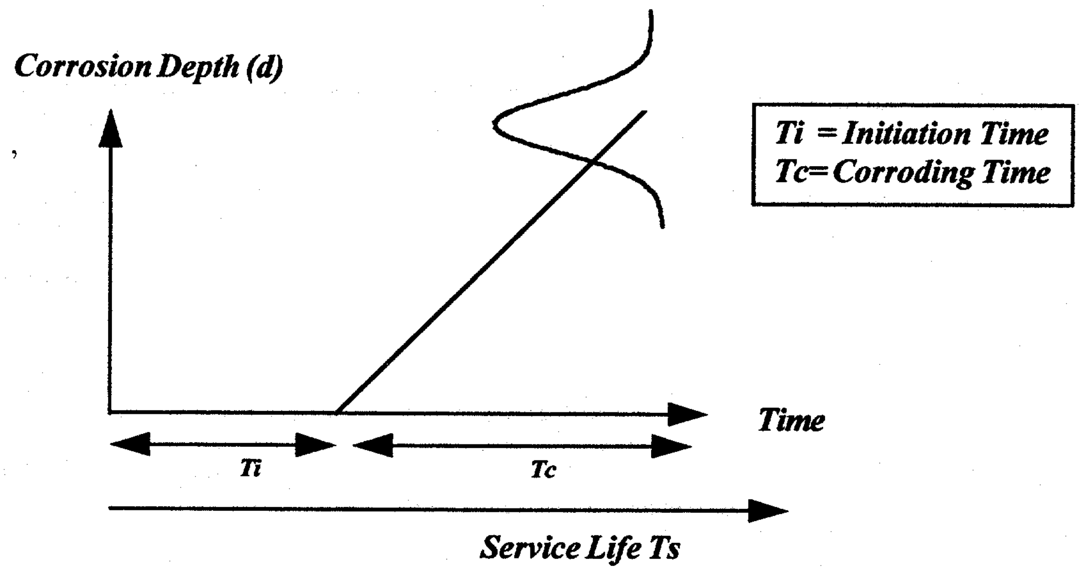
α = Inhibitor efficiency (random)

ν = Corrosion rate (mills per year)

T_s= Service Life (yrs)

T_i= Time (random) to initiate corrosion (yrs)

The time to intiate, Ti, is a random variable, since corrosion can initiate at any time, given suitable conditions are present. i.e. corrosive medium without inhibition (internal corrosion) or malfunctioning of the cathodic protection (external corrosion).



Modelling Corrosion Initiation and Penetration

Description	Corrosion Rate vc (mm/yr)	V (vc)	Time To Initiate T_i (years)
Extreme High	10	200	100
Very High	1	100	10
High	0.5	75	5
Moderate	0.1	50	1
Low	0.05	25	0.5
Very Low	0.01	10	0.1
Extreme Low	0.001	1	0.01

Table 1: Expert Assessment of Corrosion Parameters

4.2 Expert Assessment of Corrosion Parameters

Since, corrosion evaluation is highly uncertain, expert judgment can be used as a means for the assessment procedure. Uncertainty arises because Ti, the time to initiate corrosion is uncertain, inhibitor efficiency is also uncertain. Table 1 details an expert assessment procedure for the corrosion parameters of interest: corrosion rate, coefficient of variation of the corrosion rate, time to initiate corrosion. These parameters are linked to linguistic terms to restrain the expert. Verification examples from current failure databases are being developed to calibrate these assessments.

5 Evaluation of Inspection, Maintenance & Repair Alternatives

Once corrosion has been detected, the pipeline operator is faced with a variety of decisions concerning inspection and/or maintenance activities. These decisions are:

- Do nothing.
- Monitor and clamp any leaks.
- Use inhibitors (internal corrosion)
- Protect ,wrap up, cathodic protection (external corrosion)
- Line pipeline
- Replace corroded segment
- Inspect to measure corrosion parameters

Selection of the best alternative is based on a cost-benefit analysis to minimize the expected cost, i.e. maximize the expected utility.

6 Part III: Analysis of Offshore Pipeline Failure Data

The US department the Interior, Minerals Management Service (MMS), Gulf of Mexico Outer Continental Shelf (OCS) region maintains failure data on offshore pipelines in the Gulf of Mexico since 1967. The pipeline failure data for the period 1967-present, is compiled in database format for processing and analysis.

Preliminary analysis of the data looked quite hopeful. For example, time to first failure seemed to follow the Weibull distribution. Such distribution belongs to a family of distributions used to model life of mechanical components where aging and wear out effects are noticeable.

The purpose of this section is to carry out a preliminary data and trend analysis on the failure data.

6.1 Preliminary Results

An analysis of the 30-year (1967-1997) pipeline failure database compiled by the US Minerals Management Service revealed the following:

- Corrosion is the leading cause of failures of subsea pipelines in the U.S. Gulf of Mexico, outer continental shelf region.

- Third-party incidents, storms, and mud slides are additional principal causes of offshore pipeline failures.

- Among corrosion failures, external corrosion accounts for 68% while internal corrosion accounts for 32%

- Almost 70% of internal corrosion failures occurred in pipelines carrying gas and or mixtures containing gas.

- An increase in the number of reported failures in 1992, as shown in figure 4, is attributed to hurricane Andrew, which resulted in approximately 400 failures.

- Time to failure due to corrosion, i.e. service life, follows a Weibull distribution. The hazard function corresponding to the Weibull density is a power function of t, and depends only on the shape and scale parameters of the Weibull density. The hazard function provides the reliability as a function of time for a particular failure mode.

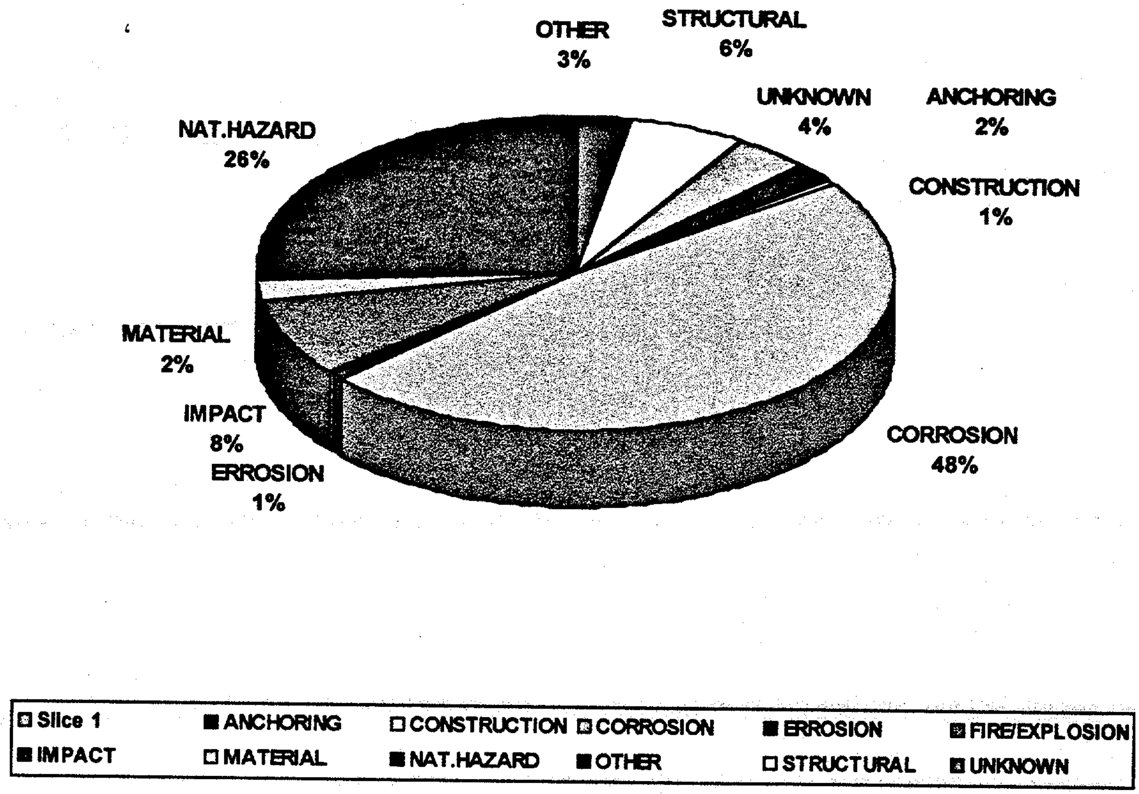


Figure 1: Offshore Pipeline Failures By Cause, Offshore Pipelines; Gulf of Mexico OCS Region; Source:MMS Database from 1967-1997

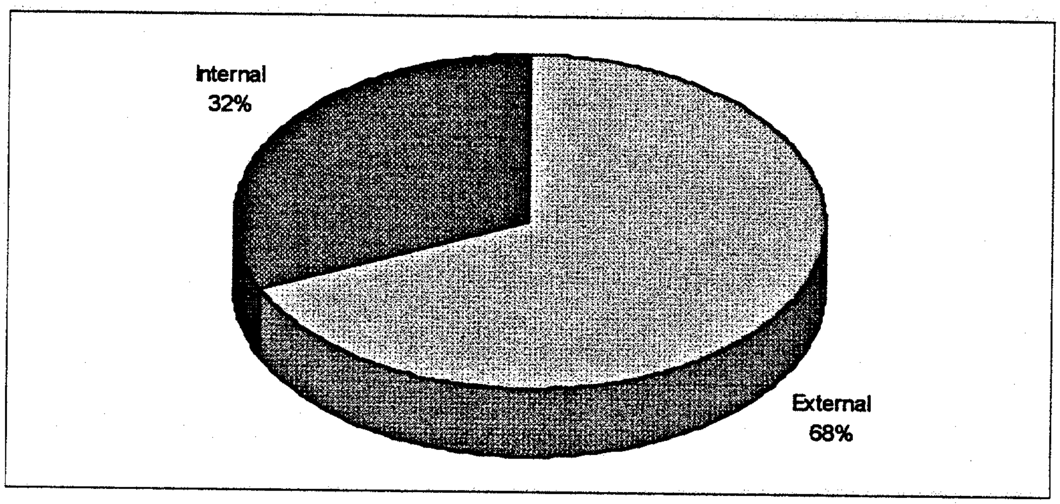


Figure 2: External Vs Internal Corrosion Failures, Offshore Pipelines; Gulf of Mexico OCS Region; Source:MMS Database from 1967-1997

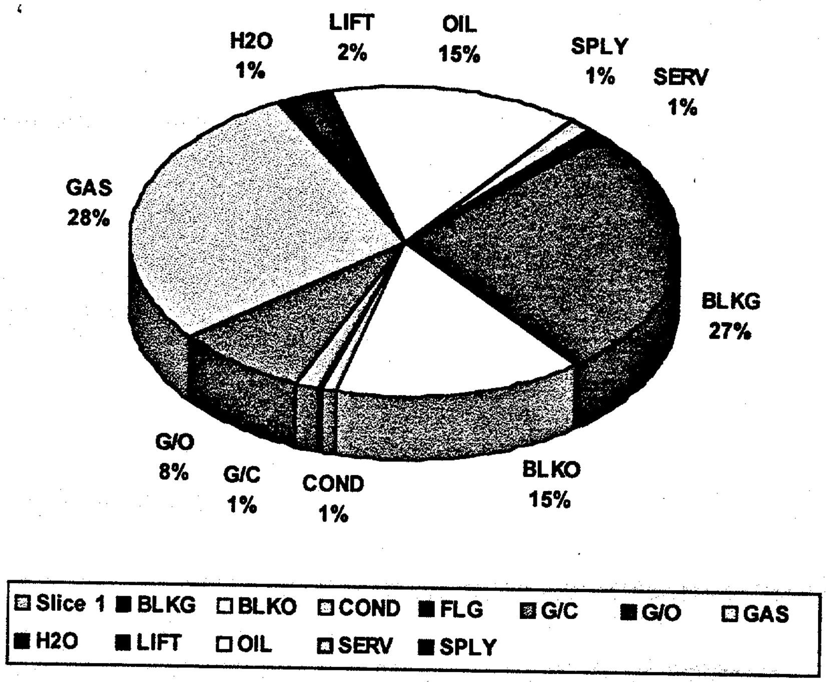


Figure 3: Internal Corrosion Failures By Product Type, Offshore Pipelines; Gulf of Mexico OCS Region; Source:MMS Database from 1967-1997

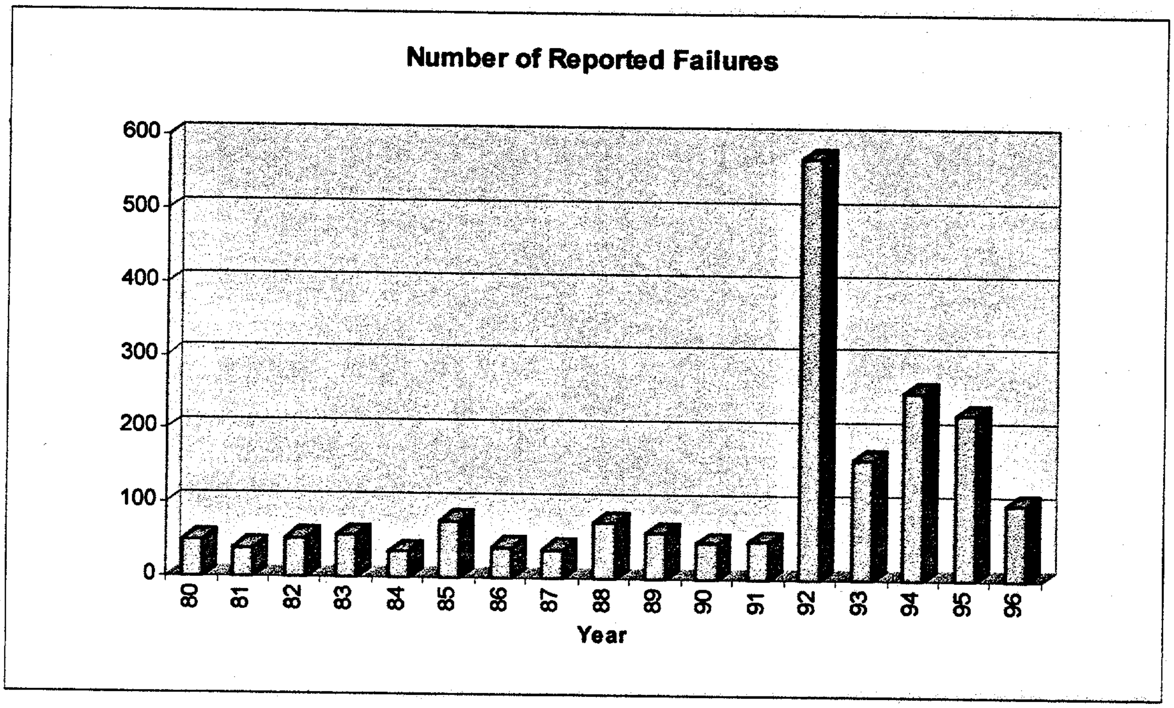


Figure 4: No of Reported Incidents per Year for the Last 10 Yrs, Offshore Pipelines ; Gulf of Mexico OCS Region; Source:MMS Database from 1967-1997

7 Summary & Conclusions

A methodology for the reliability assessment of offshore pipelines is presented. Offshore pipelines are divided into two main categories. Piggable pipes, for which internal inspection results are available and non-piggable pipes for which no inspection information is available.

Reliability assessment procedures for both categories were developed. An expression to evaluate the segment failure probability under combined failure modes is developed. Another expression for computing the failure probability of the *entire pipeline* is developed. With these expressions, an evaluator can assess high risk segments on a single pipeline level as well as on a network of pipelines level. Finally, a preliminary analysis of offshore pipeline failure data is presented. This analysis identifies the major failure mechanisms and highlights weak points in the system.

8 Appendix A: Determination of Maximum Allowable Corrosion Defect Depth

The remaining strength of a corroded pipe is commonly derived from:

$$\sigma_f = \bar{\sigma}\frac{1 - \frac{A}{A_o}}{1 - \frac{A}{A_o}M^{-1}} \tag{34}$$

where

$\bar{\sigma}$ =Material flow stress=1.1SMYS

σ_f= Maximum allowable hoop stress.

$A =$ Projected area of corrosion defect

$A_o = Lt_o$

$L =$ Axial extent of the corrosion defect

$t_o =$ Pipe wall thickness

M= Folias bulging factor to account for stress concentration $\sqrt{1 + \frac{0.8L^2}{Dt}}$

By lettig the maximum allowable hoop stress equals $SMYS$ and the flow stress equals $1.1SMYS$ equation (27) can be rearranged to:

$$1 = 1.1SMYS\frac{1 - \frac{A}{A_o}}{1 - \frac{A}{A_o}M^{-1}} \tag{35}$$

Kiefner (Ref. 3) approximated the projected area of the corrosion defect A, to be:

$A = \frac{2}{3}L.d$ if $L \leq 4.48\sqrt{Dt}$.

$A = L.D$ if $L > 4.48\sqrt{Dt}$

Combining equations (31) and (32) and noting that as L becomes infinitely large (or $L > 4.48\sqrt{Dt}$), so does M and thus $\left(1 - \frac{A}{A_o M}\right) \rightarrow 1$, the maximum allowable corrosion depth for short corrosion $L \leq 4.48\sqrt{Dt}$:

$$d = \frac{0.1}{\frac{2}{3t}(1.1 - M^{-1})} \tag{36}$$

and for long corrosion $L > 4.48\sqrt{Dt}$:

$$d = \frac{t}{11} \tag{37}$$

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