

REAL-TIME RELIABILITY ASSESSMENT & MANAGEMENT OF MARINE PIPELINES

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ABSTRACT

In-line instrumentation information processing procedures have been developed and implemented to permit 'real-time' assessment of the reliability characteristics of marine pipelines. The objective of this work is to provide pipeline engineers, owners and operators with additional useful information that can help determine what should be done to help maintain pipelines.

This paper describes the real-time RAM (reliability assessment and management) procedures that have been developed and verified with results from laboratory and field tests to determine the burst pressures of pipelines. These procedures address the detection and accuracy characteristics of results from in-line or 'smart pig' instrumentation, evaluation of the implications of non-detection, and the accuracy of alternative methods that can be used to evaluate the burst pressures of corroded and dented – gouged pipelines.

In addition, processes are described that have been developed to permit use of the information accumulated from in-line instrumentation (pipeline integrity information databases) to make evaluations of the burst pressure characteristics of pipelines that have not or can not be instrumented.

Both of these processes are illustrated with applications to two example pipelines; one for which in-line instrumentation results are available and one for which such information is not available.

Keywords: Pipelines, Reliability, Instrumentation

INTRODUCTION

Pipeline in-line instrumentation has become a primary means for gathering detailed data on the current condition of pipelines. It would be very desirable for the pipeline owner, operator, and regulator to have a highly automated process to enable preliminary assessment of the reliability of the pipeline in its current and projected future conditions (Fig. 1)

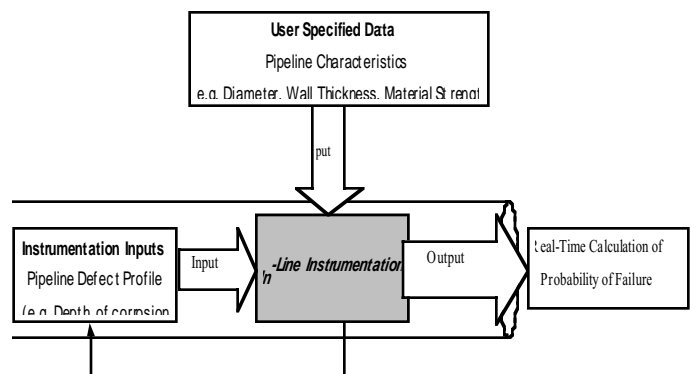


Fig. 1: Real-Time RAM process

Pipeline in-line instrumentation data can provide a large amount of data on damage and defects (features) in a pipeline. This data must be properly interpreted before the features can be characterized. The detection of features varies as a function of

the size and geometry of the features, the in-line instrumentation used, and the characteristics and condition of the pipeline. Given results from in-line instrumentation, it is desirable to develop a rapid and realistic evaluation of the effects of the detected features on the pipeline integrity. This evaluation requires and analysis of how the detected features might affect the ability of the pipeline to maintain containment.

RELIABILITY FORMULATION

The Reliability Assessment and Management (RAM) formulation used in this development is based on a probabilistic approach based on Lognormal distributions for both pipeline demand and capacity distributions. Such distributions have been shown to provide good approximations to the ‘best-fit’ distributions, particularly when the tails of the Lognormal distributions are fitted to the region of the distributions that have the greatest influence on the probability of failure. The Lognormal formulation for the probability of failure (Pf) is:

$$Pf = 1 - \Phi \left[\frac{\ln \left(\frac{R_{50}}{S_{50}} \right)}{\sigma_{\ln RS}} \right] = 1 - \Phi[\beta]$$

Φ is the Cumulative Normal Distribution for the quantity [•]. R₅₀ is the median capacity. S₅₀ is the median demand. The ratio of R₅₀ to S₅₀ is known as the median or central Factor of Safety (FS₅₀). σ_{lnRS} is the standard deviation of the logarithms of the capacity (R) and demand (S):

$$\sigma_{\ln RS} = \sqrt{\sigma_{\ln R}^2 + \sigma_{\ln S}^2}$$

σ_{lnR} is the standard deviation of the capacity and σ_{lnS} is the standard deviation of the demand. For coefficients of variation (V_x = ratio of standard deviation to mean value of variable X) less than about 0.5, the coefficient of variation of a variable is approximately equal to the standard deviation of the logarithm of the variable. The quantity in brackets is defined as the Safety Index (β). The Safety Index β is related approximately to Pf as 1 ≤ β ≤ 3):

$$Pf \approx 0.475 \exp -(\beta)^{1.6}$$

The results of this development are summarized in Fig. 2. The probability of failure (loss of containment) is shown as a function of the central factor of safety (FS₅₀) and the total uncertainty in the pipeline demands and capacities (σ). Note that the probability of failure can be determined from two fundamental parameters: the central factor of safety (FS₅₀ = R₅₀/S₅₀) and the total uncertainty in the demands and capacities (σ_{lnRS}=σ).

TIME DEPENDENT RELIABILITY

When a pipeline is subjected to active corrosion processes, the probability of failure is a time dependent function that is dependent on the corroded thickness of the pipeline (t_c/e). The corroded thickness is dependent on the rate of corrosion and the time that the pipeline or riser is exposed to corrosion.

Insight into the change in the uncertainty associated with the pipeline capacity associated with the loss of wall thickness due to corrosion, can be developed by the following:

$$\bar{t}_{\ominus} = \bar{t} - \bar{d}$$

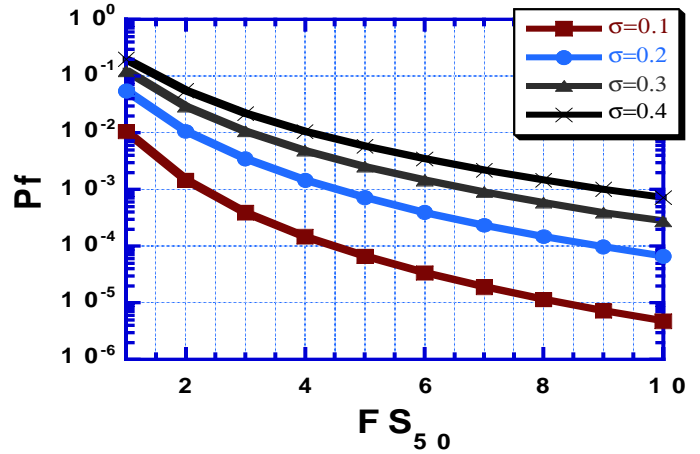


Fig. 2: Probability of failure as function of central Factor of Safety and total uncertainty

t’ is the wall thickness after the corrosion, t is the wall thickness before corrosion, and d is the maximum depth of the corrosion loss. Bars over the variables indicate mean values.

Based on First Order – Second Moment methods, the standard deviation of the wall thickness after corrosion can be expressed as:

$$\sigma_{t\ominus} = \sqrt{\sigma_t^2 + \sigma_d^2}$$

The Coefficient of Variation (COV = V) can be expressed as:

$$V_{t\ominus} = \frac{\sigma_{t\ominus}}{\bar{t}_{\ominus}} = \frac{\sqrt{(V_t \bar{t})^2 + (V_d \bar{d})^2}}{\bar{t} - \bar{d}}$$

A representative value for the COV of t would be 2%. A representative value for the COV of d would be V_d = 40%. Fig. 3 summarizes the foregoing developments for a 16-in. (406 mm) diameter pipeline with an initial wall thickness of t = 0.5 in. (17 mm) that has an average rate of corrosion of 10 mpy (0.010 in. / yr, 0.25 mm / yr). The dashed line shows the results for the uncertainties associated with the wall thickness. The solid line shows the results for the uncertainties that include those of the wall thickness, the prediction of the corrosion burst pressure, and the variabilities in the maximum operating pressure.

At the time of installation, the pipeline wall thickness COV is equal to 2%. But, as time develops, the uncertainties associated with the wall thickness increase due to the large uncertainties associated with the corrosion rate – maximum depth of corrosion. The solid line that reflects all of the uncertainties converges with the dashed line that represents the uncertainties in the remaining wall thickness, until at a time of about 20 years, the total uncertainty is about the same as that of

the remaining wall thickness ($Vt-d \approx 25\%$). As more time develops, there is a dramatic increase in the COV associated with the remaining wall thickness. These uncertainties are dominated by the uncertainties attributed to the corrosion processes.

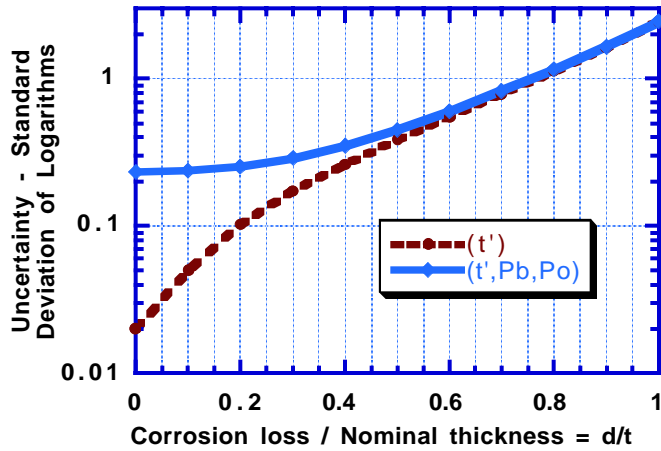


Fig. 3: Uncertainty in pipeline wall thickness and burst pressure capacity as a function of the normalized loss in pipeline wall thickness

These observations have important ramifications on the probabilities of failure – loss of containment of the pipeline. After the ‘life’ of the pipeline is exceeded (e.g. 20 to 25 years), one can expect there to be a rapid and dramatic increase in the uncertainties associated with the corrosion processes. In addition, there will be the continued losses in wall thickness. Combined, these two factors will result in a dramatic increase in the probability of failure of a pipeline.

Fig. 4 summarizes example results for a 16-in. (406 mm) diameter, 0.5 in (13 mm) wall thickness pipeline that has a maximum operating pressure (MOP) of 5,000 psi (34.5 Mpa). The COV associated with the MOP is 10%. The pipeline is operated at the maximum pressure, and at 60% of the maximum operating pressure for a life of 0 to 50 years. The average corrosion rate was taken as 10 mills per year (mpy). For the 60% pressured line, during the first 20 years, the annual probability of failure rises from $1E-7$ to $5 E-3$ per year. After 20 years, the annual probability of failure rises very quickly to values in the range of 0.1 to 1. Perhaps, this helps explain why the observed pipeline failure rates associated with corrosion in the Gulf of Mexico are in the range of $1 E-3$ per year.

TRUNCATED DEMAND & CAPACITY DISTRIBUTIONS

Real-time RAM analytical models have been developed to allow determination of the effects of user specified truncations in pipeline demands, capacities; separately or combined.

The effect of pressure testing is to effectively ‘truncate’ the probability distribution of the pipeline burst pressure capacity below the test pressure (Fig. 5). Pressure testing is a form of ‘proof testing’ that can result in an effective increase in the reliability of the pipeline.

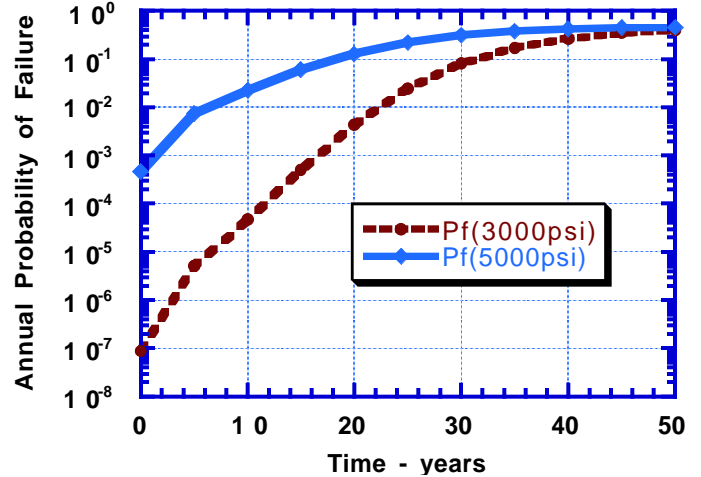


Fig. 4: Example pipeline failure rates as function of exposure to corrosion

There can be a similar effect on the operating pressure demands if there are pressure relief or control mechanisms maintained in the pipeline. Such pressure relief or control equipment can act to effectively truncate or limit the probabilities of developing very high unanticipated operating pressures (due to surges, slugging, or blockage of the pipeline).

Pipeline capacity before testing

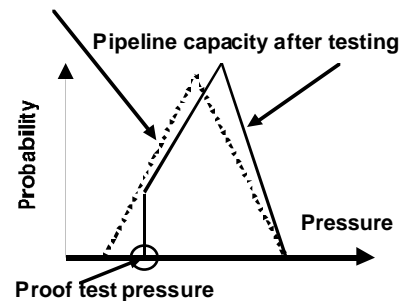


Fig. 5: Effects of proof testing on pipeline capacity distribution

This raises the issues associated with pressure testing and pressure controls on the computed probabilities of failure. It is important to note that such distribution truncation considerations have been omitted from all pipeline reliability based studies and developments that have been reviewed during the past 10 years of research on this topic.

Fig. 6 summarizes the results of pipeline proof testing on the pipeline Safety Index (the probability of loss of containment is $Plc \approx 10^{-\beta}$) as a function of the ‘level’ of the proof testing pressure factor, K:

$$K = \ln(Xp / p_b) / \sigma_{\ln p_b}$$

where Xp / p_b is the ratio of the test pressure to the median burst pressure capacity of the pipeline (test pressure deterministic, burst pressure capacity Lognormally distributed) and is the standard deviation of the Logarithms of the pipeline burst pressure capacities. These results have been generated for

the case where the uncertainty associated with the maximum operating / incidental pressures is equal to the uncertainty of the pipeline burst pressures and for Safety Indices in the range of $\beta = 3$ to $\beta = 4.5$.

For example, if the median burst pressure of the pipeline were 2,000 psi and this had a Coefficient of Variation of 10 %, there was a factor of safety on this burst pressure of 2 ($f = 0.5$) (maximum operating pressure = 1,000 psi), and the pipeline was tested to a pressure of 1.25 times the maximum operating pressure ($X_p = 1,250$ psi), the proof testing factor $K = 4.7$. The results in Fig. 6, indicate that this level of proof testing is not effective in changing the pipeline reliability. Even if the pipeline were tested to a pressure that was 1.5 times the operating pressure, the change in the Safety Index would be less than 5 %.

If the test pressure were increased to 75% of the median burst pressure, the Safety Index would be increased by about 25 %. For a Safety Index of $\beta = 3.0$ ($P_f = 1E-3$), these results indicate a $\beta = 3.75$ ($P_f = 1E-4$) after proof testing.

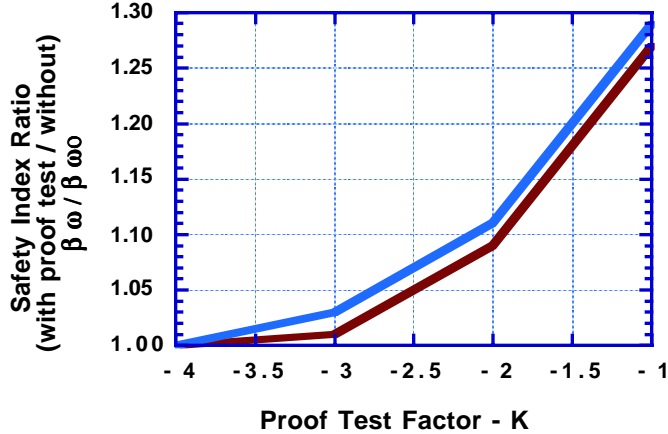


Fig. 6: Effects of proof testing on pipeline reliability

Very high levels of proof testing are required before there is any substantial improvement in the pipeline reliability. These results indicate that conventional pressure testing may not be very effective at increasing the burst pressure reliability characteristics. Such testing may be effective at disclosing accidental flaws incorporated into the pipeline (e.g. poor welding).

PROBABILITIES OF DETECTION

Fig. 7 shows results from inline Magnetic Flux Leakage (MFL) instrumentation of a 20-in (508 mm) diameter gas line in the Bay of Campeche (Pig C) [1]. The measured and corrected corrosion expressed as a percentage of the wall thickness is shown.

Fig. 8 summarizes data for two inline MFL instruments in which the in-line data on corrosion defect depths were compared with the corrosion defect depths determined from direct measurements on recovered sections of the pipeline that was in-line instrumented. For this particular condition, both in-line instruments tend to underestimate the corrosion depth. The uncertainties associated with the measured depths ranged from 35% (for 50 mils depths) to 25% (for 200 mils depths). The

corrected wall thickness shown in Fig. 7 was based on these data.

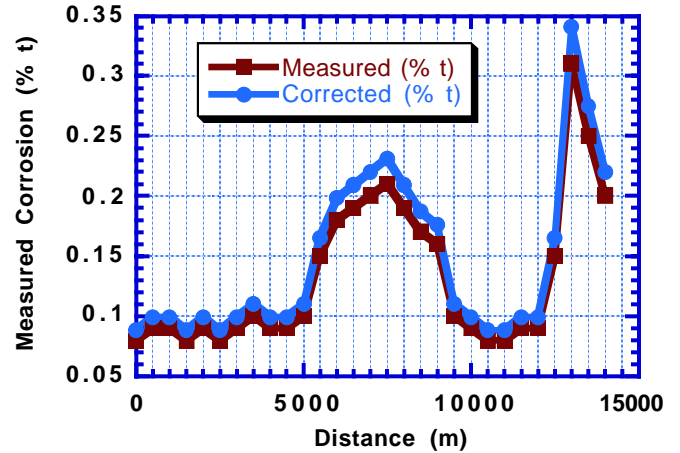


Fig. 7: Measured and corrected corrosion readings

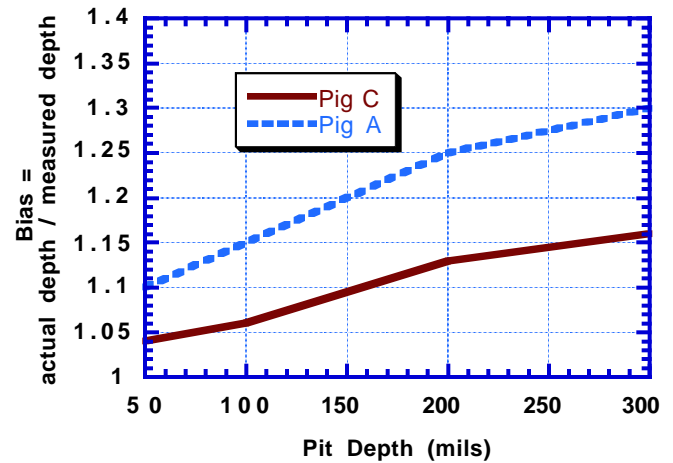


Fig. 8. Bias in measured corrosion depths

Based on using results from inline instrumentation, the probability of failure can be expressed as:

$$P_f = P_{f_D} + P_{f_{ND}}$$

where P_{f_D} is the probability of failure associated with the detected flaws and $P_{f_{ND}}$ is the probability of failure associated with the non-detected flaws. It is important to recognize that making evaluations of corrosion rates and wall thicknesses from the recordings have significant uncertainties/ Fig. 9 shows a comparison of the Probability of Detection (POD) of corrosion depths (in mils, 50 mils = 1.27 mm) developed by three different inline MFL instruments. This information was based on comparing measured results from sections of a pipeline that were repeatedly in-line instrumented and then retrieved and the directly measured corrosion depths determined. These are results from three similar MFL in-line instruments. However, there are significant differences in the POD. This indicates an important need to standardize in-line instrumentation and data interpretation.

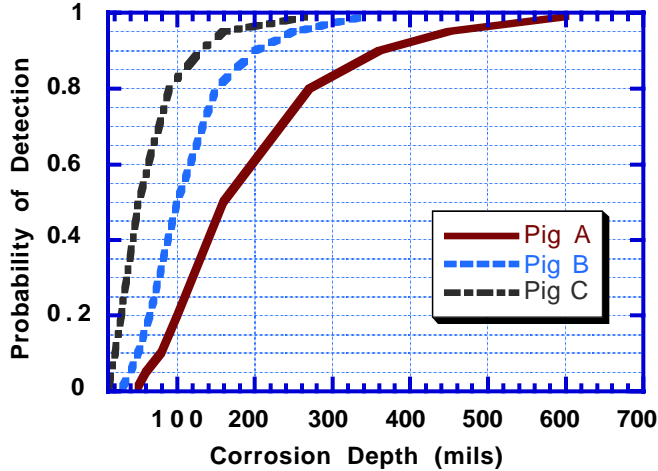


Fig. 9: Probability of detection curves for three in-line instruments

The probability of failure associated with the detected depth of corrosion can be expressed as:

$$P_{fD} = 1 - \Phi\left\{\frac{\ln(p_{B50}/p_{O50})}{[(\sigma_{pB}^2 + \sigma_{pO}^2)^{0.5}]}\right\}$$

where p_{B50} is the 50th percentile (median) burst pressure, p_{O50} is the 50th percentile maximum operating pressure, σ_{pB} is the standard deviation of the logarithms of the burst pressure, and σ_{pO} is the standard deviation of the logarithms of the maximum operating pressures. The pipeline burst pressure is determined from the RAM PIPE formulation:

$$Pbd = 3.2 t \text{ SMYS} / Do \text{ SCF}$$

$$\text{SCF} = 1 + 2 (d / R)^{0.5}$$

where Pbd is the burst pressure capacity of the corroded pipeline, t is the nominal wall thickness (including the corrosion allowance), Do is the mean diameter ($D-t$), D is the pipeline outside diameter, SMYS is the specified minimum yield strength, and SCF is a stress concentration factor that is a function of the depth of corrosion, d ($d \leq t$), and the pipeline radius, R .

The median of the burst pressure is determined from the medians of the variables. The uncertainty in the burst pressure is determined from the standard deviations of all of the variables:

$$\sigma_{\ln p_{B50}}^2 = \sigma_{\ln S}^2 + \sigma_{\ln t}^2 + \sigma_{\ln c}^2 + \sigma_{\ln D}^2$$

The probability of a corrosion depth, X , exceeding a lower limit of corrosion depth detectability, x_0 , is:

$$P[X \geq x_0 | ND] =$$

$$P[X > x_0] P[ND | X \geq x_0] / P[ND]$$

$P[X \geq x_0 | ND]$ is the probability of no detection given $X \geq x_0$. $P[X > x_0]$ is the probability that the corrosion depth is greater than the lower limit of detectability. $P[ND | X \geq x_0]$ is the probability of non detection given a flaw depth. $P[ND]$ is the probability of non detection across the range of flaw depths where:

$$P[ND] = 1 - P[D]$$

and:

$$P[ND] = \sum P[ND | X > x_0] P[X > x_0]$$

The probability of failure for non-detected flaws is the convolution of:

$$P_{fND} = \sum [P_f | X > x_0] P[X \geq x_0 | ND]$$

Fig. 24 shows the probabilities of burst failure (detected and non-detected) of the pipeline. The majority of the pipeline has probabilities of failure of about $1 \text{ E-}2$ per year. However, there are two sections that have substantially higher probabilities of failure. One section is a low section in the pipeline where water can accumulate and the other is in the riser section that is subjected to higher temperatures and external corrosion. The probabilities of failure for these two sections are $1.7 \text{ E-}2$ and $2.9 \text{ E-}2$ per year, respectively. These two sections of the pipeline would be candidates for replacement.

ANALYTICAL MODEL BIAS

One of the most important parts of a reliability assessment is the evaluation of the Bias that is associated with various analytical models to determine the capacity of a pipeline. In this development, Bias is defined as the ratio of the true or measured (actual) loss of containment (LOC) pressure capacity of a pipeline to the predicted or nominal (e.g. code or guideline based) capacity:

$$\text{Bias} = B_x = \frac{\text{True}}{\text{Predicted}} = \frac{\text{Measured}}{\text{Nominal}}$$

It is important to note that the measured value determined from a laboratory experiment is not necessarily equal to the true or actual value that would be present in the field setting. Laboratory experiments involve ‘compromises’ that can lead to important differences between the true or actual pipeline capacity and that measured in the laboratory. For example, the end closure plates used on laboratory test specimens of pipelines will introduce axial stresses that can act to increase the LOC pressure capacity relative to a segment of the pipeline in the field in which there would not be any significant axial stresses.

One important example of the potential differences between the true pipeline capacity and the experimentally determined pipeline capacity regards laboratory experiments that are used to determine the burst pressure capacity of corroded pipelines. To facilitate the laboratory experiments (controlled parameter variations), the corroded features frequently are machined into the pipeline specimen. This machining process can lead to important differences between actual corroded features and those machined into the specimens; stress concentrations can be very different; residual stresses imparted by the machining process can be very different; and there can be metallurgical changes caused by the machining process. Thus, laboratory results must be carefully regarded and it must be understood that such experiments can themselves introduce Bias into the assessment of pipeline reliability.

Another important example regards true or ‘measured’ results that are based on results from analytical models. Such

an approach has been used to generate ‘data’ used in several recent major reliability based code and guideline developments. The general approach is to use a few high quality physical laboratory tests to validate or calibrate the analytical model. Then the analytical model is used to generate results with the model’s parameters being varied to develop experimental data. One colleague has called these “visual experiments.” The primary problems with this approach concern how the model’s parameters are varied (e.g. recognition of parameter correlations recognized and definition of the parametric ranges), and the abilities of the model to incorporate all of the important physical aspects (e.g. residual stresses, material nonlinearity). The use of analytical models introduces additional uncertainties and these additional uncertainties should not be omitted. In one recent case, the analytical models have been calibrated based on machined pipeline test sample results. Thus, the analytical models have ‘carried over’ the inherent Bias incorporated into the physical laboratory tests.

In this study, a differentiation has been made between physical laboratory test data and analytical test data. Further, differentiation has been made between physical laboratory test data on specimens from the field and those that are machined or involve simulated damage and defects. Earlier studies performed on these databases have clearly indicated potentially important differences between physical and analytical test data based Biases and differences between ‘natural’ and simulated defects and damage.

Burst Capacities of Corroded Pipelines

A test database consisting of 151 burst pressure tests on corroded pipelines was assembled from tests performed by the American Gas Association [2], NOVA [3], British Gas [4], and the University of Waterloo [5]. The Pipeline Research Committee of the American Gas Association published a report on the research to reduce the excessive conservatism of the B31G criterion (Kiefner, et al, 1989)[2] Eightysix (86) test data were included in the AGA test data. The first 47 tests were used to develop the B31G criterion, and were full scale tests conducted at Battelle Memorial Institute. The other 39 tests were also full scale and were tests on pipe sections removed from service and containing real corrosion.

Two series of burst tests of large diameter pipelines were conducted by NOVA during 1986 and 1988 to investigate the applicability of the B31G criterion to long longitudinal corrosion defects and long spiral corrosion defects [3]. These pipes were made of grade 414 (X60) steel with an outside diameter of 4064 mm and a wall thickness of 50.8 mm. Longitudinal and spiral corrosion defects were simulated with machined grooves on the outside of the pipe. The first series of tests, a total of 13 pipes, were burst. The simulated corrosion defects were 203 mm wide and 20.3 mm deep producing a width to thickness ratio (W/t) of 4 and a depth to thickness ratio (d/t) of 0.4. Various lengths and orientations of the grooves were studied. Angles of 20, 30, 45 and 90 degrees from the circumferential direction, referred to as the spiral angle, were used. In some tests, two adjacent grooves were used to indicate interaction effects. The second series of tests, a total of seven pipes, were burst. The defect geometries tested were

longitudinal defects, circumferential defects, and corrosion patches of varying W/t and d/t. A corrosion patch refers to a region where the corrosion covers a relatively large area of pipe and the longitudinal and circumferential dimensions were comparable. In some of the pipes, two defects of different sizes were introduced and kept far enough apart to eliminate any interaction.

Hopkins and Jones (1992) [4] conducted five vessel burst tests and four pipe ring tests. The pipe diameter were 508 mm. The wall thickness was 102 mm. The pipe was made of X52. The defect depth was 40% of the wall thickness. Jones et al (1992) also conducted nine pressurized ring tests. Seven of the nine were machined internally over 20% of the circumference, the reduced wall thickness simulating smooth corrosion. All specimens were cut from a single pipe of Grade API 5L X60 with the diameter of 914 mm and wall thickness of 22 mm.

As part of a research project performed at the University of Waterloo, 13 burst tests of pipes containing internal corrosion pits were reported by Chouchaoui, et al [5]. In addition, Chouchaoui et al reported the 8 burst tests of pipes containing circumferentially aligned pits and the 8 burst tests of pipes containing longitudinally aligned pits.

The laboratory test database was used to determine the Bias in the DNV RP F-101 [6], B31G [7], and RAM PIPE [8] formulations were used to determine the burst pressure bias (measured burst pressure divided by predicted burst pressure). The results for the 151 physical tests are summarized in Fig. 10 and Fig. 11. These tests included specimens that had corrosion depth to thickness ratios in the range of 0 to 1 (Fig. 11). The statistical results from the data summarized in Fig. 10 are summarized in Table 1.

Table 1: Bias statistics for three burst pressure formulations (d/t = 0 to 1)

Formulation	B mean	B ₅₀	V _B %
DNV 99	1.46	1.22	56
B 31 G	1.71	1.48	54
RAM PIPE	1.01	1.03	22

The RAM PIPE formulation has the median Bias closest to unity and the lowest COV of the Bias. The DNV formulation has a lower Bias than B31G, but the COV of the Bias is about the same as for B31G. The B31G mean Bias and COV in Table 1 compares with values of 1.74 and 54 %, respectively, found by Bai, et al [9]. The burst pressure test data were reanalyzed to include only those tests for d/t = 0.3 to 0.8. The bias statistics were relatively insensitive to this partitioning of the data.

A last step in the analysis of the physical test database was to analyze the Bias statistics based on only naturally corroded specimens. The results are summarized in Fig. 12 and Table 2. The Bias statistics for the DNV and B31G formulations were affected substantially. The results indicate that the machined specimens develop lower burst pressures than their naturally corroded counterparts. Even though the feature depth and area might be the same for machined and natural features, the differences caused by the stress concentrations, residual stresses, and metallurgical effects cause important differences.

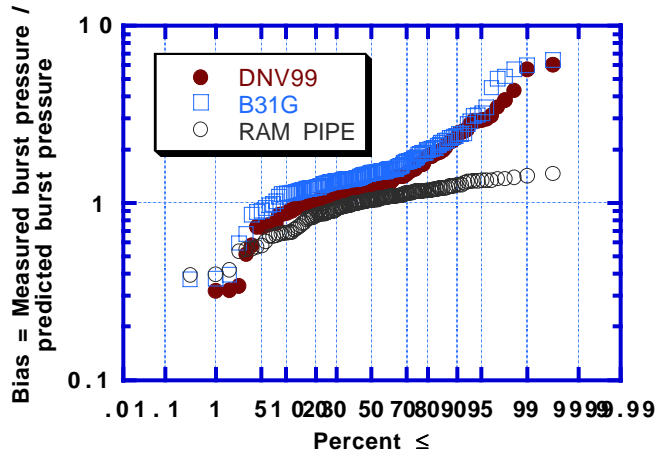


Fig. 10: Bias in burst pressure formulations (Lognormal probability scales)

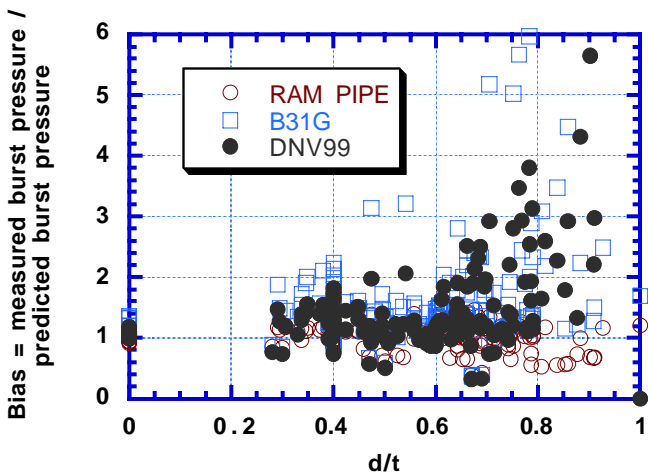


Fig. 11. Bias in burst pressure formulations as function of corrosion depth to wall thickness ratio (d/t)

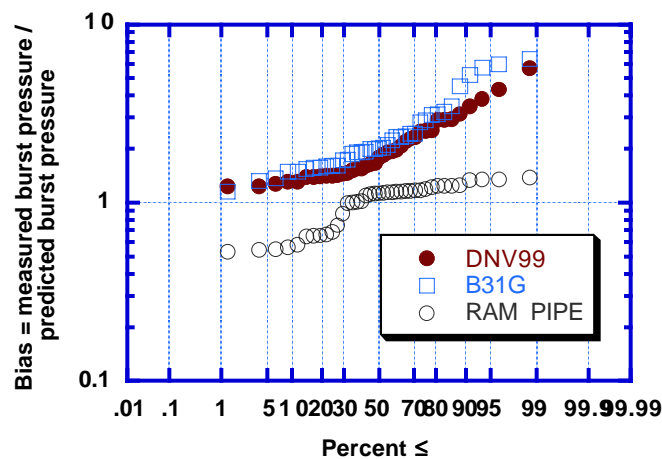


Fig. 12: Bias in burst pressure formulations for naturally corroded test specimens (Lognormal probability scales)

Table 2. Bias statistics for three burst pressure formulations – naturally corroded tests

Formulation	B mean	B ₅₀	V _B %
DNV 99	2.10	1.83	46
B 31 G	2.51	2.01	52
RAM PIPE	1.00	1.10	26

Burst Capacities of Dented & Gouged Pipelines

A database on dented and gouged pipeline tests consisting of 121 tests was assembled from test data published by Battelle Research Corp. and British Gas [10-16]. This database was organized by the sequence of denting and gouging and type of test performed. Study of this test data led to the following observations:

- Plain denting with smooth shoulders has no significant effect on burst pressures. Smooth shoulder denting is not accompanied by macro or microcracking and the dent is re-formed under increasing internal pressures.
- Denting with sharp shoulders can cause macro and micro cracking which can have some effects on burst pressures and on fatigue life (if there are significant sources of cyclic pressures – straining). The degree of macro and micro cracking will be a function of the depth of gouging. Generally, given pressure formed gouging, there will be distortion of the metal and cracking below the primary gouge that is about one half of the depth of the primary gouge.
- Gouging can cause macro and micro cracking in addition to the visible gouging and these can have significant effects on burst pressures. In laboratory tests, frequently gouging has been simulated by cutting grooves in the pipe. These grooves can be expected to have less macro and micro cracking beneath the test gouge feature.
- The combination of gouging and denting can have very significant effects on burst pressures. The effects of combined gouging and denting is very dependent on the history of how the gouging and denting have been developed. Different combinations have been used in developing laboratory data. In some cases, the pipe is gouged, dented, and pressured to failure. In other cases, the pipe is dented and gouged simultaneously, and then pressured to failure. In a few cases, the pipe is gouged, pressured, and then dented until the pipeline loses containment. These different histories of denting and gouging have important effects on the propagation of macro and micro cracks developed during the gouging and denting. It will be very difficult for a single formulation to be able to adequately address all of the possible combinations of histories and types of gouging and denting.
- Gouging is normally accompanied by denting a pipeline under pressure. If the pipeline does not lose containment, the reassessment issue is one of determining what the reliability of the pipeline segment is given the observed denting and gouging. Addressing this problem requires an understanding of how the pipeline would be expected to perform under increasing pressure demands (loss of containment due to pressure) or under continuing

cyclic strains (introduced by external or internal sources). In the case of loss of containment due to pressure, the dent is re-formed under the increasing pressure and the gouge is propagated during the re-forming. Cracks developed on the shoulders of the dents can also be expected to propagate during the re-forming.

The analyses of the laboratory test database on the loss of containment pressure of dented and gouged pipelines was based on:

$$P_{bd} = (2 \text{ SMTS} / \text{SCF}_{DG}) (t / D)$$

where SCF H_{DG} is the Stress Concentration Factor for the combined dent and gouge. Two methods were to evaluate the SCF associated with gouging and denting. The first method (Method 1) was based on separate SCF for the gouging and the dent reformation propagation:

$$\text{SCF}_G = (1 - d/t)^{-1}$$

$$\text{SCF}_D = 1 + 0.2 (H/t)^3$$

$$\text{SCF}_{DG} = [(1 - d/t)^{-1}] [1 + 0.2 (H/t)^3]$$

The second method (Method 2) was based on a single SCF that incorporated the gouge formation and propagation:

$$\text{SCF}_{DG} = \{[1 - (d/t) - [16 H/D(1-d/t)]\}^{-1}$$

Fig. 13 summarizes results from analysis of the test database. The dent depths (H) to diameter ratios were in the range $H/D = 1.0\%$ to 3.6% . The gouge defects had depths (h) to wall thickness ratios that were $h/t = 25\%$.

Results of the analyses indicate Method 1 has a median Bias of $B_{50} = 1.2$ and a COV of the Bias of $V_B = 33\%$. Method 2 has a $B_{50} = 1.3$ and $V_B = 25\%$.

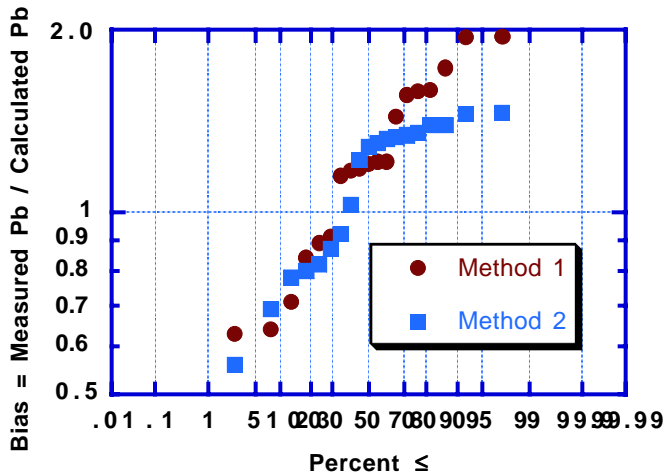


Fig. 13: Analysis of test database on pipelines with dents and gouges

SYSTEMS AND SEGMENTS

In development of the formulation for the probability of failure, it is important to discriminate between pipeline 'segments' and 'systems'. A pipeline system can be

decomposed into sub-systems of a series segments. A series segment is one in which the failure of one of the segments leads to the failure of the system.

A series (weak-link) system fails when any single element fails. In probabilistic terms, the probability of failure of a series system can be expressed in terms of the unions (\cup) of the probabilities of failure of its N elements as [17]:

$$P_{f_{system}} = (P_{f_1}) \cup (P_{f_2}) \cup \dots (P_{f_N})$$

For a series system comprised of N elements, if the elements have the same strengths and the failures of the elements are independent ($\rho = 0$), then the probability of failure of the system can be expressed as:

$$P_{f_{system}} = 1 - (1 - P_{f_i})^N$$

If P_{f_i} is small, as is usual, then approximately:

$$P_{f_{system}} \approx N P_{f_i}$$

If the N segments of the pipeline are independent and have different failure probabilities:

$$P_{f_{system}} = 1 - \prod_{i=1}^N (1 - P_{f_i})$$

If the segments are perfectly correlated then:

$$P_{f_{system}} = \text{maximum} (P_{f_i})$$

There can be a variety of ways in which correlations can be developed in elements and between the segments that comprise a pipeline system. Important sources of correlations include:

- segment to segment strength characteristics correlations, and
- segment to segment failure mode correlations.

The correlation coefficient, ρ , expresses how strongly the magnitudes of two paired variables, X and Y, are related to each other. The correlation coefficient ranges between positive and negative unity ($-1 \leq \rho \leq +1$). If $\rho = 1$, they are perfectly correlated, so that knowing X allows one to make perfect predictions of Y. If $\rho = 0$, they have no correlation, or are 'independent,' so that the occurrence of X has no affect on the occurrence of Y and the magnitude of X is not related to the magnitude of Y. Independent random variables are uncorrelated, but uncorrelated random variables (magnitudes not related) are not in general independent (their occurrences can be related) [17].

Frequently, the correlation coefficient can be quickly and accurately estimated by plotting the variables on a scattergram that shows the results of measurements or analyses of the magnitudes of the two variables. Two strongly positively correlated variables will plot with data points that closely lie along a line that indicates as one variable increases the other variable increases. Two strongly negatively correlated variables will plot with data points that closely lie along a line that indicates as one variable increases, the other variable decreases. If the plot does not indicate any systematic variation in the variables, the general conclusion is that the correlation is very low or close to zero.

In general, samples of paired pipeline segments are strongly positively correlated; tensile strengths, collapse pressures, and burst pressures show very high degrees of correlation (Figs. 14-16) [18]. These test data were taken from samples of delivered pipeline joints and were not intentionally paired from the same plate or runs of steel. High degrees of correlation of pipe properties were also found by Jaio, et al (1997) for samples of the same pipe steel plate.

These results have important implications regarding the relationship between the reliability of a pipeline system and the reliability of the pipeline system elements and segments. The probability of failure of the pipeline system will be characterized by the probability of failure of the most likely to fail element – segment that comprises the system.

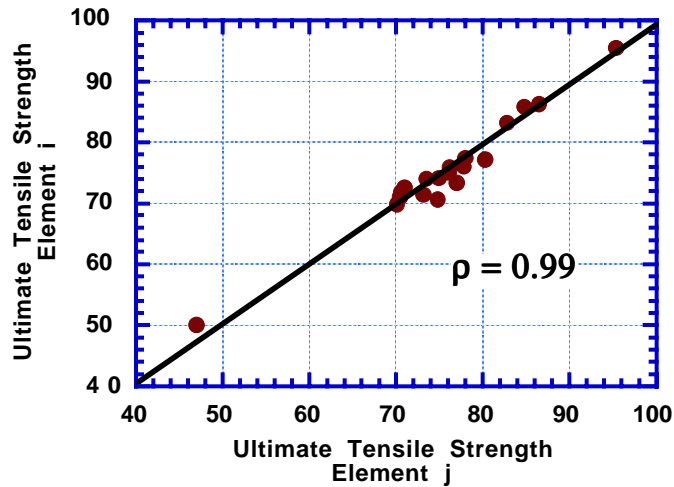


Fig. 14: Correlation of measured ultimate tensile strengths of paired pipeline steel samples from adjacent pipeline segments

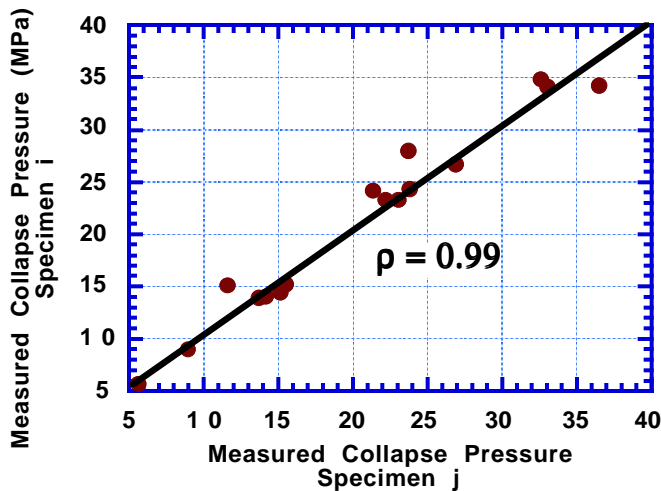


Fig. 15: Correlation of measured collapse strengths of paired steel pipeline samples from adjacent pipeline segments

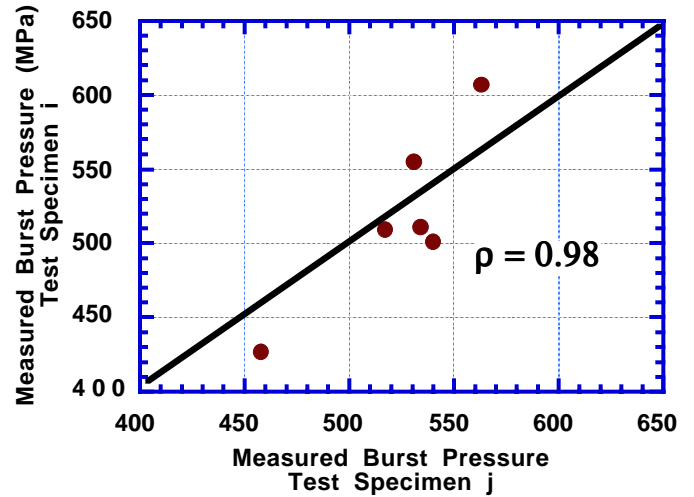


Fig. 16: Correlation of measured burst strengths of paired steel pipeline samples from adjacent pipeline segments

Correlations can also be developed between the failure modes. A useful expression to determine the approximate correlation coefficient between the probabilities of failure of a system’s components (or correlation of failure modes) is:

$$\rho_{fm} \approx \frac{V_S^2}{V_R^2 + V_S^2}$$

where V_S^2 and V_R^2 are the squared coefficients of variation of the demand (S) and capacity (R), respectively. It is often the case for pipeline systems that the coefficients of variation of the demands are equal to or larger than those of the capacity. Thus, the correlation of the probabilities of the failure of the system’s segments can be very large, and there is a high degree of correlation between the system’s failure modes. Again, this indicates that the probability of failure of the system can be determined by the probability of failure of the system’s most likely to fail segment.

CONCLUSIONS

A practical formulation has been developed to allow ‘real-time’ assessments of pipeline likelihoods of LOC (probabilities of failure). This development as involved developing analytical models to evaluate time effects, Biases introduced by different models used to evaluate the LOC pressures, and system versus segment probabilities of failure. Laboratory test data has been used to provide the important parameters for these analytical models.

The real-time RAM formulation is a Level 2 approach in the general pipeline Inspection, Maintenance, and Repair process proposed by Bea, et al [19]. This formulation is consistent with the Risk Based Inspection process proposed by Bjornoy, et al [20]. Verification of the real-time RAM LOC analytical models with field hydro-test to failure data is the subject of a companion paper [21].

The ability to develop real-time estimates of the probabilities of LOC can provide the pipeline owner / operator, pipeline engineers, and regulators with useful additional

information to help guide their decisions regarding pipeline maintenance.

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