Summary Report

Reliability Based Assessment of Pipeline Class Changes

Prepared for:

INGAA

Purpose:

Reliability-based approach to assess treatment of External corrosion and External SCC threats for pipeline class location changes from Class 1 to Class 3.

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1 Executive Summary

Underground gas transmission pipelines are classified according to the presence of human populations in their proximity. These classifications are governed by PHMSA regulation (49 Code of Federal Regulations (CFR) Section 192.5) and industry standards. Operations, maintenance and integrity management requirements and acceptable operational conditions are more stringent with increasing class designations. Over time, specific sections of Class 1 pipelines may be re-classified as Class 3 with increase of population near such sections. With such reclassification, the maximum allowable operating pressure (MAOP) over the entire pipeline may have to be reduced, the reclassified sections may have to be replaced with new pipe, or enhanced pipeline integrity management approaches will have to be used to obtain a "Special Permit" for operating at the original MAOP.

Integrity of pipelines can be compromised by a number of threats, such as corrosion and stress corrosion cracking. Enhanced integrity management therefore requires that these threats be identified and tracked over time using periodic in-line inspections (ILI) of the pipeline. The operator is also subjected to requirements to take action on repair or replacement according to a specified time schedule after an ILI is performed and reveals integrity concerns. These action requirements are based on deterministic analyses of the anomalies and pipeline integrity at the time of an ILI (Year Zero). The operator is required to take repair or replacement actions at specific times, depending upon the nature of the anomaly, and the magnitude of a deterministic *safety factor* (SF) in Year Zero. The protocols for action, stipulated by PHMSA, are subject, like deterministic safety factors in any structural design discipline, to changes. These changes can be perceived as too stringent, or too lenient, depending upon one's perspective. This leaves technical judgment, heuristics, and negotiations as the basis for these action guidelines. Ultimately, engineers and regulators are unable to make quantitative risk-based decisions, particularly when determining if a given protocol results in acceptable safety and reliability of the pipeline.

Unlike deterministic safety factor based approaches, reliability based approaches explicitly quantify the risk of failure of the pipeline, given the statistical behavior of the underlying strength and load parameters. The use of reliability-based assessment is a powerful way to quantify the risk of failure (and hence the reliability) of pipelines, regardless of pipeline Class. In particular, it allows quantitative assessment of the effect of the enhanced integrity management approaches on pipeline reliability, and provides a rational basis for comparing different protocols for repair action, especially when the protocols are based on multiple parameters (such as anomaly depth and safety factor).

In this work, we have developed a comprehensive reliability-based approach that can be applied to pipeline integrity management. The approach has been implemented in Blade's statistical design tool **πSTAT**. Using this approach, the probability of failure of any pipeline at any location (or any anomaly) can be quantified. Two common integrity threats have been considered in this work: External Corrosion, and External Stress Corrosion Cracking (SCC). A case study of an example pipeline is presented to illustrate the reliability of class changes when applying the PHMSA protocol or alternative protocols proposed by INGAA. The time-dependent reliability of the pipeline in response to both the PHMSA protocol and the INGAA protocol is shown to demonstrate their impact. Although the focus of this work is sections reclassified from Class 1 to Class 3, the impact of the repair protocols on reliability of Class 1 locations is also shown. This report provides a summary of the technical approach developed by Blade, the assumptions made, and results from its application to the example pipeline. Further technical details can be found in the Detailed Report accompanying it.

The main conclusions that may be drawn from this work for a typical Case Study are presented below.

- For Class change locations from 1 to 3, the PHMSA requirements deliver robust pipeline reliability for the time-dependent Corrosion and SCC threats that were analyzed in this work. Application of the reliability-based assessment to the Class change locations (1 to 3) in the example pipeline shows that:
    - For Corrosion anomalies in the Class change locations (1 to 3) multiple anomalies violated SF of 1.39, however the highest Probability of Failure (POF) was still 10^{-7}. Following repair of these anomalies in Year 1 the POF falls below 10^{-10}. While the POF increases from this low in Year 1 during subsequent years due to the corrosion growth of the unrepaired anomalies, it stays below 10^{-7}. As a result, the highest POF for the Class 3 section over the seven year period is 10^{-7}, which meets or is more conservative than the most stringent requirements of other structural reliability design codes.
    - The alternative protocol proposed by INGAA yields results identical to PHMSA, and may be considered equivalent.
    - For SCC anomalies in the Class change locations (1 to 3), the POF falls below 10^{-7} after the immediate repairs according to the PHMSA protocol, and falls further in Year 2 due to additional (Year 2) repair actions. The POF is less than 10^{-9} following the repairs. Following repair actions, the probability of failure of the pipeline slowly increases in future years due to the growth of the worst unrepaired anomaly, but never rises above $10^{-5.6}$. These probabilities are lower than required in most structural reliability codes.
    - The INGAA proposal is similar to the PHMSA requirements with the exception of the additional depth based criteria for PHMSA for corrosion and SCC. In the case study considered in this analysis, PHMSA's proposed depth criteria had no impact on the POF, as the application of the SF captured these anomalies. In the SCC case the SF reaches 1.39 before the depth reaches 40%.
- For Class 1 locations within the vicinity of Class location changes, the PHMSA guidelines still deliver strong reliability for the Corrosion and SCC threats analyzed in the example pipeline.
    - For Corrosion anomalies, the probability of failure remains consistently below $10^{-4.4}$ over all seven years, regardless of whether the PHMSA or INGAA protocol is applied (both of which follow the ASME B31.8S schedule for anomaly repair in subsequent years). Both protocols yield identical outcomes.
    - For SCC anomalies, the highest POF using the PHMSA protocol is 10^{-4} (in Year Zero). Once the Year 1 repairs are performed, the POF drops to less than 10^{-9}, gradually rising (due to growth of unrepaired anomalies), but never rising above $10^{-5.6}$. This is in line with structural reliability codes for moderate consequence failures.
    - For SCC anomalies, the INGAA proposal, which defers repair of anomalies with Year Zero SF less than 1.39 to Year 2 (instead of Year 1 with PHMSA protocol), the POF is slightly higher than obtained using PHMSA protocol. The highest POF is $10^{-3.9}$, in Year 1 but drops to less than 10^{-9} following repairs in Year 2.
- Overall, PHMSA requirements for enhanced integrity management deliver pipeline reliability that is in excess of that required by many structural reliability codes, based on the quantitative assessment of probability of failure for the two time dependent threats considered here.
- Repair criteria based solely on depth do not demonstrate benefit in terms of reliability. This is because failure is dictated by both depth and length of the anomaly. Therefore, a deep anomaly

often will not have an appreciable effect on failure pressure unless it is of adequate length. It is suggested that the criteria include both depth and length of the anomaly to create a more rational basis for repair decisions.

It should be remembered that the quantitative conclusions made here are for a Case Study. The exact POF may change for specific pipelines. However, conservative assumptions were made during this Case Study to ensure a conservative POF. Depending on the extent and dimensions of unrepaired anomalies that exist on the pipeline, the POF will change. Further, ILI frequency will also impact the POF; some anomalies may never grow and ones that exhibit growth will be addressed by the repair actions. For pipelines with fewer inspection related anomalies the POF will be substantially lower than demonstrated in the case study here.

2 Enhanced Integrity Management Requirements

The enhanced integrity management requirements are based on deterministic safety factors and/or anomaly depth that are calculated from in-line inspection (ILI) data. The safety factor (SF) is the ratio of the estimated failure pressure to the operating pressure (MAOP). ILI data are analyzed to determine anomaly location and dimensions, and failure pressure is calculated for each anomaly. The equations used to calculate failure pressure are specific to the type of integrity threat. For a corrosion or metal loss anomaly, the effect of wall loss on remaining strength is described in ASME B31.G [1]. For SCC, the Level 2 FAD from API 579 is used to calculate failure pressure. From the failure pressure and known MAOP, the safety factor at each anomaly can be calculated. The safety factor and anomaly depth together then drive the repair decisions for any anomaly, as per the guidelines. By requiring repair or replacement actions within a prescribed time, the guidelines attempt to maintain the safety of the pipeline until the next scheduled ILI.

The current PHMSA guidelines for corrosion anomalies and SCC anomalies are briefly recapped below. In these guidelines, "Year Zero" refers to the year in which ILI data have been gathered and analyzed.

2.1 Corrosion Anomaly Assessment Guidelines

The current PHMSA guidelines are show in Table 1 for corrosion or metal loss anomalies. The repair action and timing are based on calculated safety factor and/or depth of the anomaly (but not its length[i]). All anomalies with SF less than 1.1 or with depths greater than 80% wall[ii] are subject to immediate repair regardless of location class. However, in Year 1, the PHMSA requirement is to repair all anomalies with a SF less than 1.39 (or depths greater than 40% wall) for segments where the Class 1 locations have been reclassified to Class 3.

Table 1: Corrosion or Metal Loss Anomalies Enhanced Integrity Guidelines (PHMSA)

SF (API B31.G)	Action and Timing	Applies to
SF ≤ 1.1 OR Depth > 80% of nominal wall	Immediate repair	All Classes
SF ≤ 1.39 OR Depth > 40% of nominal wall	Repair in Year 1	Class 1→ 3
SF > 1.39 AND Depth < 40% of nominal wall	No action until next ILI	Class 1→ 3
SF > 1.1	Remediate as per ASME B31.8S, Sec 7, Fig 4	Class 1

The INGAA proposal (Table 2) is similar to PHMSA, except that Year 1 repair of anomalies in Class change (1 to 3) locations does not include depth criteria.

[i] Failure pressure is a function of both depth and length of anomaly, as per ASME B31.G

[ii] Unless the MAOP is very low, invariably the SF is < 1.1 much before anomaly depth reaches 80%.

Table 2: Corrosion or Metal Loss Anomalies Enhanced Integrity Proposal (INGAA)

SF (API B31.G)	Action and Timing	Applies to
SF ≤ 1.1 OR Depth > 80% of nominal wall	Immediate repair	All Classes
SF ≤ 1.39	Repair in Year 1	Class 1→ 3
SF > 1.39	No action until next ILI	Class 1→ 3
SF > 1.1	Remediate as per ASME B31.8S, Sec 7, Fig 4	Class 1

Both protocols call for the use of the ASME B31.8S, Section 7, Figure 4 schedule for the remediation of anomalies that exhibit SF > 1.1 in a Class 1 location. Table 3 summarizes this remediation schedule. Thus, by the time Year 7 is reached, all anomalies with SF ≤ 1.3 have been repaired.

Table 3. Schedule of Remediation as per ASME B31.8S, Class 1

If Year Zero SF Less than	Repair in
1.13	Year 1
1.16	Year 2
1.19	Year 3
1.22	Year 4
1.25	Year 5
1.27	Year 6
1.30	Year 7

Repair is commonly conducted using a composite wrap (or sleeve) repair and reinforcement system applied at the location of the anomaly. However, depending on the extent of metal loss, replacement may be an option. The choice of strategy usually depends upon the MAOP and severity of the anomalies. These two strategies are investigated in this work by quantifying the resulting reliability.

2.2 External Stress Corrosion Cracking Assessment

Owing to the greater severity and consequences of failure, the decision logic currently recommended by PHMSA for the treatment of SCC threats is more detailed (and more conservative) than for corrosion. The current criteria are shown in Table 4. As can be seen, the safety factors prompting repair action are higher than for corrosion. Depth (but not length) of anomaly is included in the criteria. The type of repair acceptable is also circumscribed by the depth of the anomaly.

Table 4. SCC Enhanced Integrity Guidelines (PHMSA)

PHMSA Proposal		
SF[1] and Crack Depth	**Action and Timing**	**Applies to**
SF ≤ 1.25 OR depth > 50%	Immediate repair	All Classes
SF ≤ 1.39	Repair in Year 1	All Classes
SF > 1.39 AND depth > 40%	Repair in Year 1	Class 1→ 3 (reclassified)
SF > 1.39 AND depth > 40%	Repair in Year 2	Class 1
SF > 1.39 AND depth < 40%	No action until next ILI	All Classes
[1]SF calculated using the API 579 Level II FAD		

An alternative protocol, proposed by INGAA, is shown in Table 4. The PHMSA guidelines and the INGAA proposal are similar, except for the SCC depth requirements that are part of the PHMSA guidelines and the timing of repairs for anomalies in Class 1 areas with an SF between 1.1 and 1.39.

Table 5: SCC Enhanced Integrity Proposal (INGAA)

INGAA Proposal		
SF and Crack Depth	**Action and Timing**	**Applies to**
SF ≤ 1.25 OR depth > 50%	Immediate repair	All Classes
SF ≤ 1.39	Repair in Year 1	Class 1→ 3 (reclassified)
	Repair in Year 2	Class 1
SF > 1.39	No action until next ILI	All classes

2.3 Behavior of Unrepaired Anomalies

In general, it is reasonable to expect that a repaired anomaly no longer poses a threat to pipeline integrity. However, anomalies that do not require repair under the guidelines remain, and continue to grow. Growth rate models are used to predict the growth of these anomalies and assess their impact on the continued safety of the pipeline. Given a model for growth of the corrosion or SCC anomaly, the safety factor of all the unrepaired anomalies (and as applicable, the repaired anomalies) in each year subsequent to Year Zero can be calculated. These calculations provide insight into the continued safety of the pipeline before another ILI. More importantly, they serve as a metric of how safe the decision logic and ILI schedule are. These predictions can also drive intermediate ILI or repair actions.

3 Reliability-Based Assessment

3.1 Background

Reliability based design (RBD) approaches have a long history, and are routinely used in structural engineering [2] [3] [4]. Indeed, reliability-based design is now standard in codes that govern the design of a wide range of structures, including well tubulars, bridges, buildings, offshore structures, aircraft, and nuclear power stations. The use of reliability-based approaches in pipeline design is presented by the Canadian Standard CSA Z662 [5]. Probabilistic assessment of class location changes and integrity management of pipelines has also received attention in the literature [6] [7]. These works suggest increasing interest in, and adoption of, reliability-based approaches in in pipeline integrity assessment.

3.2 Conceptual Description

In reliability based (stochastic, probabilistic) design, given a limit state for any failure mode, the load and strength variables in the limit state are no longer deterministic. They are instead treated as stochastic, with Probability Density Functions (PDFs) based on the statistical behavior of the underlying parameters defining the load and strength. The approach is canonically illustrated in Figure 1.

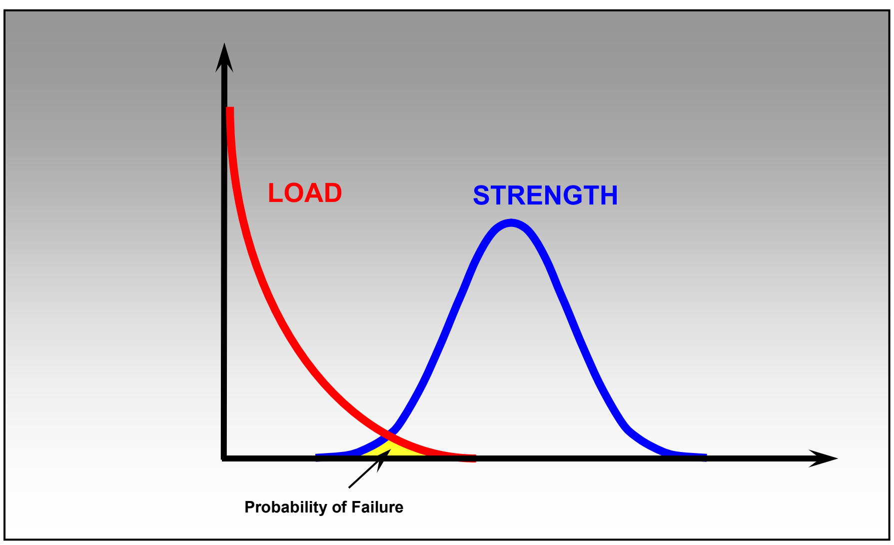


Figure 1. Illustration of Canonical Reliability Based Design

In Figure 1, as can be seen, load and strength are presented as probability density functions (probabilistic distributions). As a result, the notion of a safety factor is no longer applicable. The design basis is then to determine the probability of failure (POF), which is the *probability that load exceeds strength*, and decide if the POF is acceptable. In the figure, POF is the area of the shaded yellow region.

In the context of pipeline integrity, the load is characterized by an operating pressure, which, as a control parameter, can be regulated to within a very tight margin of deviation from the nominal. This implies that the load is essentially deterministic. However, the strength (which, in the context of pipeline integrity, is the failure pressure) is not. Fortunately, statistical information on strength (material properties, anomaly dimensions, time dependent behavior of anomalies, etc.) is more readily available, through material reports, manufacturer data, and in-line inspection data. From these data, the distribution of strength can be constructed. Figure 2 illustrates this Deterministic Load – Probabilistic Strength approach (sometimes referred to as “Level 4 RBD”) graphically.

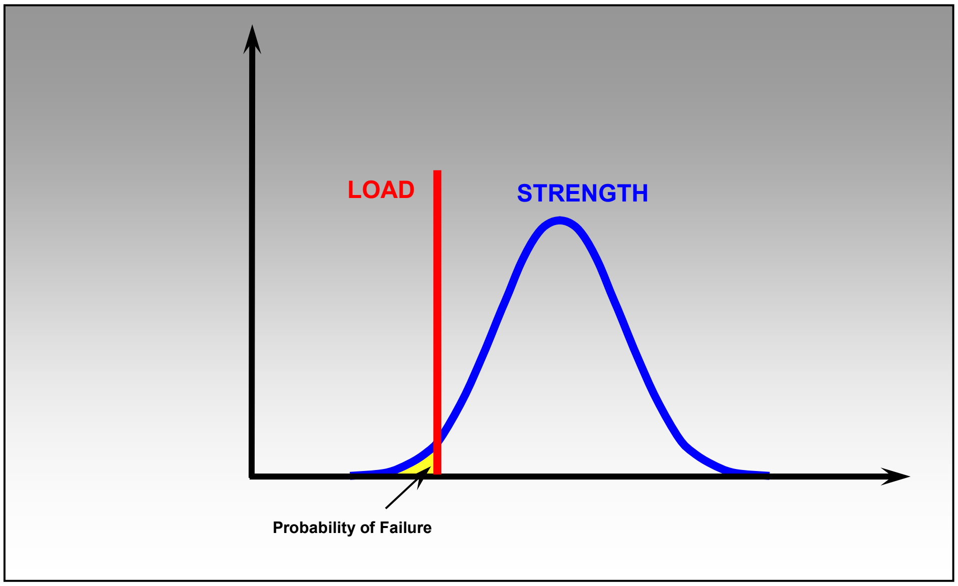


Figure 2. Illustration of Deterministic Load and Probabilistic Strength (DLPS) Approach for Reliability-Based Pipeline Integrity Assessment

Once the statistical behavior of all the parameters that define strength (and load) is described, the probability of failure (yellow shaded area in Figure 2) has to be calculated. This can be done using solution techniques such as Monte Carlo simulations, FORM (First Order Reliability Methods), SORM (Second Order Reliability Methods), FOSM (First Order Second Moment), etc. These techniques are described in some detail in the technical report. The results presented in this work are mainly based on SORM, although all the above methods are implemented in the software tool.

3.3 Target Probability of Failure

Design codes that use RBD set target probabilities of failure (or equivalently, target reliabilities) for specific loads and structures. For time-dependent problems (where either the strength or the load is a function of time), the POF is calculated as a function of time. The time in which the POF reaches the target value is then the useful life of the structure before remedial action is taken.

Suryanarayana and Lewis [4] provide a useful summary of the target POF used in various structural design codes. This is reproduced below in Table 6. In general, the accepted structural design target POF for ultimate limit states, with medium cost of safety measures, lies between 10^{-5} and 10^{-4}. Most design codes are fairly close to this target, with variations based on load types and consequences. The most stringent code is the AFCEN (French Association for Design, Construction and Surveillance Rules of Nuclear Power Plants Components), with a target probability of failure of 10^{-7}. The only pipeline code in the table, the CSA Z662 standard, recommends a target POF of 10^{-4}/km/yr.

Table 6. Target Probabilities of Failure in Various Structural Codes

Code	Application	Target P_f
ACI 318-14 (2014)	Structural Concrete	10^{-4} to $10^{-4.18}$ / yr
AASHTO LRFD (2015)	Bridge Beam Design	10^{-4} to 10^{-5}
AISC Steel Construction Manual (2011)	Structural Steel	10^{-5}
Canadian Std CSA Z662	Oil and Gas Pipeline Systems	10^{-4} per km/yr
ISO 19900 (2013), ISO 19906 (2010), ISO 19902 (2007)	Offshore structures	10^{-3} to 10^{-5}
AFCEN (1997), French	Nuclear Installations	10^{-7}

4 Summary of Technical Approach

The technical approach followed in this work is briefly described below. The reader is requested to consult the technical report for further details. The entire approach has been built into ***πSTAT***, Blade's special purpose Excel-based software program for reliability-based assessment of pipeline integrity. The application of the approach to an example pipeline is described in the next section.

4.1 Repair Decisions

We begin with a complete catalog of all the anomalies in the pipeline over the segment inspected. We therefore know the type, length, and depth for each measured anomaly. We also know the material and geometric properties of the pipeline segment (wall thickness, yield strength, outer diameter, fracture toughness, etc.), and the MAOP for the segment. With this information, the safety factor and the probability of failure are calculated for each anomaly, according to the threat type and appropriate failure equation[iii]. Depending upon the threat type and calculated safety factors (and anomaly depth, if applicable), repair actions are taken according to Table 1 through Table 5. The repair decisions are deterministic in their basis.

4.2 Strength Parameter Assumptions for Reliability Based Assessment

For deterministic calculation of safety factor, the nominal properties and anomaly measurements are adequate. However, for probabilistic calculations, we need to construct the distributions for the underlying parameters. Assumptions made in this work are described below. The current assumptions are conservative, reasonable, and serve to illustrate the approach. It should be noted that all of these assumptions are user inputs, and can be easily modified by the user if desired.

- Yield strength, OD and wall thickness distributions are based on data provided by ISO TR 10400 (API TR 5C3) for M65 grade pipe. This pipe is used as a reasonable substitute for pipelines, since ISO TR 10400 (API TR 5C3) does not include distributions for line pipe grades. Manufacturer-provided data can be used where available for a more accurate representation.
- Fracture toughness (relevant for SCC anomalies) is treated as deterministic. A reasonably conservative input for this parameter is expected.
- An "Equation Error" distribution is included to account for the uncertainty in the predictions of the failure equation. The equation error is constructed from available literature data for ASME B31.G equation for corrosion, and from ISO TR 10400 Level II FAD recommendations for SCC.

4.3 Treatment of Anomalies

4.3.1 Repair of External Corrosion Anomalies

For corrosion, two repair strategies are included in ***πSTAT***. If replacement is chosen as the repair strategy, the entire joint containing the anomalies to be repaired is replaced with a new joint. As a result, all other anomalies contained in this joint are also eliminated. If composite or equivalent repair is

[iii] Recall that for corrosion anomalies, the ASME B31.G equation is used as the failure limit state for SCC anomalies, the API 579 Level II FAD is used as the failure limit state.

chosen as the repair strategy, the wall thickness (or failure pressure) is scaled by a factor of 2 over a 2-ft length of the section, 1 ft on either side of the anomaly being repaired. The scale factor is a user input and can be modified with additional information.

4.3.2 Repair of SCC Anomalies

For SCC anomalies, two repair strategies are included. As in the case of corrosion, if replacement is chosen as the repair strategy, the entire joint containing the anomalies to be repaired is replaced with new pipe, thus removing all anomalies in this joint. If a compression sleeve is chosen as the repair strategy, the sleeve is assumed to span the anomaly 1 ft on each side. Over this section, the sleeve isolates the anomaly from the environment and is also considered to reduce the hoop stress by about 50%.

4.4 Post Repair Behavior of Anomalies

4.4.1 Corrosion Anomalies

All unrepaired corrosion anomalies can be expected to continue to grow, at least until the next ILI. The growth is modeled using a Corrosion Growth Rate (CGR) as a function of time. If a previous ILI run is available, the growth rate is based on the difference between the anomaly depths at each ILI. This leads, as expected, to a data set containing as many CGR calculations as there are anomalies. In the deterministic approach, the CGR calculated for a given anomaly can be uniquely applied to that anomaly, or a constant conservative CGR can be calculated from the entire data set and applied to all anomalies. In the probabilistic approach, a log-normal distribution is fitted to *all* the calculated CGR values for the given segment, and this distribution is used. The log-normal distribution best describes corrosion behavior, based on analysis of CGR from several pipelines performed by Blade. The CGR is only applied to un-repaired anomalies. If the anomalies are repaired, the CGR is assumed to be zero.

4.4.2 SCC Anomalies

As with corrosion anomalies, all unrepaired SCC anomalies continue to grow. The crack growth rate is more difficult to establish for SCC. In this work, we use an estimated crack growth rate, based on extensive prior work in literature, and by Blade, on SCC in pipelines. For deterministic analysis, the crack growth rate is assumed to be 0.2 mm/yr. In the probabilistic analysis, the crack growth rate is assumed to follow a normal distribution between 0.1 mm/yr to 0.3 mm/yr, with a mean value of 0.2 mm/yr.

For repaired anomalies, it is assumed that SCC is arrested, and there is no further growth of cracks.

5 Case Study

The above approach is illustrated by applying it to a case study based on an example pipeline[iv]. The pipeline in question is a 25,000 ft (approximately 5 miles) long segment where two sections have been reclassified from Class 1 to Class 3. The MAOP of this pipeline (36 in. OD, 0.388 in. nominal wall, 65 ksi minimum yield) is 1,008 psi. The segment was subjected to ILI in 2007, and again in 2014. For the purpose of this analysis, we assume that 2014 is "Year Zero". We examine this segment in the context of corrosion as well as SCC anomalies. We focus first on locations where a Class change (from 1 to 3) has occurred, and then on the rest of the pipeline (Class 1).

5.1 Class 1 to Class 3 Changes

5.1.1 External Corrosion Anomalies in Class Change (1 to 3) Locations

The Year Zero (2014) ILI revealed several corrosion anomalies. Using the ILI data, the calculated probabilities of failure and safety factors for each anomaly are shown in Figure 3. The yellow highlighted sections are the ones that have been reclassified from Class 1 to Class 3. The rest of the pipeline remains at Class 1. The upper panel shows the calculated Probability of failure (POF), while the lower panel shows the calculated SF, for each anomaly. The lower panel includes lines at safety factor of 1.1 and 1.39, which trigger repair actions, as discussed in Table 1 and Table 2. The upper panel shows, for comparison, a line at POF = 10^{-4}, which is the target POF in CSA Z662. It should be noted that this is shown here to provide context, and a basis for comparison and gaining insights.

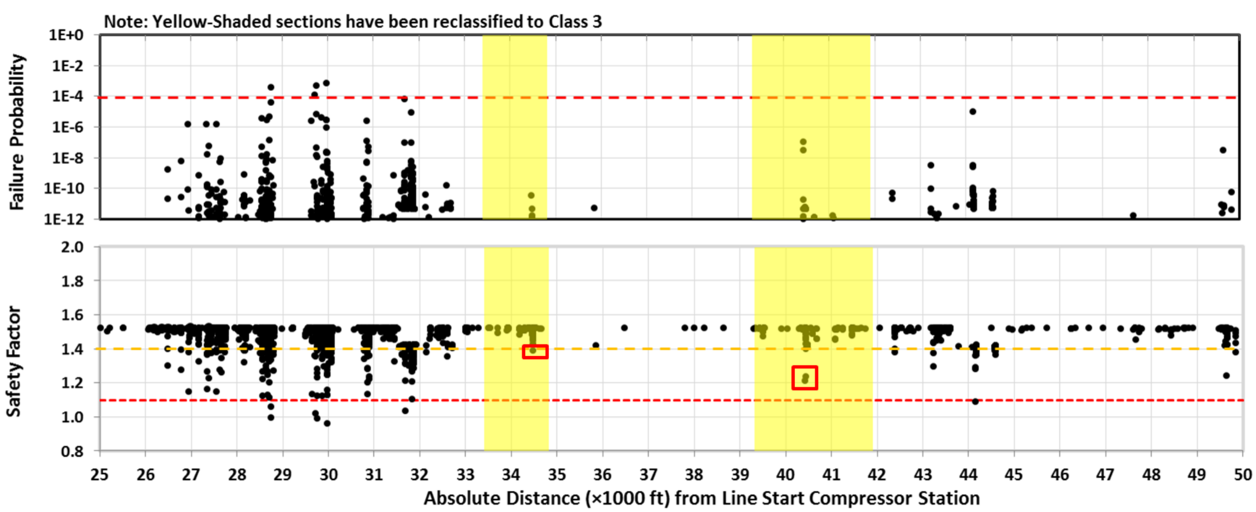


Figure 3. Probability of Failure and Safety Factor Results for Pipeline Segment, Year Zero. Class change (1 to 3) locations are highlighted in yellow.

Focusing on the yellow-highlighted (Class Change from 1 to 3) sections, we find anomalies (indicated by red boxes) that have a SF > 1.1, but < 1.39. These are not subject to immediate repair, but are targeted for repair in Year 1 according to both the PHMSA protocol and the INGAA proposal. It should be noted that the PHMSA protocol has a depth criterion for repair, which is not triggered by the anomalies

[iv] It is noted that this example is based on an actual pipeline

identified. In other words, the SF < 1.39 criterion catches the anomaly before the depth criterion is triggered[v].

In Year Zero, the highest POF among the boxed anomalies is 10^{-7}, dictated by the "worst" anomaly, in the right yellow panel (between 40,000 ft and 41,000 ft). The probability of failure *anywhere* in the Class 3 (reclassified) 1 to 3 section of the pipeline is 10^{-7} or lower[vi]. This is lower than the target POF in most structural design codes, and is in line with the AFCEN target POF for nuclear installations (Table 6).

Repair of these anomalies in Year 1 means these (and neighboring anomalies, depending upon the repair strategy) are eliminated from further consideration. After repair, the POF of the repaired sections falls below 10^{-12}, and no longer dictate the highest POF in the pipeline. *Rather, the worst unrepaired anomaly dictates the POF* (as well as the SF). In the case of the example pipeline is an anomaly of length 9.16 in. and depth 13% of nominal wall, located at 40,441.1 ft. The Year Zero safety factor of this anomaly is 1.3998, just missing the threshold for action by both protocols. This anomaly continues to grow. Using the ILI data from 2007 and 2014, an average corrosion growth rate (CGR) for unrepaired anomalies can be calculated. For this pipeline, the calculated CGR is 0.212 mm/yr. Applying this growth rate to the worst anomaly, the POF and SF at this anomaly as a function of time can be calculated. The results are shown in Figure 4.

In Figure 4, the red bars correspond to the action of "No Repair", that is, we have not followed any protocol, and all anomalies remain unrepaired. This may be the case, for instance, if an enhanced pipeline integrity management protocol is not used. The green bars correspond to the case where the PHMSA (or INGAA) protocol is followed to make repair decisions, and these repairs are made. Note that the shorter the POF bars, the higher the probability of failure, and hence, lower the reliability.

The results clearly illustrate the efficacy of the PHMSA and INGAA repair protocols. The highest POF of the unrepaired anomaly is less than 10^{-10}. If the protocol is not followed, the SF of the worst anomaly falls to 1.06 in 7 years, and the POF increases to higher than 10^{-4} by year 7. However, if either the PHMSA or INGAA protocol are followed (both of which lead to the same outcomes in this pipeline), the POF of the Class 1-3 section never rises above 10^{-10} in year 1 to 10^{-7} in year 7, even though the depth of the worst remaining anomaly is increasing with time due to the CGR. Thus, for this example pipeline, we can see that enhanced integrity management indeed results in significantly higher safety, with POF exceeding the requirements of most structural reliability codes.

[v] Recall that length of anomaly also plays a role in failure pressure and hence the SF (or POF). Exceptional cases can be constructed that pass the SF criterion but fail the depth criterion, by adjusting the length of the anomaly. The impact of length is discussed in more detail in the detailed report.

[vi] The highest probability of failure in any given section is generally taken as the probability of failure of that pipeline section.

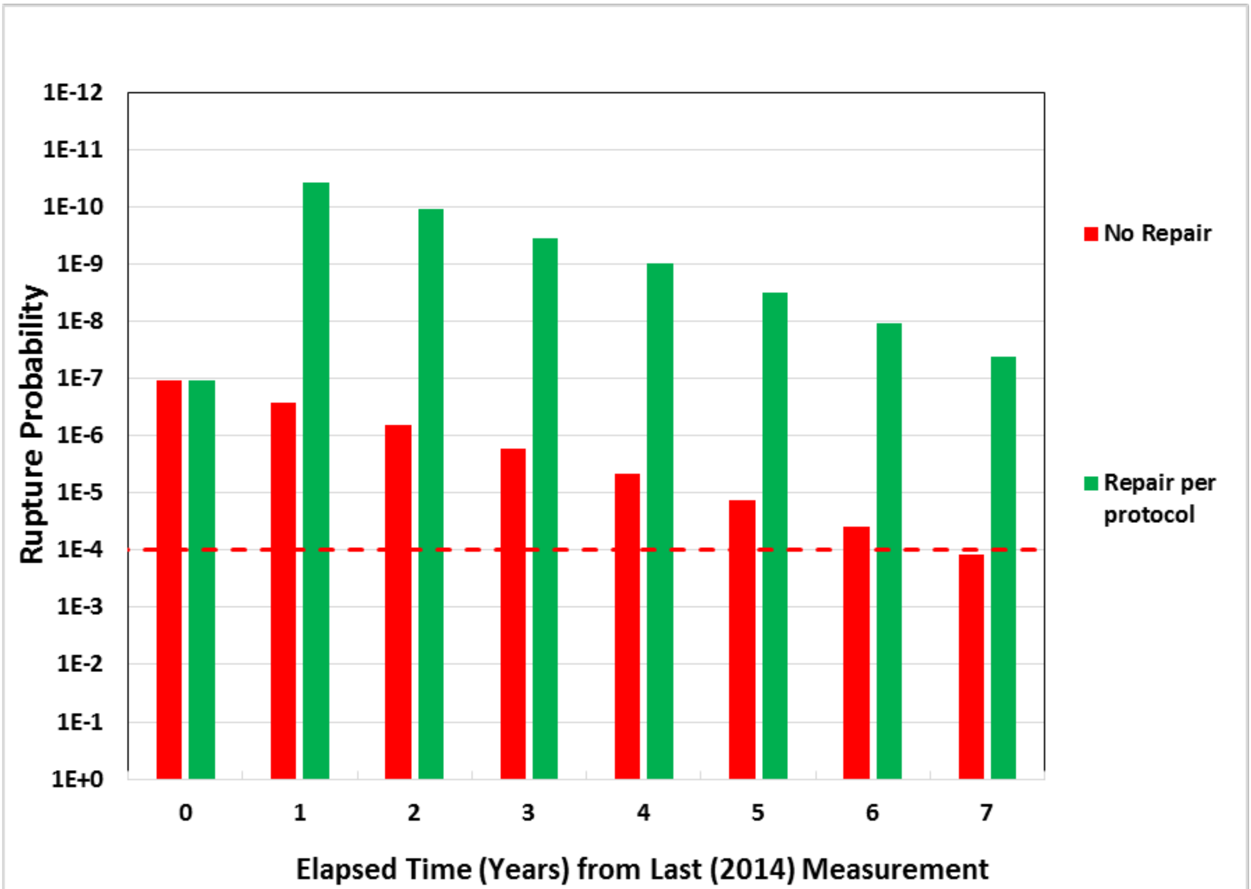


Figure 4. POF and SF for Class 3 Section as a Function of Time for Corrosion Anomalies – Both PHMSA and INGAA Protocols lead to the same outcomes and hence there is no distinction in the graphs

5.1.2 SCC Anomalies in Locations Changed to Class 3

We continue the case study with a consideration of SCC anomalies. In this analysis, we treat 230 of the anomalies identified earlier as SCC anomalies (rather than corrosion anomalies). The pipeline segment is the same, and the MAOP is still 1,008 psi. The limit state now changes to the API 579 Level II FAD, and the resulting safety factors and probabilities of failure are shown in Figure 5 for Year Zero (2014).

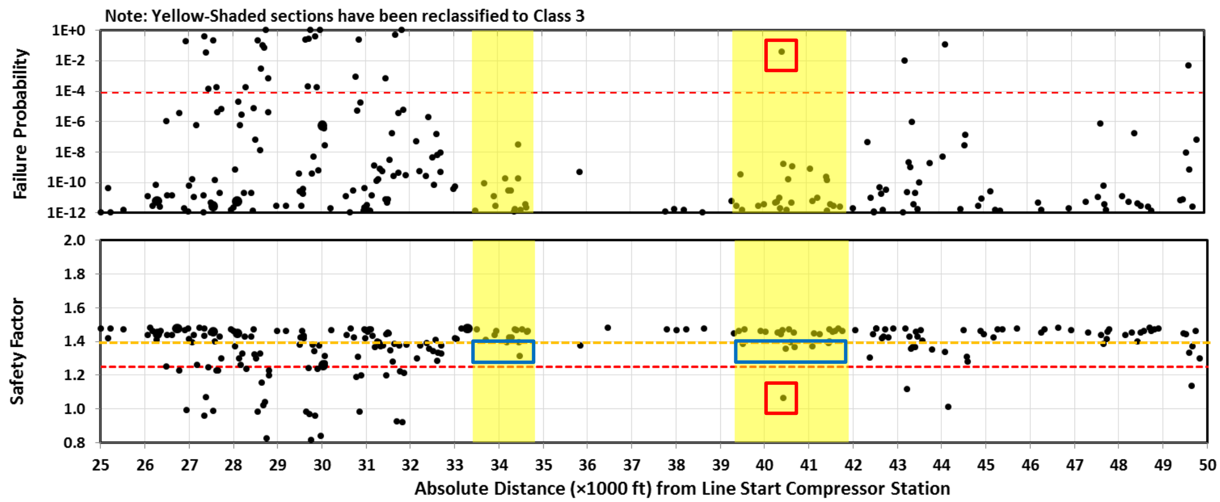


Figure 5. SCC Anomalies – SF and POF in Year Zero

In the figure, focusing again on the locations that were changed from Class 1 to Class 3 (yellow highlighted sections), we find one anomaly that meets the criteria for immediate repair (SF < 1.25 or anomaly depth > 50% of nominal wall) according to both the PHMSA and INGAA protocols for SCC (Table 4 and Table 5). This is indicated by the red box. In fact, this anomaly has an SF = 1.06, and POF of $10^{-1.4}$. All other anomalies have SF > 1.25. The unrepaired anomalies provide a POF less than 10^{-7} following immediate repairs.

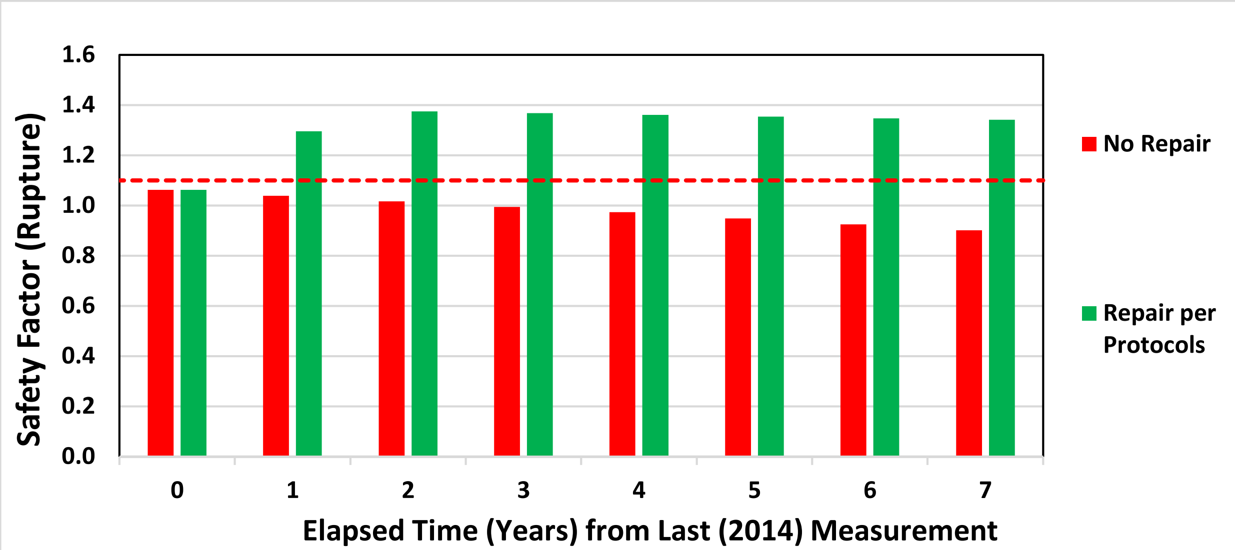
The anomalies shown outlined by the blue boxes are anomalies that have SF greater than 1.25, but less than 1.39, and are scheduled for repair in Year 1, according to both protocols. The PHMSA protocol also has a depth criterion for Year 1 action- anomalies with depth greater than 40% of nominal wall should also be repaired in Year 1. However, the SF criterion catches the anomalies before the depth criterion does, just as in the case of corrosion anomalies[vii]. As a result, both protocols result in repair of the same anomalies in Year 1. The POF of this section of the line goes below 10^{-9}.

From Year 2 onwards, the worst remaining (unrepaired) anomaly dictates the SF and POF as a function of time, as it continues to grow. For this example, the worst remaining anomaly has a length of 3.303 in., depth of 12% of wall, and a Year Zero SF of 1.392 (just over the threshold).

Figure 6 shows the evolution of the dictating POF and SF as a function of time. This is the highest POF (and lowest SF) anywhere in the sections that have been reclassified to Class 3, as a function of time. The figure also shows the consequence of not repairing any anomaly. The figure immediately highlights the risk of not repairing any anomaly – the POF starts at $10^{-1.4}$, and goes to 1.0 (certain failure) by Year 6 (by which time, SF falls to 0.93). However, with either PHMSA or INGAA protocol being followed, the

[vii] In other words, anomaly depths greater than 40% almost always have SF < 1.39. Of course, the length of the anomaly also plays a role in the magnitudes of the safety factor and the probability of failure.

POF stays below 10^{-7} up to Year 6, rising to $10^{-5.6}$ in year 7. It should be remembered that the high POF in Year Zero is driven by the anomaly scheduled for immediate repair.



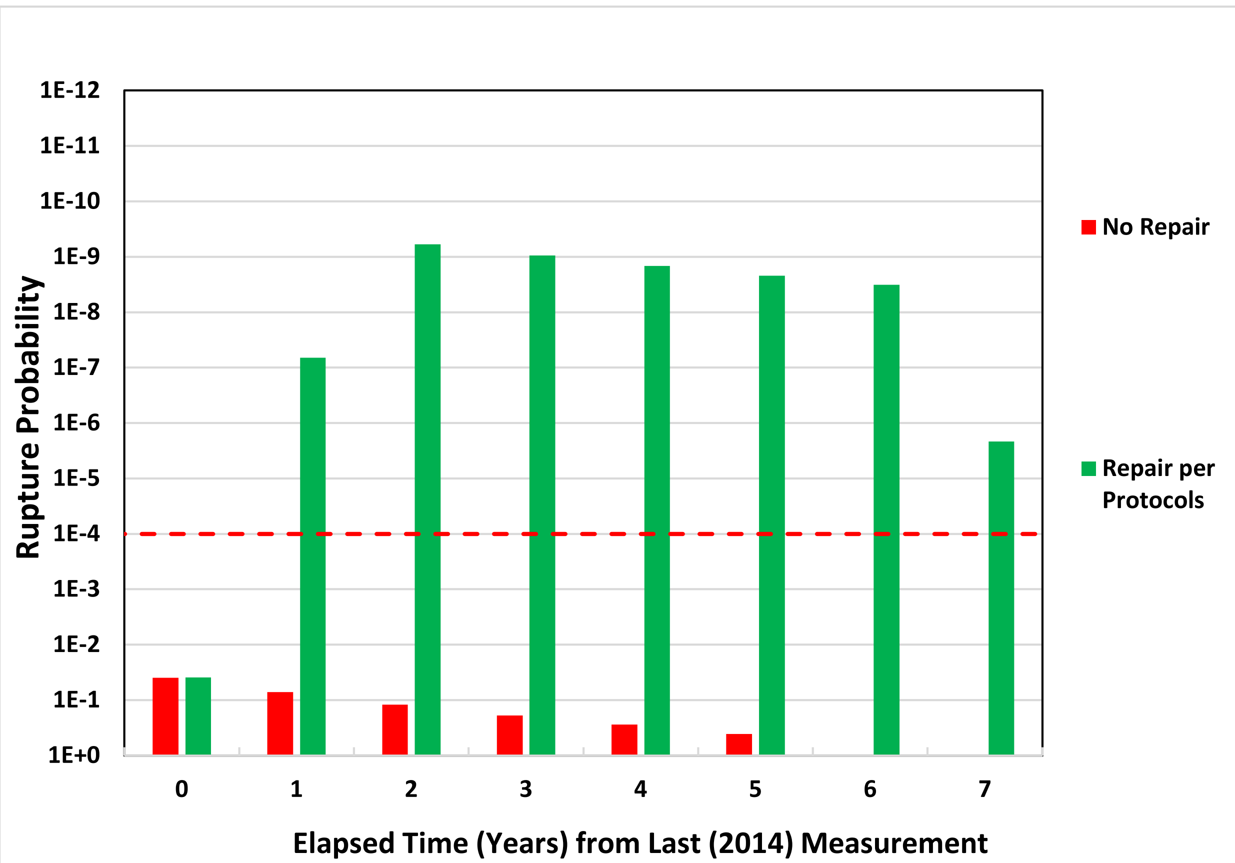


Figure 6. POF and SF for Class 3 Section as a Function of Time for SCC Anomalies – Both PHMSA and INGAA Protocols lead to the same outcomes and hence there is no distinction in the graphs

5.2 Class 1 Locations

Although the focus of this work is sections that were subjected to Class change from 1 to 3, we also examine the effect of the repair protocols on the reliability of the locations where the Class is unchanged and remains at Class 1.

5.2.1 Corrosion Anomalies

Figure 7 is a repeat of Figure 3, but this time focusing on Class 1 locations. In the figure, the blue boxed anomalies violate an SF of 1.1 in Year Zero, and require immediate repair according to both protocols. The POF for these corrosion anomalies approaches 10^{-3} and following repair fall below 10^{-12}.

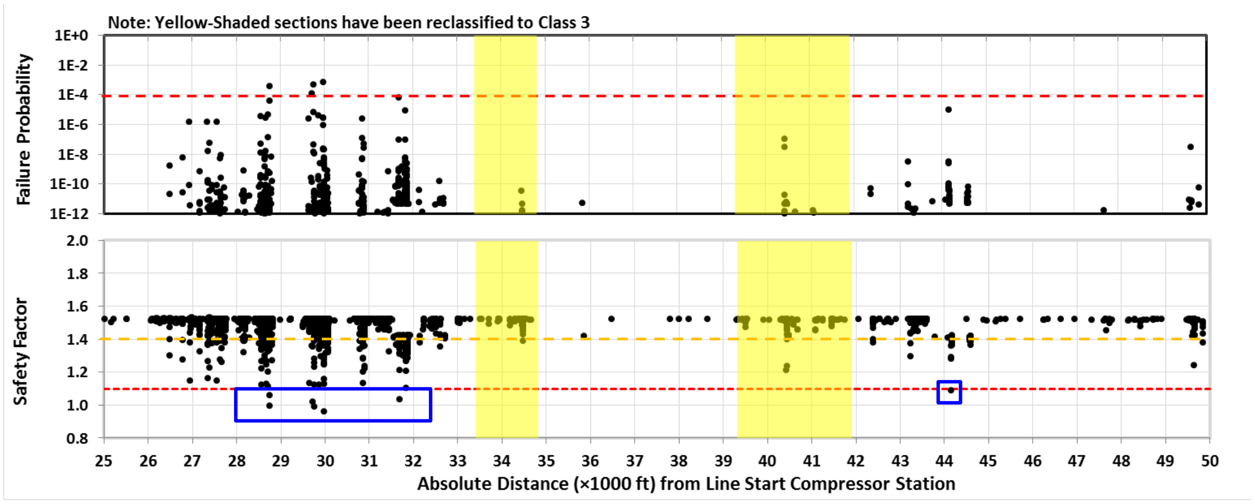


Figure 7. Probability of Failure and Safety Factor Results for Pipeline Segment, Year Zero. Class 1 Anomalies Scheduled for Immediate Repair are Indicated.

Actions in future years follow the ASME B31.8S schedule, which was shown in Table 3. This is somewhat more involved than the treatment of anomalies in Class 3. In essence, repair action can be delayed to future years depending upon the Year Zero SF of the anomalies. Both the PHMSA and INGAA protocols advocate the same repair strategy and therefore lead to identical outcomes. By the time we reach Year 7, all anomalies with SF < 1.3 in Year Zero have been repaired. It is instructive to observe how this repair strategy affects the maximum POF (and minimum SF) in any given year in the Class 1 Sections. This is summarized in Table 7. In Year Zero, the POF and SF are dictated by the worst anomaly that was discovered. This anomaly (together with all the others with SF < 1.1) will be replaced immediately. As we progress through the years, and follow the protocol of Table 3, more and more anomalies are replaced. In this pipeline, a total of 63 anomalies are repaired over the seven years, according to the ASME B31.8S schedule (followed by both PHMSA and INGAA protocols for Class 1 pipeline). This results in a very consistent evolution of POF with time after the immediate repairs, with the highest POF after Year 0 occurring in Year 3 ($10^{-4.4}$), and the lowest occurring in Year 7 ($10^{-5.4}$). The corresponding SFs are in a narrow band around 1.1. This clearly demonstrates that both protocols provide adequate reliability of pipeline for Class 1 locations.

Table 7. Max POF and Min SF in Class 1 (PHMSA and INGAA Protocols for Repair)

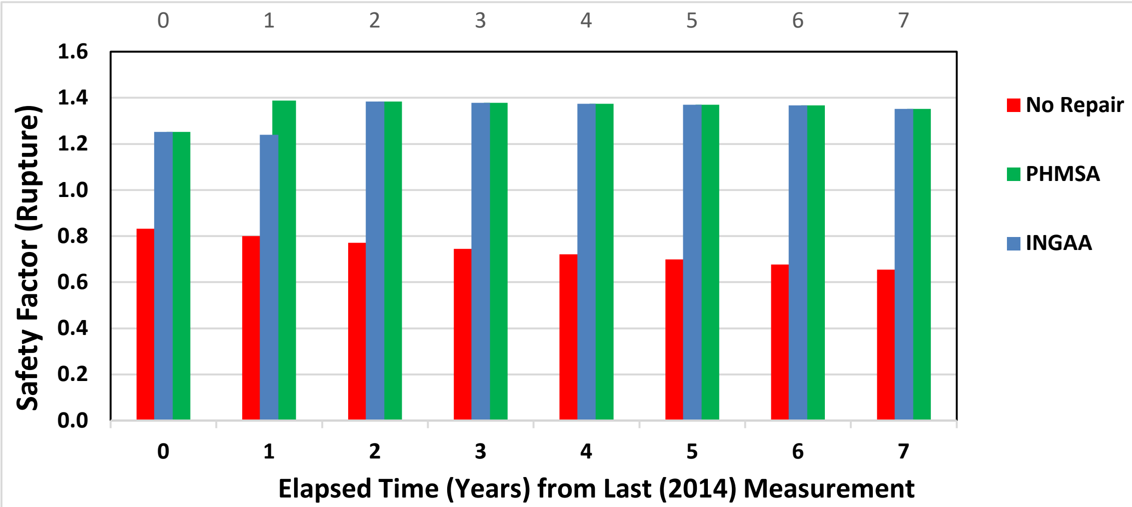
Year	Max POF	Min SF
	Power of 10	
0	-3.1	0.96
1	-4.5	1.08
2	-4.8	1.09
3	-4.4	1.09
4	-5.0	1.11
5	-4.8	1.1
6	-4.8	1.14
7	-5.4	1.14

5.2.2 SCC Anomalies

The requirements for SCC anomalies are identical for Class location and Class change locations in Year 0. Similarly, in the PHMSA requirement in Year 1 both Classes (1 and 1 to 3) require repairs of anomalies with SF less than 1.39. In the INGAA proposal for Class 1 locations the SF less than 1.39 is required in Year 2 rather than Year 1 for Class change (1 to 3) locations. The impact of this difference in approaches on the maximum POF of the Class 1 sections is illustrated in Figure 8. The lower graph compares the evolution of POF using the PHMSA and INGAA repair protocols, as well as a hypothetical scenario of no repair. The "No Repair" bars are not even visible in the figure, as the POF = 1.0 if no repair is performed. The graph also illustrates the difference between the PHMSA and INGAA protocols. The highest POF from both the PHMSA and INGAA protocols occurs in Year zero after immediate repair of anomalies with SF < 1.25 (or depth > 50%), and is 10^{-4}. In Year 1, after repair of additional anomalies (with Year Zero SF < 1.39), the POF reduces to below 10^{-9}, increasing gradually to $10^{-5.6}$ by Year 7 due to the continuing growth of unrepaired anomalies. Due to the postponement of repair of anomalies with Year Zero SF < 1.39 to Year 2, the INGAA protocol yields a POF of $10^{-3.9}$ in Year 1, slightly higher than the highest POF with the PHMSA protocol. The difference is eliminated from Year 2 onwards, where the POF of both approaches is identical.

The behavior of the SF with time (upper graph) also shows the reduction in SF in Year 1 with the INGAA proposal. The lowest SF in the Class 1 section is the same for both protocols (in Year Zero). The o difference is in Year 1, where the INGAA protocol yields the same SF as in Year Zero, while the PHMSA protocol yields a higher SF.

Since a high POF is of interest regardless of the year it occurs in, the two protocols yield similar reliability of the pipeline, with the PHMSA protocol being slightly better.



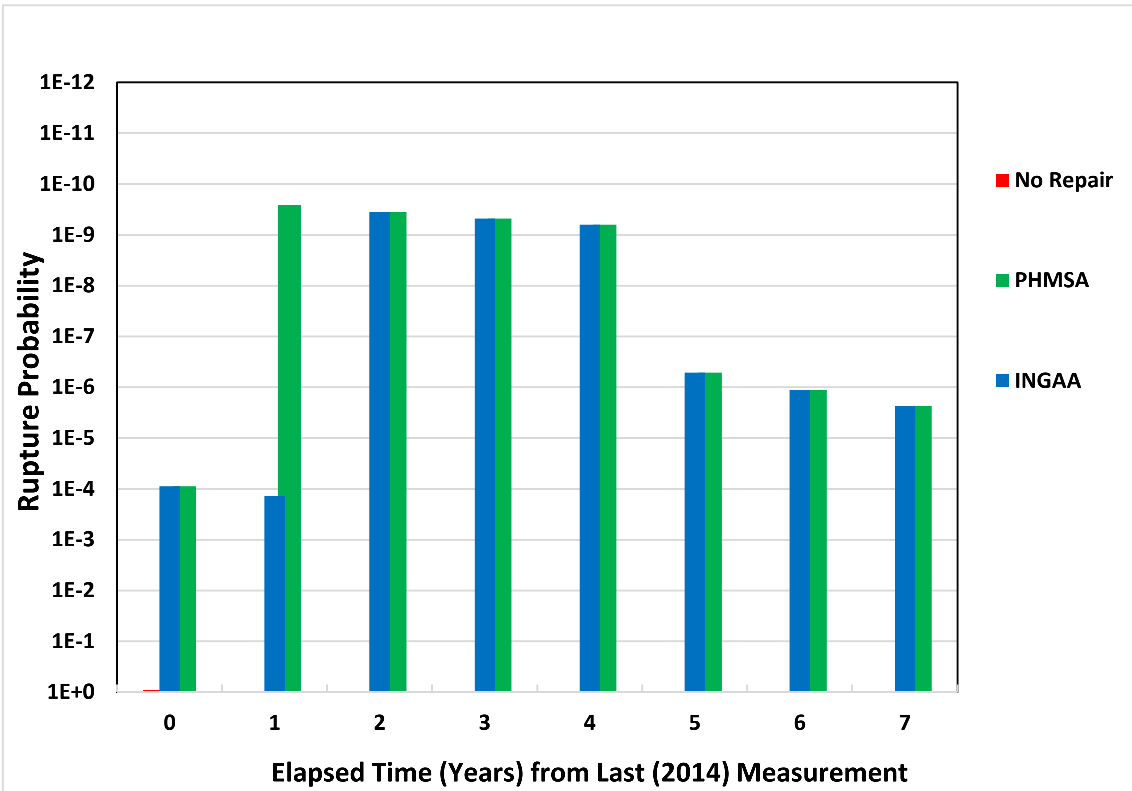


Figure 8: Comparison of SF and POF Changes with Time According to INGAA and PHMSA Protocols

6 References

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