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RISK-BASED MITIGATION OF MECHANICAL DAMAGE

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ABSTRACT

According to the PHMSA data on reportable incidents, for the 20 years ranging from 1995 to 2014, excavation damage accounted for 16.4% of the incidents on 301,732 miles of gas transmission pipelines and 15.6% of the incidents on 199,210 miles of hazardous liquid pipelines. On the whole, excavation damage is a major cause of incidents, ranking third following incidents caused by material/weld/equipment failure and corrosion.

For the purposes of this study, mechanical damage is separated into two categories, i.e. immediate failures and delayed failures. An immediate failure is one which occurs at the instant the damage is done to the pipeline. A puncture, for example, is an immediate failure. Delayed failures involve damage that is not sufficient to cause a leak or a rupture at the time it is inflicted. On average, 14.6% of the mechanical damage incidents in gas transmission pipelines and 13.3% of the mechanical damage incidents in hazardous liquid pipelines can be classified as delayed failures.

The immediate failures are generally minimized through the preventative measure and design efforts. For instance, it is shown herein that the puncture probability can be calculated through the comparison between the likelihood of any given external load being imposed and inherent pipe resistance.

While preventative measures serve to reduce the occurrences of delayed failures as well as the occurrences of immediate failures, delayed failures are largely mitigated through in-line inspection and timely remediation actions. The fact that the assessment methods for mechanical damage are generally not as robust as those for cracks and corrosion tends to limit the reliability of deterministic calculations of response times. Therefore, in the study described herein, risk-based approaches to minimizing delayed failures were developed. Three different approaches to deciding which dents need to be excavated after an ILI were pursued. One involves the use of reportable incident rates based on the PHMSA statistics in conjunction with the number of ILI dent indications per mile to get a probability of failure. The second consists of a decision-making process based on the ILI-reported dent depths and the dent fatigue life probability-of-exceedance function. The third relates to a decision-making process based on successive excavations of dents located by ILI, in which the Bayesian method is applied to compare predicted versus actual severity and thereby determine the probability of failure associated with stopping after a specific number of excavations.

INTRODUCTION

Pipeline integrity management standards such as ASME B31.8S and API Standard 1160 provide guidance to pipeline operators with respect to identifying threats to pipeline integrity, gathering data for estimating risks associated with different threats, prioritizing pipeline segments, conducting integrity assessments, evaluating remaining lives, and scheduling future re-assessments. While these standards have served the industry well, they could be improved in two areas, i.e. Interaction of Threats/Anomalies and Guidance for Scheduling of Excavations and Re-Assessments. To specifically address these two aspects, a project was supported by PHMSA under DOT agreement # DTPH5614H00005 – “Threat/Anomaly Mitigation Decision-Making Process” to constitute the study of flaw interaction and probabilistic assessment methodologies. Three categories of anomalies, corrosion, crack-like, and mechanical damage, were investigated. This paper particularly summarizes the findings related to mechanical damage mitigation.

PHMSA INCIDENT DATA AND STATISTICS

The U.S. Federal Pipeline Safety Regulations have specific requirements regarding dents on pipelines, particularly in High Consequence Areas, for instance: immediate repair conditions, one-year conditions, and monitored conditions in 49 CFR §192.933 for gas transmission (GT) pipeline integrity management; immediate repair conditions, 60-day conditions, and 180-day conditions in 49 CFR §195.452 for hazardous liquid (HL) pipeline integrity management.

These regulations provide guidance for operators to respond once they receive the in-line inspection results. It is noticeable that within the gas regulations, engineering analyses are deemed legitimate to extend the one-year condition to a monitored condition. However, there is no counterpart with regard to the liquid pipelines.

According to the most up-to-date PHMSA data and statistics on their website as indicated in Table 1, for 20 years ranging from 1995 to 2014, for the 301,732 miles of gas transmission pipelines, excavation damage occupies 30.4% of the serious incidents and 16.4% of the significant incidents; for the 199,210 miles of hazardous liquid pipelines, excavation damage occupies 31.6% of the serious incidents and 15.6% of the significant incidents. On the whole, excavation damage is the leading cause of serious incidents and ranks third for significant incidents following material/weld/equipment failure and corrosion.

Table 1. PHMSA Incidents between 1995 and 2014

Pipeline System	Incident Type*	Mileage up to 2014	Number of All Incidents	Number of Excavation Damage	Percentage of Excavation Damage
GT	serious	301,732	102	31	30.4%
GT	significant	301,732	1265	207	16.4%
HL	serious	199,210	76	24	31.6%
HL	significant	199,210	2697	421	15.6%
Total	serious	500,941	178	55	30.9%
Total	significant	500,941	3962	628	15.9%

*: "Serious incidents" involve injury or fatality. "Significant incidents" include serious incidents and those meeting thresholds for property damage or size of release.

IMMEDIATE FAILURES AND DELAYED FAILURES

Mechanical damage incidents are typically classified as "immediate" (those that occur right away upon impact of an external force) or "delayed" (those in which the pipeline sustains an impact of an external force but does not fail until later). According to Kiefner [1], equipment-induced damage fails immediately 83% of the time in the hazardous liquid pipelines and 90% of the time in the natural gas pipelines.

Since 2010, Reported Cause of Incidents of "Excavation Damage" is comprised of three sub-types: operator or contractor excavation damage, previous damage due to excavation, and third party excavation damage. According to PHMSA, the first and third types are meant for immediate failures, and the second type is meant for delayed failures. The compilation of significant incidents caused by excavation damage from 2010 to 2014 in Table 2 implies the ratio between immediate and delayed failures [2]. There are 14.6% delayed incidents in gas transmission pipelines and 13.3% delayed incidents in hazardous liquid pipelines. Those numbers are slightly different from the Kiefner prior study for Gas Research Institute (GRI) [1] covering the period between 1985 and 1997, i.e. 10% in gas transmission pipelines and 17% in hazardous liquid pipelines. These differences may reflect improvements in damage prevention or in detection of latent damage by in-line inspection that has occurred since the earlier study.

Table 2. Significant Incidents by Excavation Damage between 2010 and 2014

Pipeline System	Operator/ Contractor Excavation Damage	Previous Damage due to Excavation	Third Party Excavation Damage	Total Number	Delayed Incidents/ Total Incidents
GT	6	7	35	48	14.6%
HL	10	8	42	60	13.3%
Total	16	15	77	108	13.9%

MITIGATION OF IMMEDIATE FAILURES

A reliability-based model for immediate failures was proposed by C-FER Technologies for PRCI in 1999 [3]. Risk factors were extracted from the survey of North American and international pipeline companies. Fifteen responses to the survey were received, representing 36,661 miles of gas transmission pipelines. The reliability assessment is comprised of two parts: (1) the impact probability model described by the fault tree method; and (2) the puncture failure model comparing the impact load exerted by the excavation equipment and the pipeline resistance capacity.

The key parameters of puncture resistance are pipe diameter, wall thickness, mechanical strength, and bucket tooth size [4,5]. An equation for puncture resistance was derived based on fitting a set of experimental data [6].

$$R_p = \left(1.17 - 0.0029\left(\frac{OD}{WT}\right)\right)(L + w)(WT \cdot \sigma_U) + E_R \qquad (1)$$

where R_p is puncture resistance in lbf, OD is pipe outer diameter in inches, WT is pipe wall thickness in inches, L is length of tooth in inches, w is width of tooth in inches, σ_U is pipe ultimate tensile strength in psi, and E_R is resistance model error in lbf. The bucket tooth cross section size information was collected from six equipment manufacturers. The length was between 1.575 inches and 5.748 inches; the width was between 0.079 inch and 0.197 inch [3]. On the other hand, bucket digging force is a function of excavator weight as described by

$$F_p = 1.5(1444 \cdot W^{0.826007}) \qquad (2)$$

where F_p is digging force in lbf and W is excavator weight in tons. A safety factor of 1.5 is imposed to take into account the possible force increase caused by heavier machines.

Information was collected on the characteristics of excavators from construction machinery sales data, including equipment manufactures [7] and the US Department of Commerce [8]. The best fit distribution for excavator weight was a shifted Gamma function with a mean value of 31.2 tons and a standard deviation of 17.2 tons as shown in Figure 1.

Two examples of the puncture analysis are illustrated below in both deterministic and probabilistic manners. One is a 16-inch OD, 0.250-inch WT, Grade X52 pipeline (Line 1); the other is a 30-inch OD, 0.375-inch WT, Grade X52 pipeline (Line 2). These two represent typical liquid and gas pipeline configurations. To be conservative, deterministic assessments were conducted by applying the nominal values of pipe geometry and tensile strength, and a lower-bound excavator tooth perimeter. Since about one quarter of equipment encountered on pipelines is an excavator and the puncture probability from a backhoe is negligible due to its much lower exerting forces compared with an excavator, the probability of puncture was calculated to be 1.67E-1 and 7.77E-2 for these two pipelines. This is largely due to Line 1 being only 2/3 as thick as Line 2. There was no essential difference between gas and liquid pipelines operating stresses assumed in this analysis.

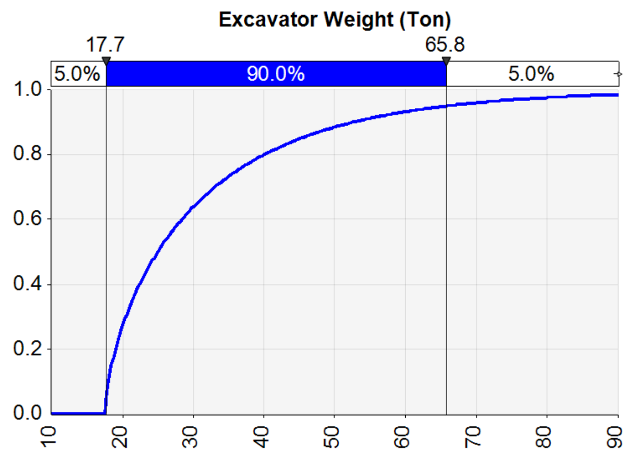

Figure 1. Cumulative Probability for Excavator Weight

In parallel, probabilistic analyses took into account other variabilities for multiple variables, such as outer diameter, wall thickness, tensile strength, puncture resistance model error, and bucket tooth length and width. The corresponding distributions are summarized in Table 3.

Table 3. Probability Density Functions

Variable	Function Type	Function Parameters	Source
Pipe Diameter	Normal	μ=1.0*nominal, COV=0.06%	CSA Z662 Annex O
Wall Thickness	Normal	μ=1.01*nominal, COV=1%	CSA Z662 Annex O
Tensile Strength	Normal	μ=1.19*SMTS, COV=11.05%	Kiefner database
Resistance Error	Normal	μ=187, COV=32	EPRG and Battelle
Tooth Length	Uniform	min=1.575, max=5.748	six equipment manufacturers
Tooth Width	Uniform	min=0.079, max=0.197	six equipment manufacturers
Excavator Weight	Gamma	α=0.632, β=21.638, shift=17.53	manufacturers and USDOC

Monte Carlo simulations were applied to find the possibility that puncture load is greater than the puncture capacity. For each case, 10^5 iterations of calculation were conducted based on the above defined distributions. The probability of puncture drops to 2.37E-2 and 7.26E-3 for Line 1 and 2 respectively. About one order of magnitude decrease of puncture probability from the deterministic assessment is attributed to the actual properties of pipelines more desirable than the claimed nominal conditions, and also the actual excavator tooth cross section size is generally larger than the lower bound assumption. These two case studies exemplify the procedure of reliability-based assessment and its functionality in the pipeline design to prevent incidents from mechanical damage. To reduce the possibility of excavation activities interfering with the pipeline right-of-way, prevention methods were recommended [1,3], such as public education, one-call system, buried markers, physical barriers, quick response to the notification, on-site supervision of excavation, signs at all crossing, magnetic or electronic pipeline locators, frequent patrol, or cover depth increased to 5 feet. Selected cases were analyzed to demonstrate the impact on failure probability reduction by different options [3]. For instance, to improve the maintenance from below average to average with respect to standard damage prevention practices in the industry, the one-call system and site-supervision for excavation lead to the highest failure probability reduction. With minimizing the pipeline exposure to nearby excavation activities through a prevention program and increasing the pipeline designed capacity to resist puncture, the risk of immediate mechanical damage failures can be reduced.

MITIGATION OF DELAYED FAILURES

While preventative measures serve to reduce the occurrences of delayed failures as well as the occurrences of immediate failures, there is also an opportunity to mitigate the delayed failures through in-line inspection and timely remediation actions. Three different risk-based approaches to deciding which dents need to be excavated after an ILI are carried out in this study, due to the fact that the assessment methods for mechanical damage are generally not as robust as those for cracks and corrosion.

Reportable Incident Risk Prediction

Dawson, et al. [9] reported the frequency of occurrence of various types of damage detected by ILI. They estimated that, on average, pipelines exhibit 2.3 dents /mile with 73% of the features being located on the bottom. As shown in Table 4, these estimated quantities suggest that there are approximately 1.15E+6 dents all together residing in 500,941 miles of gas transmission and hazardous liquid pipelines. Among those, 8.41E+5 are rock dents located in the bottom half and 3.11E+5 are mechanical damage located in the upper half.

Table 4. Statistics of Dents for Different Systems

Pipeline System	2014 Mileage	Total Dents	Total Rock Dents (Bottom)	Total Mechanical Damage (Top)
GT	3.02E+5	6.94E+5	5.07E+5	1.87E+5
HL	1.99E+5	4.58E+5	3.34E+5	1.24E+5
Total	5.01E+5	1.15E+6	8.41E+5	3.11E+5

According to Kiefner's experience, excluding hydrostatic test-induced failures of latent damage and excavation puncture, the ratio between top half damage and bottom half damage is 0.83 to 0.17. The above statistics provide the reference to infer the probability of reportable incidents in association with mechanical damage (MD) features or rock dent (RD) features left in place and not repaired. The delayed failure rates for reportable incident, i.e. per feature per year, are calculated in Table 5 and plotted in Figure 2 for each pipeline type. Comparing the gas transmission to hazardous liquid pipelines, within significant incidents, the hazardous liquid pipelines has more frequent failures, around one order of magnitude, than the gas transmission pipelines. This observation might be mostly attributed to thinner absolute wall thickness associated with smaller diameter for liquid pipelines than gas pipelines in general terms. Overall, the probability of delayed MD failures is one order of magnitude greater than that of delayed RD failures.

Table 5. Significant Incident Rate per Feature per Year

Pipeline System	GT	HL	Total
Total MD failures from 1995 to 2014	207	421	628
Total MD failures per year	10.35	21.05	31.4
Delayed MD failures per year	1.51	2.81	4.36
Total MD features	187,375	123,709	311,085
Delayed MD failures per feature per year	**8.06E-6**	**2.27E-5**	**1.40E-5**
Delayed RD failures per year	0.30	0.56	0.87
Total RD features	506,607	334,473	841,081
Delayed RD failures per feature per year	**5.96E-7**	**1.68E-6**	**1.04E-6**

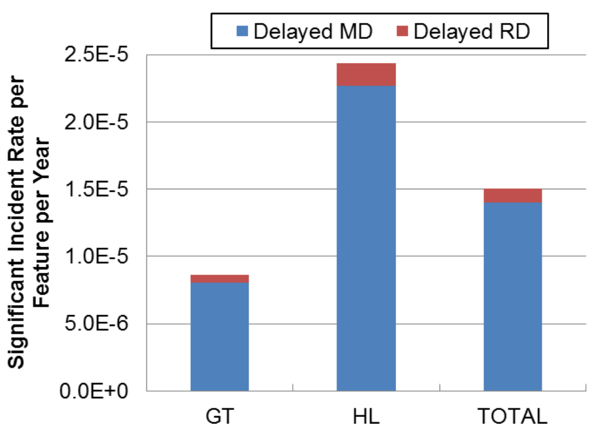

Figure 2. Significant Incident Probability

A hypothetical example is given to demonstrate repair criteria determination from the risk perspective. The cumulative frequency of dent severity from ILI reviewed for this project, for instance, depth/pipe diameter (d/D), is shown in Figure 3. To simplify the problem, the density of dent indications is assumed to be 10 per mile. The annual risk levels of incidents per mile accompanying different repair criteria are listed in Table 6. By and large, the expected incident rates are on the order of 1.0E-5 or less except the incident risk caused by mechanical damage on liquid pipelines.

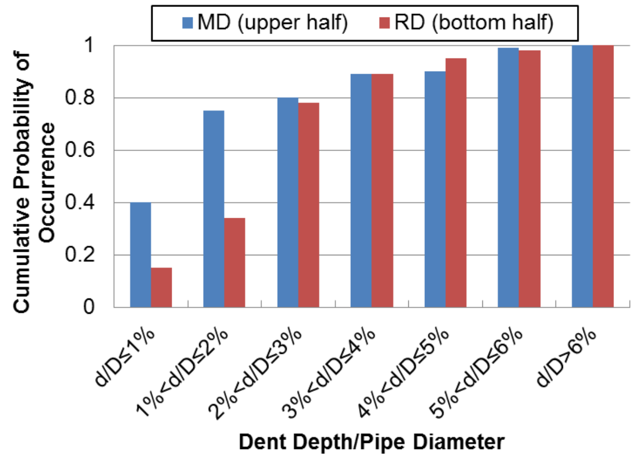

Figure 3. Cumulative Probability of ILI Dent Features

Table 6. Risk Levels Associated with Repair Criteria

Feature Type	Repair	Leave in Place	Cumulative Percentage	Incident Risk per Mile per Year (gas)	Incident Risk per Mile per Year (liquid)
MD	d/D>6%	d/D≤6%	0.99	7.97E-5	2.25E-4
MD	d/D>5%	d/D≤5%	0.9	7.25E-5	2.04E-4
MD	d/D>4%	d/D≤4%	0.89	7.17E-5	2.02E-4
MD	d/D>3%	d/D≤3%	0.8	6.44E-5	1.82E-4
MD	d/D>2%	d/D≤2%	0.75	6.04E-5	1.70E-4
MD	d/D>1%	d/D≤1%	0.4	3.22E-5	9.08E-5
RD	d/D>6%	d/D≤6%	0.98	5.84E-6	1.64E-5
RD	d/D>5%	d/D≤5%	0.95	5.66E-6	1.59E-5
RD	d/D>4%	d/D≤4%	0.89	5.30E-6	1.49E-5
RD	d/D>3%	d/D≤3%	0.78	4.65E-6	1.31E-5
RD	d/D>2%	d/D≤2%	0.34	2.03E-6	5.71E-6
RD	d/D>1%	d/D≤1%	0.15	8.94E-7	2.52E-6

POE-Based Mitigation Plan

As another example, Probability of Exceedance (POE) analysis was shown here to explain a decision-making process for mitigating a fairly large number of dents on a pipeline. If the failure probability at the ith dent is α_i, the probability of no failure at the ith dent is $1-\alpha_i$. Assuming there are n dents in total, the probability of no failure at any dents in the entire pipeline is $(1-\alpha_1)(1-\alpha_2)\ldots(1-\alpha_i)$, hence the probability of failure for this particular pipeline is

$$P = 1 - \prod_{i=1}^{n}(1-\alpha_i) \tag{3}$$

One of the probabilistic dent fatigue life models was developed by the European Pipeline Research Group (EPRG) in 1995 [10]. The approach was later recommended in the Pipeline Defect Assessment Manual (PDAM) [11]. The model prediction error based on 45 full scale tests is described by

$$\ln \hat{N} = \ln N + \left[\hat{\beta}_0 - t_{n-r-1}(\alpha)\sqrt{s^2 + Var(\hat{\beta}_0)}\right] \quad (4)$$

where $\hat{N}$ is the actual fatigue life of an unconstrained plain dent with the (100α)th percentile probability of failure based on the deterministic model prediction N (see Appendix A for details), and $t_{n-r-1}(\alpha)$ is the upper (100α)th percentile (i.e. one-tail confidence level) of a t-distribution with $n-r-1$ degrees of freedom. The remaining parameters are determined as $\hat{\beta}_0 = 0.0168$, $var(\hat{\beta}_0) = 0.0522$, $s^2 = 2.35$ and $n-r-1 = 44$. For 5% of failure probability, i.e. a 95% confidence of survival, $t_{44}(0.05) = 1.680$. Note that this model is also applicable to constrained dents. Though only a limited number of experimental data about the fatigue life of constraint dents is available, based on these data and general experience from the industry, a constrained plain dent should have a fatigue life which is at least that of an unconstrained plain dent of the same depth. Consequently, the above model can be applied to constraint dents as a conservative approach.

Below is a working example for the dent fatigue life POE analysis. A recent in-line inspection in a pipeline found a series of dent anomalies in the year of 2015. After several very deep dents had been repaired, nine mild and shallow dents were left in place as shown in Table 7. This pipeline is 30-inch OD, 0.625-inch WT, Grade X60, and operated at the MOP of 1,806 psig. It was constructed between 1976 and 1977. In 1990, a short segment was replaced with pipes having the same grade and dimensions. No historical records are available relevant to when those dents were formed. All of the nine dents are located at or near the bottom half of the pipeline. It is planned to re-assess the pipeline in 10 years, i.e. the year of 2025. To have a 95% confidence level that none of the dents left in place will fail until the next re-assessment, the operator wishes to determine on a risk-prioritized basis which dents in the list should be remediated at this time.

Table 7. ILI Dent Anomaly Information

Dent No.	Installation Year of Pipeline Segment	Pipe OD (inches)	Pipe Wall Thickness (inch)	Dent Depth from ILI (inch)
1	1976	30	0.625	0.445
2	1976	30	0.625	0.525
3	1976	30	0.625	0.240
4	1977	30	0.625	0.222
5	1990	30	0.625	0.233
6	1977	30	0.625	0.168
7	1977	30	0.625	0.194
8	1977	30	0.625	0.329
9	1977	30	0.625	0.221

The remediation list can be developed following the approach below. For an illustration purpose, it is assumed that the pressure spectrum is equivalent to two MOP cycles per year (which is typical of many natural gas pipelines) and the pipeline will be operated in a similar fashion for the next 10 years. The probability of fatigue failure α was back calculated from the value of $t_{n-r-1}(\alpha)$ for each dent in Table 8.

Table 8. Probability of Dent Fatigue Failure

Dent No.	Dent Depth at Zero Pressure (inch)	Fatigue life with 50% Probability of Failure (Cycles)	Age of Dent by 2025 (Years)	Probability of Failure by 2025
1	0.636	780	49	9.56%
2	0.751	547	49	13.90%
3	0.343	2936	49	1.72%
4	0.317	3473	48	1.30%
5	0.334	3113	35	0.94%
6	0.240	6333	48	0.50%
7	0.277	4658	48	0.82%
8	0.470	1492	48	4.28%
9	0.315	3516	48	1.27%

Without any remediation, the fatigue failure probability of entire pipeline before the re-assessment is 30.2%. If mitigating dents in a decreasing order of individual failure probability, once dents 1, 2, 3 and 8 are added to the current remediation list, the probability of failure of the entire pipeline in the year of 2025 is 4.8%. The target risk value 5% is reached. Note that it may not be necessary to conduct remediation all at once. The excavation and repair may be carried out in a few consecutive years. A similar analysis for each year can provide the clue regarding the remediation list.

Bayesian-Based Mitigation Plan

In the above example, the POE function of dent fatigue life is known, so the failure probability in the future can be calculated straightforwardly. There are other situations where the failure probability function is unknown or partially known. Additionally, the in-line inspection may have undefined reliability or exhibit inconsistency with the in-ditch findings.

A pipeline operator can hypothesize an initial severity function and, based on excavations or experiment, derive the best estimates of inherent parameters. The Bayesian method is exercised here to exhibit its capability for assisting this kind of situation. Essentially it solves the question, "*how many excavations would be required to determine the safety of the remaining features*?".

To describe the approach, suppose n mechanical damage feature (MDF) anomalies exist, $A_1, A_2, \ldots A_n$ which have been identified using ILI. Based on the analysis of the ILI data, the severity of each anomaly is given by $x_1 \ldots x_n$. Furthermore, it is assumed that the x_i's are related to the ultimate safety of the MDF's. When an MDF is excavated, a full assessment of the feature is conducted, and the feature is repaired if it is unsafe. The probability that the MDF is unsafe is postulated to be a function of x as

$$p(x) = 1 - e^{-\lambda x} \quad (5)$$

Initially, the value of λ is unknown, but its value is determined from the results of the excavations. With each excavation, the value of λ is updated using a Bayesian estimator. Yang, et al. [12] proposed that λ can be estimated where the prior distribution is a non-informative Gamma distribution:

$$\lambda \sim \text{Gamma}(\lambda; \alpha, \beta) \tag{6}$$

It is also proposed to be $\lambda \sim \text{Gamma}(\lambda;\ \alpha_0, \beta_0)$, where $\alpha_0 = 0$ and $\beta_0 = 0$. The Bayesian procedure updates the values of α and β with each data point received. For the current problem, if m excavations have found safe features, then the estimate of α and β are:

$$\alpha = \alpha_0 + m \tag{7}$$

and

$$\beta = \beta_0 + \sum_{i=1}^{m} x_i \tag{8}$$

The expected value and variance of λ are given by

$$E[\lambda] = \frac{\alpha}{\beta} \tag{9}$$

$$\text{Var}[\lambda] = \frac{\alpha}{\beta^2} \tag{10}$$

Note that if $\alpha_0 = 0$ and $\beta_0 = 0$ then the estimate of $1/\lambda$ is the simple average of the values of safe x_i's. Another conservative estimator, i.e. 90% upper and lower bound value, of λ is:

$$\lambda = \frac{\alpha}{\beta} \pm 1.96\sqrt{\frac{\alpha}{\beta^2}} \tag{11}$$

The procedure is outlined below by three alternative stopping conditions:

1. Identify the MDF anomalies, $A_1 \ldots A_n$
2. Estimate x_i for each anomaly A_i from the ILI data so that the probability that the anomaly will fail within some predetermined period of time is given by
$$p(x_i) = 1 - e^{-\lambda x_i} \tag{12}$$
3. Initialize
   a. set $k \leftarrow 1$
   b. $\alpha = \alpha_0$
   c. $\beta = \beta_0$
4. Excavate anomaly A_k
5. If anomaly A_k is safe then go to step 8
6. Set $k \leftarrow k + 1$
7. Go to step 4
8. Update
   a. $\alpha \leftarrow \alpha + 1$
   b. $\beta \leftarrow \beta + x_k$
   c. λ:
      i. The best estimate of $\lambda \leftarrow \alpha/\beta$ or
      ii. A conservative estimate of $\lambda \leftarrow \alpha/\beta + 1.96\sqrt{\alpha/\beta^2}$ (90% upper bound value)
9. Calculate stopping criteria:
   a. The probability of the next MDF to be excavated being unsafe is
   $$p(x_{k+1}) = 1 - e^{-\lambda_k x_{k+1}} \tag{13}$$
   b. Update the estimated number of unsafe and unexcavated MDF anomalies. The probability that there is at least one unsafe unexcavated MDF on the pipeline is
   $$P_k = 1 - \prod_{i=k+1}^{n} e^{-\lambda_k x_i} \tag{14}$$
   c. Update the estimated number of unsafe and unexcavated MDF anomalies. The total expected number of remaining unexcavated unsafe anomalies is
   $$N_k = \sum_{i=k+1}^{n} (1 - e^{-\lambda_k x_i}) \tag{15}$$
10. Check for stopping condition and STOP if it is satisfied. The stopping criterion may be any one of the following:
    a. $p(x_{k+1}) < \alpha_1$,
    b. $P_k < \alpha_2$, or
    c. $N_k < \alpha_3$,

    where α_1, α_2, α_3 are the levels of confidence.
11. Set $k \leftarrow k + 1$
12. Go to step 4

An example is given for an illustrative purpose. Suppose that an ILI has identified a total of 50 MDF anomalies on a pipeline. The ILI signal of each feature has been examined and given a severity value. The anomalies are then sorted from the most severe to the least severe in Figure 4. This is a completely hypothetical example, but if such a distribution of severities were to be observed, the operator might wonder "*where the cut off is between those anomalies which do pose a threat and which do not?*".

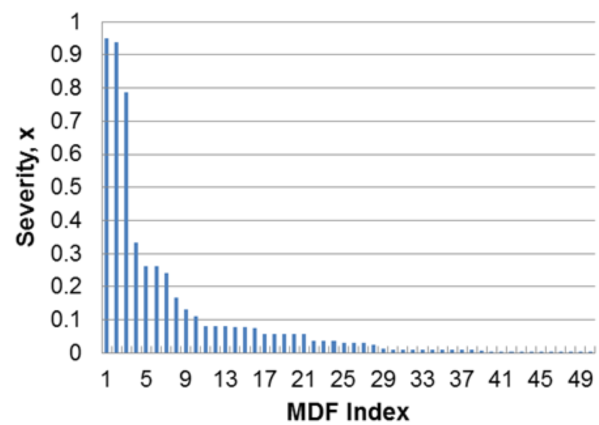

Figure 4. Severity of Each of Fifty ILI Indications

Following the above procedure, if three digs turn out to be unsafe, e.g. Dig Nos. 1, 11 and 12, after 33 excavations, $\alpha = 30$ and $\beta = 4.117$. The expected value of $\lambda = \alpha/\beta = 7.286$. This value of λ implies an estimate of the number of remaining unsafe anomalies to be less than 0.5 (N_k<0.5). It is regarded as a suitable stopping condition as shown in Figure 5.

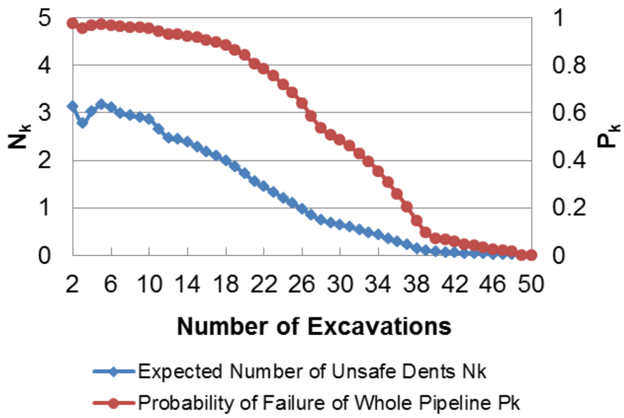

Figure 5. Convergence of Stop Criteria

Since a non-informative Gamma distribution was initially assumed for λ in this study, such a distribution is often appropriate to avoid any bias of the results from a preconceived idea of what λ should be. The disadvantage of this approach is that the number of excavations required to converge on the correct value of λ may be large. If this procedure were to be used then, over time, a range of values of λ may be known. From this range, initial values of α_0 and β_0 could be set to incorporate the range of λ and quicken the rate at which the procedure converges to the correct value.

CONCLUSION

In this paper, the mitigation of mechanical damage is mainly approached from the risk standpoint. This is in conjunction with the fact that the assessment methods of mechanical damage are generally not as robust as those for cracks and corrosion. Three different angles have been pursued for case studies, including (1) significant incident probability based on the most up-to-date PHMSA reportable incident rate; (2) decision-making process based on the full knowledge of POE function; (3) decision-making process without knowledge of the POE function based on excavation. These investigations shed light on circumstances of remediation of in-line inspection anomalies and can be easily tailored to other called-out features, such as corrosion anomalies or crack-like anomalies.

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APPENDIX A

The fatigue life of an unconstrained plain dent, N, with 50% probability of failure is given by

$$N = 1000\left(\frac{\sigma_U - 50}{2\sigma_A K_s}\right)^{4.292} \quad \text{(A-1)}$$

$$2\sigma_A = \sigma_U[B(4 + B^2)^{0.5} - B^2] \quad \text{(A-2)}$$

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$$B = \frac{\frac{\sigma_a}{\sigma_U}}{\left[1 - \left(\frac{\sigma_a}{\sigma_U}\right)\left(\frac{1+R}{1-R}\right)\right]^{0.5}} \quad \text{(A-3)}$$

$$\sigma_a = \sigma_{max} - \sigma_{min} \quad \text{(A-4)}$$

$$R = \frac{\sigma_{min}}{\sigma_{max}} \quad \text{(A-5)}$$

where
σ_U is ultimate tensile strength of pipe steel, ksi
σ_a is equivalent cyclic hoop stress range, ksi
R is stress ratio
σ_{min} is minimum hoop stress, ksi
σ_{max} is maximum hoop stress, ksi
The dent stress concentration factor K_S is determined by

$$K_S = 2.871\sqrt{K_d} \quad \text{(A-6)}$$

$$K_d = C_u d_0 \frac{t}{D} \quad \text{(A-7)}$$

$$d_0 = 1.43 d_p \quad \text{(A-8)}$$

where
d_0 is dent depth measured at zero pressure, inches
t is wall thickness of pipe, inch
D is diameter of pipe, inches
C_u is unit conversion factor as 1.0 for d_0 in millimeters and 25.4 for d_0 in inches
d_p is dent depth under pressure after rebounding, inches