The Present and Future of Practical Pipe Body Hard Spot Integrity Management

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Abstract

Pipe body hard spots have been recognized as a pipeline integrity threat in certain types of vintage line pipe, causing ruptures, leaks, and near-miss events. Hard spots can now be managed within the template of Integrity Management, including threat assessment, whether and when to perform a baseline assessment, in-line inspection, prioritization of assessment response, field examination, repair decisions, and reassessment decisions. However, the technology is still evolving, and important gaps remain. This paper discusses key factors, recommendations, and pitfalls to consider in the integrity management process. Areas for further development to address current knowledge gaps are also discussed.

1. Introduction

1.1 Hard spots as an integrity threat

In 2005, INGAA issued its vintage pipeline characteristics report [1], which identified 26 failures due to pipe body hard spots. The Pipeline Research Council International (PRCI) recently completed Project MAT-7-2 [2] to review the parameters associated with the integrity threat to pipelines posed by metallurgical hard spots in the pipe body. The project compiled 88 pipeline ruptures, leaks, or near-miss incidents associated with pipe body hard spots, reviewed the causes of such hard spots, identified the susceptibility factors, and discussed appropriate integrity management responses. More recently, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued Advisory Bulletin (ADB) 24-01 [3] advising operators to review records to determine whether the types of pipes in their systems are susceptible to hard spots and develop assessment program to validate hardness anomalies.

1.2 Lessons from historical hard spot incidents

The 88 incidents and some influencing parameters compiled in MAT-7-2 are summarized as follows:

Vintage: Almost all incidents occurred in pipe manufactured between 1944 and 1961.

Pipe sizes: Pipe size ranged from NPS 6 to 36-inch OD, but 65% occurred in 30-inch OD pipe.

Pipe grade: About 90% of incidents occurred in X52 line pipe.

Pipe type: The pipe types involved 58 flash welded (FW) seam pipe, 19 submerged-arc welded (SAW) seam pipe, 7 electric resistance-welded (ERW) pipe (but only 2 were manufactured from continuous-roll skelp), 1 seamless (SMLS) pipe, 1 SMLS bend fitting, and 2 not reported with sufficient information to infer the pipe type.

Pipe manufacturer: Nine pipe manufacturers were identified in 84 of the 88 hard spot incidents (the manufacturer was not reported in 4 cases). The largest incident count was associated with A.O. Smith (AOS) FW pipe; however, due to the extensive installed mileage of AOS pipe, the highest normalized incident rate was actually Bethlehem SAW pipe with AOS second. Youngstown ERW pipe was third.

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Note that many of the identified pipe manufacturers received plate produced by Bethlehem, US Steel, or others.

Failure mode: Of the 88 compiled incidents, 46 were ruptures, 38 were leaks, and 4 were intact but exhibited cracks (which were classified as "near-miss" events).

Stress level: Hard spot size, crack lengths, and stress levels varied widely, however it was observed that the median hoop stress at failure was 63.8% of SMYS in ruptures but only 50.4% in leaks, and the median lengths of cracks was greater in ruptures than leaks. The lowest-stress rupture and lowest-stress leak were reported to be 7.7% SMYS and 8.6% SMYS, respectively, both in hazardous liquid pipelines. The lowest-stress rupture and lowest-stress leak in natural gas service were 42.3% SMYS and 33.8% SMYS, respectively.

2. Background

2.1 What is a hard spot

A hardness anomaly is a localized area in the pipe body having elevated hardness levels compared with normal hardness levels prevalent in the rest of the pipe body. They are, in most cases, the result of unintended rapid cooling (quenching) of the steel while in a hot condition in the plate or hot strip mill. In rare cases, they could develop during the forming or forging process for seamless pipe or wrought fittings. Following rapid cooling some amount of subsequent annealing or tempering can occur. There are two other exceptional scenarios. One is where the plate stock or pipe has been repaired by grinding to remove an imperfection and the resulting cavity is filled by depositing weld metal which is then ground flush to the pipe surface. Susceptibility to the mill repair weld scenario may differ from susceptibility to hard spots from plate or skelp quenching. The second exception is the formation of hard microstructures during the mechanical damaging process caused by accidental contact from excavating equipment. Mechanical damage (with associated local hard microstructure) is distinctly independent of the susceptibility of hard spots associated with pipe manufacturing and should be managed separately from a hard spots threat management program. Moreover, mechanical damage and hard spots associated with manufacturing should not be treated as "interacting threats" referred to in ASME B31.8S, Article 2.2.

Hardness anomalies exhibit a variety of morphologies. Patterns include sawtooth, splash, single or multiple spots, elongated or oval spots, or nearly round spots. Examples are shown in Figure 1 [4]. Hard spots may occur on the exterior or the interior, can be subsurface or embedded, or extend through the wall. Metal hardness is usually nonuniform through the wall. They may be created from either or both surfaces. The flat plate may be flipped one or more times during the plate manufacturing, inspection, shipping, or pipe forming processes, so hardness anomalies cannot always be assured of being on the outside of the pipe. However, none of the ruptures, leaks, or cracks associated with hard spots for which a metallurgical examination was performed (fewer than half of the incidents) initiated from the inside surface. This may be consistent with the role of CP or external

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corrosion in many cases of hard spot cracking. That said, a hard spot on the inside might be a threat for a sour-gas gathering line or a pipeline transporting hydrogen blended with natural gas.

Figure 1. Example of different hardness anomaly morphologies observed on the pipe surface

2.2 Definition of a hard spot

"Hardness" is defined as the resistance to indentation and is correlated with ultimate tensile strength. In an unalloyed steel, carbon (C) content is primarily responsible for determining the maximum achievable hardness. The hardness is an indication of how much martensite, a microstructure that is hard, strong, but brittle (unless tempered), is present.

"Hardenability" refers to the relative ability to achieve maximum hardness by controlling the cooling rate from above the austenitizing temperature of approximately 900 C (1,652 F), referred to as the A3 temperature. Hardenability is influenced by the content of alloying elements in steel, including carbon and particularly manganese (Mn). Hardenability is important to the welding of steel and to manufacturing of steel products including plate and skelp used to form line pipe.

The baseline hardness in the pipe body of vintage steels is typically between 165 and 180 BHN. The range of maximum hardness values reported in hard spots that failed was 313 BHN to 554 BHN, with an average of 429 BHN.

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Not all hardness anomalies are hard spots. For example, there may be an area with hardness of 235 HB which is higher than the pipe body that is say 180 HB, but not a 'hard spot' that needs to be addressed.

Hard spots were first recognized as an actionable pipe manufacturing defect by API 5L and 5LX in the 1971 editions (under "Workmanship" paragraphs 10.5 and 8.5, respectively). The provisions only applied to pipe in sizes over 20 in. OD. A hard spot was rejectable if visual inspection revealed a curvature irregularity not due to mechanical damage, the hardness exceeded 35 Rockwell C, and the dimensions in any direction exceeded 2 in. These criteria essentially extended through the 1983 merging of API 5LX into API 5L, and the 2008 harmonization of API 5L with ISO 3183 to the present time (except the restriction to pipe larger than 20-inch OD was dropped in 1987). The criteria are used by industry, and is recognized by PHMSA in CFR 49 192.

2.3 The role of composition and cooling rates

Above the A_3 temperature1 on the Fe-C phase diagram, the steel consists of a solid solution of C in gamma iron (γ-Fe, a face-centered cubic (FCC) crystal structure) called austenite. Austenite is not stable in carbon steel below the A_3 temperature. When the steel cools under equilibrium conditions below A_3 it begins to decompose to alpha Fe (α-Fe, a body-centered cubic (BCC) crystal structure) called ferrite, containing 0.02% C, while the γ-Fe picks up carbon. As the steel cools from the A_3 temperature to the A_1 temperature of 1,333 F (723 C) it transforms to a mixture of ferrite and pearlite, pearlite being a lamellar microstructure of ferrite and crystals of iron-carbide (FeC_3, cementite). Under equilibrium cooling conditions the transformation is complete at the A_{r1} temperature, approximated as the A_1 temperature. (The exact A_{r1} temperature depends upon the rate of cooling and the steel composition.)

The normal microstructural phase changes may be prevented when the steel is cooled under nonequilibrium conditions. The cooling rates are dictated by net metal thickness, the cooling fluid (water, oil, or air), and the heat transfer environment (spray or immersion) while hardness is determined by the proportion of microstructure consisting of martensite. A higher alloy steel will exhibit a higher percentage of martensite at a given cooling rate. Hence, alloyed steels have greater hardenability than plain carbon steel. These differences vanish with very slow cooling.

Therefore, the following routes to martensite and high hardness are possible: rich steel chemical content (dominated by C and Mn in the materials of interest), or high cooling rates, or both.

Hard spots that failed tended to exhibit richer carbon (C) and manganese (Mn) content than is typical of similar-vintage line pipe, as indicated in Figure 2. A Carbon Equivalent (CE) of 0.45 represented the 45th percentile for hard spot failures but the 80th percentile for the general population of line pipe of similar vintage.

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[1] A_3 varies with carbon content but is between 1,550 F and 1,590 F for the typical steel of interest.

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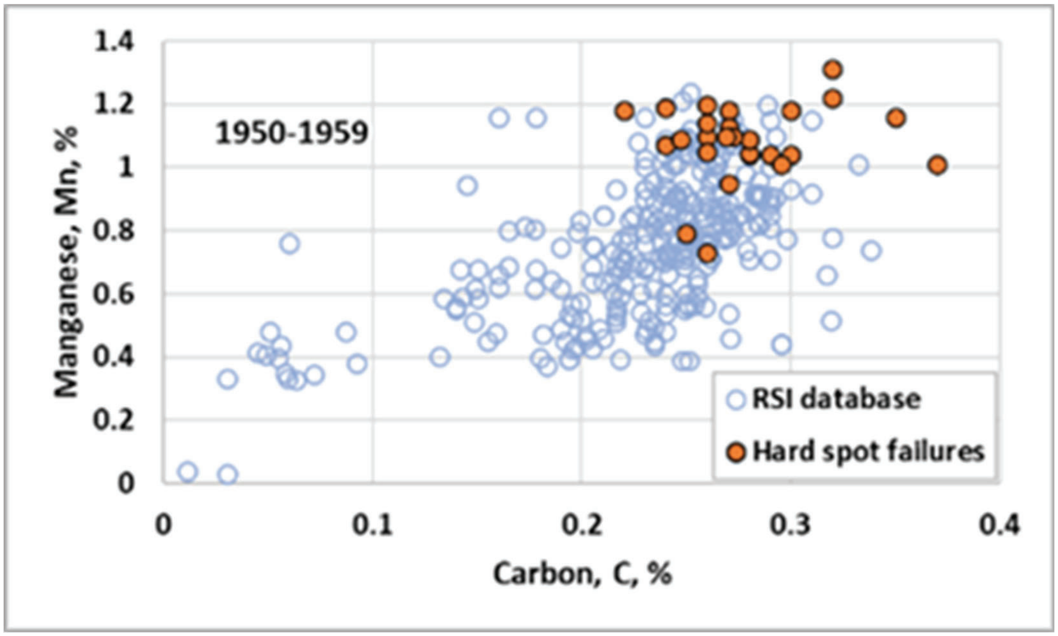

Figure 2. C-Mn composition of hard spot failures compared with general population

Analysis that considered the nominal steel composition reported in metallurgical analyses of hard spot failures led to the conclusion that the high hardness values observed in hard spots is most likely due to unintended quenching or cooling of the steel in the plate or hot strip mill2. This is consistent with the assertions of failure analyses of hard spot failures conducted in the 1960s.

2.4 How do pipe body hard spots occur in pipe manufacturing?

Pipe body hard spots have predominantly affected large-diameter pipelines. In most cases they originated as an upset thermal cycle presenting increased rate of cooling or quenching of the hot plate during some phase of the plate manufacturing process. In the US, continuous slab casting only began to be adopted during the 1960s, so most if not all hard-spot-affected pipe was manufactured using plate or skelp hot rolled from cast ingots. Ingots were rolled to slabs weighing between 9 and 30 tons which were reheated to around 2,400 F for rolling to final thickness. High-pressure sprays (e.g. 1,500 psig to 4,000 psig) were typically used at various stages of the rolling process to knock scale off the hot slab before rolling, at intermediate and final rolling stages to cool the rollers, and after plate rolling to partially cool the plate on the runout table. Cooling sprays were also used in the hot strip mill in the rolling of continuous skelp prior to coiling. Hence, one might postulate a plausible scenario wherein water sprays were applied to the steel while it was above the austenite recrystallization temperature of approximately 1,700 F and in its near-final thickness, but other scenarios might also explain some observed hard spots.

[2] On the other hand, it is acknowledged that no failure analyses, even those performed recently, explored the possibility of unusual, nonhomogeneous composition enrichment as a factor.

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Localized over-quenching could occur if (and perhaps only if) the travel speed of the hot plate is briefly interrupted but the spray is not. The travel speed of the hot plate or skelp increases significantly with each reduction in thickness because the plate must get longer to maintain the original volume of the slab. Sometimes a “cobble” occurred where a process component such as a roller or manipulator failed to engage (“bite”) the leading edge of a plate or strip as intended, or the plate became misaligned or otherwise became hung up in the process train. This would result in a pileup much like a train wreck [5]. In some mills the spray heads were supposed to rotate aside in the event of a cobble, but the possibility of a spray head not moving aside or a shutoff valve not closing when it should have or as quickly as it should have, seems reasonable. Several hard spot patterns observed in the field, including the sawtooth and splash patterns, the multiple spots arrayed circumferentially, and individual oval spots with an elongated longitudinal axis appear to be consistent with such events[3].

A major cobble will cause the shutdown of the line and potential loss of significant quantities of plate or strip in process. Other circumstances may merely slow or momentarily impede forward motion. This seems more likely if it involves at that point a 2- or 3-ton plate for a single pipe, which might be cleared out of the way before upstream plates or bars have cooled significantly, rather than 20 tons or more and several hundred feet of continuous strip moving several hundred ft/min. So the accidental over-quench scenario seems more likely to affect discrete hot plates rather than continuous ERW skelp.

Skelp coils in the 1950s could weigh 30 tons (up to 50 tons today) and were coiled at temperatures of around 1,500 F. A coil that large can take up to 3 days to cool due to its thermal mass. Thus, even if local hard spots were accidentally caused in a strip of ERW skelp in a way that did not cause a cobble, the slow cooling of the coil would have tempered the hard spot. The microstructure would then consist of tempered martensite at a much lower hardness than before tempering[4]. The occurrence of a small number of hard spots in ERW pipe may possibly be due to coiling the skelp at below a temperature that could provide effective tempering. Coiling at low temperatures may have occurred to salvage skelp after a cobble.

The above points may explain why hard spots preferentially occurred in SAW pipe but are uncommon in ERW pipe. If that is the case, why were hard spots observed in pipe manufactured by Youngstown or A.O. Smith? The explanation is that those two manufacturers produced their pipe using single plate feedstock like that used to produce SAW pipe.

As with ERW pipe, relatively few hard spot failures have been identified with SMLS pipe or wrought fittings. SMLS pipe is a wrought product in which all the forming occurs while hot. SMLS pipe

[3] Anecdotes that hard spots were caused by rainwater dripping through holes in the mill roof are unlikely to be factual. The plates were sufficiently hot that unless the water was pressurized, it would evaporate before reaching the pipe surface.

[4] The effect of tempering on hardness is closely related to tempering temperature. The effect of tempering time is strongest within the first 5-10 minutes of tempering with longer hold times resulting in comparatively smaller additional further reductions in hardness.

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forming takes place in several mechanical stages generally as follows. Cylindrical billets are heated in a furnace to 2,200-2,300 F. The billet then undergoes forming steps while hot including initial piercing, plug milling for wall thickness, rotary milling to expand the diameter (for larger sizes), reel milling to smooth surfaces, roller stand sizing (or stretch reducing for small diameters) to the final diameter, and offset rollers for straightening. The hot tube will encounter water sprays to cool the forming equipment at various stages. Generally, it will be necessary to reheat-soak the tube in a furnace between each forming stage or perhaps every second forming stage in order to maintain formability. The reheating would eliminate hard microstructures formed due to incidental exposure to water sprays.

Most seamless pipe undergoes slow cooling which promotes grain growth, resulting in low or moderate strength appropriate for Grades A and B, and perhaps X42. Seamless pipe having higher specified minimum strength will typically have a richer chemical content than the corresponding grades of line pipe rolled from plate and will be quenched and tempered. The most common seamless pipe manufacturing process presents few opportunities for accidental exposure to rapid cooling conditions without subsequent heating and slow cooling that could cause hard spots. Nevertheless, hardness anomalies in seamless pipe have been reported. One ILI vendor has anecdotally reported a large number of hard spots indicated in a pipeline segment consisting of SMLS pipe, but none appeared to exceed a hardness of 300 BHN, or a level that would define them as hard spots, and below the hardness considered to be susceptible to cracking.

3. Adapting the IM Template to the Hard Spots Integrity Threat

3.1 The IM process cycle

Integrity management standards including ASME B31.8S [6], API Recommended Practice 1160 [7] , and CSA Z662 Annex N [8], specify a continuous process for managing the risks associated with pipeline integrity threats. Although these standards apply process flows that differ from each other in many details, each can be summarized by the cycle shown in Figure 3. This figure is admittedly oversimplified and glosses over the many nuances and complexities that challenge a real IM program, but the main process components and their sequence are represented. The main purpose in presenting Figure 3 is that it is the authors' collective opinion that the hard spots integrity threat can be managed by applying a conventional IM process flow tailored to the threat. ADB 24-01 sets forth PHMSA's expectation that operators can and should apply such principles to the hard spot threat.

Figure 3 provides structure for subsequent discussion in this paper, mainly around identifying the scope or severity of the hard spot integrity threat, performing the integrity assessment, prioritizing response to the assessment, and making decisions around repair and mitigation. The authors further note that pipeline operators are already executing on their interpretation of how the IM process applies to the hard spot threat in their systems.

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There exist technical gaps or limitations in these steps that should be subjects for future industry cooperation and development. These will also be discussed.

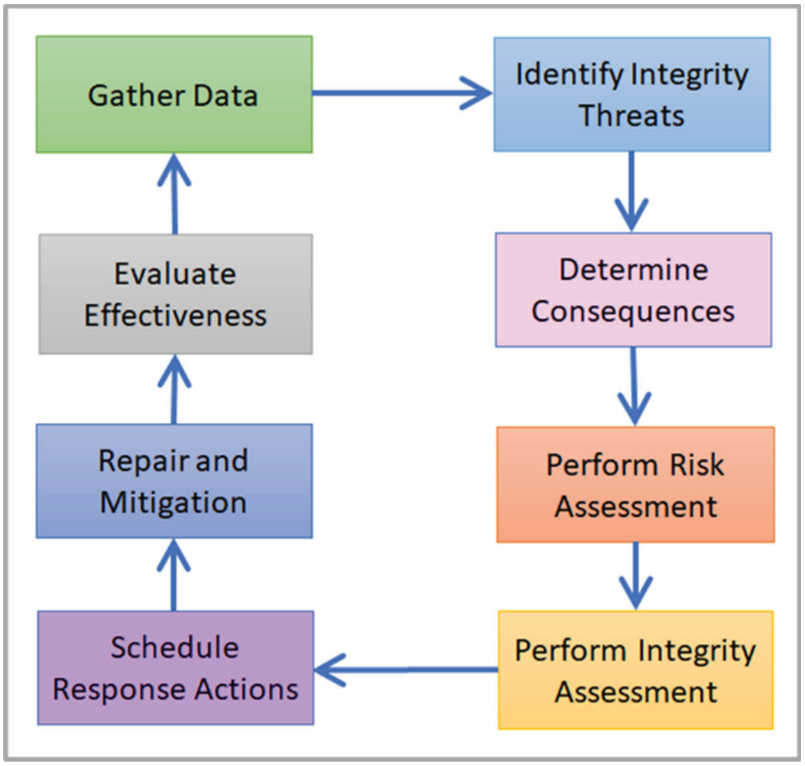

Figure 3. Simplified integrity management process cycle

3.1 Identifying hard spot susceptibility

Assessments by ILI for hardness anomalies have demonstrated that hard spots may exist in large numbers in some pipeline systems while being nonexistent in others. Moreover, most hardness anomalies appear to be below a threshold of severity at which they pose a threat. This is not unlike other types of threats as well, including corrosion, ERW seam defects, or defective girth welds where most cases, while undesirable, are also nonthreatening, while a few pose a significant threat. The challenge for the operator is to find those small numbers of cases that are meaningful threats in an efficient way that does not interfere with operation or unnecessarily divert attention from other threats. Doing so requires an understanding of where to focus efforts for assessment, and how to prioritize response. Meeting this challenge must start with understanding (a) whether hard spots could be present; (b) if hard spots are present, whether a crack could be present; and (c) if a crack is present, whether a rupture could occur. As with other threat types, this understanding can come from analysis of industry incidents or by a review of their system-unique experiences. Where an operator has little or no prior experience of hard spots, the historic incidents analysis performed in MAT-7-2 can be informative.

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As already noted, pipe vintage between 1944 and 1961 and rich C-Mn composition are susceptibility factors. These parameters are not entirely independent as C-Mn steelmaking was prevalent during that period until the basic oxygen steelmaking practice saw increasing use in the early 1960s.

Common plate, skelp, or forging processes do involve exposing the hot slab, plate, or skelp to high pressure water sprays at various stages of rolling or forming. As discussed above, the prevalence of pipe manufactured from discrete plate (FW, SAW, and certain ERW) is understood to reflect a greater opportunity for plate mill upsets that could result in unintended quenching of the hot plate. Rolling of the continuous skelp while hot (for conventional ERW pipe) tends to induce self-annealing, while the seamless pipe forming process usually involves furnace reheating after intermediate forming steps; both processes reduce the opportunities for hard spots to persist.

It was also observed that almost all the incidents involved natural gas (NG) service. Of the 88 incidents, only 4 occurred in hazardous liquid (HL) service. This comparatively low rate of incidents is attributed to two factors: (1) HL system mileage is biased toward smaller pipe diameters consisting mainly of continuous skelp ERW pipe compared with NG transmission pipelines, and (2) HL pipelines tend to operate at a lower stress averaged over the hydraulic gradient compared with NG Class 1 transmission pipelines.

As with any other integrity threat, the operator can and should apply a method to determine what portions of their system may exhibit factors that can influence susceptibility. ADB 24-01 directs operators to do just that. MAT-7-2 presented an algorithm for ranking the susceptibility for the purpose of prioritizing pipeline segments for a baseline assessment according to the following information, which does not rely on foreknowledge of the existence of hard spots. The high-level susceptibility screening categories are shown below in Table 1. The full detail of the susceptibility scoring is given in the MAT 7-2 report.

Table 1. MAT-7-2 Susceptibility Categories and Factors

Category	Factor
A. Could hard spots be present?	1. Vintage
	2. Prior hard spot experiences
	3. Pipe manufacturer
	4. Pipe grade
	5. Pipe type
B. If a hard spot is present, could cracks be present?	1. Corrosion or non-CP sources of hydrogen
	2. Other triggering conditions
C. If cracks are present, could a rupture occur?	1. Stress level
	2. Pipe body has arrest CVN

Defining susceptibility requires consideration of many factors in combination. No single factor can be used to define a population of pipes as susceptible. It is clear from historic data that pipe > 20” diameter, made from plate feedstock, before 1960 from particular manufacturers is the most

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susceptible. Combining the exact variables for each population in a pipeline enables the operator to prioritize susceptibility.

Only pipe manufactured from discrete plate, namely SAW, FW, and ERW pipe manufactured by Youngstown is considered susceptible. Very few incidents have been associated with pipe body hard spots in SMLS pipe or continuous-skelp ERW pipe, and none in BW/FBW pipe. SMLS pipe, continuous-skelp ERW pipe, and BW/FBW pipe are therefore considered to represent an inherently low threat level unless there is information available that the specific pipe of interest is susceptible. This does not preclude hardness anomalies from existing in these varieties pipe. Nevertheless, this exemption is supported by actual failures associated with hard spots in such pipe as being very rare events. One could take a similar position with respect to line pipe manufactured from modern, lean-chemistry, thermos-mechanically controlled and processed steel from circa 1990 or later. MAT-7-2 then ranks susceptibility as shown in Table 2.

Table 2. MAT-7-2 Susceptibility Categories and Factors

Threat Level	**Recommended Baseline ILI**
Not a threat	None
Low threat	Reevaluate threat in 10 years
Moderate threat	Plan ILI within 7 years
Meaningful threat	Advanced response

Pipe ranked as "Not a Threat" requires no baseline assessment. At the "Low Threat" level, the need for a baseline hard spot assessment should be reevaluated in 10 years to allow for recognition of new information such as new records of susceptible pipe in a pipeline segment, actual presence of hard spots, or conditions changing in a segment containing susceptible pipe that could promote hydrogen affecting hard spots if they are present. At the "Moderate Threat" level, a baseline assessment within 7 years is recommended to align with ILI intervals associated with high consequence areas to enable an operator to bundle the hard spot assessment with other ILI tools to be run.

A baseline hard spots assessment for "Meaningful Threat" pipe should occur sooner than for the "Moderate threat" pipe, e.g. 4 years. Circumstances such as operational constraints, tool availability, or the line not being piggable may prevent a baseline ILI for hard spots in that period. Alternatively, the highest-threat pipe may be present in relatively small quantities in a piggable segment consisting primarily of lower-threat pipe types. For such situations, alternative approaches to manage the risk could be implemented. Following are example alternatives:

- Align known populations of Meaningful Threat pipe with other threat factors such as CP protection levels, coating degradation, corrosion activity, or new sources of cathodic current that could interact with unknown hard spots. If specific locations of Meaningful Threat pipe

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are known, prioritize locations based on proximity to causal and consequence risk factors, consider examining such pipe in the field for hard spots.

- If Meaningful Threat pipe is thought to be present but the specific locations are unknown, review construction records, maintenance records, and other ILI data to identify likely locations of pipe of concern, align with causal and consequence risk factors, followed by field investigation for confirmation. The need for further digs may be informed by a model that accounts for prior findings[5].

The above strategies are consistent with the expectations of ADB 24-01 and IM guidance in codes and standards, but an operator may choose to apply a different process reflecting its system, data, and risk modeling practices. Absent in the above discussion is the decision about how to respond to ILI indications of hard spots which will be discussed later.

4. External Influences

4.1 The role of hydrogen

The incident review determined that 49 of the 88 compiled incidents were attributed to hydrogen stress cracking (HSC), 9 were attributed to stress-corrosion cracking (SCC), and the remaining 30 were not attributed to a specific cracking mechanism. None were attributed to fatigue.

Early investigations of hard spots failures recognized that HSC appeared to be involved, and that two likely sources of hydrogen were the cathodic protection system or external corrosion. At about this time, A.G.A. supported several research studies into the susceptibility of high strength steels to hydrogen stress cracking due to interest in moving to higher strength steel. Studies concluded that cathodic protection (CP) at interrupted potentials more negative than -1,200 mV for prolonged periods could produce atomic hydrogen in sufficient quantities to induce HSC in sensitive microstructures [9] [10]. Also, some hard spot failures exhibited light corrosion pitting or SCC; corrosion processes can also produce hydrogen (although in many cases the generated atomic hydrogen (H+) recombines to molecular hydrogen (H2) before diffusing into the pipe wall as H+. H2 cannot diffuse into the pipe wall).

Cathodic conditions or coating conditions can change over time. The 2007 "Stability of Defects" report prepared for INGAA and PHMSA [11] notes that hard spots may remain stable until it is affected by an increase in cathodic protection levels.

[5] For example, a model could be developed to determine the probability of unexamined pipe being Meaningful Threat pipe and the probability of such pipe containing hard spots, based on the results from an adequately sized population of digs. The residual probabilities can be adjusted as findings as further digs accumulate. Digs would continue until the residual probabilities reach a threshold judged by the operator to be adequately low.

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4.2 Location, location, location

A strong trend of proximity to sources of CP current or interference was evident in the incident review, Figure 4. Apparent sensitivity to cathodic hydrogen is consistent with laboratory studies already cited, and others. No trend with distance downstream from compressor stations was apparent.

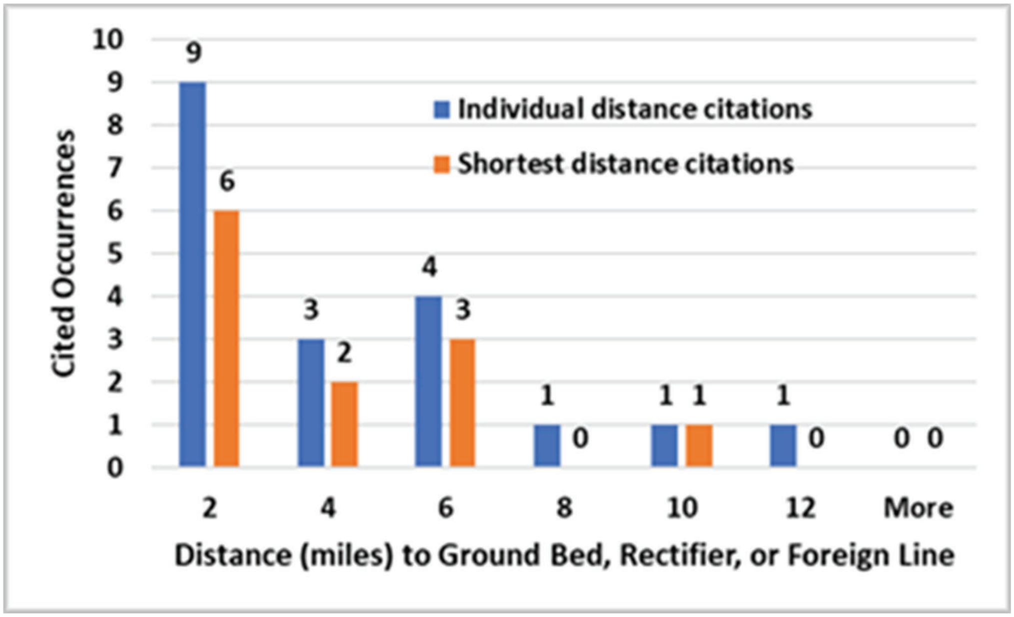

Figure 4. Cited distances to source of cathodic protection or interference

4.3 Time to failure

Time to failure in hard spots ranged from 2 to 70 years. Changes in operating conditions associated with the cathodic environment due to additional anode ground beds nearby, recorded increases in rectifier output, or flow reversals resulted in shortened time of failure in 50% of cases, Figure 5. When compared to simple service age, time to failure was reduced by half or 10 years, whichever was less. These observations are consistent with laboratory studies of the influence of cathodic hydrogen on cracking time to failure, Figure 6 [12].

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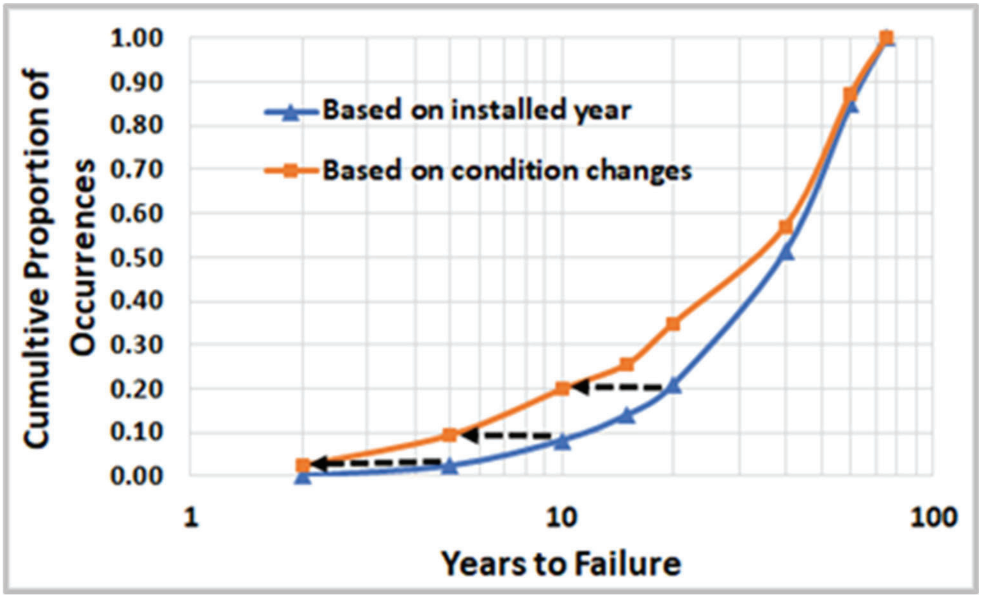

Figure 5. Cumulative distribution of time to failure

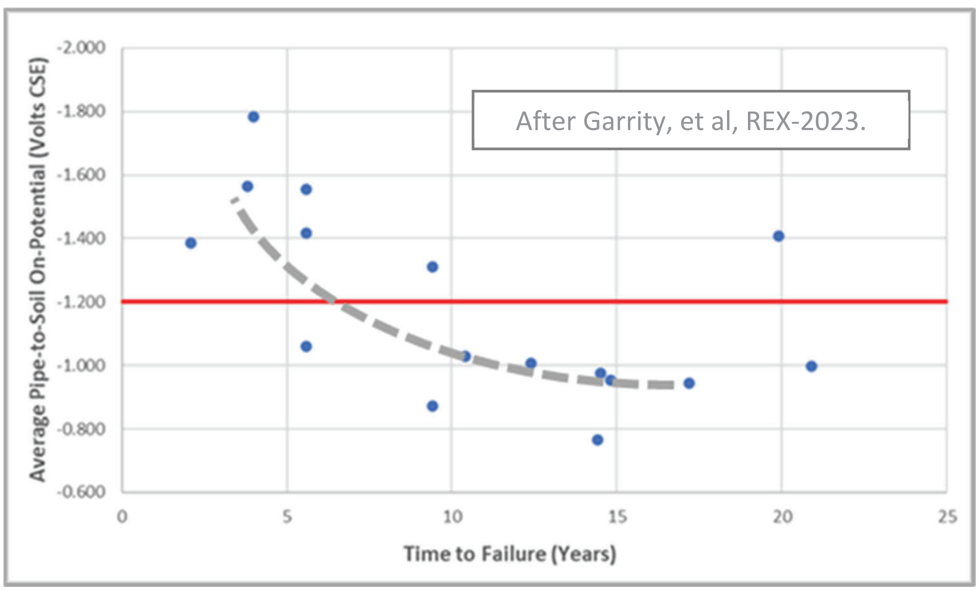

Figure 6. Time to failure as a function of pipe-soil on-potential (after Garrity, et al.)

The foregoing studies and incident data confirm that hard spots do not have a predictable time to failure. B31.8S asserts that a system pressure test to 1.25 x MAOP mitigates pipe manufacturing defects, which includes hard spots, however B31.8S is also clear that this is conditional on operating conditions not changing. Changes in operating conditions can include the cathodic environment or other external factors.

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4.4 Comparing the risk to other integrity threats

Some pipeline operators utilize risk models that rely on risk normalized to mileage. MAT-7-2 estimated hard spot risk levels per mile for different pipe manufacturers and vintage categories at between 3.18E-6 incidents/mile/year and 1.16E-4 incidents/mile/year.

A reasonable question is how that compares with annualized failure rates from other integrity threats. The expected range of failure rate is not unlike those of other integrity threats that only occur infrequently or that preferentially affect particular segments of the pipeline system. An example may be failures of girth welds, which are vintage-sensitive due to technological factors, normally considered stable unless exposed to conditions that occur later in service and cannot be managed by hydrostatic pressure testing. A review of PHMSA's reportable incidents data from 2010-2023 suggested that, depending on vintage category, girth welds pose a risk between 2.42E-6 and 5.51E-5 incidents/mile/year.

Another risk metric for comparison is that of failures due to manufacturing defects in vintage ERW seams which would include DC-welded ERW, low-frequency AC-welded ERW, and flash-welded seams. The US DOT reportable incident data was reviewed covering 2002-2017 for such failures in pre-1970 ERW pipe [13]. The effective vintage ERW seam defect failure rates are 7.65E-5 incidents/mile/year for HL pipelines, and 3.77E-5 incidents/mile/year for NG pipelines. Thus, the hard spot risk is reasonably comparable to the risk posed by vintage girth welds and vintage seams.

5. Hard Spot Integrity Assessment

5.1 ILI for hard spots

Hard spots may be discovered because of a leak or rupture, or by chance in a field investigation for other purposes. More useful is the application of magnetic flux leak (MFL) technology in an in-line inspection (ILI) tool.

Available ILI systems for assessing hardness anomalies in pipelines are based on measuring a local increase in the retained magnetism in the pipe. The main issue with using magnetic measurements to determine hardness is that the best magnetic properties are difficult to measure and the easiest properties to measure are not the best at determining hardness values. Magnetic coercivity and permeability correlate well with hardness, but these are best measured on cut-out samples. On the other hand, the magnetic remanence is relatively easy to measure on a piece of pipe. Increasing hardness will cause greater retention of the applied magnetic field. However, remanence does not directly correlate with the absolute hardness. To get a hardness value from a remanence measurement on a specific piece of pipe, calibration may be required using hardness values from other pipes from the same population.

The capability for detecting hard spots by ILI has existed for a surprisingly long time: hard spots were discovered using an AMF magnetic ILI tool and examined in the field in 1968 [14]. As with any other ILI technology, significant evolution has occurred leading to present-day technologies. The industry

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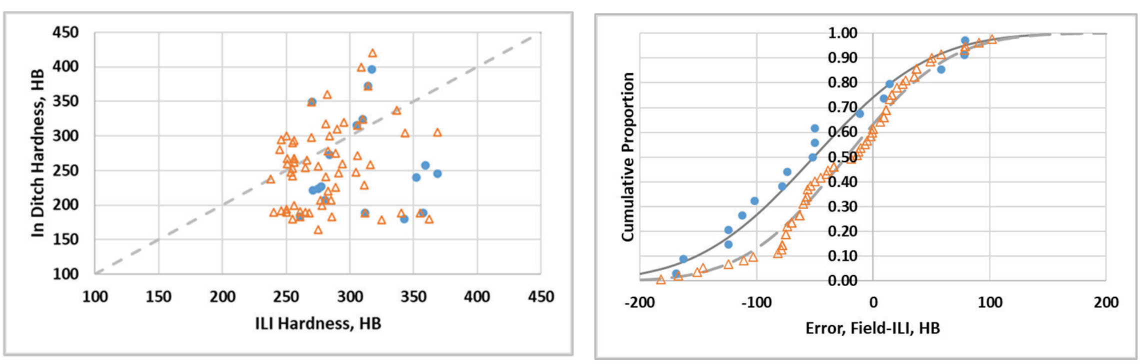
migration to permanent magnets instead of electromagnets has affected both the residual magnetic field and how it is sensed. Present systems currently rely on a dual-field technique wherein the first magnetizer produces the strong saturating magnetic field used for assessing metal loss corrosion; the second magnetizer provides a lower magnetization level, which is used to assess hardness anomalies. The complexity of a continuously variable permeability makes determination of the hard spot hardness, dimensions, and depth more challenging than determining the dimensions and depth of metal loss. The capabilities continue to evolve.

5.2 ILI performance expectations today

Hardness indicated by the ILI tool is based on a correlation to an indirect measurement; therefore, tolerances on measurement values should be expected. From a review of field data provided by one operator (Operator A), in 11 digs, 81 magnetic anomalies indicating potential hard spots were identified, 27 of which were significant (hardness greater than 300 BHN) with two containing cracks. There was at least one significant feature at 10 of the 11 digs. Pipe was replaced in at least 8 of the digs (documentation of the remaining 3 did not indicate whether the pipe was replaced).

Figure 7(a) is a hardness unity plot of data provided by Operator B. There is an initial set of 17 anomalies (solid blue circular symbols) and an expanded set of 66 anomalies (open orange triangle symbols). Figure 7(b) shows the error (field hardness minus ILI indicated hardness. Both exhibit an approximately Gaussian cumulative distribution, but the expanded (orange symbol) data set shows less error. The ILI system overpredicted the hardness by 23 BHN on average (where the cumulative curve crosses the 50th percentile) with a standard deviation of 69 BHN.



(a) (b)

Figure 7. Hard spot ILI results for Operator B

Figure 8(a) is a unity plot for a small data set of 12 hard spots from Operator C. There appears to be a strong tendency for the ILI tool to overpredict the hardness. This is verified in Figure 8(b). The error again looks like a Gaussian cumulative distribution but the ILI system overpredicted the

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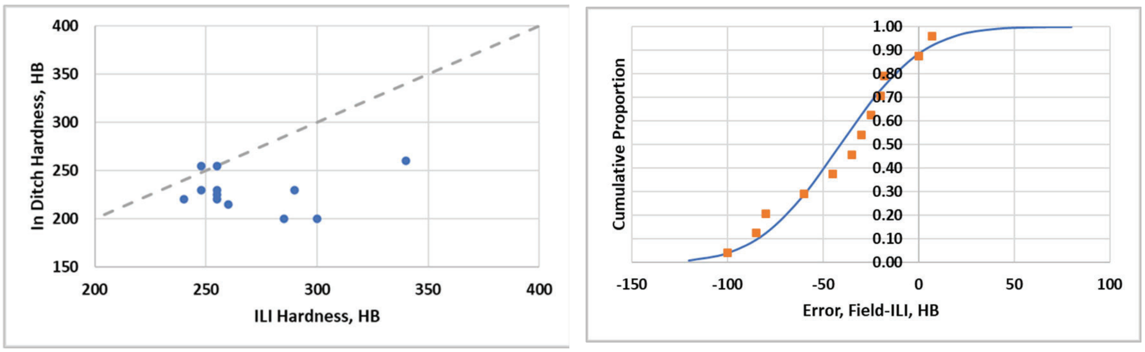
hardness by 41 BHN on average with a standard deviation of 34 BHN. So, the average error or bias is larger but the scatter is less, compared with Operator B's data.



(a) (b)

Figure 8. Hard spot ILI results for Operator C

What do these differing tool performances mean for an investigation criterion either for the rest of the uninvestigated hardness anomalies, or investigations in another pipeline? This same question comes up when responding to corrosion or crack like features. One could simply add the ILI vendor's claimed tool tolerance, perhaps ±25 BHN or whatever is appropriate, to the indicated hardness and dig those that exceed a dig criterion such as 325 BHN. That would mean digging anomalies indicated to have hardness greater than 300 BHN.

Alternatively, one could apply a Probability of Exceedance (POE) analysis, starting with the vendor's claim but adjusting after several digs to account for actual tool error. This is a technique that has been used with corrosion. The POE analysis answers the question "If ILI indicates Hardness = X what is the probability that actual Hardness > Y?" Using the probability functions in Excel, it is relatively straightforward to develop curves for a selected hardness level of concern accounting for positive or negative bias (underpredicting or overpredicting hardness, and the standard deviation). These are shown in Figure 9(a) for Operator B and Figure 9(b) for Operator C. As an example, consider the POE curves for Operator B. The blue line shows that if the ILI tool indicates a hardness of 250 BHN, there is a probability of 1.5E-1 that it actually exceeds 300 BHN, about 3.5E-2 that it exceeds 350 BHN, and 6E-3 that it exceeds 400 BHN. The probabilities are much lower for Operator C because there is a larger bias toward overpredicting the hardness with lower scatter: 3.7E-3 that it exceeds 300 BHN, 1.7E-5 that it exceeds 350 BHN, and 9.4E-9 that it exceeds 400 BHN. If Operator B wishes to investigate any hard spot that has a probability greater than 1E-1 of exceeding 350 BHN, then the dig criterion is any hardness anomaly indicated to have hardness greater than 280 BHN. For Operator C, the dig criterion at the same level of conservatism is any hardness anomaly indicated to have hardness greater than 350 BHN.

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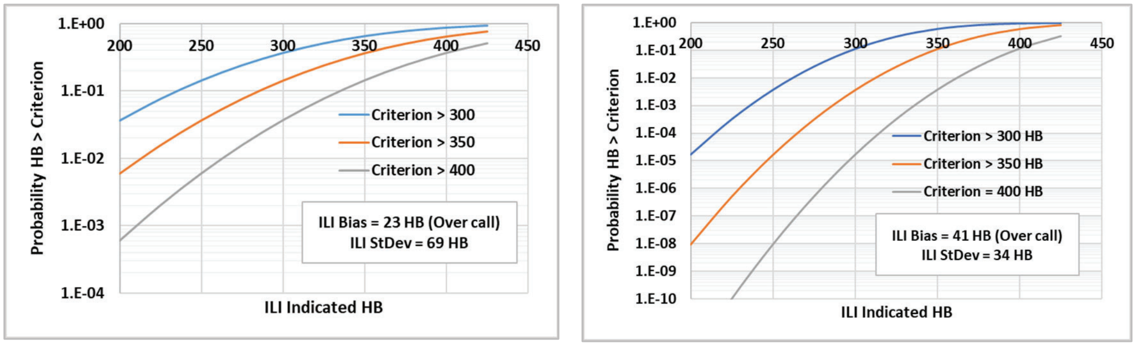

(a) (b)

Figure 9. Hardness probability of exceedance curves

The exact dimensions of a hard spot, with the possible exception of those created by weld metal deposition are inherently uncertain. The edges of the hard spots are indistinct, not unlike the edges of an indentation which vanishes smoothly into adjacent round non-indented pipe. Consequently, error in sizing should be expected.

Figure 10compares the lengths and widths as indicated by ILI (orange open symbols) to the lengths and widths as measured in the field (blue solid symbols). Two observations are made. Firstly, length and width generally increase together. Most of the hard spots affecting this particular operator's pipe (manufactured by Bethlehem Steel) are relatively round or oval in shape. Secondly, field dimensions tend to be a bit smaller than what was indicated. These observations apply to this variety of pipe in one operator's system, inspected by one ILI system. They cannot be generalized to all hard-spot-susceptible pipe or all ILI hard spot assessment systems.

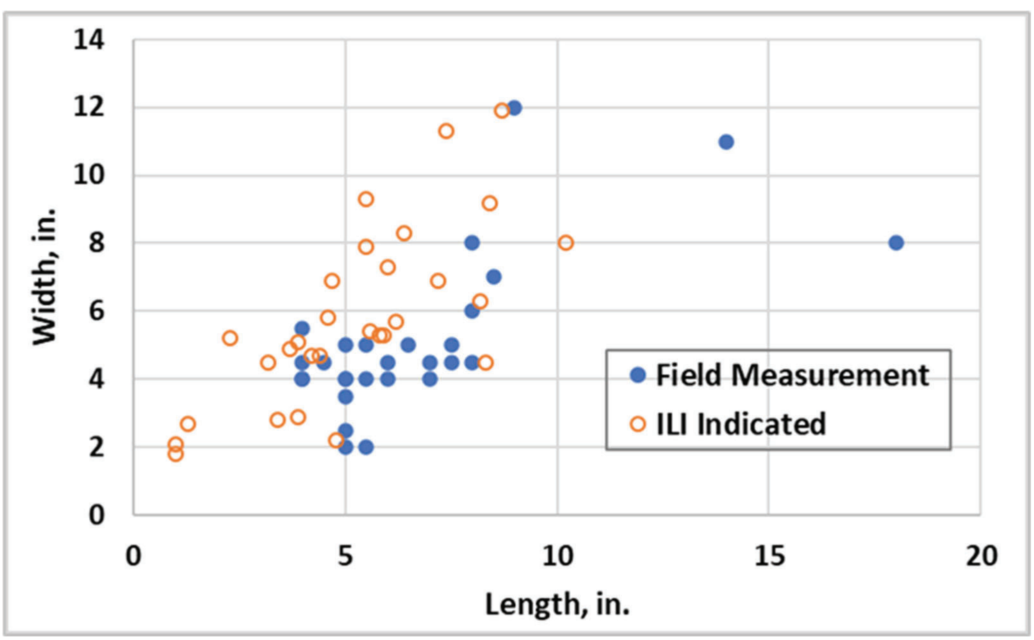

Figure 10. Example comparison of indicated and measured hard spot dimensions

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Figure 11 is a unity plot of the same data comparing ILI indicated length against field measured length (blue triangle symbols) and ILI indicated width against field measured width (orange circular symbols). (This is actually two unity plots in one which is only possible because the two dimensions are of similar magnitude.) The central diagonal line represents perfect agreement between the ILI indicated metric and the field measurement while the upper and lower diagonal lines represent an arbitrary error band of ±2 inches (50 mm).

The ILI tool underpredicted the lengths by 1.3 inches on average; 82% of the features fell within ± 2 inches, however, a few were far outside that range. The reason for such large discrepancies should be evaluated. The tool tended to overpredict the width with a lot of scatter; only 54% of the features fell within ± 2 inches. This may have to do with the primary axis of magnetization being longitudinal. The length dimension is more important from the fitness for service standpoint, which is why an understanding of the few cases of large error on the length estimate should be evaluated more closely. It should also be noted that ILI reports the anomaly with one hardness value over the full area, whereas in-ditch nondestructive examination is usually applied to map out a range of hardness across a grid. Where the hardness anomaly ends is difficult to define as the high hardness region transitions to pipe body hardness, especially if the shape is not a simple 'spot '.

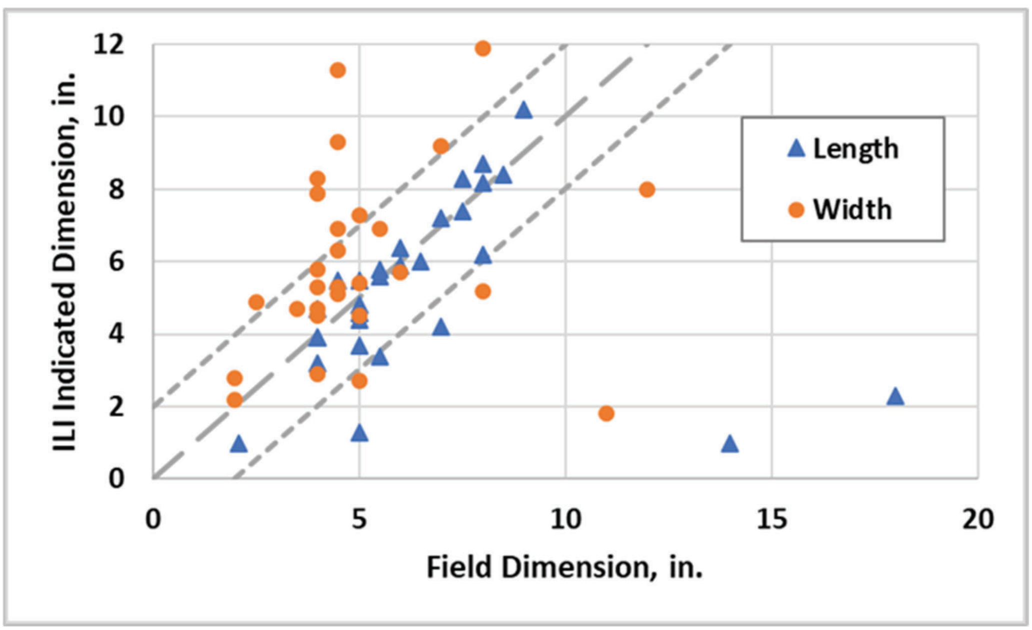

Figure 11. Unity Plot for hard spot lengths and widths

There currently is no guidance document specifically addressing validation of hard spot ILI performance. API 1163 provides a structured approach for ILI run validation that could be adapted to inspection for hard spots, addressing feature indication, sizing, and characterization in terms of hardness. Available methods for in-ditch examination of hard spots are only effective at the pipe exterior surface. This limitation could affect the ILI validation and is discussed later in this paper.

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5.2 Should hard spot ILI be repeated?

New hard spots do not develop through operation, but awareness of their existence or perception of their severity could change. Whether a reassessment is necessary and, if so, when might depend on the baseline assessment outcomes:

- Were hard spots of potential interest indicated by the baseline assessment?
- Was the assessment by ILI generally accurate or at least conservative when evaluated against field investigations?
- Were hard spots discovered incidentally that were not indicated, or were indicated to be much less significant than they actually were?
- Did leaks occur in hard spots that were indicated as not significant?
- Have ILI technologies for hard spot assessment, or knowledge of signal characteristics associated with hard spot type, evolved or improved since the baseline assessment?

If the hard spots inspection meets a Level 2 or Level 3 validation according to API 1163, no re-assessment is deemed to be necessary.

Example situations in which an operator may consider performing a reassessment for hard spots in conjunction with the standard integrity assessment schedule in pipe segments comprised of Meaningful Threat pipe could include:

- The ILI performance was not reliable or conservative as judged by a validation per API 1163 or in the operator's judgment.
- A higher probability of detection or probability of indication than currently stated in the performance specification is required.
- The ILI technology or the signal recognition process has improved since the baseline assessment.
- The operator's own experience with later inspections in other pipeline segments has shown that the expected performance has improved since a prior assessment.
- The ILI performance specification has changed.

5.3 Is hydrostatic pressure testing an effective assessment?

Virtually every hard spot that has ever ruptured, leaked, or developed a crack experienced a pressure test at the pipe mill and again at the time of commissioning or later in service. In a few cases, multiple field hydrostatic pressure tests occurred. Analysis of the incidents showed no clear relationship between time to failure and test pressure ratio (TPR) with either initial or later tests, or the number of tests. This suggests that conditions that affect the integrity of a hard spot can occur after a pressure test, negating the effectiveness of pressure testing for managing the hard spot integrity threat. Pressure testing can prove that a pipeline containing hard spots is safe the day of the test and for a little while

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afterward. But it provides no mitigation against changing or worsening conditions at a later time and should not be counted on as an effective long-term mitigation.

These observations are entirely consistent with those of the “Stability of Defects” report to INGAA and PHMSA [15]. Crucially, they are contrary to an interpretation often made by operators of ASME B31.8S’s assertion that a system pressure test to 1.25 x MAOP mitigates pipe manufacturing defects. B31.8S is clear that this is conditional on operating conditions not changing, but operators sometimes overlook changes in cathodic environment, coating condition, gas quality, or the onset of corrosion as changes in operating conditions [16].

There are a few situations where a hydrostatic pressure test may be effective; a couple examples follow. One might be a short, non-piggable segment of susceptible pipe, with the pressure test supplemented by careful management of exposure to sources of hydrogen from CP. Another might be a non-piggable segment of susceptible pipe scheduled for “make-piggable” upgrades within the near future.

5.4 Are there any other alternatives?

The authors consider that a “hard spots direct assessment” (HSDA) program might be feasible for non-piggable susceptible segments in critical service that cannot be interrupted for testing. Aggregated data from ILI gives information about the number of hard spots per mile that could be used to estimate the expected population of hard spots in a segment of interest. A starting sample size for the segment length can be determined using established sample theory, while sites could be selected for accessibility. A sampling model, perhaps similar to ANSI/ASQ Z1.4 [17] or others, could be applied to determine the allowed number of discoveries to meet target confidence levels about hard spots exceeding a severity threshold in the balance of pipe; or Bayesian methods could be applied to update probabilities based on discoveries. A progressive dig plan could be developed to attain confidence targets if necessary.

In 2012, a research team at the University of Arizona demonstrated an ability to detect and characterize different heat treatments in aluminum plate based on a guided ultrasonic Lamb wave. [18] This suggests the possibility of using guided wave ultrasonic (GWUT) testing to discover significant hard spots. If this is feasible with steel pipe, it could perhaps be used with HSDA to increase confidence in a limited number of digs, or could supplement a pressure test that has no test failures. (The authors are not stating that this will be feasible. Significant research may be necessary to prove feasibility and develop a practical technique.)

6. Response to the Assessment

6.1 Prioritization

The susceptibility process described above was structured assuming no foreknowledge of the existence, locations, or attributes of hard spots. However, once hard spots have been indicated (a) to

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be present, (b) at known locations, and (c) having indicated sizes and hardness, then other decisions become necessary namely (d) which features to investigate, (e) in what sequence, and (f) when.

Applying a risk informed approach means accounting for both likelihood of a failure (rupture, leak, or near-miss) and consequence based on location. In other words, accepted integrity management principles must be applied. What matters at this stage are: whether hard spots are present, their attributes (size and hardness), and where they are located relative to external conditions (mainly sources of hydrogen) that could aggravate the threat. The manufacturer and vintage of the pipe no longer enter into the decision about how to sentence a known hardness anomaly. An analogy is coating type can influence susceptibility to corrosion, but once corrosion is discovered by ILI, prioritization of response is dependent on corrosion severity and location (i.e., risk); the coating type becomes relatively unimportant to the decision whether to repair the pipe.

CP status, corrosion activity, and stresses vary locally. In the susceptibility process discussed above those factors could only be considered broadly because the proximity of those conditions to specific hard spots was unknown. With specific hard spot locations, sizes, and hard-ness indicated by ILI, the status of CP or corrosion must be considered locally in the context of specific proximity to the identified hard spots.

CP status or corrosion activity vary with time. Past conditions could have already introduced hydrogen embrittlement, HSC, or SCC if conditions were conducive to those effects; present or future conditions could do so given time. Note also that corrosion that could affect a hard spot may be too superficial to be indicated by ILI. Thus, any corrosion indicated on the same pipe joint or an adjacent pipe joint could represent a potential threat of interaction between undetected or unreported corrosion and a hardness anomaly.

6.2 Determination of Maximum Acceptable Hardness for Hard Spots; How Hard is Too Hard?

A survey of several regulatory codes, industry consensus standards, and pipeline operator practices revealed the following references to hard spot hardness as a consideration in hard spot assessment, listed below in Table 3.

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Table 3. Hardness Criteria in Codes, Standards, and Operator Plans

Source	Hardness Criterion
ASME B31.4	Considered a defect only if it has been examined and its hardness determined to exceed 35 HRC (approximately 345 HV)
ASME B31.8	Makes no reference to hardness. A hard spot is a defect only if it exhibits a crack.
ASME B31.8S	Pipe body hard spots are not discussed.
API RP 1160	Hard spots are prone to HIC in the presence of atomic hydrogen If the hardness exceeds 350 HV10 (33 to 35 HRC)
CSA Z662	Recognized as a material defect but hardness limit not defined
49 CFR 192	No reference to a hardness limit; it refers only to hard spots with cracking.
49 CFR 195	Does not discuss pipe body hard spots
PHMSA ADB 24-01	Hard spots are defined as having hardness ≥ 325 HB and a dimension > 2 inches.
NACE MR-0175 / ISO 15156	Hardness hardness limit of HRC 22 (approx. 248 HV) along with specified heat treatment conditions and limits on steel composition to avoid sulfide stress cracking in sour service
Operator #1 IMP	Response to ILI indicated hardness anomaly to consider: • Hardness ≥ 400 BHN, or ≥ 280 BHN and interacting with other features such as dents is Priority 1; • Hardness between 340-399 BHN: Priority 1 in HCAs and Priority 2 outside HCAs; • Hardness between 300-339 BHN, Priority 2 within and outside of HCAs; • Hardness between 280-299 and area ≥ 4 sq. in., Priority 2 within and outside of HCAs.
Operator #2 IMP	Dual-field MFL ILI detected hard spots having indicated hardness > 300 BHN or 2 times base hardness results in consideration of the hard spot being an elevated threat

The recognition that martensite hardness is dependent upon steel composition has resulted in adoption of different acceptable weld heat affected zone hardness values for different steel compositions when welds are made onto in-service piping. The accelerated cooling of welds made onto pipes containing pressurized fluids increases the likelihood of martensite formation. The

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martensite is susceptible to cracking from hydrogen that enters the weld zone during the welding process. The steel composition expressed as carbon equivalent (CEIIW), can be related to the amount of hydrogen in the weld zone (based on details of the welding process and welding consumables), and the maximum acceptable hardness [19]. As illustrated in Figure 12, the allowable hardness to avoid weld HAZ cracking decreases as CEIIW decreases (since the hardness of martensite also decreases with lower %C) and as the amount of diffusible hydrogen increases. HV 300 was determined to be a "safe" maximum hardness for all studied carbon equivalents and hydrogen levels, but appreciably higher hardness values are acceptable at some combinations of higher CE and/or lower hydrogen content. The illustrated lower limit of 300 HV for welds made using cellulosic flux-coated consumables (i.e., EXX10 SMAW electrodes) on low carbon equivalent steels is comparable to, although slightly lower than, the hardness limits of HV 320 [20] and HV 318 (from MAT-7-2) for hardness values below which effects of hydrogen embrittlement appear to be minimal, regardless of steel composition.

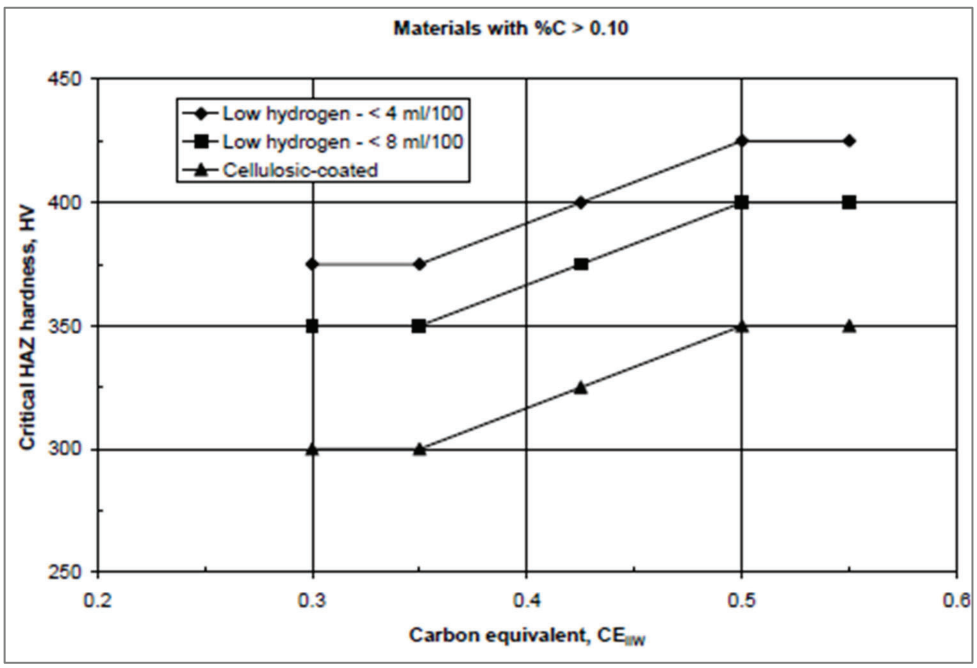

Figure 12. Critical Hardness Level for In-service Welds vs. CE IIW and Weld Hydrogen Level (Bruce, et al [17])

Susceptibility to hydrogen embrittlement is highly related to microstructure. Therefore, determining whether uncracked hard spots are acceptable for continued service or need mitigation requires consideration of the type of microstructure that is present. However, hardness measurements are typically much easier and faster to perform than quantitative metallography under field conditions than microstructure analysis. As a result, hardness has become a popular proxy for an indicator of susceptibility to embrittlement since hardness can be an indicator of microstructure. Unfortunately,

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the adoption of a hardness value as a threshold for acceptance vs. repair is problematic for the following reasons:

1) Untempered martensite is the microstructural phase most susceptible to hydrogen embrittlement, but the hardness of martensite is highly dependent upon the steel composition, especially carbon content.
2) The percentage of martensite at which a significant increase in susceptibility to embrittlement occurs has not been well defined.
3) In the field, only the hardness of the external surface of the pipe can be measured using conventional hardness measurement methods. The maximum hardness of the hard spot may or may not be at or near the outside surface of the pipe.

One equation for calculating the maximum likely HV hardness of untempered martensite (HM) based on percent carbon is shown in equation (1) [21]:

$$H_m = 802 \times (\%C) + 305 \tag{1}$$

Resulting HM values for examples of steel carbon content are in Table 4.

Table 4. Theoretical Maximum Hardness of Martensite vs. Carbon Content

%C	Calculated H_M (HV)	Approx. Equivalent BHN
0.10	385	365
0.15	425	402
0.20	465	438
0.25	506	476
0.30	546	512

Note that within the range of alloy additions used in pipeline steels, alloying elements other than carbon do not materially affect the hardness of martensite. They only significantly affect the cooling rate at which the martensite forms. Of the elements used in steel pipe, only cobalt does not increase hardenability [22].

The relationship between elevated hardness and the amount of martensite present can be exploited in two different ways to facilitate assessing the integrity threats posed by hard spots. First, the measured maximum hardness can be compared directly to the theoretical maximum hardness of martensite in steel of the same carbon content. The closer the measured hardness is to the theoretical maximum hardness, the more likely it is that the amount of martensite present is high. This method benefits from only requiring that the carbon content and the measured maximum hardness be known.

In a second method, the measured maximum hardness at the hard spot can be compared to both the hardness remote from the hard spot and to the theoretical maximum hardness. The remote hardness and theoretical maximum hardness are the boundary conditions representing 0% martensite and 100% martensite. The maximum measured hardness falls somewhere between those two boundaries. Simple calculations are used to determine what percentage of the way from the 0% martensite

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condition to the 100% martensite condition the maximum measured hardness represents. This method requires that both the remote base metal hardness and the maximum measured hardness be known, in addition to the carbon content. The advantage of this method is that it gives a better representation of how much the microstructure of the hard spot has been altered relative to the remote base metal, in addition to facilitating a calculation of how close the maximum hardness is to the theoretical maximum hardness. Table 5 summarizes the difference in results for the two different methods for some hypothetical examples.

Table 5. Comparison of Results for Two Methods of Expressing the Measured Hardness Relative to Martensite Hardness

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
Steel Carbon Content	**Hypothetical Hardness Remote from Hard Spot (H_r)**	**Hypothetical Maximum Measured Hardness at Hard Spot (H_{max})**	**Calculated Theoretical Maximum Hardness (H_M) Based on %C**	$\mathbf{H_{max}/H_M}$	$\frac{(H_{max} - H_M)}{(H_M - H_f)}$
0.15%	200 HV	350 HV	425 HV	0.82	0.67
0.15%	165 HV	350 HV	425 HV	0.82	0.71
0.28%	200 HV	350 HV	530 HV	0.66	0.46
0.28%	165 HV	350 HV	530 HV	0.66	0.51

The examples in Table 5 show the following:

1) When the maximum measured hardnesses are the same for both steels, the lower carbon steel is expected to have more martensite. (See Col. 5)
2) For either steel, when the hardness remote from the hard spot is lower, but the maximum measured hardness is the same, the steel with the lower remote hardness is expected to have more martensite. This is not discernable when only the maximum hardness of the hard spot is measured. (See Col. 5 versus Col. 6)
3) When the hardnesses are the same in the two steels, the difference in calculated values for the two steels in Col. 5 (i.e., when only the maximum measured hardness is considered and remote hardness is omitted) is smaller than the difference in calculated values in Col. 6 (i.e., when the remote hardness is considered in addition to the maximum measured hardness). Therefore, consideration of BOTH the maximum measured hardness at the hard spot and the remote hardness accentuates the differences between different steels.

Unfortunately, a review of the available data for hard spot failures shows that the hardness of the pipe remote from the hard spot is almost never reported, although it would be expected to be somewhat related to pipe grade and steel composition. Therefore, it is not possible to determine what calculated values of ((H_max-H_M))⁄((H_M-H_f)) are commonly associated with hard spot failures and method 1 requires more case histories with more complete hardness data to be useful. In contrast, 31 cases of hard spot failure incidents with known percent carbon content of the steel and the maximum hard spot hardness were reported. All the incidents except one fell above a Hmax/HM ratio of 0.70. Taking

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a hardness ratio of 0.70 as a cutoff below which a failure is unlikely, one can calculate a maximum allowable hardness based on known percent carbon content using equation (2) (from MAT-7-2).

$$BHN_{Allowable} = 523.5 \times (\%C) + 202.1 \quad (2)$$

6.3 Fitness for service assessment

Hardness alone does not define whether a given hard spot or hardness anomaly is tolerable. MAT-7-2 describes two distinctly different models that apply fracture mechanics to predict failure pressures. While promising, further research and development will be necessary to reduce these to a usable practice.

An empirical model was developed informed by prior hard spot failures and relying solely on the information that an operator would have about the pipeline of interest and the attributes of hard spots reported by ILI prior to investigation in the field. A severity index was defined as simply the product of the operating stress as a proportion of SMYS (% SMYS/100), indicated hard spot hardness in BHN units, and the hard spot length in inches, equation (3):

$$\text{Hard Spot Severity Index (HSSI)}=(\%\ \text{SMYS})\times(\text{BHN})\times(\text{L [in.]}) \quad (3)$$

The HSSI metric demonstrated an ability to distinguish between hard spots that leaked from those that ruptured, and more importantly, to differentiate between hardness anomalies that have a high likelihood of leaking or rupturing from those hardness anomalies that will likely not do either, using only the information available from ILI in order to prioritize digs for field investigation. This is shown in Figure 12(a) showing actual hard spot leaks or ruptures along with over 4,500 indicated hardness anomalies in one operator's pipeline system. An arbitrary field-investigation criterion represented by HSSI = 1,000 corresponds to a low percentile of the leak or near miss population (20th percentile) and even lower percentile of the rupture population (10th percentile) without condemning a large proportion of the operator's intact hardness anomalies. Applying HSSI =1,000 to differing hardness anomaly hardness levels results in criteria for the field investigation in terms of reported hard spot length (inches) versus operating stress (ksi) shown in Figure 12(b).

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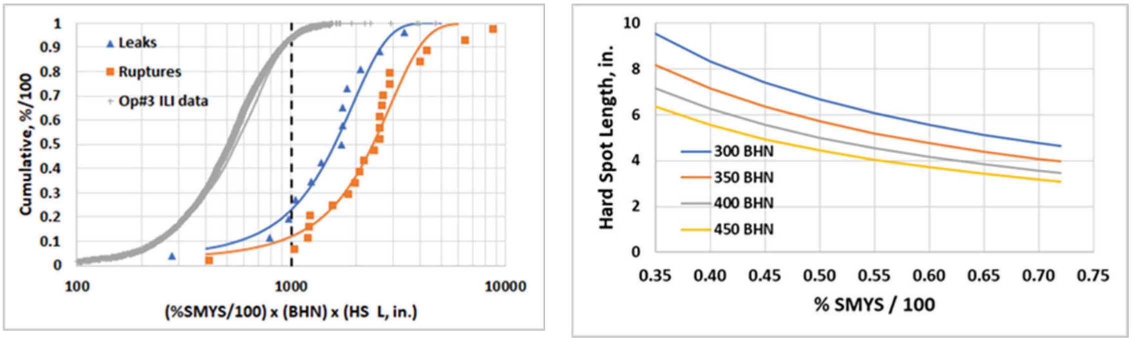

(a) (b)

Figure 12. Cumulative distribution of hard spot failures and intact hardness anomalies by Severity Index (a), and allowable hard spot hardness and size at HSSI = 1,000 (b)

7. Mitigation

Like low-strength girth welds, hard spots are tolerable so long as other conditions do not develop that could activate or aggravate the threat. For hard spots, the aggravating conditions reduce to sources of hydrogen with or without increased stress. Sources of hydrogen are generally either corrosion processes external or internal to the pipe, or cathodic protection. These processes can vary along the pipeline. Therefore, it is essential to know where the hard spots are, especially the large or high-hardness ones, relative to those other conditions. So understanding whether a segment of pipeline containing hard spots is near a CP rectifier, or is sometimes in a state of overprotection or subject to highly variable cathodic protection (both over- or under-protection), or in an area where coating is not in good condition, or where corrosion, SCC, or MIC have been previously identified, could be useful to decisions about how to respond to indicated hard spots or how to protect existing hard spots.

There is also the question of what constitutes an effective mitigation, short of a cut out. One operator experienced failures in numerous hard spots repaired by Type A sleeves, probably due to water entry under the sleeves. Type B sleeves avoid that problem, as do Type A sleeves for which an effective and durable coating material is used to seal the unwelded ends. A non-metallic composite wrap could be effective provided (a) no cracks are initially present, (b) the surface is prepared to absolutely assure a good bond to the pipe to prevent moisture entering underneath it, and (c) an inner or outer wrap shields the hard spot from the cathodic protection.

Thus P&MM short of cutouts or Type B sleeves on the more significant hard spots will require continued attention to the coating degradation, corrosion processes, and precision management of CP system performance. That approach may be more difficult than performing a lot of digs to cut out or sleeve hard spots that exceed a threshold in size and hardness level.

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8. Areas for Further Development

Several subjects related to hard spots that may merit further research are listed in Table 6.

Table 6. Areas for further development

Study Area	Problem to be addressed
Improve in-ditch NDE tools	• Present in-ditch NDE cannot detect internal hard spots; as a result, NDE may undersize ID-biased hard spots leading to incorrect ILI qualification and Type II errors
Improve ILI accuracy and precision	• Reduce sizing and hardness error • Reduce Type I (false positive) and Type II (false negative) errors
Develop HSDA process	Needed for non-piggable critical service lines
Explore GWUT capabability	Supplement non-ILI based methods to find hard spots
Improve hard spot fitness for service methods	Present fracture mechanics models are inadequate for FFS decisions
Probabilistic risk assessment	The methods already exist for probabilistic assessment, but confidence levels should be quantified for expected ILI and in-ditch NDE errors
Managing CP to avoid overprotection and under-protection	Guidance is needed for: • moderating CP levels spatially and over time where sensitive materials are present • cost versus benefit of precision CP management versus excavate and repair all hard spots
Operator data sharing	Developing a platform for sharing results from ILI and field NDE on populations of hard spots identified from ILI, updated risk estimates, and other IM activities, per ADB 24-01
Tolerance for hydrogen blended with natural gas	Guidance is needed for determining the tolerance (if any) of hard spots for conversions of service to NG-H_2 blends
Develop guidance and assessment for other hard microstructures	Seams and girth welds may also contain hard spots that are a challenge to present technologies
Investigate how hard spots formed	• Coupled thermal and metallurgical modeling could shed more light on the conditions under which hard spots formed. • Investigate composition of hard spots for localized enrichment (this has not been done previously)

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9. Summary

Various statistics related to the occurrence and failure of hard spots have been summarized. Probable mechanisms for the formation of hard spots and the observed variations in hard spot size, shape, location, and hardness are described. The means by which hard spot assessment and management can be incorporated into typical integrity management programs are discussed, including the use of ILI for hardness anomaly detection and characterization, and descriptions of various existing and potential acceptance criteria. Areas for further development and study to address current knowledge gaps are also discussed.

10. Acknowledgments

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