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Forensic Engineering Investigation of Factors Contributing to the Explosion of an International Natural Gas Pipeline

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Abstract

Following the explosion of a natural gas pipeline that resulted in extensive property damage, personal injury, and loss of life, a forensic engineering investigation was performed to determine factors that significantly contributed to the failure. Metallurgical analysis of the failure region resulted in the conclusion that the pipeline rupture was caused by hydrogen embrittlement acting on hard spots created during manufacturing. The next phase of this investigation involved root cause analysis of factors contributing to the pipeline rupture as well as evaluation of missed risk-reduction opportunities of the nondestructive analyses employed. It was ultimately determined that hydrogen embrittlement, caused by improper operation and maintenance procedures, resulted in an overabundance of hydrogen from excessive cathodic protection. Additionally, excessive operating pressure exceeded the resulting degraded ultimate capacity of the pipeline, which then manifested in the rupture of the natural gas pipeline and the ensuing explosion. It is recommended that operators exercise due diligence by considering the age of a pipeline when determining appropriate operating, monitoring, and maintenance procedures.

Keywords

Pipeline, hydrogen embrittlement, hard spot, cathodic protection, operating pressure, maintenance, natural gas pipeline, pipeline inspection, forensic engineering

Background

Gas transmission pipelines play a critical role in national economies and are an essential part of the world's infrastructure. As such, it is essential to properly operate, maintain, and monitor them to prevent gas distribution interruptions due to pipeline failures.

According to the Pipeline and Hazardous Materials Safety Administration (PHMSA), more than 12,794 pipeline failures were recorded between 2002 and 2021 in the United States, resulting in 276 fatalities, 1,147 injuries, and $10.1 billion in damages[1]. Failures can be classified as leaks or ruptures. While either can result in fire or explosion, leaks represent the bulk of pipeline failure and typically result in less damage; ruptures are significantly more costly and catastrophic. Of all reported pipeline failures, 24.1% result in fires, and 12.3% result in explosions[2].

As shown in **Figure 1**, the 1950s and 1960s saw the installation of a large number of natural gas pipelines in the United States. As of this paper's publication date, the average pipeline in the United States is approximately 47 years old, as per the analysis of PHMSA data. As such, engineers and technical operators should be mindful of the detrimental effects of age-related degradation and environmental factors that adversely affect the operation of the world's energy infrastructure.

The Present Case

An incident occurred involving a section of a vintage natural gas pipeline in the United States that unexpectedly ruptured, resulting in one fatality, destruction of 30 acres of the surrounding area, hospitalization of six people, and the evacuation of more than 75 residents (**Figure 2** and **Figure 3**). The families of those affected filed suit against the owners of the pipeline, pursuing legal theories of recovery based on negligence and gross negligence.

Following a thorough investigation, it was determined that significant factors synthesized to create the perfect

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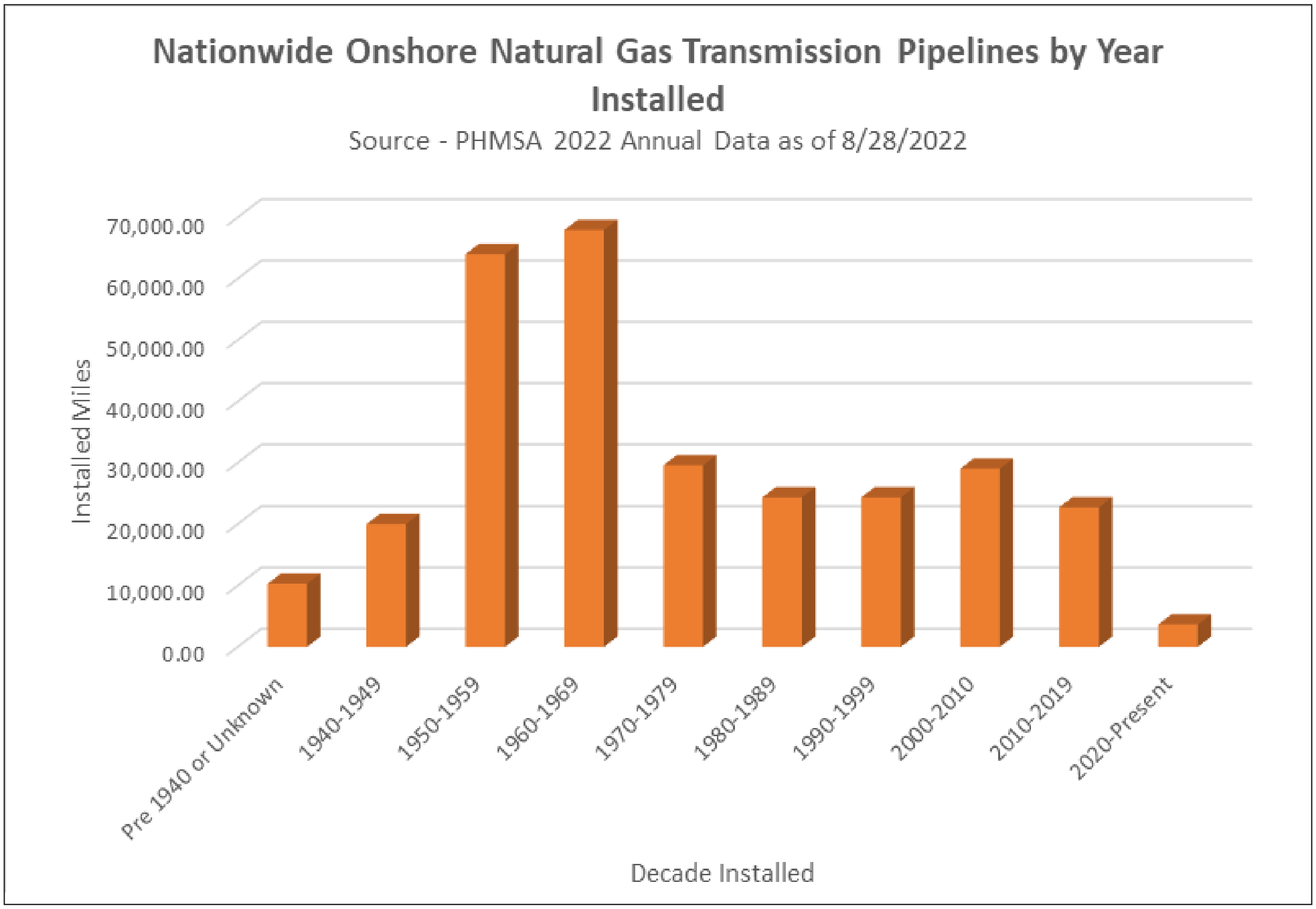

Figure 1

Miles of onshore gas transmission pipelines installed in the United States by decade[3].

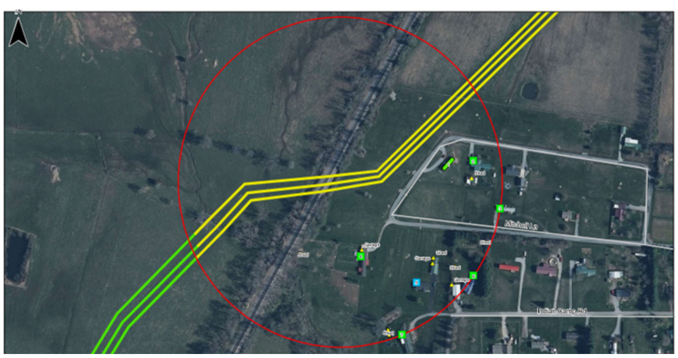

Figure 2

Arial photograph of the mobile home park with location of the pipeline highlighted[4].

Figure 3

Crater left by the pipeline explosion[4].

conditions for the occurrence of the incident at issue. These factors included excessive operating pressures that were not commensurate with the age and conditions of the pipeline along with inappropriate corrosion protection procedures in the form of over-active cathodic protection.

Pipeline Specifications and History

According to provided discovery documents, the pipeline was manufactured in 1957. It was 30 inches in diameter, $^{3}/_{8}$-inch thick, and was made from X-52 carbon steel with an electric flash-welded seam. Additionally, it had a Specified Minimum Yield Strength (SMYS) of 52,000 psi and was being operated at a Maximum Allowable Operating Pressure (MAOP) of 936 psig at the time of the incident. More information about the pipeline's specifications is shown in **Figure 4**.

The pipeline was noted to have experienced a previous rupture 15 years ago about 78 miles north of where the incident rupture occurred. At the time of this previous incident, the pipeline was operating at 907 psi. An investigation report of this incident found that the rupture was

Pipeline Specification	**Value**
Diameter	30-inch
Material	Carbon Steel
Grade/Specified Minimum Yield Strength (SMYS)[12]	X-52/52,000 psi
Long Seam Weld	Electric Flash-Welded
Manufacturer	
Year Manufactured	1957
Wall Thickness	0.375 inches
Flow Direction (at time of failure)	
MAOP, south flow	936 psig
Operating Pressure (at time of failure)	925 psig
Compressor Station Gas Discharge Temperature (at time of failure)	115 °F
External Coating Type	Coal Tar Enamel
Soil Type	Shale
Cathodic Protection Method	Impressed Current

Figure 4
Pipeline specifications at the rupture origin.

caused by hydrogen-induced cracking that initiated at a hard spot — a region of elevated material hardness.

Fracture Origin

Examination of a segment of the ejected pipe section (**Figure 5**) revealed the presence of chevron marks that were utilized to identify the failure origin (**Figure 6** and **Figure 7**). The failure origin was located 90 inches from a girth weld at approximately the 4 o'clock position of the pipe (seam weld at 12 o'clock). Corrosion pitting was also observed near the failure origin and throughout the surrounding area.

Figure 5
The 33-foot-long segment of pipe that was ejected as a result of the explosion[4].

Figure 6
Sectioned segments of the pipeline at the failure origin[4].

Figure 7
The fracture surface of the pipeline at the failure origin[4].

The surface of the pipeline segment near the failure origin was ground, polished, and etched to create a grid for the measurement of hardness variation within this area (**Figure 8**). The etched surface revealed a darker region (**Figure 9**) near the failure origin where higher hardness values were measured as compared to areas away from the failure origin (**Figure 10**).

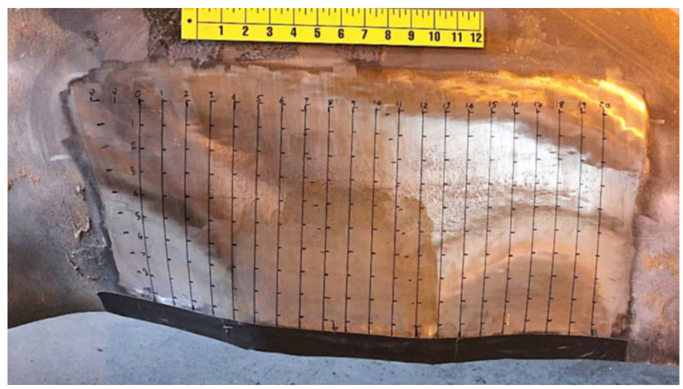

Figure 8
Hardness grid on a polished and etched surface of the pipeline near the failure origin[4].

Figure 9
Close-up of the polished and etched surface near the failure origin. Note the presence of the darker region where high hardness values were measured, as shown in **Figure 10**[4].

East Grid

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	169	164	169	165	166	168	169	170	166	179	169	165	161	165	159	161	169	160	168	156
2	161	163	168	166	165	162	173	170	161	167	167	166	167	165	165	161	163	162	160	163
3	167	169	169	164	169	160	176	169	159	172	168	170	164	163	161	171	164	164	160	170
4	168	167	165	165	163	167	168	169	170	173	170	167	171	173	168	162	167	170	163	174
5	167	162	170	170	169	171	177	177	190	174	166	171	154	162	161	162	157	162	164	167
6	164	168	165	164	169	178	186	255	245	181	179	178	165	166	173	167	163	161	172	171
7	166	163	166	164	168	176	251	301	295	283	232	164	163	164	162	164	160	163	157	171
8	162	161	164	203	186	208	289	293	309	305	282	169	154	162	167	164	158	160	155	173
9	150	158	166	194	202	210	291	310	319	313	303	173	165	162	158	162	161	157	159	160
9.5	161	146	164	195	202	211	280	336	326	304	303	245	155	163	155	157	163	167	159	163

Fracture Origin

West Grid

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	163	196	190	167	231	280	287	285	276	236	151	156	159	153	151	149	149
2	151	158	170	162	170	248	250	257	245	149	144	158	160	166	154	149	150
3	164	150	160	162	159	175	174	162	146	153	148	156	160	164	157	156	150
4	159	159	156	157	155	153	149	146	144	148	148	144	152	156	158	149	147
5	153	161	156	152	154	147	148	151	147	147	146	146	154	153	157	153	150
6	153	153	158	153	152	149	156	151	140	149	146	149	149	159	157	155	147
7	156	155	155	152	157	151	153	148	152	151	150	152	153	153	159	152	149

Figure 8: East and West Grid Hardness Values

Figure 10
Results of the conducted hardness testing[4].

A 6-inch x 1.5-inch segment of the pipe containing the fracture origin was cut out, cleaned, and examined under Scanning Electron Microscope (SEM). As shown in **Figure 11**, the fracture origin was observed to exhibit intergranular fracture from the exterior surface to approximately 0.1 inches below the surface, up to ~30% of the nominal thickness of the pipe. A mixed-mode fracture region was observed from 0.1 inches below the exterior surface up to the edge of a shear lip on the inner surface. The presence of intergranular features was noted to decrease with increasing distance from the exterior surface. Based on the above observations, it was concluded that the exterior surface of the pipeline was exposed to an embrittling environment.

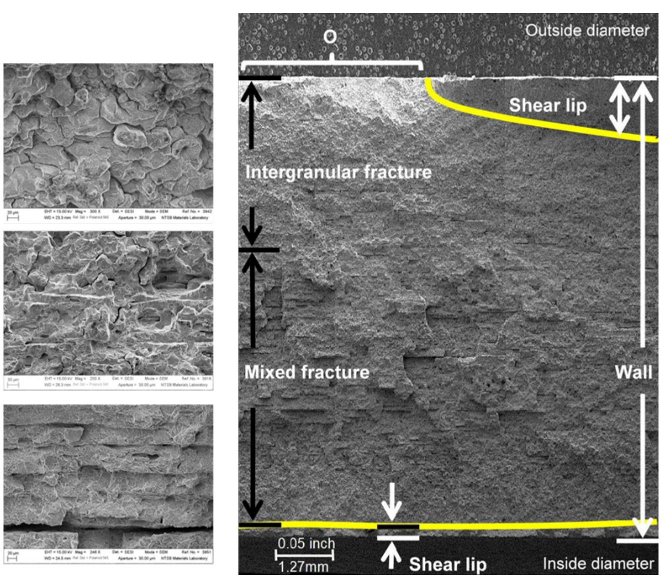

Figure 11
SEM image of the fracture surface at the fracture origin, displaying regions of intergranular and mixed mode fracture[4].

Hard Spots

A "hard spot" is a term used to indicate regions of elevated hardness within a material, typically with these areas displaying hardness values considerably higher than the surrounding metal. In pipelines, hard spots refer to areas of martensite generated from the rapid quenching of the pipeline steel during manufacturing[5].

Hard spots on steel form when heated metal in the austenitic phase is rapidly quenched, forming martensite[6]. It has been reported that pipelines produced from 1952 to 1957 were susceptible to hard spot development as a result of unintentional water leakage onto the production line[5,7]. It is well known in the industry that vintage pipes with high concentrations of hard spots are highly susceptible to brittle failure.

Non-Destructive Detection of Hard Spots

To inspect buried pipelines, pigging operations are performed that incorporate In-Line Inspection (ILI) tools capable of surveying the interior surface of a pipeline for the presence of various metallurgical and environmental conditions that can adversely affect the safety and efficiency of the pipeline.

Magnetic Flux Leakage (MFL) is routinely used for the detection of hard spots. MFL ILI tools work by inducing a magnetic flux into the pipeline while measuring variations in the rate of magnetic flux leakage. A homogeneous metal surface produces a uniformly distributed magnetic flux, while the presence of defects results in an altered flux field[8]. To detect hard spots, an MFL ILI tool must run a dual, low, or residual field inspection[8].

A review of the maintenance records revealed that eight years before the incident, a pipeline inspection company performed ILI for the detection of hard spots within the pipeline. Their inspection identified 16 hard spots, four of which were excavated and repaired. The remaining 12 did not meet the owner's criteria for excavation; therefore, they were not excavated or repaired.

Following the incident, the pipeline inspection company performed a re-analysis of its original data from the inspection performed eight years before the incident. This re-analysis utilized an improved version of the company's analysis software, which now incorporated AI instead of human operators to identify potential hard spots. As shown in **Figure 12**, this re-analysis revealed a total of 441 hard spots (compared to only 16 that were originally identified), nine of which were located within the same section of pipe that ruptured and one that was located at the failure origin.

According to the manufacturer of ILI tools, such devices have a corresponding probability of detecting an anomaly or defect in the pipeline, known as their Probability of Detection (PoD). This parameter is based on the number of known defects the tool is able to detect. The PoD is reduced based on the depth of the defect, so defects on the outer surface of the pipe will be more difficult to detect[8]. The ILI tool pipeline inspectors used for the original hard spot inspection were noted to have a PoD of 90%, typical of the average tool on the market[8,10,11]. Therefore, the ILI tool used by the pipeline inspectors in their original inspection would have missed 10% of potential critical defects in the pipeline. As this information was supplied to the pipeline owners prior to the original run of the ILI tool, they knew (or should have known) there was a considerable chance that critical defects in the pipeline would have been missed — such as the case with the hard spot at issue.

As a result of this, federal regulations require that pipeline operators perform hard spot inspections every seven years[11,12,13]. According to reviewed documents, the pipeline owners had scheduled another hard spot inspection more than a year before the incident but failed to carry through with this plan. However, even if they had performed this scheduled inspection, they would not have satisfied their due diligence as owners. According to a 2016 publication by PHMSA, "Defaulting to the maximum reassessment interval allowed by code and not analyzing each unique inspection segment for each pipeline threat can lead to failures and undermine an effective integrity management

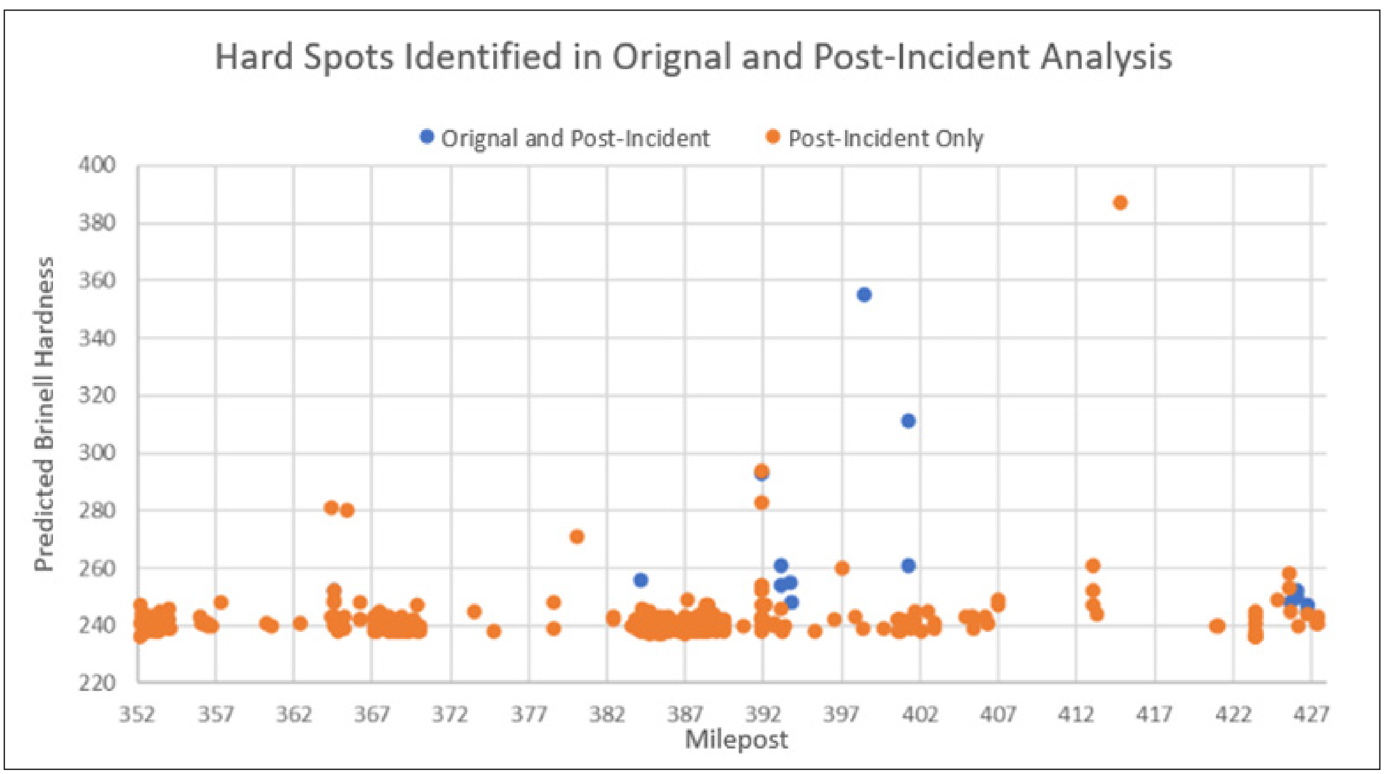

Figure 12
Comparison of hard spots identified in the original and post-incident analysis.

program[14].” As the pipeline at issue was a vintage pipe with a known susceptibility to hard spots, the pipeline owners should have instituted an inspection interval well below the maximum stated interval of seven years in order to account for the increased risk of hard spots presented. Had the pipeline owners run ILI multiple times as required by federal regulations, they would have — in all probability — caught 99% of the defects present in the pipeline, and the incident may likely have been prevented.

Cathodic Protection and the Consequences of Overprotection

Potential sources for the embrittlement observed at the failure origin were investigated. Based upon provided documentation, the production of hydrogen by the cathodic protection system of the pipeline was considered the most likely source of said embrittlement.

Corrosion protection of pipelines is routinely performed via cathodic protection, where the pipeline is electrically connected to a more anodic material. By electrically connecting the pipeline to a more anodic material, the couple undergoes an oxidation-reduction reaction — where the anode transfers its electrons to the cathode. Thus, the anode that is coupled to the pipeline acts as a “sacrificial metal” that takes on the corrosion the pipeline would normally experience[14]. The effectiveness of cathodic protection depends on the difference in electrical potential between the two anode and cathode materials. The material that undergoes electron loss will act as the anode of the galvanic couple while the material that gains electrons will act as the volume of the pipeline.

Cathodic protection of a pipeline can also be accomplished via impressed current. Instead of solely relying on the potential difference between the anode and cathode, an external power source is employed to run either DC or AC current through the system to increase the cathodic current for protecting the cathode from corroding (**Figure 13**). This method is typically applied to large structures (such as pipelines) where the natural potential difference (per unit volume) between anode and cathode would be insufficient to protect the entire structure[15,16].

To ensure that the cathode does not experience corrosion, a minimum level of potential must be maintained. For pipelines, this minimum potential, as dictated by NACE SP0169 and ASTM G218 is ~ -0.85 V[17]. Potentials slightly over or under this recommended level are allowed to account for environmental conditions.

Since the recommended minimum value of applied potential is ~ -0.85 V, some operators erroneously conclude that increasing this potential to even higher values would offer further benefits for the pipeline. While increasing the potential difference to values greater than the recommended minimum value of -0.85 V does increase the corrosion protection of the system, such increased corrosion protection comes with unintended adverse consequences. By increasing the potential of the impressed current, the excess potential causes nearby water in the soil or local environment to undergo electrolysis, releasing atomic hydrogen and hydroxide around the pipeline. The increased level of atomic hydrogen and hydroxide leads to the development of two unwanted phenomena — namely, hydrogen

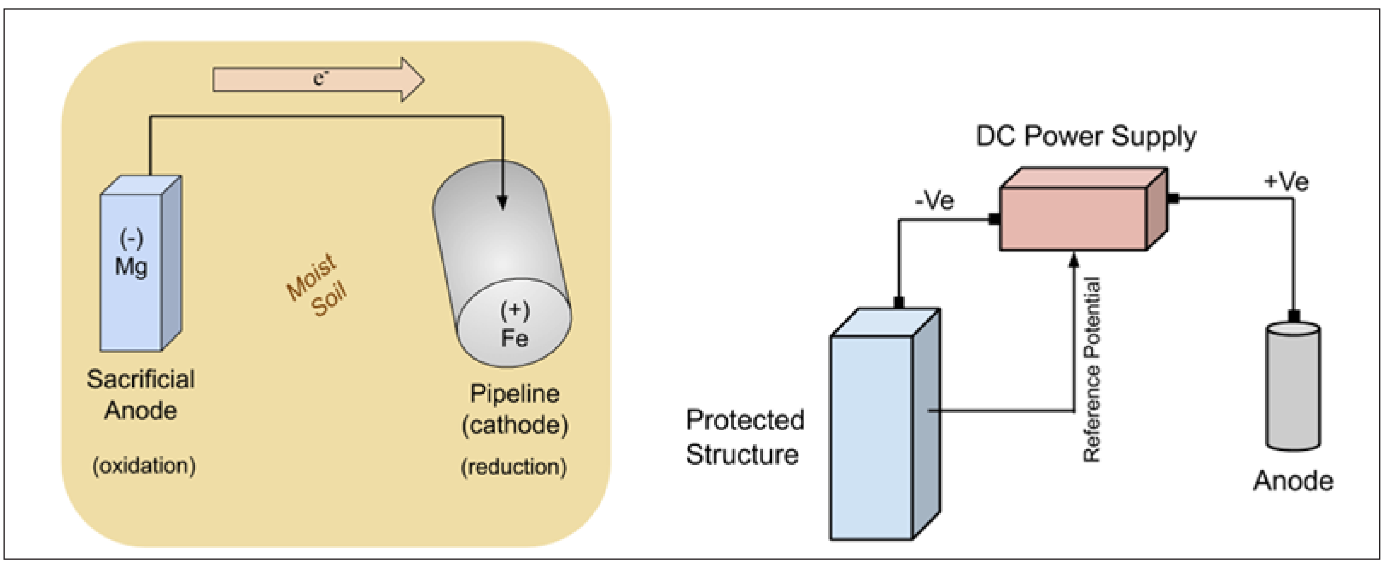

Figure 13
A typical sacrificial anode system (left) and a DC impressed current system (right)[15].

embrittlement and coating disbondment.

Hydrogen Embrittlement (HE) is a complex phenomenon in which atomic hydrogen is absorbed into the metal, reducing the material's strength, toughness, and ductility. This occurs due to a variety of different mechanisms, such as hydride formation, hydrogen-enhanced decohesion mechanism (HEDE), hydrogen-enhanced local plasticity (HELP), and adsorption-induced dislocation emission (AIDE)[18]. While these mechanisms differ dramatically from each other, ultimately, they all manifest as cracking in steel through either strain-controlled plastic flow or stress-controlled decohesion. The strain-controlled mechanism (combined with concentrated plastic flow) typically results in transgranular cracking while stress-controlled decohesion results in intergranular cracking[19]. An increase in hardness allows for higher stresses to be sustained by the steel and for more hydrogen to collect at these regions of elevated stress, thereby increasing decohesion-based hydrogen embrittlement[20].

As hydrogen diffuses through a steel pipeline over time, resulting in its gradual embrittlement, a critical hydrogen concentration level will be reached that causes nominally applied stresses to result in catastrophic failure of the material[21]. Probabilistically, older structures that have been consistently exposed to relatively low levels of hydrogen will eventually reach a critical hydrogen concentration that ultimately results in their failure. As such, it is critical that the occurrence of hydrogen embrittlement be closely monitored to identify and mitigate the risks associated with the aging population of pipelines.

Organic coatings such as coal tar enamel applied to the pipelines are partially permeable to cathodic current[22]. When a cathodic potential over the recommended value is applied, the elevated cathodic current facilitates an increased rate of hydrogen reduction at the surface of the metal, leading to a greater rate of hydrogen embrittlement[15]. In addition, the hydroxide ions produced by electrolysis are absorbed into the organic coating, degrading it and leading to its delamination. The resulting delamination exerts additional stresses on the coating, which, in turn, causes its disbondment from the pipeline. Since organic coatings such as coal tar enamel are permeable by hydrogen, oxygen, and water, these constituents are able to diffuse their way into the disbonded area and corrode the metal or accelerate hydrogen embrittlement[24,25,26]. Coating disbondment can also occur at locations of defects inherent in the coating, such as scratches, holes, and nicks[25,26,27]. Delamination causes the coating to disbond around these defects, which readily allows hydrogen, water, and hydroxide to pool in the coating defect and accelerate the diffusion of hydrogen into the metal, further disbonding of the coating (**Figure 14**)[22].

NACE SP0169 warns about the use of excessive potentials on coated pipelines and instructs that such excessive potentials should be avoided to minimize the occurrence of coating disbondment. This is due to the fact that as the level of cathodic protection is increased, the rate of hydrogen reduction, corrosion, and coating degradation increases[23,24,28,29].

According to available literature, the general consensus in the industry is that polarized (IRF) potentials of -1.05 V and higher (more negative) should be avoided to avoid cathodic overprotection[30]. In addition, ISO 15589-1 instructions for preventing disbondment of pipeline coatings state that the limiting critical potential for all metals should not be more negative than -1.20 V[31]. It is also to be noted that under normal pipeline operating conditions, this stated upper limit of -1.20 V could still be enough to result in high levels of hydrogen reduction, leading to hydrogen induced cracking of steel pipelines[21,27,32,33,34,35,36,37,38,39].

In this case, the pipeline owners utilized a series of cathodic protection test stations located roughly every mile along the pipeline for annual monitoring. These stations measured two types of potentials: the "Pipe-to-Soil" (P/S) potential, which includes the resistance inherent in the soil, and polarized (IRF) potential that is a reading corrected for soil resistance. The IRF is used as the effective cathodic protection level in accordance with ISO standards[31]. The cathodic protection readings at the

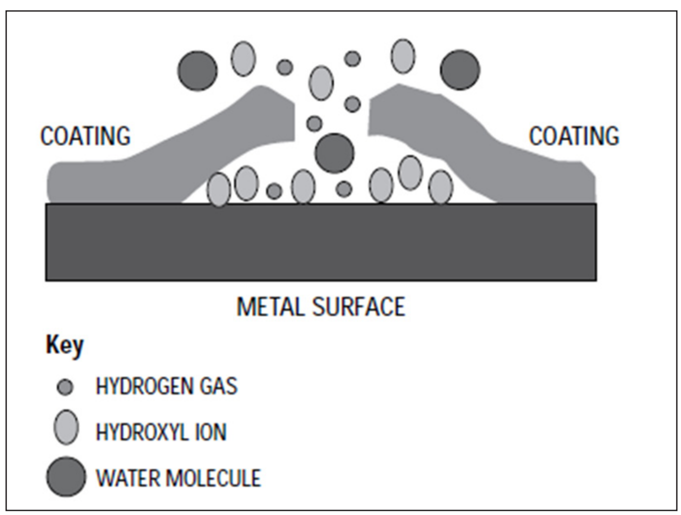

Figure 14
Elements of coating disbondment[27].

milepost where the rupture occurred in the years prior to the incident are shown in **Figure 15**. As can be seen from the data in **Figure 15**, there were numerous locations of low cathodic potential, exceeding the recommended value of -0.85 V with some of the locations exceeding the limit of -1.20 V. These highly negative potentials were kept in place for years, damaging the pipelines and increasing the risk of catastrophic ruptures.

The pipeline owner's standard operating procedure acknowledged that a high level of cathodic protection can cause damage to the pipeline coating as well as the pipe itself. As such, they required that error-corrected potentials (IRF) readings more negative than -1.20 V be investigated. While the pipeline owners at the time of the incident sought to maintain the cathodic protection potential between -0.85 V and -1.20 V, there was no indication that they made any organized effort to investigate and correct the high levels of cathodic protection that were known to be in place at the location of the subject incident as well as numerous other pipeline segments. Further evidence of disregard by the pipeline operators to prevent subjecting the pipeline to potentials above the critical -1.20 V level was obtained through discovery documents — where a corrosion technician employed by the pipeline operators who was interviewed by NTSB stated that he or she did not consider potentials up to -2 V as a cause for concern.

By taking into account the applied level of cathodic overprotection, the pipeline was subjected to, the presence of a hard spot at the failure origin, and the age of the pipeline, it was concluded that decohesion-based hydrogen embrittlement took place which caused the pipeline to fail in an intergranular manner. Based on the body of knowledge available in the previously cited open literature, the owners knew (or should have known) the susceptibility of steel pipelines to elevated cathodic protection levels at or near -1.20 V level, but their lack of due diligence in understanding proper cathodic protection levels led to improper cathodic protection operations at levels detrimental to the structural integrity of the pipeline.

Determination of Maximum Allowable Operating Pressure (MAOP)

One of the methods for determination of Maximum Allowable Operating Pressure (MAOP), as described in 49 CFR 192.619, is to operate at 80% of the hydrostatic burst pressure. Given that the as-manufactured (in 1959) pipeline's hydrostatic burst pressure was 1,170 psi, the operating pressure of the pipeline was set at 936 psi from the onset of operations. At the time of the incident, the operating pressure of the vintage pipeline was 925 psi or ~98.8% of the MAOP of 936 psi. Another method for determination of MAOP, as prescribed by 49 CFR 192.619, is to utilize the following equation:

$$P = \left(2\frac{St}{D}\right)\ x\ F\ x\ E\ x\ T \qquad \text{EQ. 1}$$

Miles From Subject	4 Years Before		3 Years Before		2 Years Before		1 Year Before		Year of Incident	
	P/S	IRF	P/S	IRF	P/S	IRF	P/S	IRF	P/S	IRF
-6	-1.884	-1.228	-1.811	-1.281	-1.832	-1.231	-1.629	-1.314	-1.443	-1.16
-5	-1.625	-1.201	-1.609	-1.261	-1.654	-1.348	-1.434	-1.22	-1.463	-1.098
-4	-1.652	-1.261	-1.67	-1.299	-1.858	-1.541	-1.453	-1.251	-1.28	-1.199
-3	-1.697	-1.256	-1.707	-1.282	-1.719	-1.321	-1.508	-1.242	-1.6	-1.176
-2	-1.275	-0.856	-1.036	-0.879	-1.006	-0.865	-0.776	-0.729	-0.8	-0.709
-1	-1.94	-1.159	-1.92	-1.15	-1.949	-1.26	-1.651	-1.145	-1.753	-1.079
0	-1.781	-1.096	-1.78	-10.41	-1.947	-1.234	-1.829	-1.081	-1.583	-1.047
1	-4.172	-1.478	-4.188	-1.4	-4.093	-1.536	-3.775	-1.469	-3.645	-1.287
2	-2.732	-1.277	-2.624	-1.175	-2.526	-1.252	-2.039	-1.333	-2.382	-1.154
3	-2.161	-1.14	-2.103	-1.011	-2.084	-1.08	-1.815	-1.066	-1.159	-1.045
4	-2.164	-1.143	-1.963	-1.066	-2.072	-1.103	-1.818	-1.045	-1.892	-1.076
5	-2.016	-1.158	-1.968	-1.093	-2.027	-1.065	-1.721	-1.008	-1.088	-1.037
6	-2.003	-1.187	-1.828	-0.927	-1.925	-0.958	-1.707	-1.058	-1.683	-1.132
7	-2.148	-1.028	-2.126	-1.029	-2.338	-1.034	-1.93	-0.967	-2.327	-1.348
8	-3.423	-1.266	-3.745	-1.254	-2.572	-1.235	-2.531	-1.215	-2.564	-1.347

Figure 15
Year-by-year readings of Pipe-to-Soil (P/S) Potentials (volts) with error correction (IRF) at the subject and nearby cathodic protection stations.

Where P is the design pressure (MAOP), S is the yield strength, t is the nominal wall thickness, F is the design factor, E is the longitudinal joint factor, and T is the temperature derating factor. As the pipeline was operating in a class 2 location (F=0.6), at operating temperatures under 250°F (T=1), and utilized electric flash welded pipes (E=1), the as-calculated MAOP would be 780 psi.

Additionally, the Interstate Natural Gas Association of America (INGAA) released a report that stated:

> *"If there is a likelihood hard spots or arc burns exist, and the coating is inferred to be of poor quality with cathodic protection levels uncontrolled and more negative than -1.2 volts, assess the stress in the pipe. If stress is less than 60% SMYS, cracks are not likely to form. Otherwise, when hard spots are located on the pipeline, measure their hardness levels. If the hardness levels are at or above Rockwell C35, experience indicates hydrogen stress cracking is possible[40]."*

The SMYS of X52 steel is 52,000 psi, and 60% of this value is 31,200 psi. Using this new yield stress in the modified hoop stress equation in EQ. (2), the resulting MAOP would be 780 psi, which is similar to the result obtained from EQ. (1).

$$P = \frac{\sigma \, x \, t}{r} \qquad \underline{\text{EQ. 2}}$$

Where P is the MAOP, σ is the SMYS, t is the pipe thickness, and r is the pipe radius.

As required by 49 CFR 192.619, when selecting the proper MAOP, a prudent operator should choose the lowest value amongst MAOPs determined via different methods. As such, the pipeline owners should have selected the MAOP value of 780 psi obtained from EQ. (1) or EQ. (2). This is especially true since the pipeline was a vintage pipe, which was known to include hard spots.

Around 16 years before the incident, the pipeline operators experienced a rupture approximately 78 miles north of the subject location. This rupture occurred at a pressure of 907 psi. This segment of the pipeline was also constructed from the same vintage pipe material that was used in the manufacturing of the subject pipeline. Failure of this segment of the pipeline was attributed to hydrogen-induced cracking at a hard spot. Given the fact that 46 years after its manufacturer the pipeline was experiencing bursts at operating pressures well below the original MAOP, the pipeline operators should have reduced their MAOP of the vintage pipe to 80% of the most recent burst pressure of 907 psi and operated at 726 psi instead of continuing operations at MAOP of 936 psi as if the pipeline was still in its original condition.

Given that the susceptibility of vintage pipelines to hydrogen-induced cracking increases with increased tensile stresses caused by excessive operating pressures — combined with the fact that pipeline owners continued to operate the pipeline at pressures (925 psi) well above the conservative MAOPs (726 psi) required by 49 CFR 192.619 — the pipeline owners failed to operate as a reasonably prudent operator. As such, they directly contributed to the incident at issue. Had the owners lowered the MAOP of its pipeline to a level consistent with recommended design guidelines (726 psi), within a reasonable degree of scientific and engineering probability, the incident would not have occurred.

Summary and Conclusions

Metallurgical analysis of the ruptured pipeline revealed that the failure of the pipeline originated at a location of elevated hardness known as a hard spot. The intergranular nature of the fracture indicated exposure to an embrittling environment. Further analysis of the operating conditions of the pipeline revealed that the embrittling environment was caused by stress-controlled decohesion hydrogen embrittlement that occurred due to excessive hydrogen production resulting from an over-aggressive cathodic protection program.

Ultimately, the vintage pipeline's rupture occurred not only due to the owner's continued use of the pipeline at excessive operating pressures that were above required levels from the onset, but also did not adequately consider the age of the pipeline. The owners knew — or should have known — that the excessive levels of cathodic protection, combined with higher-than-acceptable operating pressures, would eventually compromise the structural integrity of the pipeline due to the long-term effects of hydrogen embrittlement. Had the owners followed established preventive maintenance procedures and operated the pipeline according to regulations, this catastrophic incident would not have occurred.

This failure highlights the fact that the vintage pipelines in the United States are at risk of failure due to hydrogen embrittlement. Regular inspection, replacement of the pipelines, and/or reduction of operating pressure can be utilized to prevent similar catastrophic failures from occurring.

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