Issued: April 27, 2023 Pipeline Investigation Report: PIR-23/01

Kinder Morgan Natural Gas–Fueled Explosion

Coolidge, Arizona
August 15, 2021

1 Factual Information

Figure 1. Ruptured pipeline and fire. (Source: Coolidge Fire Department.)

1.1 Accident Description

On August 15, 2021, about 5:29 a.m. local time, a 30-inch-diameter natural gas transmission pipeline owned and operated by Kinder Morgan, Inc., (Kinder Morgan) ruptured in a rural area of Coolidge, Arizona.[1] The rupture resulted in the release of natural gas vapor that ignited and exploded, causing a blast wave and gas-fed fire.[2] (See figure 1.) The explosion and fire destroyed a farmhouse about 451 feet away, killing two of the three occupants and seriously injuring the other. About 33 acres of vegetation were damaged in some areas about 878 feet away from the rupture crater. A 47-foot segment of pipe was ejected about 133 feet from the center of the crater. (See figure 2.) Kinder Morgan estimated property damage and emergency response costs to be $5,541,740.

[1] (a) Visit www.ntsb.gov to find additional information in the public docket for this NTSB accident investigation (case number PLD21FR003). Use the CAROL Query to search safety recommendations and investigations (b) All times in this report are local time unless otherwise noted.

[2] A *blast wave* is created when an explosion occurs and instantaneously over-pressurizes the ambient atmospheric pressure.

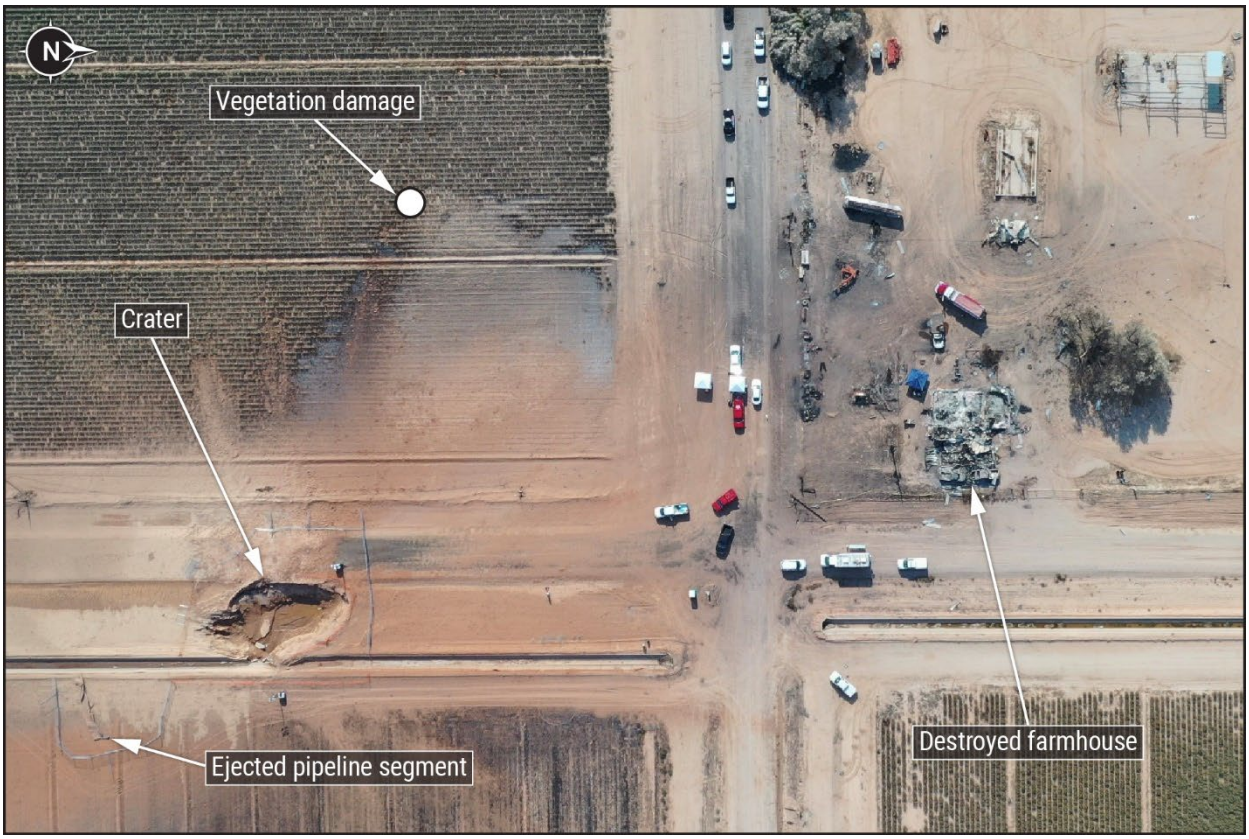

Figure 2. Aerial image of the accident site following the explosion and fire. (Source: Pinal County Fire Investigation Task Force.)

The rupture occurred at milepost 497.07 on Line 2000.[3] The location was designated a Class 1 location under Title 49 *Code of Federal Regulations* (*CFR*) 192.5 and was not designated a high consequence area (HCA) or moderate consequence area under 49 *CFR* 192.905 and 49 *CFR* 192.3, respectively.[4]

Pipeline operations on Line 2000 were controlled and monitored by Kinder Morgan's control center in Colorado Springs, Colorado. At 5:36 a.m., about 7 minutes after the rupture, Kinder Morgan personnel at the control center received 5

[3] A *milepost* is a unit of measure used to define the location on a pipeline relative to a chosen starting point in miles and fractions of miles.

[4] (a) *Class locations* are defined by the population density within an onshore area that extends 220 feet on either side of the centerline of any continuous 1-mile length of pipeline. Class 1 locations represent the lowest population density and Class 4 locations represent the highest population density. (b) Pipeline safety regulations for gas transmission pipelines define areas that have higher potential consequences to health and safety as *high consequence areas* or *moderate consequence areas*.

informational pressure rate-of-change alarms in 4 minutes, alerting them to a rapid drop in pressure in the segment of the pipeline near the rupture site.

Working with Kinder Morgan personnel near the rupture site, control center personnel initiated emergency response activities in accordance with company operations and maintenance procedures at 6:02 a.m.[5] To isolate the affected pipeline segment, Kinder Morgan personnel needed to manually close three mainline valves (MLVs), MLV 37, MLV 38, and MLV 39. MLV 39, to the west of the rupture, was closed first, about 6:29 a.m. MLV 37, to the east of the rupture, was closed next, about 6:55 a.m. MLV 38, the valve closest to the rupture to the east, was closed about 8:16 a.m. About 8:20 a.m., 4 minutes after MLV 38 was closed and 2 hours and 51 minutes after the rupture, the gas-fed fire stopped.

1.2 Line 2000

Line 2000 was installed in 1986 by the All American Pipeline Company for crude oil service. The ownership of Line 2000 changed in 2000 to El Paso Natural Gas Company, LLC (El Paso). In 2002 and 2003, under the ownership of El Paso, Line 2000 was converted from a crude oil pipeline to a natural gas transmission pipeline and its flow reversed from a west to east direction to an east to west direction. El Paso made several modifications to Line 2000 as part of the conversion, including the removal of a pump station that was located about 6 miles downstream of the rupture site, relative to the original crude oil flow direction of west to east.[6]

On September 6, 2002, as part of the conversion to natural gas operations and flow reversal, El Paso hydrostatically tested the segment of Line 2000 that ruptured in this accident to a pressure of 1,212 pounds per square inch, gauge (psig).[7] This test detected no leaks.

In 2012 Kinder Morgan became the parent company of El Paso, which continued to operate the pipeline. Line 2000 is located within Kinder Morgan's Western Operations Region, specifically the Phoenix Area, which covers about 1,540 miles of natural gas

[5] Kinder Morgan, *O&M Procedure 1900: Area/Facility Emergency Response Plan*. April 1, 2020.

[6] According to a 2014 Pipeline and Hazardous Materials Safety Administration (PHMSA) advisory bulletin, pipeline flow reversals and conversions from crude oil to natural gas service—including removal or modification of pump stations—can have system impacts related to a shift in locations along the pipeline at risk for stress corrosion cracking (SCC), cyclic fatigue, or both. See PHMSA, *Pipeline Safety*: *Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service*, September 2014.

[7] In *hydrostatic testing*, water is pumped into a pipeline and held at pressure to determine whether the pipeline can withstand the pressure without leaking. The hydrostatic testing conducted at this time noted a leak at a nearby location, milepost 496.9. See section 1.3.2.

pipeline in Arizona and California. At the time of the rupture, the operating pressure of Line 2000 was about 863 psig, which was less than the maximum allowable operating pressure of 944 psig.[8] The pipeline was coated with two layers of spiral wrap tape as the primary means of corrosion protection and supplemented with an impressed current cathodic protection system.[9] Other specifications for Line 2000 are shown in table 1.

Table 1. Line 2000 specifications

Pipeline Specification	Value
Diameter	30-inch
Material	Steel
Grade[1]	X-70
Longitudinal Seam Weld	Double Submerged Arc-Welded
Wall Thickness	0.281 inches
Coating	Kendall Polyken Wrap Tape (two layers)
Manufacturer	Bergrohr Herne or Vallourec
Corrosion Protection	Impressed Current Cathodic Protection

[1] American Petroleum Institute 5LX defines specific grades of carbon steel pipeline, each with a minimum yield strength. The higher the grade of the pipeline, the higher the strength of the steel used to manufacture that pipeline.

1.3 Integrity Management

The Pipeline and Hazardous Materials Safety Administration's (PHMSA's) regulations on gas transmission integrity management (IM) fall under 49 *CFR* Part 192 Subpart O, Gas Transmission Pipeline Integrity Management.[10] IM has three goals: (1) to determine pipeline segments where the potential consequences are the highest; (2) to evaluate the soundness, stability, and reliability of pipelines; and (3) to address risk in a scientific, consistent, and prioritized manner.

[8] Title 49 *CFR* 192.619, Maximum allowable operating pressure: Steel or plastic pipelines, specifies how the maximum allowable operating pressure is determined.

[9] *Cathodic protection* is a corrosion mitigation method used by the pipeline industry to protect underground steel structures. To prevent corrosion of any exposed steel, cathodic protection supplies a protective electrical current through a ground bed that typically contains a string of suitable anodes, with soil as an electrolyte. A wire connected to the pipeline provides the return path for the current to complete the circuit.

[10] On December 15, 2003, the Research and Special Programs Administration issued its final rule on natural gas transmission integrity management, setting the minimum regulatory requirements for pipelines in HCAs.

Kinder Morgan was not required to implement the IM regulations at the rupture location because the rupture site was designated a Class 1 location and was not designated as an HCA. However, before the accident, Kinder Morgan had voluntarily included the ruptured pipeline segment in their IM program as part of a nonregulatory internal program.

1.3.1 Pipeline Open Database Standard

Starting in 2014, when Kinder Morgan field personnel exposed any segment of Line 2000, including excavations for defects, they completed a Pipeline Examination Report (PER). The data from PERs were then integrated into a Pipeline Open Database Standard (PODS). PODS was Kinder Morgan's internal data management tool to identify and document pipeline specifications such as coating type.[11] Data factors recorded in PODS were used as inputs during the risk assessments discussed in section 1.3.2.

Between 2014 and the day of the rupture, six PERs were completed on Line 2000 within about two miles of the rupture origin; the latest PER was completed in February 2018. In each of these PERs, which Kinder Morgan personnel then entered into PODS, the coating type for the ruptured pipeline segment was listed as fusion-bonded epoxy.

One pipeline data report, submitted in 2011 after a composite sleeve was installed on Line 2000 approximately 375 feet from the rupture location, noted that the coating type listed as fusion-bonded epoxy was incorrect at that location and that the actual coating type was spiral wrap tape.[12] This was not recorded in PODS.

1.3.2 Risk Assessment

At the time of the rupture, Kinder Morgan used a risk assessment to evaluate their pipeline segments for the threats to pipeline integrity identified by the American Society of Mechanical Engineers (ASME) standard B31.8S.[13] The risk assessment algorithm determined the probability of failure from stress corrosion cracking (SCC) by examining

[11] Kinder Morgan relied upon PODS to record various pipeline-specific data by location, meeting the requirements of 49 *CFR* 192.947.

[12] This pipeline data report was a Streamline report, which was the type of report used to denote pipeline exposures before 2014, when PERs were introduced.

[13] ASME standard B31.8S-2004, *Managing System Integrity of Gas Pipelines*, is incorporated by reference into PHMSA regulation. B.31.8S identifies nine types of threat criteria; SCC is one type of time-dependent threat.

near neutral and high pH SCC, the two types of SCC defined in ASME B31.8S.[14] Kinder Morgan further calculated the baseline susceptibility of pipeline segments to the threat of SCC as the direct product of several correlating factors recorded in PODS: pipe age; year of installation; pipe manufacturer and mill location; pipe diameter and wall thickness; downstream distance from a compressor station; location of pipe (above or below ground); soil conditions (susceptibility, pH, and resistivity); and coating type. Before the rupture, the coating type of the ruptured pipeline segment was listed in PODS as fusion-bonded epoxy.[15] The coating type was spiral wrap tape.

The Kinder Morgan risk assessment algorithm at the time of the rupture determined that near neutral SCC was an active threat to pipeline safety and integrity on Line 2000 at milepost 496.9, based on a 2002 hydrostatic test failure. Kinder Morgan records listed that the coating at that location was a multilayer tape system with urethane foam insulation. Kinder Morgan did not identify threats of SCC on the ruptured pipeline segment at milepost 497.07 where the coating type was incorrectly listed as fusion-bonded epoxy.

1.3.3 Potential Impact Radius

Under 49 *CFR* 192.903, PHMSA requires operators to mathematically calculate a pipeline's potential impact radius (PIR), or the area where the failure of a pipeline could have a significant impact on people or property when deciding whether a pipeline is in an HCA. Using the requirements provided by the regulations, the NTSB calculated the potential impact radius for the rupture site to be 636 feet. Physical evidence identified during the NTSB's onsite examination showed that damage to the surrounding vegetation was found up to 878 feet from the rupture crater.

1.4 Postaccident Examinations

NTSB investigators conducted onsite metallurgical examinations of the ruptured pipeline on August 17–22, 2021. Examination of the pipeline just south of the fracture

[14] (a) *Stress corrosion cracking* is a form of environmentally assisted cracking produced under the combined action of corrosion and tensile stress. SCC typically manifests as clusters of small cracks in the external body of the pipe. (b) The pH of the local environment of the pipeline surface is between 5 and 7 in *near neutral SCC* and between 9 and 13 in *high pH SCC*.

[15] *Fusion-bonded epoxy* coating, also known as fusion-bond epoxy powder coating, is an epoxy-based powder coating that is widely used to protect steel pipe used in pipeline construction from corrosion.

noted that the undamaged pipe was covered in an adhesive coating followed by two layers of plastic spiral wrap tape.[16]

The ejected pipe segment was cut into several pieces, which were sent to the NTSB Materials Laboratory in Washington, D.C., for testing. The laboratory examination of these pieces found the pipeline fracture was caused by SCC that originated on the outside surface of the pipe, predominantly along the edge, or toe, of the longitudinal seam weld. (See figure 3.)

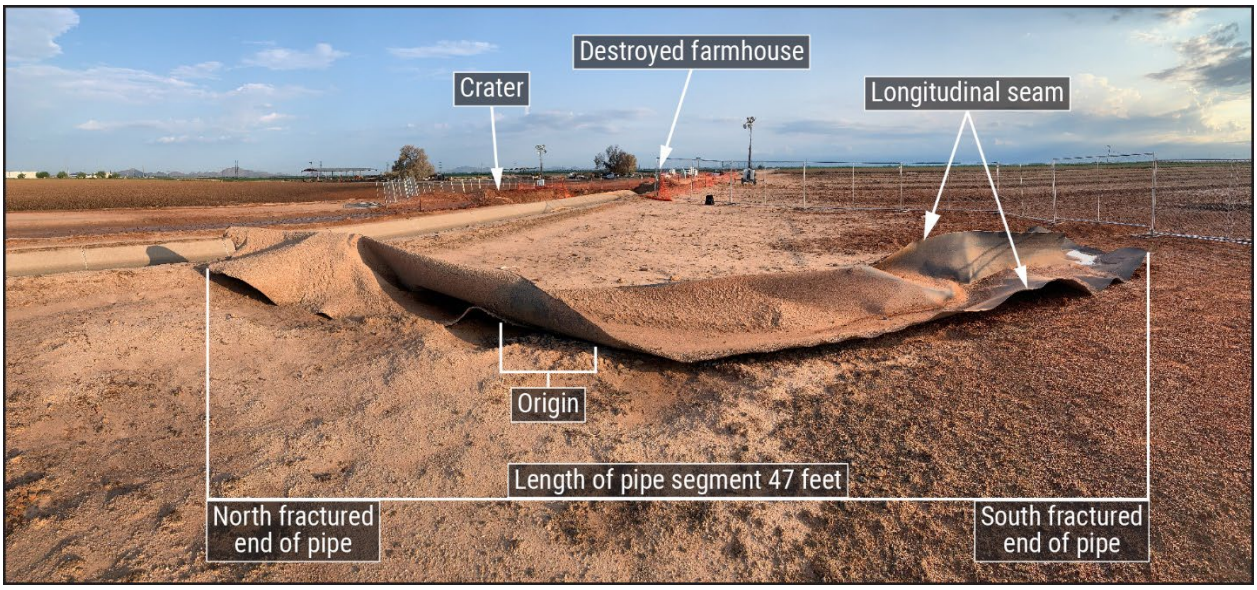

Figure 3. Ejected pipe segment just after the rupture.

The NTSB's examination of the ejected pipe segment observed colonies of longitudinal surface breaking cracks that had propagated through the wall as intergranular cracking consistent with high pH SCC.[17] The maximum depth of the SCC present in the ejected pipe segment was about 0.14 inches—approximately 50 percent of the nominal wall thickness. (See figure 4.) The origin of the fracture contained three SCC regions with a combined length of about 3.1 feet, whose ends were connected by a

[16] NTSB investigators observed that most of the coating of the ejected pipe segment had been consumed by fire, leaving most of the external surface bare.

[17] *Intergranular cracking* is the propagation of cracks along the grain boundaries of a polycrystalline metal or alloy.

transverse overstress crack.[18] The longitudinal cracks had coalesced and formed a crack at the rupture site large enough to split open the pipeline.

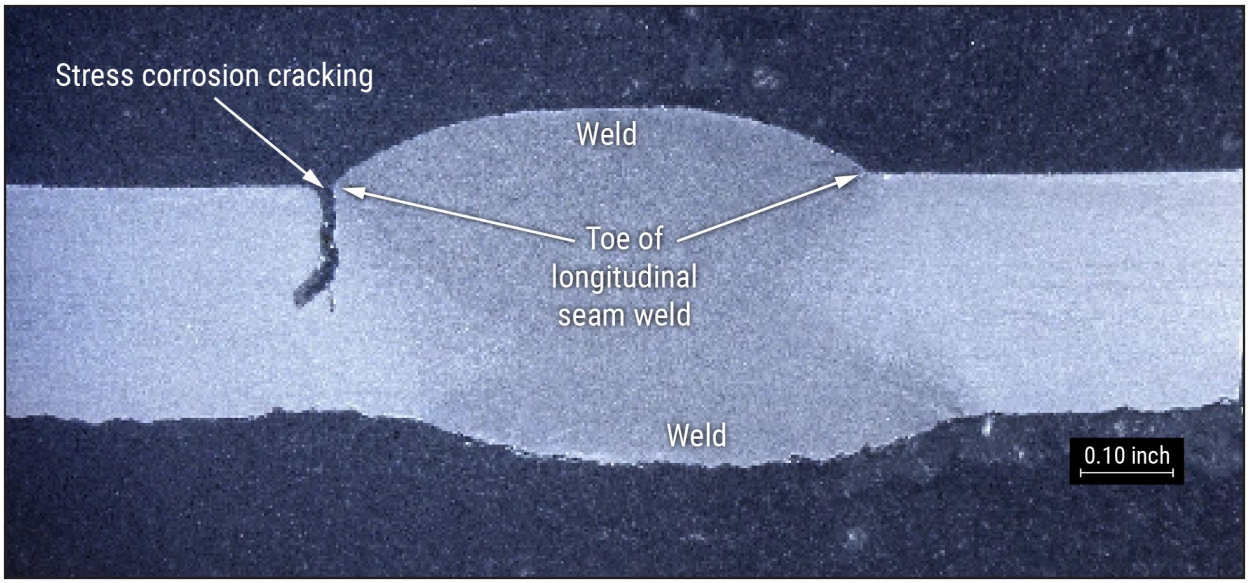

Figure 4. Cross section of ejected pipe segment.

Evidence of pitting corrosion was observed on the outer surface of the pipe at the toe of the longitudinal seam weld, consistent with disbonded coating from tented tape wrap that had shielded the toe of the weld from cathodic protection.[19]

1.5 Postaccident Actions

[18] (a) Details of the fracture examination can be found in the *NTSB Materials Laboratory Factual Report No. 21-003, March 7, 2022*, in the docket for this accident. (b) A *transverse* crack is a circumferentially oriented crack extending around the pipe, usually perpendicular to its length. (c) An *overstress* crack occurs when the strength of a material is exceeded; this crack can extend through the thickness of the material.

[19] (a) *Disbonded coating* is when pipeline coating separates from the metal of the pipe, causing a gap between coating and pipe surface. (b) *Tented tape wrap*, or tenting, is a form of disbonded coating that can occur at longitudinal seams. Tenting causes a gap between the coating and where the weld meets the pipe surface. (c) Tape coating can *shield* the cathodic protection current from reaching the exposed pipe wall, allowing corrosion to form on the external pipe surface.

1.5.1 Pipeline and Hazardous Materials Safety Administration

On August 19, 2021, PHMSA issued a corrective action order to Kinder Morgan regarding the August 15 rupture.[20] The corrective action order required El Paso to isolate, or shut down, the 38.6-mile segment of Line 2000 from MLV 37 to MLV 39; to reduce the operating pressure of Line 2000; to conduct a leakage survey and to review prior in-line inspections on Line 2000; to verify the records that established the maximum allowable operating pressure for Line 2000; and to develop a plan, approved by PHMSA, to resume operation of the isolated pipeline segment.[21]

1.5.2 Kinder Morgan

Kinder Morgan corrected the Line 2000 coating data that were placed in PODS. Kinder Morgan created a new procedure for all its natural gas transmission and gathering pipelines that, in cases when a PER field observation shows coating type inconsistent with PODS data, requires the PODS data team to compare the original source documentation with the PER and to make the necessary corrections in PODS. After completing a review of PODS and PER data for Line 2000, Kinder Morgan conducted a new risk assessment for Line 2000.

On December 19, 2021, Kinder Morgan conducted electromagnetic acoustic transducer testing on the segment of Line 2000 that ruptured. This testing resulted in excavations to four areas; upon examination of these areas, Kinder Morgan found one area of SCC. By June 25, 2022, Kinder Morgan had completed about 19 miles of spike hydrostatic testing on Line 2000, including at the rupture site, to validate the results from the electromagnetic acoustic transducer testing. Three hydrostatic test failures were observed, none of which were within 500 feet of the rupture site. The pipe sections that experienced hydrostatic test failures were cut out and sent to a metallurgical laboratory to determine the failure mechanism; results did not indicate the presence of SCC. These pipe sections were replaced and retested successfully.

2 Analysis

[20] (a) The corrective action order (CPF No. 2-2021-012-CAO) was issued to Kinder Morgan as the parent company of El Paso. (b) PHMSA enforcement actions include corrective action orders that are issued when a pipeline facility is or would be hazardous to life, property, or the environment, and specifies corrective measures that must be taken under the authority of 49 U.S.C. 60112.

[21] *In-line inspection* is an inspection method in which a highly specialized tool is passed within a pipeline to inspect the pipeline from the inside. In-line inspection uses nondestructive examination techniques to identify, locate, and size various damages and defects, depending on the type of tool.

In this accident, a Kinder Morgan natural gas pipeline ruptured in rural Coolidge, Arizona, destroying a nearby farmhouse and killing two of its three occupants. A segment of the pipe was ejected in the rupture.

NTSB investigators conducted metallurgical testing of the ejected pipe segment and found longitudinal surface breaking cracks, evidence of high pH SCC, in three regions at the toe of the ejected pipe segment's longitudinal seam weld. Pitting corrosion observed on the surface of the tested pipe pieces indicated that moisture had settled on the pipe surface, likely due to tenting of the spiral wrap tape coating at the gap between the coating and where the weld meets the pipe surface. The tape coating had most likely shielded the toe of the weld from cathodic protection, allowing the toe of the weld to corrode from SCC. Over time, the three SCC regions had spread, eventually connecting into one larger fracture, which split open the pipeline on August 15, 2021.

Kinder Morgan had voluntarily included the segment of Line 2000 that ruptured in its integrity management program and subsequently conducted risk assessments on the accident segment. However, the data on coating type on the accident pipeline segment, recorded in PODs and used in Kinder Morgan's risk assessment algorithm, was incorrectly listed as fusion-bonded epoxy rather than as spiral wrap tape. The coating type data for the accident pipeline segment remained incorrect despite at least one instance of information gathering that documented the error.

Different pipeline coating types offer different levels of protection from SCC. Spiral wrap tape coating is known by the pipeline industry to be more vulnerable than other coating types to SCC. Had the coating data in PODS been correctly listed as spiral wrap tape coating, as it was at milepost 496.9, the threat of SCC could likely have been identified. However, Kinder Morgan's IM program did not identify the threat of SCC at the rupture location and thus did not address it.

As a result of this accident, Kinder Morgan corrected their records in PODS. They also tested the section of Line 2000 that ruptured and replaced several areas of pipe. PHMSA issued a corrective action order to Kinder Morgan to shut down the affected pipeline segment, reduce the operating pressure of the pipeline, and develop a plan for reopening the segment.

Federal regulations require operators to mathematically calculate a pipeline's PIR, the area where a pipeline's potential failure could have a significant impact on people or property. The NTSB calculated the PIR for the rupture site to be 636 feet; however, physical evidence identified during the NTSB's onsite examination showed that damage to the surrounding vegetation was found up to 878 feet from the rupture crater. Such discrepancies between the calculated PIR and evidence collected at accident scenes has been seen before and prompted the NTSB to further evaluate the assumptions on which the PIR equation is based during the investigation of a pipeline rupture in

Danville, Kentucky. On August 15, 2022, NTSB Recommendation P-22-1 was issued to PHMSA: "Revise the calculation methodology used in your regulations to determine the potential impact radius of a pipeline rupture based on the accident data and human response data discussed in this report."[22] The recommendation is classified "Open—Acceptable Response."

3 Probable Cause

The National Transportation Safety Board determines that the probable cause of the August 15, 2021, pipeline rupture in Coolidge, Arizona, was tented tape wrap leading to stress corrosion cracking, a fracture at a longitudinal seam weld, and subsequent rupture of the pipe. Contributing to the rupture was Kinder Morgan's failure to record the correct coating type used for this segment of pipeline, leading to a risk assessment that did not fully identify the risk of stress corrosion cracking.

[22] See Pipeline Investigation Report NTSB/PIR-22/02, *Enbridge Inc. Natural Gas Transmission Pipeline Rupture and Fire, Danville, Kentucky, August 1, 2019*.