Enbridge Inc./Texas Eastern Transmission, LP

Party Submission to the

National Transportation Safety Board

For the Investigation of

NTSB Accident Number PLD19FR002
Danville, KY
August 1, 2019

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I. FACTUAL INFORMATION

a. Summary of Accident

On August 1, 2019, at approximately 1:23 a.m. Eastern Daylight Time, a 30-inch-diameter natural gas transmission pipeline owned and operated by Texas Eastern Transmission, LP (Enbridge)[1] ruptured and released natural gas, which ignited causing an explosion and fire.[2] The rupture occurred on the Enbridge Line 15 pipeline at Milepost 423.40 in Lincoln County, KY.[3] The accident site is located approximately eight miles south of Danville, KY, near the Indian Camp Mobile Home Park.[4] The segment of pipeline involved in this accident was not a "High Consequence Area" as defined in applicable PHMSA regulations.[5]

b. Isolation of the Rupture Site

The Line 15 rupture occurred at approximately 1:23 a.m. EDT.[6] Gas Control received a SCADA rate-of-change alarm at 1:24 a.m.[7] This is considered an "informational" alarm, which is the lowest of four levels of alarms based on urgency and importance.[8] At 1:25 a.m., the Line 15 alarm reset and, for the first time, rate-of-change alarms were received for Lines 10 and 25, which parallel line 15 at the accident site.[9]

At 1:26 a.m., Gas Control attempted to call the station operator at the Danville Compressor Station, but no one answered.[10] At the same time, an off-duty Station Operator who saw fire at the rupture site called his Area Supervisor, who sent him to Danville Compressor Station ("Danville CS") to assist the on-duty Station Operator.[11]

At 1:27 a.m., Gas Control answered a call from a member of the public notifying Gas Control of a loud sound and fire near her home.[12] A second Gas Controller overheard the phone call and notified the on-duty Gas Control Manager of the pressure drop and phone call.[13] The Manager instructed the Controller to isolate the segment "by any means necessary."[14]

[1] Texas Eastern Transmission, LP is a wholly owned subsidiary of Spectra Energy Partners, LP (Spectra), which is in turn a wholly owned subsidiary of Enbridge Inc. *See* NTSB Pipeline Operations and Integrity Management Factual Report ("Ops/IM Report"), pp. 8-9. To avoid confusion, we will hereafter refer to the owner and operator as "Enbridge", even though the entity operating the pipeline is an Enbridge subsidiary, Texas Eastern Transmission, LP and other companies owned the pipeline at various points in time.
[2] Ops/IM Report, p. 6.
[3] Ops/IM Report, p. 6.
[4] Ops/IM Report, p. 6.
[5] Survival Factors Group Chairman's Factual Report of the Investigation ("SF Report"), p. 29.
[6] Ops/IM Report, p. 6.
[7] Ops/IM Report, p. 6.
[8] The four SCADA alarm priority levels are: (1) critical, (2) urgent, (3) warning, and (4) informational. *See* Ops/IM Report, pp. 40-41.
[9] Ops/IM Report, p. 43.
[10] Ops/IM Report, p. 43.
[11] Ops/IM Report, p. 43.
[12] Ops/IM Report, p. 43.
[13] Ops/IM Report, p. 43.
[14] Ops/IM Report, p. 43.

At 1:28 a.m., the Area Supervisor who was contacted by an employee about the rupture dispatched an employee to close valve 15-382, the first Line 15 valve upstream from the accident site.[15] These valves are manually-operated[16] and there is no regulatory requirement that they be remotely or automatically actuated.[17]

At 1:30 a.m., Gas Control remotely shut-off the compressors at Owingsville Compressor Station ("Owingsville CS"), the nearest upstream compressor station to the accident site.[18] Gas Controllers then continued to alter operations upstream and downstream of the damaged segment to pull gas away from the rupture site by increasing horsepower downstream and reduced flow to the rupture site by shutting down stations to the North and coordinating with customers to adjust gas receipts and deliveries.[19]

At 1:31 a.m., Gas Control initiated a command to close the remotely-operated Line 15 valve nearest to the rupture, valve 15-438. At 1:33 a.m., valve 15-438 was confirmed closed.[20]

At 1:34 a.m., Gas Control initiated a command to close an additional remotely-operated Line 15 valve, valve 15-446, which was confirmed closed at 1:35 a.m.[21] Closure was initiated for other remotely-operated valves, 25-551 and 25-1449, which were confirmed closed at 1:35 a.m. and 1:38 a.m., respectively.[22]

At 1:35 a.m., the Area Supervisor contacted the Danville CS Station Operator and instructed him to close valve 15-393 at the Danville CS, the first valve downstream from the accident site.[23] The on-duty Station Operator manually closed valve 15-393 between 1:35 a.m. and 1:39 a.m. (accounts vary slightly).[24]

At 1:50-51 a.m., all compressor units at the Danville CS were shut down.[25]

At 2:13 a.m., the first Enbridge pipeliner arrived at the site of valve 15-382 after driving for approximately 45 minutes to reach the site, including a stop at Danville CS to pick-up a company work vehicle.[26] He immediately began closing valve 15-382 and had it fully closed by 2:19 a.m.[27] The total elapsed time from the first indication of a possible rupture to full isolation of the rupture site was 55 minutes.[28] Industry guidance establishes a response time goal of one hour from incident recognition to the start of valve closure procedures.[29]

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[15] SF Report, Attachment 17.
[16] Ops/IM Report, pp. 43-44.
[17] *See* 49 CFR 192.935.
[18] Ops/IM Report, p. 43.
[19] Ops/IM Report, pp. 43-44.
[20] SF Report, Attachment 17.
[21] SF Report, Attachment 17.
[22] SF Report, Attachment 17.
[23] Ops/IM Report, p. 45.
[24] Ops/IM Report, p. 45.
[25] Ops/IM Report, p. 46.
[26] Ops/IM Report, p. 47.
[27] Ops/IM Report, p. 47.
[28] Ops/IM Report, p. 47.
[29] *See* Interstate Natural Gas Association of America (INGAA) Action Plan, August 12, 2011, Enbridge DR 116.

At 2:22 a.m., additional block valve 10-292 was closed. At 2:23 a.m. valve 25-512 was closed.[30]

At 2:56 a.m., the natural gas fire was reported as under control by emergency responders.[31]

By 3:20 a.m., fire suppression of the surrounding area ended.[32]

c. Enbridge Personnel

All six gas controllers and the station operator on duty at the time of the accident were drug and alcohol tested after the accident, per 49 CFR 199.105 and 199.223, and all tests were negative.[33] The Gas Controller and Operators on duty each had valid, non-expired Operational Qualification Certificates for their respective Covered Tasks in compliance with 49 CFR 192.801, et seq.[34]

d. Local Emergency Responders

While Gas Control and local Enbridge personnel were responding the accident, local emergency responders were on scene to limit access to the site, perform emergency medical services, and protect and assist people nearby.[35]

e. Public Awareness Program

Enbridge maintained a Public Awareness Program ("PAP") as required by 49 CFR 192.616.[36] Enbridge's PAP included a public education program to inform emergency responders and property owners along the pipeline of appropriate safety information, as set forth in American Petroleum Institute's (API) Recommended Practice (RP) 1162.[37]

Enbridge performs PAP public outreach activities consisting of an annual distribution of PAP materials that is mailed to property owners adjacent to the pipeline Right of Way ("ROW").[38] Additionally, a "hand-out" of PAP printed materials, similar to that which is mailed, is also distributed to property owners adjacent to the pipeline ROW through a "door-to-door canvas" hand-delivery activity.[39]

Operations officials of the emergency services agencies that responded to the incident recalled that their agencies had received, either by hand-delivery or by mail, the annual 2019

[30] Ops/IM Report, p. 46.
[31] Ops/IM Report, p. 7.
[32] Ops/IM Report, p. 7.
[33] Ops/IM Report, p. 46.
[34] Ops/IM Report, Attachments 44, 45, 56 and 60.
[35] SF Report, pp. 58-62.
[36] Pipeline Operations/Integrity Management and Survival Factors Group Chairman's Supplemental Factual Report of the Investigation ("Supp. Factual Report"), p. 22.
[37] RP 1162 is incorporated by reference into 49 CFR 192.616; *see* SF Report, pp. 47-48.
[38] SF Report, p. 48.
[39] SF Report, p. 48.

printed safety brochures.[40] Enbridge documented that for the four-years prior to the accident, the printed safety brochures were distributed to the local emergency officials.[41] The materials include the following, along with other information:[42]

- Presence of pipelines and general attributes
- Pipeline purpose and reliability
- Hazard awareness and prevention measures
- Leak recognition and response
- Emergency preparedness communications
- Damage prevention and safe working practices
- Damage reporting process
- Pipeline location information
- Right-of-Way encroachment prevention
- Security
- 811/One Call services and locate request requirements
- Pipeline location information and availability of the National Pipeline Mapping System
- Description of pipeline markers and signage
- Emergency and non-emergency contact information
- How to get additional information

The materials also include a statement that information relating to specific line size and/or pressure, which varies across the Enbridge pipeline, will be provided upon request.[43] Neither the regulations regarding Public Awareness Plans at 49 CFR Part 192 nor API 1162 require that Public Awareness or Pipeline Awareness materials contain specific details such as the pipeline diameter, maximum operating pressure, or number of pipelines in a right of way. Including such information would require that separate brochures be created for each segment of pipeline that has a different diameter, maximum operating pressure or multiple pipelines in the ROW. Enbridge's PAP brochure also directs recipients to the National Pipeline Mapping System, which contains current information about all of the pipelines in a given area, not just those belonging to a single operator.[44]

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[40] SF Report, p. 50.
[41] SF Report, p. 51.
[42] Supp. Factual Report, pp. 23-24.
[43] Supp. Factual Report, p. 24.
[44] Supp. Factual Report, p. 23.

Enbridge also conducts annual "Liaison Training" for emergency services personnel and their organizations.[45] Documentation provided to the investigation confirmed that for the five-year period prior to the accident, Liaison Training was conducted and offered to the emergency services jurisdictions proximate to the accident site, compliant with API 1162 and 49 CFR 192.616.[46]

f. Pipeline Attributes, Original Testing, and Class Location/non-HCA Designation

The pipeline at issue was manufactured to American Petroleum Institute (API) Standard 5LX,[47] 6th edition, dated February 1956, grade X52, as 30-inch nominal outside diameter (OD), 0.375-inch nominal wall thickness, electric flash weld (EFW) longitudinal seam, ordered as cold-expanded welded steel plain end line pipe, and manufactured by A.O. Smith in 1957.[48] The OD surface was coated with coal tar enamel.[49] The pipe was installed in Line 15, Valve Section 04, in 1958.[50] The pipe was hydrostatically tested to 1377 PSIG, which is more than 1.25 times MAOP and is appropriate for Class 2 Locations (49 CFR 192.505 and 192.619).[51] The site was appropriately designated as a non-HCA (High Consequence Area)[52] and a Class 2 Location.[53]

g. Direction of Flow Modification

Line 15 flowed from south to north when constructed in 1957 and continued to flow in that direction until 2014 when work began to modify Lines 10, 15 and 25 to allow for reversed flow to the south from Pennsylvania to Louisiana.[54] This flow reversal accommodated increased production in the northeastern United States from Marcellus and Utica shale plays and changed the pipelines from unidirectional flow to bi-directional flow.[55]

A number of issues were evaluated before reversing the flow direction, including ensuring that overpressure protection devices were appropriately set and managing discharge temperatures to protect pipeline coating.[56] Enbridge developed and executed a comprehensive Management of Change process as required by its Integrity Management System.[57] The MOC process was utilized to identify and mitigate or remediate risks before the gas flow direction change was accomplished.[58]

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[45] SF Report, p. 51.
[46] SF Report, p. 52.
[47] API 5LX defines specific grades of carbon steel pipeline, each with a minimum yield strength. The higher the grade of the pipe, the higher the strength of the steel used to manufacture that pipe.
[48] Materials Laboratory Factual Report ("Materials Report"), p. 1; Ops IM Report, p. 13.
[49] Materials Report, p. 1.
[50] Materials Report, p. 12.
[51] Materials Report, p. 12.
[52] *See* 49 CFR 192.903.
[53] *See* 49 CFR 192.5 and 192.903.
[54] Ops/IM Report, p. 14.
[55] Ops/IM Report, p. 14.
[56] Ops/IM Report, Attachment 14, p. 2.
[57] Ops/IM Report, Attachments 14, 17.
[58] Ops/IM Report, Attachment 14.

Maximum Allowable Operating Pressure ("MAOP") was also considered for the reverse flow direction.[59] To determine appropriate MAOP when flow was in the traditional direction (south to north), Enbridge used 49 CFR 192.619(c), which set MAOP as the "highest actual operating pressure to which the segment was subjected during the 5 years preceding [July 1, 1970]." This section of Line 15 was pressure tested to a minimum pressure of 1377 PSIG, well over 1.25x its MAOP of 1000 PSIG.[60]

Because there was no pre-1970 flow history in the southbound direction, Enbridge set the southbound MAOP at 936 PSIG in compliance with 49 CFR 192.619(a), which requires a pressure that is lower than the test pressure (1,377 PSIG) divided by 1.4, which in this case was 984 PSIG.[61] At the time of the accident, the line was operating at 925 PSIG.[62]

In addition to reevaluating and lowering MAOP with reverse flow, Enbridge updated its Standard Operating Procedures to reflect discharge temperatures from compressor stations appropriate for the southbound flow.[63] In some instances, such as the Danville Compressor Station, that meant that gas coolers were installed to make sure the discharge temperatures did not exceed limits in place to protect pipeline coating from heat-based deterioration.[64]

The temperature limits were set by Enbridge based on the coating classification for each pipeline segment.[65] The temperature recordings show that, in fact, discharge temperatures were not exceeded at the Danville CS following the change in flow direction.[66] While pipeline temperatures rose somewhat between 2014 and 2017, that rise was attributable to the fact that in the phase 1 reversal (2014-2017), gas was not compressed in the southern direction.[67] In the 2017 phase 2 reversal, compression was added in the southbound direction and temperatures naturally increased from those experienced during the no-compression phase, but discharge temperature limits were not exceeded in either phase 1 or phase 2 of the Danville CS flow reversal.[68]

h. Integrity Management at Enbridge

Enbridge uses a combination of Standard Operating Procedures, the Integrity Management Program procedures and a series of Enbridge Threat Response Guidance Documents (TRGDs) designed for each type of pipeline threat.[69] While PHMSA regulations, Part 192, Subpart O, required the development and use of an integrity management plan only in High Consequence Areas (HCAs), Enbridge performs voluntary risk assessments and integrity

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[59] Ops/IM Report, Attachment 14, p. 2.
[60] Ops/IM Report, p. 12.
[61] Ops/IM Report, Attachment 6.
[62] Ops/IM Report, p. 13.
[63] Ops/IM Report, Attachment 15.
[64] Ops/IM Report, p. 15.
[65] Ops/IM Report, pp. 16-17.
[66] Ops/IM Report, Attachment 19.
[67] Ops/IM Report, pp. 18-19.
[68] Ops/IM Report, p. 19; Ops/IM Report, Attachment 19.
[69] Ops/IM Report, Attachment 63, p. 2.

assessments in non-HCA areas, including in the area containing the rupture site.[70] For example, Standard Operating Procedure 9-2010 governs the use of in-line inspection tools in HCA segments *and non-HCA segments*, setting out 16 factors for consideration in determining frequency of inspection.[71]

External corrosion is the most significant threat to the system as a single threat, and is also the most significant *interacting* threat as it has potential to interact with 7 of the remaining 8 identified threat categories.[72]

Enbridge has also sought third party assessments of its integrity management programs several times, including in 2003, 2012 and 2018. For example, after Enbridge determined it needed more certainty in the integrity of its pipelines, Enbridge set explicit and lower risk tolerance thresholds, changed the assessment approach (to a more quantitative basis) and engaged Dynamic Risk Assessment Systems (DRAS) to conduct an Independent Pipeline Integrity Program Review in late 2018/early 2019, which focused on "the current state of six integrity-related programs – IMS, IMP, Geohazards, Cracking (stress corrosion and pipe seam weld), Dents and Corrosion (external, internal and selective seam weld)," and which identified pipe segments at higher risk (against the new risk thresholds) for which additional diagnostics and/or data was needed to more confidently evaluate the risk.[73] The risk of hard spot manufacturing defects was not among the most significant identified risks.

As a result of the 2018/2019 risk assessment and tolerance shift, Enbridge placed voluntary pressure restrictions in various portions of the system, increased staffing of the Asset Integrity team by 2.25x, increased the number of annual ILI tool runs by 4.30x, and increased the number of subsequent anomaly investigations by nearly 2x the 2018 level.[74]

Additionally, all of the gas transmission assets were merged into a single Integrity Management System, which required a consolidation and refresh of the supporting procedures and guidelines. The Asset Integrity Program was restructured to leverage and integrate this aggressive acquisition of integrity resources, as well as to provide a "check function" assessing the effectiveness of planning and risk assessments, and their implementation through acquisition of data from in-the-field digs and assessments. The "check function" was designed to provide risk thresholds and to identify places where those thresholds may not be met. The program also required that lessons learned be captured and shared, and that continual improvement be the focus of forward-looking activities.[75]

i. Enbridge pipeline inspection and hard spot detection

Over the 15 years preceding this accident, Enbridge inspected its pipelines using a number of inline inspection (ILI) tools to assess for internal and external corrosion, third party

[70] Ops/IM Report, p. 50.
[71] *See* Enbridge Data Response 13.
[72] Ops/IM Report, p. 60, Figure 25.
[73] Ops/IM Report, Exhibit 109.
[74] Ops/IM Report, Exhibit 107.
[75] Ops/IM Report, Exhibit 107.

damage, dents, deformation, pipe location, and hard spots.[76] For time-dependent threats such as internal and external corrosion, the tools were run on intervals of seven years or less in HCAs and on a frequency established pursuant to Enbridge SOPs in non-HCAs.[77]

For stable threats, such as hard spots, Enbridge uses "[subject matter experts] to identify and assess the threat."[78] "If the data review indicates a significant potential for hard spots", Enbridge "requires evaluation of the line using ILI…."[79] Enbridge IMP Threat Response Guidance Document 440, specifically addressing manufacturing defects, requires that in situations where the manufacturing defect "has been identified as a 'high' relative risk and the threat is not effectively mitigated" then the covered segment will be assessed utilizing ILI capable of assessing hard spots, pressure testing, or direct non-destructive examination."[80]

A hard spot is an isolated area with hardness greater than the base steel.[81] Hard spots, including the one at issue here, are manufacturing defects caused by localized quenching of the steel plate during the manufacturing of the plate for the pipe, and if present on a pipeline, are there from the date of original steel plate manufacture.[82]

Based on an early study by industry of line-pipe field failures in hardened regions, hardness values greater than 360 Brinell (about 39 RHC) were necessary for cracking to initiate, and in most cases, the hardness levels were measured in excess of 400 Brinell.[83] API has created a standard for hardness in manufacturing that requires line pipe with hardness above a Brinell Hardness score of 327 (Rockwell 35 HRC) to be rejected as defective.[84] Hardness levels below 327 Brinell (35 Rockwell C) "provide protection against hydrogen related cracking" per common industry guidelines.[85] Hydrogen-stress cracking was not seen in line pipe with normal properties as covered by API 5L (hardness values less than 327 Brinell).[86]

In addition to a hard spot, other conditions must exist before a hard spot can cause hydrogen embrittlement and cracking; the following factors must first align[87]:

1) A coating flaw is required because a steel surface must be exposed to an electrolyte for the hydrogen reaction to be possible.

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[76] *See*, for example Ops/IM Report, p. 72, Table 16.
[77] Ops/IM Report, Attachment 25, SOP 9-3010, Section 13, pp 48-49.
[78] Ops/IM Report, Attachment 63, Section 13.3.3.
[79] Ops/IM Report, Attachment 63, Section 15.1.2.2.
[80] Ops/IM Report, Attachment 23, Section 5.0.
[81] Ops/IM Report, p. 27.
[82] Ops/IM Report, p. 27; DR 154B; Groeneveld, T.P., *Hydrogen Stress Cracking,* sponsored by the Pipeline Research Committee of the Pipeline Research Council International Inc., (1979), page X-16 (*hard spots are a mill condition and are present in the steel before the pipe is made or installed)*
[83] DR 154B; Groeneveld, T.P., *Hydrogen Stress Cracking,* sponsored by the Pipeline Research Committee of the Pipeline Research Council International Inc., (1979), page X-11; See also Ops/IM Report, Exhibit 34, page 4 (*It also is interesting to note that the minimum hardness of the hard spots that led to failure was 350 Brinnell [sic], except where there were other extenuation circumstances; i.e., fire damage or SCC.*)
[84] *See* API 5L, "Specification for Line Pipe", 41st Ed., April 1, 1995; 46th edition dated April 2018.
[85] CC Technologies Report, Ops/IM Report, Attachment 34, p 18.
[86] DR 154B Groeneveld, T.P., *Hydrogen Stress Cracking*, sponsored by the Pipeline Research Committee of the Pipeline Research Council International Inc., (1979), page X-11.
[87] CC Technologies Report, Ops/IM Report, Attachment 34, p. 16.

2) A large amount of hydrogen reduction reaction must take place. This rate is measured by current density and not directly by pipe-to-soil potential.
3) A local hard spot.
4) A location with poor hydrogen recombination reaction catalytic properties. If all the hydrogen atoms recombine, none will enter the metal and embrittlement cannot occur.

Hydrogen cracking is "unpredictable" in nature, requiring elimination or mitigation of one of the three necessary elements to allow hydrogen cracking; tensile stress, susceptible pipeline material, and available atomic hydrogen.[88] Of these three choices, the only practicable option is to eliminate or mitigate susceptible pipeline materials, or in other words, to find and eliminate or repair hard spots.[89]

Data regarding hard spot ruptures between 1940 and 1985 show that the largest number of failures occurred on pipe that was manufactured during the 1950s.[90] Failed pipes having diameters between 20 and 30 inches made up 77 percent of the failures.[91] The most prevalent grade of failed pipe was X52 (50%) and of those, 41% were manufactured by A.O. Smith.[92]

In 2003, Line 15 ruptured in a different segment of A.O. Smith pipe 78.3 miles from the 2019 accident site.[93] The cause of the rupture was found to be a combination of two coexistent pipe manufacturing defects, a hard spot and a mid-wall lamination.[94] The root cause of the rupture was determined to be hydrogen-induced cracking that initiated in a hard spot that was coexistent with a mid-wall lamination, an extremely rare occurrence.

In response, the company developed a Hard Spot Assessment Plan that used ILI to assess threats from hard spots.[95] Specialized magnetic flux leakage (MFL) tools known as "hard spot MFL" (HSMFL) were used to detect hard spots. Essentially, these tools detect and measure differences in magnetic permeability in the pipeline. Because hard spots have a lower magnetic permeability than normal steel, they can be detected by HSMFL tools. The technology involves using both a low-level magnetic field and a high-level magnetic field and comparing the results to detect hard spots. The analysis of the data comparison between the two readings of a HSMFL tool is proprietary knowledge specific for each tool vendor.

Enbridge began implementing its Hard Spot Assessment Plan and chose to use a HSMFL tool technology developed by Tuboscope Pipeline Services (Tuboscope), which was later acquired by NDT Systems and Services (America) Inc. (NDT).

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[88] Ops/IM Report, Attachment 23, Section 2.1.4; Ops/IM Report, Attachment 21, p. 40.
[89] DR154 B, Groeneveld, T.P., *Hydrogen Stress Cracking*, sponsored by the Pipeline Research Committee of the Pipeline Research Council International Inc., (1979), page X-25.
[90] CC Technologies Report, Ops/IM Report, Attachment 34, p. 8.
[91] CC Technologies Report, Ops/IM Report, Attachment 34, p. 9.
[92] CC Technologies Report, Ops/IM Report, Attachment 34, p. 10.
[93] Ops/IM Report, p. 26.
[94] Ops/IM Report, p. 27.
[95] Ops/IM Report, Attachment 32.

Enbridge set reporting criteria at a more conservative Brinell rating than industry adopted, requesting to be informed of potential indications above 235 Brinell. Enbridge ran the Tuboscope/NDT HSMFL tool on nine (9) segments of pipe between 2005 and 2012. The NDT report on the 2004-2005 ILI runs stated that there were 5 anomalies between 235 and 250 Brinell, 15 anomalies between 251 and 300 Brinell and 2 anomalies greater than 301 Brinell.[96] All indications above 300 Brinell were excavated and tested in the ditch, along with numerous indications reported below 300 Brinell. Enbridge found generally good agreement between the as-called (ILI) and as-found (measured) hardness values, with the ILI tool often over-calling the hardness value, with the measured hardness value being lower than the predicted hardness value, particularly of outliers.[97]

For example, during the initial validation work following the 2004 and 2005 Tuboscope/NDT HSMFL tool runs, two joints of pipe were removed from service and sent to a lab for testing.[98] For these joints, all of the ILI calls were within +/– 50 Brinell of the lab measurements, except for two which were overcalled by 75 and 99 points, respectively.[99] Enbridge understood that the Tuboscope/NDT tool was the best tool available to estimate predictive hardness values of hard spots, and this was recognized by industry as well as Enbridge.[100]

The Company also engaged an outside consultant, C.C. Technologies, to assess the body of industry and technical information regarding hard spots and hard spot related ruptures, to provide an independent evaluation of the Company's hard spot evaluation and mitigation program.[101]

Enbridge also undertook a Close Interval Survey (CIS) to evaluate the cathodic protection system that protected the pipe from external corrosion risk. Through the CIS, Enbridge determined that overvoltage of the cathodic protection system was not present in the location of the 2003 incident and thus could not have played a role in that incident.[102]

Enbridge conducted HSMFL tool runs on four line segments (approximately 260 miles) containing approximately 165 miles of A.O. Smith pipe in 2004-2005.[103] The inspections were conducted on pipe categories with a known history of hard spots.[104] Of the 22 hard spots identified during the 2004/2005 ILI runs, 14 were excavated and tested for hardness based on their predicted hardness and cluster density.[105] The field hardness measurements determined good, conservative correlation of the hardness as called by the ILI analysis.[106]

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[96] Ops/IM Report, p. 29, Table 8.
[97] Ops/IM Report, p. 79, Figure 33.
[98] Ops/IM Report, pp. 30-31, Table 9.
[99] Ops/IM Report, pp. 30-31, Table 9.
[100] Ops/IM Report, Attachment 32, pp. 7-8.
[101] *See* CC Technologies Report, Ops/IM Report, Attachment 34.
[102] CC Technologies Report, Ops/IM Report, Attachment 32, Appendix F, page 3; Ops/IM Report, Attachment 30.
[103] DR124B, p. 5. Ops/IM Report, Attachment 26, Table 9; Ops/IM Report, p. 29.
[104] Ops/IM Report, p. 29.
[105] Ops/IM Report, p. 29.
[106] Ops/IM Report, p. 30.

The C.C. Technologies analysis concluded that the Tuboscope hard spot inspection tool accurately and reliably detected and estimated the hardness of hard spots.[107] They also concluded, based on their assessment, that the company's hard spot management program was consistent with best practice and none of the results indicated a significant hard spot "problem" on the company's pipeline systems.[108]

In 2011, Enbridge conducted another hard spot tool run using the Tuboscope/NDT HSMFL tool.[109] The performance standards for the tool state an accuracy of ±50 Brinell for hard spots and a stated probability of detection of 90 percent (although it was not clear whether the probability of detection applied to hard spots).[110] An NDT brochure from 2008 stated that NDT "typically reports hardness over 250 Brinell in bands of 50 Brinell," as did an NDT brochure attached as Appendix A within the company's 2012 internal review of their hard spot program.[111]

NDT's July 9, 2011 analysis determined there were 14 hard spots with a Brinell Hardness reading between 200 and 300 Brinell, and 2 hard spots between 301 and 400 Brinell on the pipeline segment between Tompkinsville CS and Danville CS on Line 15.[112] The closest hard spot feature reported by NDT in their 2011 report was located about 2.2 miles north of the accident site.[113] The technical analyst responsible for creating the anomaly listing had worked for NDT for 29 years and was certified by NDT as a Level III Axial MFL Analyst.[114] Enbridge relied on NDT's "contractual requirements, and confirmation using the vendor's quality checks" for primary validation "regarding data coverage and quality."[115] Enbridge did not possess the proprietary expertise to independently evaluate the data provided by NDT.

Following the 2019 accident, the NTSB and Enbridge requested that NDT Global reassess the underlying data from the 2011 HSMFL tool run and provide an updated report and evaluation.[116] In the post-accident reassessment, NDT Global identified for the first time two previously detected but unreported hard spots at/near the rupture location, and a total of nine detected indications in the 20' long pipe joint that ruptured.[117] All nine indications had been detected by the 2011 hard spot ILI tool, but none had been disclosed to Enbridge prior to the accident.[118] The origin of the fracture was discovered by the NTSB to coincide with the "general location of hard spot indications #2 and #3 shown on the Global NDT ILI screen shot dated August 8, 2019."[119]

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107 Ops/IM Report, p. 31.
108 CC Technologies Report, Ops/IM Report, Attachment 34, p. iii.
109 Ops/IM Report, p. 73.
110 Ops/IM Report, p. 73.
111 Ops/IM Report, p. 74.
112 Ops/IM Report, p. 74.
113 Ops/IM Report, p. 74.
114 Ops/IM Report, p. 74.
115 Ops/IM Report, p. 79.
116 Ops/IM Report, p. 81.
117 Ops/IM Report, p. 82, Figure 34.
118 Ops/IM Report, pp. 81-82.
119 Materials Report, p. 3 and Appendix 2, pp. 30-31.

The microhardness testing performed by the NTSB on the pipe post-rupture conclusively determined the actual Brinell Hardness value at the failure origin was between 362 and 381 Brinell, more than 100 Brinell higher than any post-accident value reported by NDT Global, significantly outside of the +/- 50 Brinell tolerance indicated in the NDT reports, and consistent with hardness levels seen in previous industry ruptures.[120]

j. Enbridge Cathodic Protection Program

Cathodic protection (CP) is used to control external corrosion on buried or submerged steel pipelines.[121] There are numerous ways to apply CP to a pipeline. Cathodic protection controls corrosion of a pipeline (the cathode) by connecting it to a more easily corroded sacrificial metal (the anode) and forcing electrical current from the anode to the cathode using a transformer rectifier.[122] Rectifiers convert alternating current to direct current, which flows in one direction from the anode to the cathode.[123] Line 15 received CP primarily through impressed current. [124]

A sufficient flow of electrical current from the anodes to the cathode (the pipeline) must occur for the cathodic protection to be effective.[125] The flow of electrical current "must be controlled so as not to damage the protective coating or the pipe".[126] CP is applied in a targeted range of -1.2V to -0.85V to maximize that protection.[127] On the higher end of the range (more positive) the standard is a regulatory requirement.[128] However, on the lower (more negative) end, this range is merely guidance. The NACE task group looking at the issue of a lower bound (more negative) for CP did not find that a need or benefit exists for setting such a bound.[129]

Pipeline cathodic protections levels are required to be tested once each calendar year, with intervals not exceeding 15 months.[130] Rectifiers or other impressed current power sources must be inspected six (6) times each calendar year, with intervals not exceeding 2 ½ months.[131] Enbridge met each of these regulatory testing requirements.[132]

The accident site (MP 423.4) sits nearest the test station at the Southern Railroad crossing (MP 423.4), approximately 70' to the southwest.[133] In four out of the five years preceding and including 2019, the IRF readings at the Southern Railroad were all below -1.2V, with a slight exception in 2017 with a reading of -1.234.[134] More importantly, the IRF reading at the

[120] Materials Report, p. 23, Table 3.
[121] Ops/IM Report, p. 19.
[122] Ops/IM Report, pp. 19-20.
[123] Ops/IM Report, p. 20.
[124] Ops/IM Report, p. 18.
[125] Ops/IM Report, p. 20.
[126] 49 CFR 192.463(c).
[127] 49 CFR Part 192, Appendix D, §I.A.(1); Supplemental Factual Report, p. 6.
[128] See 49 CFR § 192.463(a); 49 CFR Part 192, Appendix D, § I.A.(1).
[129] CC Technologies Report, Ops/IM Report, Attachment 34, Appendix F, p. 1.
[130] 49 CFR 192.465(a).
[131] 49 CFR 192.465(b).
[132] Ops/IM Report, p. 23.
[133] Ops/IM Report, p. 11 and p. 24, Table 6.
[134] Ops/IM Report, p. 24, Table 6.

Southern Railroad test station in 2019 was -1.047.[135] Timing of any CP survey including IRF readings is important because "hydrogen embrittlement is not a permanent condition. If environmental conditions change, "hydrogen can rediffuse from the steel."[136]

In addition to checking voltage at rectifiers and test stations, Enbridge conducted a Close Interval Survey (CIS) of areas including the accident site in 2012, a test method that takes readings every couple of feet along the pipeline. The CIS data provided the most accurate indication of the cathodic protection situation precisely at the accident site at the time it was taken.[137] The 2012 close interval survey show voltage at the accident site more positive than -1.2V (voltage between -1.2V and -0.85V).[138]

k. Safety Improvements

Since the time of the accident, Enbridge has undertaken and/or completed a number of safety improvements, as follows:[139]

- Worked with ILI vendors to develop, test, evaluate, and qualify in line inspection tools capable of detecting, identifying and characterizing hard spots;
- Refined hard spot response and repair criteria;
- Run new hard spot tools in numerous segments of Line 15 and limited segments of other lines, resulting in over 120 digs in the field;
- Validated the accuracy and conservatism of the new ILI hard spot tools, supporting the conclusion that the Affected Segment is fit for service with respect to the threat of hard spots in A.O. Smith pipe;
- Evaluated and employed controls to adjust cathodic protection targets, leveraging an understanding about the role that the environment, coatings, and cathodic protection play in hydrogen embrittlement;
- Undertook a transformation of its Asset Integrity Program for Gas Transmission and Midstream assets by shifting its approach away from peer companies and toward other industries with superior performance levels. Fundamental to this shift is that we be able to prove the integrity of our assets using a quantitative, as opposed to a qualitative, approach to risk assessments. This shift will entail a 3-5 year, iterative transformation of the organization, programs, behaviors, data and support systems as structured by our Integrated Management System. Enbridge has developed and implemented the framework and process documents necessary to implement its transformative approach to asset integrity;
- As part of the program transformation, Enbridge has significantly increased the number of ILI tool runs, and resulting number of anomaly digs, as well as staffing and budget to support the increased level of integrity work;

[135] Ops/IM Report, p. 24, Table 6.
[136] https://www.nace.org/resources/general-resources/corrosion-basics/group-3/hydrogen-embrittlement.
[137] Roberge, P.R., *Corrosion Basics: Close-Interval Potential Surveys Materials Performance*, May 4, 2020 (Houston, Texas (*The CIS technique provides a complete P/S potential profile, indicating the status of CP levels).*
[138] Ops/IM Report, Attachment 86, pp. 17-21 and Exception Report p. 3.
[139] See supporting documents found at DRs 37, 104, 115, 151, 156, 161, 162, 163, and 164.

- Contracted with third party industry expert RCP, Inc. to assess the effectiveness of its Public Awareness Program and its Emergency Response Program;
- Streamlined its Emergency Response Plan for the region in which the accident occurred;
- Simplified and made consistent its Safety Data Sheet regarding natural gas, and made that SDS available to the public on the Enbridge Inc. website; and
- Assured proper signage on Texas Eastern's pipeline markers, including a telephone number to call for information or in the event of an emergency.

II. ANALYSIS

NOTE: All facts referenced in this section are also contained in the "Factual Information" section of this Submission and are supported by the references cited in that Section unless otherwise indicated.

a. Enbridge's response to the accident complied with PHMSA regulations and industry standards

1. Enbridge promptly isolated the accident site

Gas Control began its response within two minutes of receiving the first alarm at 1:24am (all times in EDT). The alarm received was classified as an informational rate-of-change alarm. Two valves needed to be closed to achieve isolation of the ruptured portion of the pipeline. The two valves were manual valves, which could not be closed remotely or automatically, and there was no regulatory requirement that the valves be able to be operated remotely or automatically. While in contact with local personnel at the Danville Compressor Station, Gas Control began steps to limit the amount of natural gas being fed to the incident site. Gas Control remotely shut off compressors at Owingsville Compressor Station, the nearest upstream station. Unlike the Danville Compressor Station, the Owingsville Compressor Station is unmanned and has remote control capabilities. Three minutes later, Gas Control closed the three nearest upstream remotely-operated valves to the Danville Compressor Station, continuing to limit the amount of gas available to the accident site. The valve 15-393 at the Danville Compressor Station (directly upstream from the accident site) was closed by the station operator between 1:35am and 1:39am (accounts differ), at most 15 minutes after Gas Control received the first alarm. The closest valve downstream of the accident site, valve 15-382 at Highway 49 VS, was closed at 2:19am, isolating the ruptured section. These actions were consistent with the industry goal of manual valve closure in 60 minutes or less.[140]

The Gas Controllers and the Danville Station Operator on duty each had valid, non-expired Operational Qualification Certificates for their respective Covered Tasks in compliance with 49 CFR 192.801, et seq.[141] Gas Control's actions were consistent with Enbridge's Gas

[140] DR 116A INGAA Action Plan to Build Confidence in Pipeline Safety
[141] Ops/IM Report, Attachment 56.

Control Standard Operating Procedures.[142] Drug and Alcohol tests were administered to the on-duty Controllers and the Station Operator, and all were negative.[143]

2. *The Enbridge Public Awareness Program complied with applicable regulations and effectively provided all required information to the public and local Emergency Responders*

While Gas Control and local Enbridge personnel were responding to the accident, local emergency responders were on scene to limit access to the site, perform emergency medical services, and protect and assist people nearby.

Enbridge's Public Awareness Program, through which it supplied Pipeline Awareness Safety Training activities to local emergency responders, complied with API 1162 and 49 CFR 192.616. Enbridge likewise provided information by mail and by door-to-door canvas to residents and businesses adjacent to the pipeline.[144] The information by mail included the areas of damage prevention and one-call programs, possible hazards associated with unintended releases from a gas pipeline, physical indications of a release, steps to be taken for public safety in the event of a release, and procedures for reporting a release event.[145]

Neither the regulations regarding Public Awareness Plans at 49 CFR Part 192 nor API 1162 require that Public Awareness or Pipeline Awareness materials contain specific details such as the pipeline diameter, maximum operating pressure, or number of pipelines in a right of way. Adding additional details would not improve pipeline safety awareness. Tailoring each brochure for the specific pipe section adjacent to a given property would be cumbersome, time consuming, lead to confusion and present inconsistent information. This would not advance pipeline safety as the awareness components of the message do not change with the diameter of the pipeline or the number of pipelines in a particular right of way. In addition, Enbridge's brochure directs recipients to the National Pipeline Mapping System, a more effective way to see current information about all of the pipelines in a reader's area, not just those belonging to a single operator.

b. Enbridge properly classified the accident site and hydrostatic testing at the time of construction was appropriate for that classification

The pipeline at issue is Texas Eastern Transmission's Line 15, a 30", X52 pipe with 0.375 nominal wall thickness that was manufactured by A.O. Smith in 1957, coated with Coal Tar Enamel coating, and installed in Line 15, valve section 04 as an extension project of Line 15 between Tompkinsville and Danville Compressor Stations in 1958. The pipe was hydrostatically tested to at least 1.25 times MAOP, which is appropriate for Class 2 Locations.[146] The site was appropriately designated as non-HCA and a Class 2 Location.[147]

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[142] Supplemental Report, pp. 7-9.
[143] Ops/IM Report, Attachment 57.
[144] Emergency Preparedness/Emergency Response Report, pp. 48-50.
[145] 49 CFR 192.616(d).
[146] 49 CFR 192.505 and 192.619.
[147] 49 CFR 192.5.

c. Enbridge properly established Maximum Allowable Operating Pressure (MAOP) in accordance with PHMSA regulations

Both the initial MAOP and the post-reversal MAOP were properly established under PHMSA regulations 49 CFR 192.619(c) (original flow direction) and 192.619(a) (reverse flow direction).

Enbridge's decision to change flow direction in Line 15 was grounded in the dynamic supply and demand market created during the development of the Marcellus and Utica shale plays. A number of issues were evaluated before reversing the flow direction, including ensuring that overpressure protection devices were appropriately set and managing discharge temperatures to protect pipeline coating. Enbridge developed and executed a comprehensive Management of Change ("MOC") process as required by its Integrity Management System.[148]

The MOC process was utilized to identify and mitigate or remediate risks before the gas flow direction change was accomplished. Additionally, MAOP was considered for the reverse flow direction. To determine appropriate MAOP when flow was in the traditional direction (south to north), Enbridge used 49 CFR 192.619(c), which sets MAOP as the "highest actual operating pressure to which the segment was subjected during the 5 years preceding [July 1, 1970]." This section of Line 15 was pressure tested to a minimum pressure of 1377 PSIG, well over 1.25x its maximum allowable operating pressure of 1000 PSIG.

Because there was no pre-1970 flow history in the southbound direction, in 2014, Enbridge set the southbound MAOP at 936 PSIG in compliance with 49 CFR 192.619(a), which requires a pressure that is lower that the test pressure (1,377 PSIG) divided by 1.4, which in this case was 984 PSIG.[149] At the time of the accident, the line was operating at 925 PSIG.[150]

d. Gas discharge temperatures never exceeded limits after the flow direction of Line 15 was reversed

In addition to reevaluating and lowering MAOP with reverse flow, Enbridge updated its Standard Operating Procedures to reflect discharge temperatures from compressor stations appropriate for the southbound flow.[151] In some instances, such as the Danville Compressor Station, that meant that gas coolers were installed to make sure the discharge temperatures did not exceed limits in place to protect pipeline coating from heat-based deterioration. The temperature limits were set by Enbridge based on the type/vintage of coating for each pipeline segment.

Temperature recordings show that, in fact, Line 15 discharge temperatures were not exceeded at the Danville CS following the change in flow direction.[152] While pipeline temperatures rose a small amount between 2014 and 2017, that rise was attributable to the fact

[148] Ops/IM Report, Attachments 14 and 107.
[149] Ops/IM Report, Attachment 6.
[150] Ops/IM Report, p. 7.
[151] Ops/IM Report, Attachment 15.
[152] Ops/IM Report, Attachment 19.

that in the phase 1 reversal (2014-2017), gas was not compressed in the southern direction. In the 2017 phase 2 reversal, compression was added in the southbound direction and temperatures naturally increased slightly from those experienced during the no-compression phase, but discharge temperature limits were not exceeded in either phase 1 or phase 2 of the Danville CS flow reversal.[153]

e. Enbridge Threat Management Activities exceed PHMSA regulatory requirements

1. Enbridge's Integrity Management Program is consistent with ASME B31.8S and meets or exceeds 49 CFR 192.901, et seq. (Subpart O)

Enbridge's Integrity Management Program (IMP) manages the nine threats currently identified by ASME/ANSI B31.8S: time-dependent (external corrosion, internal corrosion, stress corrosion cracking); stable (manufacturing related defects including defective pipe seams and defective pipe, welding/fabrication related, and equipment); and time-independent (third party/mechanical, incorrect operations, and weather-related/outside force), and as articulated in previous industry standards.[154] Enbridge uses a combination of Standard Operating Procedures, the Integrity Management Program procedures and a series of Enbridge Threat Response Guidance Documents (TRGDs) designed for each type of pipeline threat.[155]

While PHMSA regulations Part 192, Subpart O require the development and use of an integrity management plan only in High Consequence Areas (HCAs), Enbridge "applies integrity management activities and technically appropriate IMP practices" throughout its entire pipeline system, regardless of HCA status.[156] By their express terms, the TRGD's are applicable only in HCAs, but consistent with the IMP, they are used as appropriate throughout the system.[157] Standard Operating Procedure 9-2010 "In-Line Tool Inspection", for example, governs the use of in-line inspection tools in HCA containing segments and non-HCA containing segments, setting out sixteen (16) factors for consideration in determining frequency of inspection.[158]

Enbridge's IMP has evolved over time, meeting PHMSA's continual improvement expectations, as new data has become available and integrated with existing data to provide information needed for assessing potentially interacting threats.[159] Because the physical location and pipeline attributes of Enbridge's gas transmission assets vary, different threats can present higher or lower risks in different pipeline systems (often dependent on attributes such as pipe manufacturer, vintage, size, or coating type) and in different geographical areas. External corrosion is the most significant threat to the system as a single threat, and is the most significant

[153] Ops/IM Report, Attachment 19.
[154] Ops/IM Report, Attachment 63, § 13.0.
[155] Ops/IM Report, Attachment 63, § 1.0.
[156] Ops/IM Report, Attachment 63, § 1.0.
[157] Ops/IM Report, Attachment 63, § 1.0.
[158] DR13 PLD19FR002_SOP_Volume 9_2010.
[159] 49 CFR 192.937.

interacting threat, understood to potentially interact with 7 of the remaining 8 identified threat categories.[160]

Enbridge has sought third party assessments of its program several times, including an independent evaluation of its hard spot assessment plan in 2005/2006 by C.C. Technologies; an effectiveness assessment of processes, procedures and records and a benchmarking against other operations in 2012 by Process Performance Improvement Consultants; and an Independent Pipeline Integrity Program Review conducted by Dynamic Risk Assessment Systems (DRAS) in 2018/2019.[161]

To support Enbridge's need for increased certainty in the integrity of its pipelines, Enbridge set explicit and lower risk tolerance thresholds, changed the assessment approach to a more quantitative basis, and engaged DRAS to conduct a program review focused on "the current state of six integrity-related programs – IMS, IMP, Geohazards, Cracking (stress corrosion and pipe seam weld), Dents and Corrosion (external, internal and selective seam weld)," and which identified pipe segments at higher risk as evaluated against the new lower risk thresholds for which additional diagnostics and/or data was needed to more confidently evaluate the risk. [162] The specific risk of manufacturing defects in the form of hard spots was not one of the most significant identified risks. As a result of the 2018/2019 risk assessment and tolerance shift, Enbridge placed voluntary pressure restrictions in various portions of the system until sufficient data could be obtained to support lifting those restrictions.

In an effort to increase the certainty of the integrity of the pipe, the Asset Integrity team increased staffing by 2.25x, increased the number of annual ILI tool runs by 4.30x, and increased the number of subsequent anomaly investigations by nearly 2x the 2018 level. Additionally, all of the gas transmission assets were merged into a single Integrity Management System, which required a consolidation and refresh of the supporting procedures and guidelines. The Asset Integrity program was restructured to leverage and integrate this aggressive acquisition of integrity-related data to support a shift to a more quantitative risk assessment, and it incorporated a "check function" assessing the effectiveness of planning and risk assessments, and their implementation through acquisition of data from anomaly and calibration excavations and assessments. The "check function" is designed to set risk thresholds, to evaluate the risk assessments performed on each pipe segment for each threat against those thresholds, and to identify places where those thresholds may not be met. The program also requires that lessons learned be captured and shared, and that continual improvement be the focus of forward-looking activities.[163]

[160] Ops/IM Report, Figure 25, p. 60.
[161] Ops/IM Report, Attachment 107.
[162] Ops/IM Report, Attachment 109, p. iv.
[163] Ops/IM Report, Attachment 107.

f. Enbridge's application of its Integrity Management Program exceeds PHMSA regulations by requiring integrity management activities in non-HCAs

Enbridge's Integrity Management Program (IMP) in place at the time of the accident was based on a number of regulatory and industry standards, including 49 CFR Part 192 (Subpart O), ANSI/ASME B31.8S, and several NACE Standards. Subpart O requires certain assessments and mitigation only in High Consequence Areas. Through its IMP, Enbridge has conducted those integrity management assessments beyond High Consequence Areas, including the Class 2 area in which the accident occurred. For example, Enbridge had run a number of ILI tools ("smart pigs") in the Tompkinsville to Danville Line 15 segment over the 15 years preceding the accident to assess for internal and external corrosion, third party damage, dents, deformation, pipe location, and in 2011, hard spots.[164]

In 2019 and 2020, Enbridge ran smart pigs to assess geotechnical stress as well. In 2020, Enbridge added EMAT tool runs to assess for stress corrosion cracking. Since Subpart O does not apply assessment requirements to the non-HCA accident site, the maximum reassessment interval of seven (7) years also does not apply as a technical requirement. Reinspection intervals for time-dependent threats in non-HCAs are developed and deployed pursuant to Enbridge's SOPs.[165] For time-dependent threats in the Tompkinsville to Danville, Line 15 segment, the tools were run on intervals of seven (7) years or less.[166]

g. Enbridge reasonably and appropriately relied on the NDT hard spot ILI tool and NDT's proprietary interpretation of ILI results

The Enbridge Hard Spot Evaluation and Mitigation Program utilized a hard spot ILI tool manufactured by Tuboscope/NDT. The manufacturer's product literature states that hard spots are "readily detected by the hard spot inspection tool."[167] An independent, third-party evaluation of the tool concluded that the NDT tool "accurately and reliably detected and estimated the hardness of hard spots". Enbridge testing of hard spots on a section of pipe removed from service showed that the NDT tool measurements were within +/- 50 Brinell of the NDT tool measurements, with the exception of two spots that were *overestimated* by the NDT tool. On this basis, Enbridge reasonably and appropriately relied on the NDT hard spot ILI tool.

Hard spots are manufacturing defects, caused by inadvertent quenching of pipe steel with water during the manufacturing process of the plate or pipe. These defects typically appear as a flat, round spot on the pipe external diameter. Hard spots need a certain level of "hardness" to be at risk of being susceptible to embrittlement and rupture, and also require the presence of the other factors before they can lead to embrittlement and rupture, such as stress, a source of hydrogen and environmental factors that prevent recombination of hydrogen.

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[164] Ops/IM Report, Table 16, p. 72.
[165] Supplemental Report, p. 12.
[166] Ops/IM Report, Table 16, p. 72.
[167] Ops/IM Report, Attachment 119.

Hard spots will not fail in service absent exposure to atomic hydrogen which leads to hydrogen embrittlement and cracking. Various technical reports have placed the minimum level of hardness necessary for embrittlement and rupture due to cracking (for pipelines that do not operate in an H2S environment) at a Brinell Hardness score of 360.

Unlike external and internal corrosion, which can grow over time and are defined as time-dependent threats, manufacturing defects such as hard spots are classified as stable. Stable threats do not require reassessment intervals. They either exist at the time of manufacturing or they do not. They do not grow, change, or increase in hardness over time.

In 2003, Enbridge's Line 15 suffered a rupture in a segment of pipe 78.3 miles from the 2019 accident site. In determining the cause of the 2003 rupture, investigators identified a hard spot in the same location as a mid-wall lamination, a statistically rare combination of manufacturing defects. The cause of the rupture was determined to be "hydrogen-induced cracking that initiated at the [outer diameter] surface of the pipe in a hard spot that was coexistent with a mid-wall lamination."[168]

In light of this new information, Enbridge designed and implemented a hard spot evaluation and mitigation program.[169] Enbridge then engaged industry experts C.C. Technologies to assess the body of industry and technical information regarding hard spots and hard spot related ruptures, and to provide an independent evaluation of the Company's hard spot evaluation and mitigation program.[170]

Also in response to the 2003 incident, Enbridge undertook a Close Interval Survey (CIS) to evaluate the Cathodic Protection system that protected the pipe from external corrosion risk to determine whether CP voltage was within the targeted range. Through the CIS, Enbridge determined that voltage of the cathodic protection levels was not excessive (more negative than–1.2V) in the location of the 2003 incident.[171]

Enbridge selected a Hard Spot Magnetic Flux Leakage (HSMFL) tool developed by Tuboscope (later purchased by NDT) as its inline inspection tool for hard spots. This technology was proprietary, and Enbridge did not have the expertise to independently evaluate raw data developed by NDT's HSMFL tool.[172] Accordingly, Enbridge established reporting criteria that NDT was to use in reporting hard spot information to Enbridge.

The hard spot reporting criteria was set at a more conservative hardness rating than the industry standard. The industry specification for new pipe was a maximum hardness level of 327 Brinell. An industry study of line-pipe field failures reported that hardness values greater than 360 Brinell were necessary for cracking to initiate, and in most cases, the hardness levels at

[168] Ops/IM Report, Attachment 30, p. 9.
[169] Ops/IM Report, Attachment 33.
[170] CC Technologies Report, Ops/IM Report, Attachment 34.
[171] CC Technologies Report, Ops/IM Report, Attachment 34, p. 16.
[172] Ops/IM Report, p. 81.

failure locations were measured in excess of 400 Brinell. Enbridge requested that NDT report to Enbridge all potential hardness indications above 235 Brinell.[173]

Enbridge hired NDT to run its HSMFL tool on nine (9) segments of pipe between 2005 and 2012. The NDT report on the 2004-2005 ILI runs stated that there were 5 anomalies between 235 and 250 Brinell, 15 anomalies between 251 and 300 Brinell and 2 anomalies greater than 301 Brinell. All indications above 300 Brinell were excavated and tested in the ditch, along with numerous indications reported below 300 Brinell. Enbridge found generally good agreement between the as-called and as-found (measured) hardness values, with the tool often overstating the hardness value, with the measured hardness value being lower than the HSMFL hardness value, particularly for outliers.[174]

For example, Table 9 of the NTSB Operations and Integrity Management Factual Report shows that during the initial validation work following the 2004 and 2005 NDT HSMFL tool runs, two (2) joints of pipe were removed from service by pipe replacement and sent to a lab for testing.[175] For these joints, all of the HSMFL hardness values were within +/– 50 Brinell of the lab measurements, except for two which were overstated by 75 and 99 points, respectively.[176] Recognition that the tool often over-called the hardness values provided confidence in the conservatism of the NDT tool.

Enbridge understood that the NDT tool was the best tool available to estimate hardness values of hard spots.[177] Enbridge reasonably relied on the NDT tool to detect, identify and characterize hard spots in Line 15, especially those that presented an integrity threat (at or above 360 Brinell). Enbridge's reliance was consistent with industry standards and an independent third-party validation of the hard spot indications identified by the NDT tool.[178] Enbridge's use of the NDT HSMFL tools to detect and evaluate hard spots was supported by diligent integrity management processes.

h. The NDT tool detected hard spots at the rupture site in a 2011 tool run, but NDT did not report those hard spots to Enbridge until after the 2019 rupture

Following the 2019 accident, NTSB and Enbridge requested that NDT Global reassess the underlying data from the 2011 HSMFL tool run and provide an updated report and evaluation.

In the post-accident reassessment, NDT Global identified and *reported to Enbridge for the first time* two previously-detected but unreported hard spots at or near the rupture location, and a total of nine previously-detected but unreported hard spots in the 20' long pipe joint that

[173] Ops/IM Report, Attachment 33, p. 2.
[174] Ops/IM Report, Figure 33, p. 79.
[175] Ops/IM Report, Table 9, p. 31.
[176] Ops/IM Report, Table 9, p. 31.
[177] Ops/IM Report, Attachment 72, page 2 (ILI tool and field harness testing methods proved to be in agreement with microhardness testing values).
[178] Ops/IM Report, Attachment 72.

ruptured. The two previously-undisclosed indications at the rupture site were identified as hard spots with a hardness ranging between 236 and 245 Brinell.[179]

Post-rupture microhardness testing performed by the NTSB Materials Lab on the accident pipe determined the actual Brinell hardness value of the two hard spots at the failure origin was between 362 and 381 Brinell, more than 100 points harder than any reported value and significantly outside of the +/- 50 Brinell tolerance stated in the NDT test reports. These hardness values are consistent with hardness levels seen in previous industry ruptures.

There is no question that the hard spots that led to the rupture were, in fact, detected by the Tuboscope/NDT tool during the 2011 ILI run, but for unknown reasons were not reported to Enbridge at the time. It is also clear that even the post-accident hardness reporting by NDT grossly mis-characterized the hardness level of the hard spots that led to the rupture. Had the hard spots been reported within 50 Brinell of their actual hardness level, Enbridge's SOPs would have required excavation and assessment.

i. Hard Spots present a threat to a pipeline only when combined with other conditions

A hard spot alone, no matter how hard, does not pose a threat to pipeline integrity.[180] It poses a threat only if it is sufficiently hard (over 360 Brinell) AND is subject to hydrogen embrittlement. For hydrogen embrittlement to occur, there must be a coating flaw in the same location as the hard spot and environmental conditions that promote the creation of atomic hydrogen.[181] If any one of these elements is missing (sufficient hardness, coating flaw and susceptible environmental conditions), a hard spot cannot crack and cause a rupture. Elimination or mitigation of one or more of the three necessary elements will prevent hydrogen embrittlement and cracking of a hard spot.[182]

Environmental conditions that support the creation of atomic hydrogen are virtually impossible to measure along a pipeline:

> *As a practical matter, there are no know field methodologies to determine site specific conditions under which excessive generation of atomic hydrogen would occur because of the role the environment plays.* [183]

Because of this, hard spot mitigation requires determining the hardness of a hard spot and mitigating or eliminating the hard spot when appropriate. It is simply assumed that the environmental conditions necessary to provide atomic hydrogen always exist.

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[179] Materials Lab Report, Appendix 2, pp. 30-31.
[180] Ops/IM Report, Attachment 21, p. 15.
[181] Ops/IM Report, Attachment 68, p. 20.
[182] Ops/IM Report, Attachment 68, p. 20.
[183] DR37 – MEARS analysis, Hydrogen Embrittlement Mechanisms in Pipeline Steel – Understanding the Role of Environment, Protective Coatings, and Cathodic Protection.

j. Excessive Cathodic Protection is not a significant factor in hard spot mitigation

The lower range guidance for Cathodic Protection (-1.2V) is not a hard rule and maintaining cathodic protection at a lower (less negative) level does not provide protection from threats due to hard spots. While excessive CP can contribute to the formation of atomic hydrogen, it alone is not the critical factor in hard spot mitigation because of the dependence on environmental conditions which are impossible to measure or control in the field, and thus are not a mitigation for hydrogen embrittlement that is controlled for integrity management purposes. Moreover, hydrogen embrittlement and cracking can occur at CP levels much more positive than -1.2V, so controlling CP for purposes of hard spot mitigation presents a false sense of security. In any event, none of the CP readings at the accident site were more negative than - 1.2V.

Cathodic protection (CP) is used to protect buried steel coated pipelines with external coating from significant external corrosion. CP is applied in a targeted range of -1.2V to -0.85V to maximize that protection. On the higher end of the range (more positive) the standard is a regulatory requirement (49 CFR 192.463 (a)); however, on the lower (more negative) end, this range is merely guidance. *There is no National Association of Corrosion Engineers (NACE) consensus on the negative end of an acceptable range of Cathodic Protection.*[184]

Excessive cathodic protection generates molecular hydrogen, which does not in itself promote hydrogen-induced cracking or embrittlement. Cracking and embrittlement require absorption of *atomic* hydrogen, which consists of hydrogen molecules that fail to recombine due to the presence of certain local environmental conditions.[185] These local environmental conditions can drive the molecular hydrogen's dissociation into atomic hydrogen, which can be absorbed into the susceptible (hard) steel and produce embrittlement in places with coating damage or disbondment that allow for access to the pipe's steel surface.[186]

Disassociation of atomic hydrogen is largely dependent on the local water chemistry.[187] Environments containing sulfides, phosphorous, and arsenic will promote the formation of atomic hydrogen.[188] The increasing role of local environmental factors on hydrogen induced cracking is an area of current research and learning.

It bears repeating that keeping CP voltage more positive than the lower end guidance of -1.2V does not guarantee a hard spot will not become embrittled and crack. There are many documented instances, including Enbridge's Owingsville and Danville incidents, in which

[184] CC Technologies Report, Ops/IM Report, Attachment 34, Appendix F, p. 1.
[185] DR 37 – MEARS analysis, Hydrogen Embrittlement Mechanisms in Pipeline Steel – Understanding the Role of Environment, Protective Coatings, and Cathodic Protection.
[186] DR 37 – MEARS analysis, Hydrogen Embrittlement Mechanisms in Pipeline Steel – Understanding the Role of Environment, Protective Coatings, and Cathodic Protection.
[187] DR 37 – MEARS analysis, Hydrogen Embrittlement Mechanisms in Pipeline Steel – Understanding the Role of Environment, Protective Coatings and Cathodic Protection.
[188] DR 37 – MEARS analysis, Hydrogen Embrittlement Mechanisms in Pipeline Steel – Understanding the Role of Environment, Protective Coatings and Cathodic Protection.

hydrogen-induced cracking (hydrogen stress cracking) failures have occurred in the presence voltage less negative than -1.2V.[189] For these reasons, excessive cathodic protection is not a critical factor in hard spot mitigation or in the cause of this accident.

k. CP levels at the accident site were at all times within the voltage target range and played no role in the accident

There are simply no CP test readings at the accident site in excess of the lower target voltage of -1.2 volts. Close Interval Surveys (CIS) that included the accident site were conducted in 2012 and 2018 and all readings at the accident site were more positive than -1.2 volts.

Testing and evaluation of CP levels is a frequent activity. Pipeline cathodic protections levels are required to be tested once each calendar year, with intervals not exceeding 15 months; rectifiers or other impressed current power sources must be inspected six (6) times each calendar year, with intervals not exceeding 2 ½ months. (49 CFR 192.465 (a) and (b)). Enbridge met each of these regulatory testing requirements.[190]

The accident site (MP 423.4) sits near, but is not collocated with, the test station at the Southern Railroad crossing (MP 423.4). The accident site is approximately 70' to the northeast of Southern Railroad. In four out of the five years preceding and including 2019, the IRF readings at the Southern Railroad were all more positive than -1.2V. In 2017, the reading was very slightly more negative than -1.2V (-1.234V). Most importantly, the IRF reading at the Southern Railroad test station the year of the accident (2019) was -1.047V. Timing of any CP survey including IRF readings is important because "hydrogen embrittlement is not a permanent condition. If environmental conditions change, "hydrogen can rediffuse from the steel."[191]

The only direct readings of CP levels at the accident site come from two Close Interval Surveys conducted in 2012 and 2018. CIS is a test method that takes readings every couple of feet along the pipeline, enabling operators to "identify possible corroding sections more accurately than test point surveys, due to the increased amount of data points within the survey start and end."[192] The CIS data provides the most accurate indication of the cathodic protection situation at any given location.[193] Both the 2012 and 2018 close interval surveys show voltage more positive than -1.2V at the accident site.[194] As stated above, while -1.2V is not a hard line, but rather a consensus target for the negative end of cathodic protection voltage, any discussion of "overvoltage" is not relevant here as there have been no readings of "overvoltage" at the

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[189] DR 154B, Groeneveld, T.P., *Hydrogen Stress Cracking,* sponsored by the Pipeline Research Committee of the Pipeline Research Council International Inc., (1979), Figure x-12, page X-16 (*60% of documented failures occurred at CP levels more positive that -1.2V).*
[190] Ops/IM Report, p. 23.
[191] https://www.nace.org/resources/general-resources/corrosion-basics/group-3/hydrogen-embrittlement
[192] Pawson, R.L, *Close Interval Potential Surveys Planning, Execution, Results,* Paper No. 97575 (Ontario, Canada: NACE 1997).
[193] Roberge, P.R., *Corrosion Basics: Close-Interval Potential Surveys Materials Performance,* May 4, 2020 (Houston, Texas).
[194] Ops/IM Report, Attachment 84, p. 237 (2018 CIS), Attachment 86, p. 99 (2012 CIS).

accident site, and the 2019 test station readings closest to the accident are well below (more positive than) -1.2V.

Likewise, as stated above, CIS data collected before the 2003 incident also showed an absence of "overvoltage" at the accident site. The Investigative Report authored by Kiefner & Associates of the 2003 incident confirmed that the presence or production of hydrogen is "not an indication that the voltage of the cathodic protection was excessive."[195] The report further confirms that hydrogen may be produced at "potentials much less than normally imposed by cathodic protection."[196]

Enbridge believes that it is important for NTSB, PHMSA and industry to be aware that merely maintaining cathodic protection within the target range of -1.2V to -0.85V is insufficient to prevent generation of atomic hydrogen and the development of hydrogen embrittlement and hydrogen induced cracking in susceptible pipe.

III. FINDINGS AND CONCLUSIONS

1) The rupture occurred at approximately 1:23 a.m. EDT.
2) Enbridge Gas Control received a SCADA rate-of-change alarm at 1:24 a.m.
3) At 1:35 a.m., the Enbridge Area Supervisor contacted the Danville Station Operator and instructed him to close valve 15-393, the Line 15 valve immediately North of the rupture.
4) By 1:39 a.m., valve 15-393 was confirmed closed.
5) At 2:13 a.m., an Enbridge pipeliner arrived at the site of valve 15-382 (nearest valve South of the rupture site) and had it fully closed by 2:19 a.m.
6) The total elapsed time from the first indication of a possible rupture to full isolation of the rupture site was 55 minutes.
7) Industry guidance establishes a response time goal of one hour from incident recognition to the start of valve closure procedures.
8) All six Gas Controllers and the Danville Station Operator on duty at the time of the accident were drug and alcohol tested after the accident, and all tests were negative.
9) The Gas Controllers and Danville Station Operator on duty each had valid, non-expired Operational Qualification Certificates for their respective Covered Tasks.
10) The Enbridge Public Awareness Program complied with API 1162 and 49 CFR 192.616.
11) Enbridge conducts annual "Liaison Training" for emergency services personnel and their organizations and Liaison Training was conducted and offered to the emergency services

[195] Ops/IM Report, Attachment 42, p. 1.
[196] Ops/IM Report, Attachment 42, p. 1.

jurisdictions proximate to the accident site for the five year period prior to the accident, in compliance with API 1162 and 49 CFR 192.616.

12) The pipeline at issue was manufactured to American Petroleum Institute (API) Standard 5LX, 6th edition, dated February 1956 as grade X52, as 30-inch nominal outside diameter (OD), 0.375-inch nominal wall thickness, electric flash weld (EFW) longitudinal seam.

13) The pipe was hydrostatically tested to 1377 PSIG, which is more than 1.25 times MAOP and is appropriate for Class 2 Locations (49 CFR 192.505 and 192.619).

14) The accident site was appropriately designated as a non-HCA (High Consequence Area) and a Class 2 Location.

15) Both the initial MAOP and the post-reversal MAOP were properly established for Line 15 under PHMSA regulations 49 CFR 192.619(c) (original flow direction) and 192.619(a) (reverse flow direction).

16) Enbridge set appropriate gas discharge temperatures for Line 15 based on the type and vintage of the pipeline coating.

17) Gas discharge temperatures for Line 15 did not exceed established limits at any time after the flow direction of Line 15 was reversed.

18) Enbridge's Integrity Management Program is consistent with ASME B31.8S and meets or exceeds 49 CFR 192.901, et seq. (Subpart O).

19) Enbridge's application of its Integrity Management Program exceeds PHMSA regulations by requiring integrity management activities in non-HCA's.

20) Enbridge reasonably and appropriately relied on the NDT hard spot ILI tool and NDT's proprietary interpretation of ILI results.

21) The Enbridge Hard Spot Evaluation and Mitigation Program utilized a hard spot ILI tool manufactured by Tuboscope/NDT.

22) Tuboscope/NDT product literature states that hard spots are "readily detected by the hard spot inspection tool."

23) An independent, third-party evaluation of the Tuboscope/NDT hard spot ILI tool concluded that the NDT tool "accurately and reliably detected and estimated the hardness of hard spots".

24) Enbridge testing of hard spots on a section of pipe removed from service showed that the Tuboscope/NDT tool measurements were within +/- 50 Brinell of the NDT tool measurements, with the exception of two spots that were overestimated by the NDT tool.

25) Actionable hard spot features reported by Tuboscope/NDT (hard spots that were identified in the field with Brinell hardness of 300 or greater) were repaired by Enbridge.

26) Post-accident hardness testing by the NTSB Metallurgical Laboratory determined that the hard spot indication near the rupture point ranged from 362 to 381 Brinell.

27) Enbridge reasonably and appropriately relied on the Tuboscope/NDT hard spot ILI tool to identify hard spots in its pipelines.

28) The Tuboscope/NDT tool detected hard spots at the rupture site in a 2011 tool run.

29) NDT did not report the hard spots detected in 2011 to Enbridge until after the 2019 rupture.

30) Hard Spots present a threat to a pipeline only if it is sufficiently hard (over 360 Brinell) AND is subject to hydrogen embrittlement.

31) For hydrogen embrittlement to occur, there must be a coating flaw in the same location as the hard spot and environmental conditions that promote the creation of atomic hydrogen.

32) Environmental conditions that support the creation of atomic hydrogen are virtually impossible to measure along a pipeline.

33) Excessive Cathodic Protection is not a significant factor in hard spot mitigation.

34) There is no upper boundary recognized by PHMSA or NACE to establish the amount of CP that is too negative with respect to hydrogen embrittlement.

35) Cathodic protection at lever lower (less negative) than -1.2V does not provide protection from threats due to hard spots.

36) There are documented cases of hydrogen embrittlement leading to hard spot ruptures in pipe with CP applied at levels less than -1.2V.

37) Atomic hydrogen is presumed by the IMP to be present in all situations (without its presence, a hard spot is benign), regardless of CP levels.

38) There is not practicable field methodology to determine specific conditions where excessive generation of atomic hydrogen would occur.

39) No Cathodic Protection test readings at the accident site were in excess of (more negative than) the lower CP target voltage of -1.2 volts.

40) Close Interval Surveys (CIS) that included the accident site were conducted in 2012 and 2018 and all readings at the accident site were more positive than -1.2 volts.

41) The accident site (MP 423.4) sits near, but is not collocated with, the test station at the Southern Railroad crossing (MP 423.4).

42) In four out of the five years preceding and including 2019, the IRF readings at the Southern Railroad test station were all more positive than -1.2V.

43) In 2017, the IRF reading at Southern Railroad was very slightly more negative than -1.2V (-1.234V).

44) The IRF reading at Southern Railroad during the year of the accident (2019) was - 1.047V.

45) No excessive CP levels caused or contributed to this accident.

IV. PROBABLE AND CONTRIBUTING CAUSES

The probable cause of the accident was hydrogen embrittlement and hydrogen-induced cracking caused by the presence of a hard spot with sufficient size and hardness in the presence of localized coating damage, sufficient hoop stress, and the presence of atomic hydrogen.

Contributing Causes:

1) The Hard Spot ILI vendor, Tuboscope/NDT, failed to inform Enbridge of two hard spots indications in the pipeline at the site of the rupture origin and seven additional hard spots in the same pipe segment detected in its 2011 hard spot ILI tool run; and

2) The Hard Spot ILI vendor, Tuboscope/NDT, failed to accurately characterize (within +/- 50 Brinell) the 362 to 381 Brinell hard spot indications at the rupture origin, which under Enbridge's response criteria would have required the location to be excavated, assessed and repaired.