NATIONAL TRANSPORTATION SAFETY BOARD
Office of Railroad, Pipeline, and Hazardous Materials Investigations
Washington, D.C. 20594

Pipeline - Operations / Integrity Management and Survival Factors

Group Chairman's Supplemental Factual Report of the Investigation[1]

– Pipeline - Operations and Integrity Management[2]

– Emergency Preparedness / Emergency Response[3]

Report Date: July 13, 2021

A. Accident

Location (accident reference):	Danville, Kentucky
NTSB Accident Number:	PLD19FR002
Physical Location:	Lincoln County, KY
Date:	August 1, 2019
Time (approximate):	1:23 a.m. EDT[4]

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[1] This Supplemental Factual Report addresses topic-points that were originally to be addressed in the Pipeline Operations / Integrity Management - Group Chairman's Factual Report of the Investigation, dated March 10, 2021, and the Survival Factors (SF) - Group Chairman's Factual Report of the Investigation, dated September 29, 2020, wherein addressing the noted topic-points was deferred to this report, for considerations of a Party to the investigation that had deemed select documentation, as had been made available to the investigation by that Party, to be subject to the confidentiality constraint stipulations of *49 CFR 831.6 Request to withhold information*, which commensurately prevented that documentation from being addressed, at that time, in the respective Group Chairman's Factual Reports.

[2] The Pipeline Operations and Integrity Management investigation exclusively addresses [1] the physical operations of the pipeline owner / operator in the transportation of [natural gas] product through a transmission pipeline, and [2] the management of programs, methodologies and practices by a pipeline owner / operator to ensure the integrity of its [natural gas] transportation system.

[3] The Survival Factors investigation exclusively addresses [1] the emergency preparedness and emergency response elements of the accident, and [2] the injury causation elements of the accident.

[4] Eastern Daylight Time; all times cited herein are local time, unless otherwise noted.

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Select abbreviations and acronym nomenclature used in this report

// s //	signature on file
≥	greater than, or equal to
<	less than
>	greater than
AP	assessment plan
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASV	automatic shut-off valves
CFR	Code of Federal Regulations
CIS	Close Interval Surveys
CP	cathodic protection
DC	direct current
DEGT	Duke Energy Gas Transmission
EDT	Eastern Daylight Time
ESA	Enhanced Survey Analysis
ESD	emergency shutdown
HCA	High Consequence Areas
ILI	in-line inspection
IM	Integrity Management
IMP	Integrity Management Program
IMPM	Integrity Management Program Manual
MAOP	Maximum Allowable Operating Pressure

MFL	Magnetic Flux Leakage
NCA	Non-Corrosion Anomalies
PAP	Public Awareness Program
PHMSA	U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (see [Internet] http://www.phmsa.dot.gov/)
PORMC	Pipeline Operational Risk Management Committee
psi	pounds per square inch [pressure]
RCFA	root cause failure analysis
RCV	remote control valves
ROW	right-of-way
SF	Survival Factors [investigation]
SCADA	Supervisory Control and Data Acquisition
SME	subject matter expert
SOP	Standard Operating Procedure
TET	Texas Eastern Transmission
VDC	volts direct current

B. Synopsis of the Accident[5]

An underground, 30-inch diameter transmission pipeline, transporting pressurized natural gas at 925 psi, in a southbound flow, experienced an in-service breach and product release, which resulted in a rupture and an intensive fire that occurred in a rural area of Lincoln County, about six miles south of the City of Danville, Kentucky. The rupture resulted in a crater at the natural gas release site, from which soil, rock and a segment of pipe was ejected. The segment of ejected pipe, measuring about 33 feet in length by just under 8 feet in width, became airborne and traveled in a southerly direction, which came to rest, on open ground, about 481 feet to the approximate south of the crater location. The flare of the fire was reported, to the jurisdictional 911 agency, as being visible at a location that was at least 38 miles to the northwest of the accident site. The investigation observed that the heat of the fire (flare) melted the plastic siding material of a residential dwelling that was located about 1,100 feet from the fire. The natural gas product release occurred proximate to an unincorporated, mobile home park community that is locally referred to as the Indian Camp Subdivision. Self-evacuations by residents near the fire initiated spontaneously, with further evacuations completed by the jurisdictional emergency responders. One resident of that community sustained fatal injury in the accident, and five other residents were transported to a local medical facility for evaluation and/or treatment, all of which were treated and released. One emergency responder (a Deputy Sheriff) sustained minor injury that occurred during a successful rescue response to the accident, who was treated and released from the medical facility. Five residential dwellings of the mobile home park community were destroyed in the ensuing fire, and 14 residential dwellings in that community sustained fire damage, in which about 30-acres of land sustained fire damage. An estimated 75 to 100 individuals were displaced as a result of damages to the Indian Camp Subdivision properties.

[5] Compiled in conjunction with data supplied by, and with the concurrence of, the Investigator in Charge (IIC).

C. **Details of the Investigation**

1.0 Enbridge – Procedural / Guidance Documentation to Address Pipeline Operations and Integrity Management

1.1 Manual of Standard Operating Procedures

1.1.1 Background / Overview

Pursuant to the requirements of 49 CFR 192.605 [titled] Procedural manual for operations, maintenance, and emergencies, "Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted."[6]

1.1.2 Enbridge - Operations and Maintenance Plan – Content

Enbridge documented to the investigation[7], that it developed, and utilizes, a formal, documented operations and maintenance plan, as comprised in a document [of the company] titled "Operations and Maintenance Plan", revision dated 04/30/2014.

Review of the subject Operations and Maintenance (O&M) Plan document indicated that the content was comprised under a general topic [label of] "Procedure", in which the document is subdivided into Sections 1.0 through 5.0., inclusive. Section 2.0 [which is titled as] "Reviews and Updates", contains a subsection 2.1, which indicated, "The O&M Plan will be reviewed and updated each calendar year not to exceed 15 months. The Director, Operational Compliance or designee is responsible for this review and the subsequent revisions.".

1.1.3 Enbridge - Standard Operating Procedures – Composition

Enbridge documented to the investigation[8], that it developed, and utilizes, a formal, documented manual of standard operating procedures, which is comprised of a document that indicates, in the header of each page, the document source as "Spectra Energy Transmission", in which the document is titled "Standard Operating Procedures" (SOP's).

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[6] Reference, and for further information, see [Internet] https://www.ecfr.gov/cgi-bin/text-idx?SID=e321f12620f9286a5ef42efa09dcf359&mc=true&node=pt49.3.192&rgn=div5#se49.3.192_1605.

[7] Source: a document, having the e-document filename "DR11 PLD19FR002 Operations and Maintenance Plan", was made available to the SF investigation during the on-scene phase of the investigation, via transfer to the NTSB Accellion FTP [secure transmittal] website, in which it was observed that the document contained a notation CONTAINS CONFIDENTIAL INFORMATION in the header of each page.

[8] Documentation to the investigation occurred by digital transfer of the subject documentation, during the on-scene phase of the investigation, into the NTSB Accellion FTP [secure transmittal] website, as further described.

Review of the subject documentation indicated that it consisted of 13 Volumes, of which select Volumes were made available to the investigation, which included the following:

Volume 2 [titled] Corrosion, revision [dated] 07/02/2019,[9]

Volume 5 Emergency Response and Common Procedures, revision 07/01/2019,[10]

Volume 8 Gas Control, revision 03/19/2019,[11] and

Volume 9 Pipeline Integrity, revision 05/28/2019.[12]

1.1.4 Review of Individual SOP Volumes by the Investigation

a. Volume 2 Corrosion

Within Volume 2, Corrosion, the investigation found the following procedures relevant to the investigation:

- SOP 2-2130, Close Interval Surveys,
- SOP 2-2160, Coating Systems for Buried and Submerged Pipelines,
- SOP 2-2230, Cathodic Protection System Design,
- SOP 2-4080, Corrosion Control Remedial Actions.

SOP 2-2130, Close Interval Surveys, discusses when and how close interval surveys (CIS) are to be performed. During a CIS, "all influencing current sources must be synchronously interrupted" and the "influencing current source interruption duty cycle shall [be] at least one second." Pipe-to-soil potential measurements are to be taken at "all casings, electrically isolated taps, dielectric insulators, bonds, valves, and test stations" and in "at 2-1/2 to 10 foot increments" along the length of the pipe being surveyed.

SOP 2-2130 also outlines the review of CIS data to identify potential issues. Section 8.0, Over Voltage, states that the employee investigating should review information from bell-hole examinations if available "to determine whether over voltage is a concern for the pipeline segment if polarized potentials more negative than -1.2 VDC are identified."[13] SOP 2-2130 further states that when determining possible overvoltage, "a balance between the potential hazards of over protection and the possible risks of under protecting other sections of the pipeline must be maintained." If the measured potentials are suspected to be excessive, the SOP

[9] Source: a document, having the e-document filename "DR13 PLD19FR002 SOP Volume 2", in which the header of each page was observed to contain a notation "CONTAINS CONFIDENTIAL INFORMATION".

[10] Source: a document, having the e-document filename "DR13 PLD19FR002 SOP Volume 5", in which the header of each page was observed to contain a notation "CONTAINS CONFIDENTIAL INFORMATION".

[11] Source: a document, having the e-document filename "DR13 PLD19FR002 SOP Volume 8", in which the header of each page was observed to contain a notation "CONTAINS CONFIDENTIAL INFORMATION".

[12] Source: a document, having the e-document filename "DR13 PLD19FR002 SOP Volume 9", in which the header of each page was observed to contain a notation "CONTAINS CONFIDENTIAL INFORMATION".

[13] A bell-hole is a small excavation performed to access or view the pipe at a specific location.

states the employee should “give serious consideration to determining the influence of DC interference from foreign current sources, Company CP systems, and/or foreign impressed current cathodic protection systems.” This SOP indicates that if excessive CP current is found, the “current must be reduced” and more CP sources considered “so as to more uniformly distribute the CP current.”

SOP 2-2160, Coating Systems for Buried and Submerged Pipelines, establishes the maximum operating temperature for the discharge (output) side of each compressor station, depending on flow direction. Each segment is classified by the coating characteristics, including manufacturer and type of coating.

SOP 2-2160 also requires review of excursions over these maximum discharge temperatures on an annual basis. This review requires regional technical staff to evaluate in-line inspection data and any increases in cathodic protection requirements to determine if an action plan was necessary to reduce the risk of coating damage. If deemed necessary, this action plan is to consider the use of close interval surveys, excavations, above ground coating surveys in the first valve segment on the discharge side, cooling needs at the compressor station, and increased and/or accelerated in-line inspection assessments.

SOP 2-2230, Cathodic Protection System Design, outlines what considerations are considered by Enbridge during the creation of a cathodic protection system. This includes current requirements based on coating condition and soil conditions. Impressed current systems are discussed, including various types of anode beds.

SOP 2-4080, Corrosion Control Remedial Actions, requires that remediation “as soon as practical after surveys, tests, or inspections indicate that corrosion protection is not adequate, and the cause has been identified.” It does not specify what actions this should include, but states that remediation “should be initiated within the first few months and in most cases should be completed prior to the next scheduled inspection.”

b. Volume 5 Emergency Response and Common Procedures

See further § 1.4.1 and § 2.2.2 (in this report).

c. Volume 8 Gas Control

Within Volume 8, Gas Control, the investigation found the following procedures relevant to the investigation:

- SOP 8-2010, Initial Notification of Potential Emergency,
- SOP 8-2020, Emergency Response,
- SOP 8-2030, Alarm Management.

SOP 8-2010, Initial Notification of Potential Emergency, outlines the actions a gas controller is to take in the event they are notified of a potential emergency condition. The gas controller is first notified of the event by telephone call from either an outside party (member of the public, emergency response personnel, etc.) or an Enbridge field technician. Notification from alarms or operating conditions is not discussed in this SOP. After receiving the phone notification, the gas controller is to record down the relevant information from the call and then contact Enbridge field personnel. The gas controller can verify the emergency is valid by speaking with field personnel or a reliable third party (i.e. local fire department). SCADA is used to evaluate the situation as well.

In the event the notification received during implementation of SOP 8-2010 indicates an emergency, then gas controllers are to follow SOP 8-2020, Emergency Response. SOP 8-2020 defines an emergency as an "unexpected situation that requires immediate action (e.g., pipeline rupture, fires, explosions, etc.), or any other event [as] determined by Gas Control management." Once an emergency condition has been determined, the controller makes a series of notifications to the other five gas controllers on duty, the field supervisor or other relevant field personnel, and gas control management. The next step is the development of an isolation plan, which is done jointly by field personnel and gas control. After this, the gas controller makes "[adjustments to the] pipeline system operations accordingly." The final step outlined in SOP 8-2020 is drug and alcohol testing, which is done for all personnel on shift. The procedure states that alcohol tests are to be completed within 2 hours and drug tests no later than 32 hours.

SOP 8-2030, Alarm Management, discusses what actions controllers should take in the event of different alarm priority levels. Enbridge classifies SCADA alarms into four priority levels based on urgency and importance: (1) critical, (2) urgent, (3) warning, and (4) informational (see Table 1). Activities to be taken upon receipt of informational alarms, including rate-of-change pressure alarms, are not identified in SOP 8-2030.

Alarm Priority Level	**Mandated Controller Action**	**Notification Method**	**Example Events**
Critical	Immediately notify field personnel	Blinking red text, audible sound	Pressure over MAOP, hazardous atmosphere at CS
Urgent	Immediately act, possibly by dispatching field personnel	Blinking orange text	Illegal entry into a facility, control failure at a meter station
Warning	Act in a timely manner to prevent escalation of issue	Blinking yellow text	High temperatures, transmitter communication failure

Table 1. Enbridge Gas Control Center alarm priority levels and actions as discussed in SOP 8-2030.

When an alarm is triggered, the gas controller covering that pipeline system is responsible for investigating the cause. As a first step, the gas controller acknowledges the alarm in the SCADA system. After acknowledging the alarm, the gas controller determines if the alarm truly represents an operating issue. The controller may take a number of actions to determine the validity of the alarm and the potential threat to the pipeline system, including delving further into the available data to evaluate any existing trends or dispatching personnel to check conditions in the field. If an emergency condition is found to exist, the gas controller is referred to SOP 8-2020.

d. Volume 9 Pipeline Integrity

Within Volume 9, Pipeline Integrity, the investigation found the following procedures relevant to the investigation:

- SOP 9-3010, Response to In-Line Inspection,
- SOP 9-3040, Enhanced Survey Analysis,
- SOP 9-4040, Defect Assessment & Repair Options for Dents and Mechanical Damage,
- SOP 9-4050, Defect Assessment & Repair Options for Miscellaneous Defects.

SOP 9-3010, Response to In-Line Inspection, begins by defining various anomaly types. Enbridge defines a dent based on depth as a percentage of outer diameter and location (see Table 2).

Category	**Outer Diameter** (inches)	**Depth** (% of outer diameter or inches)	**Location**
Bottom Side Pipe Body	≥ 12	≥ 2%	4 to 8 o'clock
Bottom Side Pipe Body	< 12	≥ 0.25"	4 to 8 o'clock
Top Side Pipe Body	Any	≥ 0.25"	8 to 4 o'clock
Ductile Weld Affected	Any	≥ 2%	Long seam and girth welds
Non-Ductile Weld Affected	Any	≥ 0.25"	Long seam and girth welds

Table 2. Enbridge dent categories.

SOP 9-3010 defines metal loss as "an in-line inspection indication that may be corrosion or mechanical damage ≥ 10% wall loss." Actionable dents with metal loss as defined as dents that contain metal loss and meet any of the following criteria:

- The extent of metal loss has reduced the strength of a facility below the maximum allowable operating pressure,
- Dents that exceed a depth of 6% of the nominal pipe diameter,
- The associated strain levels exceed 6% strain.

SOP 9-3010 requires that in-line inspection (ILI) data be validated and verified within 180 days of the tool run date. This can be done by "either by comparing previous excavation data or by performing verification digs." When using previous excavation data, this comparison can be completed by the ILI project manager or a subject matter expert (SME). When performing verification digs, there must be "a minimum of two graded ILI indications." If the verification digs do not validate the data, the following options are available:

- Perform additional verification excavations,
- Consult the ILI program manager and the ILI vendor to determine if the defect sizing needs to be adjusted and the inspection completely regraded,
- Consult the ILI program manager and apply a larger tolerance to the ILI data. This may require a recalculation of FPR_{TC} for the entire inspection.[14]

SOP 9-3010 also requires the ILI vendor, or an Enbridge SME compare results from a new ILI run with the previous high-resolution ILI within 1 year of the new run. Per SOP 9-3010, the comparison must contain all metal loss anomalies with wall loss over 40% wall thickness in a non-HCA or over 20% in an HCA, among other points of interest. Hard spots are not listed within the SOP.

When evaluating the assessment results, SOP 9-3010 requires the following data to be collected:

- Predicted wall loss of indication (Magnetic Flux Leakage ILI only),
- Predicted length of indication (Magnetic Flux Leakage ILI only),
- Interaction criteria and clustering,
- Clock position of indication,
- Distance to welds and long seams,
- Type of long seam weld,
- Pipeline specifications (diameter, wall thickness, and grade),

[14] FPR_{TC} is the failure pressure ratio, tolerance compensated. This is a calculated number and is used to predict the ratio of the "tolerance compensated" Failure Pressure (FP) divided by the Maximum Allowable Operating Pressure (MAOP) of the pipeline segment. The "tolerance compensated" failure pressure accounts for the tolerance of the in-line tool.

- Tolerances (depth and length) of the inspection tool,
- Interaction with other anomalies,
- Predicted depth, width, and length of deformation (geometry ILI only),
- Longitudinal profile (geometry ILI only).

When evaluating anomalies with corrosion, SOP 9-3010 states that corrosion anomalies are analyzed based on the following:

- Calculated FPR_{TC},
- Calculated anomaly burst pressure,
- Predicted anomaly depth (as a percentage of outer pipe diameter),
- Interaction with other non-corrosion defects,
- Interaction with welds or long seams,
- Opinion of Enbridge SME.

SOP 9-3010 outlines how FPR_{TC} is calculated for various anomalies based on the specific tolerance of the in-line inspection tool. Based on this calculation and the other factors outlined above, anomalies are scheduled for repair or monitoring by category:

- Immediate (5-day, and 30-day),
- Scheduled (1-year, 2-year, FPR_{TC}-based, and SME-determined),
- Monitored.

One specific class of anomalies called Non-Corrosion Anomalies (NCA) covers all anomalies where no metal loss has occurred, including hard spots. Enbridge SMEs determine which NCAs require additional inspection or remedial action by considering the following factors:

- The strength of the NCA signal recorded by the ILI tool,
- Interactions with other anomalies,
- Interactions with a longitudinal-seam of low frequency electric-resistance-welded or flash-welded pipe,
- High operating stress level or class location,
- Anomaly length,
- Location of the NCA,
- Casings and depth-of-cover,
- Susceptibility to 3rd party damage.

SOP 9-3010 states that hard spots only require excavation and repair when the Brinell hardness exceeds 300 Brinell.

SOP 9-3010 requires that when Enbridge personnel are determining the length of time between integrity assessments, also known as inspection intervals, they consider the following parameters:

- Operating stress of the pipeline,
- Quantity and severity of remaining unrepaired anomalies,
- Results of anomaly excavations,
- Tolerance of the ILI tool,
- Corrosion growth rates,
- ILI run comparison results,
- Active corrosion found during an excavation,
- Low pipe-to-soil potential readings,
- Significant changes in cathodic protection current requirements.

Enbridge has an additional procedure for ILI data validation, SOP 9-3040, Enhanced Survey Analysis (ESA). It outlines how an analyst performs a “detailed supplemental review … to identify anomalies that might not fit the anomaly filtering criteria” by looking at the raw signal data. The intent of the ESA is to “allow for a detailed quality check to verify documentation and perform a series of data checks, including data validation and integration.” Procedures are specified for standard Magnetic Flux Leakage (MFL) ILI and caliper ILI. Procedures are not specified for Hard Spot MFL (HSMFL) ILI. Enbridge stated, “ the same approach to review signal trace data is not possible for hard spots, EMAT, or other specialized ILI technologies due to certain barriers that exist due to the proprietary nature of the data, specialized expertise for reviewing the data, and limited industry experience when compared to MFL technology.”

SOP 9-4040, Defect Assessment & Repair Options for Dents and Mechanical Damage, outlines what actions Enbridge takes should a dent or other deformation meet their repair criteria. If a dent requires permanent repair, SOP 9-4040 states that the following repair methods may be used if there are no cracks or gouges present:

- Type A full encirclement reinforcement sleeve,
- Type B full encirclement reinforcement sleeve,
- Composite sleeve of appropriate design with filler, or
- Pipe replacement.

SOP 9-4050, Defect Assessment and Repair Options for Miscellaneous Defects, outlines what actions Enbridge takes should a hard spot meet their repair criteria (see Table 3).

Brinell Hardness Range	Cracking Present?	Repair Type	Actions
< 300	No	None, not an integrity threat	Recoat and backfill
> 301 and < 400	No	Permanent repair	Type A or B full encirclement reinforcement sleeve
> 301	Yes	Permanent repair	Type B full encirclement pressure containing sleeve (welded ends) or pipe replacement
> 401	No	Permanent repair	Type B full encirclement pressure containing sleeve (welded ends) or pipe replacement
Unknown	Unknown	Permanent repair	Type B full encirclement pressure containing sleeve (welded ends) with Metallurgy & QA approval or pipe replacement

Table 3. Enbridge hard spot repair methods.

1.2 System Integrity Management - Program / Plan

1.2.1 Background / Overview

The regulations within 49 CFR 192 Subpart O, Gas Transmission Pipeline Integrity Management, are applicable to high consequence areas, as defined in §192.903. Pursuant to the requirements of 49 CFR 192.907 [titled] What must an operator do to implement this subpart?, “… an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §192.911 and that addresses the risks on each covered transmission pipeline segment.”

Regulation under 49 CFR § 192.911 [titled] What are the elements of an integrity management program?[15], requires [under subsection] “(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.”, among other criteria.

Regulation under 49 CFR § 192.935 [titled] What additional preventive and mitigative measures must an operator take?[16], requires [under subsection]:

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[15] Source, and for further information, see [Internet] https://www.ecfr.gov/cgi-bin/text-idx?SID=3128e6bf6c159a15dc370d6132870ab4&mc=true&node=pt49.3.192&rgn=div5#se49.3.192_1911.

[16] Source, and for further information, see [Internet] https://www.ecfr.gov/cgi-bin/text-idx?SID=3128e6bf6c159a15dc370d6132870ab4&mc=true&node=pt49.3.192&rgn=div5#se49.3.192_1935.

> "(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs."

Additionally, as promulgated in API Recommended Practice 1173 Pipeline Safety Management Systems (see further SF Factual Report § 1.6.2), as relevant to the investigation, System Integrity is addressed as an advocated practice of API RP 1173, which, generally described, involves the pipeline operator assuring that … 'pipeline systems … are designed, manufactured, fabricated, installed, operated, maintained, inspected, and tested … to maintain safety in a manner consistent with the specified requirements, regulations, and applicable standards'.[17, 18]

1.2.2 Enbridge - System Integrity Management – Program Content

Enbridge documented to the investigation[19], that it developed, and utilized, a formal, documented System Integrity Management Program (SIMP), which is documented in a publication [of Enbridge] titled "Spectra Energy Integrity Management Program (IMP) Manual", revision dated January 5, 2019. Section 8.0 of the IMP Manual addresses the Enbridge Communications Plan, to which, within that section, the document further addresses the Enbridge Public Awareness Program, wherein within that subsection, narrative further describes utilization of the Enbridge External Communications Plan (see further § 2.1).

Enbridge's integrity management program, as outlined in the IMP Manual, consists of seven elements: high consequence area identification, data management, risk assessment, assessment plan administration, integrity assessments, prevention and mitigation, and response and repair. The IMP manual refers to a series of Threat Response Guidance Documents (TRG) which address the nine categories of threats to pipeline systems.[20]

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[17] Reference, a paraphrased narrative segment of § 8.2.1 [System Integrity] General, of API Recommended Practice 1173 Pipeline Safety Management Systems, © 2018 American Petroleum Institute, Washington, DC.

[18] The investigation noted that compliance with API RP 1173 was voluntary, and not a regulatory requirement.

[19] Source: a document, having the e-document filename "DR12 PLD19FR002 Integrity Management Plan Manual-c2", was made available to the SF investigation during the on-scene phase of the investigation, via transfer to the NTSB Accellion FTP [secure transmittal] website.

[20] For more information on TRG 440 – Manufacturing, which includes material on hard spots, see the Pipeline Operations and Integrity Management Factual Report and supportive docket item [titled] "Pipeline Operations & Integrity Management Attachment #5 - A. O. Smith Purchase Orders".

A review by the investigation, of the seven noted integrity management program elements, identified the following considerations.

a. High Consequence Area Identification

Under 49 CFR 192.903, PHMSA requires pipeline operators use one of two available methods to evaluate whether or not a pipeline segment falls within a high consequence area (HCA). For the vast majority of their pipeline systems, including at the rupture site, Enbridge utilizes Method 2, which defines an HCA as an area within the pipeline’s potential impact radius that contains either: (a) 20 or more buildings intended for human occupancy (with some exceptions), or (b) an identified site. An identified site is a location intended for mass occupancy, such as a stadium or office building, or a facility with occupants that would be difficult to evacuate, such as a nursing home or prison.[21]

b. Data Management

Enbridge collects data on “Covered and Non-Covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and internal inspection records and all other conditions specific to each pipeline.” During risk assessment, “the most current data will be reviewed and analyzed to ensure its relevance in the decision making process.” Enbridge integrates data from sources including “risk assessment software, corrosion control surveys, integrity assessment data, and Subject Matter Expert (SME) input.”

c. Risk Assessment

Enbridge states that the “first step in performing a risk assessment is to identify which threat(s) exist within a covered segment.” Enbridge also has sections of pipe that fall outside of HCAs which they voluntarily include in their integrity management program; these sections are called assessment segments, as stated in their integrity management program.

American Society of Mechanical Engineers (ASME) standard B31.8S, Managing System Integrity of Gas Pipelines, is a standard incorporated by reference into PHMSA regulation and is also referenced in Enbridge’s IMP Manual. It splits all threats to pipeline integrity into nine types which fall under three time-categories (see Table 4).

Enbridge identifies manufacturing threats such as hard spots “through a review of pipe materials, in-service material related failure history, and pressure test history.” Pipe “segments that have not been pressure tested to a minimum of 1.25 times the MAOP, contain susceptible materials, or have a history of material related failures” are considered to be susceptible to manufacturing threats, per Enbridge’s integrity management program.

After identifying potential threats and obtaining relevant data on them, the next step is to determine if any threats interact with one another, and if so, how much. Enbridge considers

[21] Full definition for an identified site can be found in 49 CFR 192.903.

stable threats to be "capable of change only under external influence or changes in operating conditions." Enbridge's IM program does not address interactions between hard spots (as classified within manufacturing-type threats) and external or internal corrosion (see Figure 1).

Time Category	Threat
Time-Dependent	External Corrosion Internal Corrosion Stress Corrosion Cracking
Stable	Manufacturing Construction/Fabrication Equipment
Time-Independent	Mechanical/3rd Party Damage Incorrect Operations Weather/Outside Force

Table 4. Pipeline threats by time categorization.

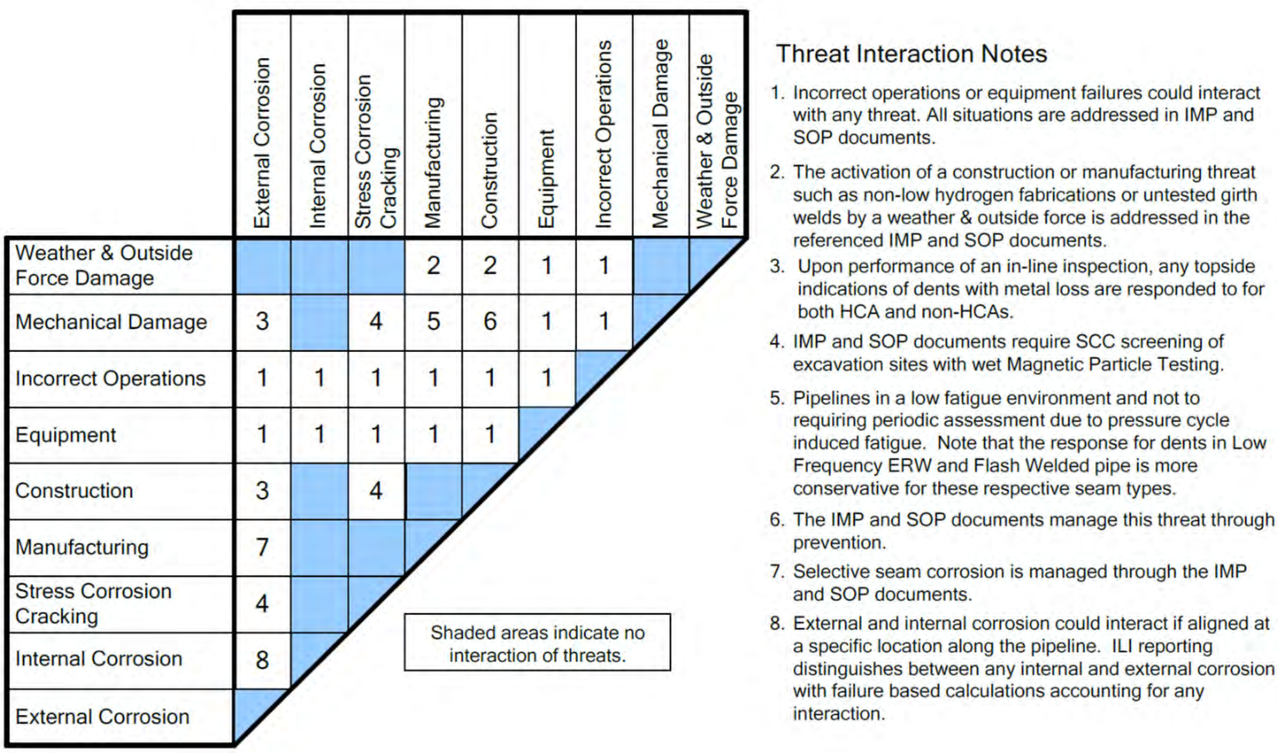

Figure 1. Enbridge threat interaction matrix. Courtesy of Enbridge.

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d. Assessment Plan Administration

Enbridge uses a database to "store all pipeline integrity assessment information on all pipeline segments, covered and non-covered;"; which is described as the assessment plan (AP). The AP "documents the integrity assessment method(s) selected, the assessment date(s), past assessment method(s) and past assessment dates." The AP is managed by the Pipeline Integrity Department, located in Houston, TX. The AP is updated both annually and continuously, depending on the data source. An assessment segment may have multiple types of integrity assessments in the AP, as different threats require different assessments.

e. Integrity Assessments

Time-dependent threats, such as internal and external corrosion, require reassessment on fixed intervals to monitor changes, per federal regulations. Enbridge policy states that stable threats, such as hard spots, require "assessment until effectively mitigated." Enbridge's IMP Manual states that time-independent threats "do not lend themselves to a specific integrity assessment technique," and "prevention is the preferred method of handling this threat."

Enbridge's Integrity Management Program Manual (IMPM) states that "MFL ILI tools are the preferred method of inspection" on natural gas pipelines for time-dependent threats. Pressure-testing is an alternative inspection method allowed by the IMPM for time-dependent threats.

The IMPM states that stable threats "will change only when acted upon by an external situation." If there is a "significant potential for hard spots," the IMPM "requires evaluation of the line using ILI to determine the extent of the problem."

This IMPM section also outlines requirements for qualification of company personnel and vendors when performing integrity assessments. After the assessment, the qualified person who performed the assessment "must review the data to determine if it is of sufficient quality and quantity."

f. Prevention and Mitigation

Enbridge evaluates prevention methods on a case-by-case basis. Personnel look at "the operating pressure, rate of potential release, pipeline profile, potential for pipeline damage, the location of response personnel, the time it takes to shut down the pipeline, and the proximity of populated areas" when determining if preventative measures are necessary. If prevention is deemed prudent, methods can include "increased patrol, increased education efforts, additional SCADA points, remote controlled valves or automatic shutdown valves." Enbridge addresses stable threats primarily through prevention, including modern construction techniques and materials.

Prevention is evaluated through threat teams and annual integrity meetings. On a threat team, a group of SMEs reviews and evaluates data relevant to one of the nine ASME B31.8S threat categories. The threat team looks at risk algorithm data and assumptions, pipeline operating conditions, and possible enhancements to current procedures. Threat teams are to meet at a minimum of once a year.

Annual integrity meetings are held for each covered segment once a year. These meetings are attended by field personnel and the Pipeline Integrity Department. Topics discussed include:

- New or expanded HCAs,
- Threats on each pipeline segment,
- Risk rank/score,
- Any new threats on the pipeline segment and potential new prevention and mitigation measures,
- Confirmation or establishment of assessment method, re-inspection interval and date,
- Past and present assessment results and related remediation work,
- Recent incident/leak data for each segment,
- Corrosion control records/effectiveness,
- Collection of SME data needed for risk analysis,
- Assessment priorities for non-covered segments,
- Remote control valve locations relative to high population areas (HCA/Class III/IV),
- Lessons learned from other areas,
- Local area integrity concerns.

g. Response and Repair

The IMPM defers to other SOPs for information on how and when defects are to be repaired, including SOP 9-4040 and 9-4050.

1.2.3 Evaluation of Integrity Management Program Performance

Enbridge uses four approaches to evaluate the performance of their integrity management program:

(1) the Pipeline Operational Risk Management Committee (PORMC),

(2) internal and external audits by subject matter experts,

(3) the annual IM performance review, and

(4) periodic evaluations of line segments and areas.

The PORMC serves as an oversight committee for the integrity management program. Its 12 core members meet at a minimum twice a year, with the director of pipeline integrity serving as committee chair. Members include personnel from pipeline integrity, technical operations, compliance, technical standards, and metallurgical services. The PORMC has 17 mandated activities, including:

- Analyze performance metrics to evaluate program effectiveness,
- Oversee the development and distribution of technical bulletins to field personnel,
- Track remedial actions from incident investigations,
- Identify opportunities for synergies and/or cost savings across the operating regions,
- Review audit results and track implementation of resulting changes,
- Review industry events and new technologies.

Upon completion of an internal or external audit, the Director of Pipeline Integrity will "forward the final audit report including recommended program changes to the Pipeline Integrity Technical Standards and Compliance group for information and implementation of recommended changes." The PORMC is responsible for tracking the progress of change implementation from these audits.

The annual IM performance review includes the following information:

- Information reported to PHMSA,
- Leading and lagging indicators regarding threat specific measures,
- Number of integrity management program changes requested by jurisdictional authorities,
- Number and type of safety related conditions,
- Number and type abnormal operating conditions,
- Injuries as a result of incidents,
- Fatalities as a result of incidents.

The periodic evaluation is an annual review of each specific pipeline segment or area. It includes information on threat identification and integrity assessments.

1.3 Automatic Shut-Off Valves or Remote-Control Valves

1.3.1 Background / Overview

Pursuant to the requirements of 49 CFR 192.935 [titled] What additional preventive and mitigative measures must an operator take?, in addition to the requirements of subsection (a) (as described, above, in § 1.2.1), requirements of this regulation also include [in subsection]:

> "(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider

the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel."

1.3.2 Enbridge Utilization of Automatic Shut-Off Valves or Remote-Control Valves

The Enbridge Line 15 transmission pipeline does not have any automatic shut-off valves or remote-control valves between the Danville Compressor Station and the Tompkinsville Compressor Station. Enbridge documented to the investigation[22] that the valve closure time was 1:39 a.m. [local time] for the manual block valve to the north of the accident site (i.e., about 16 minutes subsequent to the release), and 2:19 a.m. [local time] for the manual block valve to the south of the accident site (i.e., about 56 minutes subsequent to the release).

Enbridge documented to the investigation[23] that in an After-Action Review of the accident, Enbridge identified that, for a line-item observation titled "Resources Areas for Improvement", it was recognized that "Response time could be improved with the installation of additional Remote Control Valves (RCVs)," which was followed by a "Recommendation - Complete a risk evaluation on response time and current RCV placement".

Given that the After-Action Review document was dated in September 2019, in which Enbridge had been extended, during the on-scene phase of the investigation, an opportunity to make documentation available to the investigation that might describe remediations employed in their transmission pipeline systems to improve safety, no additional documentation was forthcoming from Enbridge that addressed conducting a "risk evaluation on response time and current RCV placement".

1.4 Investigation of Failures – Process by Enbridge

1.4.1 Background / Overview

Pursuant to the requirements of 49 CFR 192.617 [titled] Investigation of failures, "Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.".

Enbridge documented to the investigation[24], that it developed, and utilized, a formal, documented procedure for addressing the investigation of failures, which is documented in a

[22] Source: Enbridge Timeline, as included in the SF Group Chairman's Factual Report, Exhibit 16.

[23] Source: email correspondence from Enbridge SF Group - Party representative to the SF Group Chair, dated 6/04/2020, which contained an e-document having a filename "Lincoln County Incient [sic] Internal Hot Wash Executive Summary", in which the document is dated September 12, 2019, in which the document is included in Exhibit 19 of the SF Group Chairman's Factual Report.

[24] Source: a document, having the e-document filename "DR12 PLD19FR002 Integrity Management Plan Manual-c2", was made available to the SF investigation during the on-scene phase of the investigation, via transfer to the NTSB Accellion FTP [secure transmittal] website.

publication [of Enbridge] that is included in the Enbridge SOP, Volume 5, Emergency Response and Common Procedures, within the procedural guidance documents, [having a procedure by the title of] "Investigation of Failures", Procedure Number: 5-2030, revision [dated] 01/03/2019.

Review of the Procedure Number: 5-2030 content indicated that:

- Section 1.0 through 13.0, inclusive, of the document contained the detailed sequence of annotated steps for the investigative methodology / process to be employed when executing the Investigation of Failures procedure,
- Section 14.0, [titled] "Reporting", contained the narrative "A draft failure investigation report shall be provided to the appropriate Director(s) in Houston Technical Services and Region Technical Management for review and comment. The comments should be transmitted to the Team Leader within 2 weeks of receipt", and
- Section 15.0, [titled] "Share Lessons Learned", contained the narrative "The applicable Regional Technical Management shall ensure that a description of lessons learned from the failure investigation is shared with each field operations office across the pipeline system no later than one month after all corrective action has been identified (refer to Section 12.0). No later than one month after receiving the lessons learned each field operations office shall document that the lessons learned have been shared with applicable personnel and shall document who the personnel were."

Further, corresponding to the above narrative content-points, review of the Procedure Number: 5-2030 content indicated that the document did <u>not</u> indicate that:

- a "final" report was to be complied / completed by the Investigation of Failures process, and
- in the sequence of annotated steps for the investigative methodology / process (i.e., detailed in Procedure Number: 5-2030, Sections 1.0 through 13.0, inclusive), the document does not address compiling any 'Lessons Learned' in the investigation methodology / process, such to be commensurately addressed in Section 15.0, "Share Lessons Learned".

1.4.2 Prior Incident Investigation – 2003 Rupture in Morehead, Kentucky

On November 2, 2003, Line 15 ruptured at MP 501.72 near Morehead, Kentucky, between Danville CS and Owingsville CS, which is the station immediately north of Danville CS.[25] No fatalities or injuries occurred as a result of the rupture or resulting fire, and parallel pipelines Line 10 and Line 25 were not impacted.

Texas Eastern Transmission (TET) [currently owned by Enbridge] was required by PHMSA's predecessor to "conduct a detailed metallurgical analysis […] to determine the cause and contributing factors for the failure." TET hired engineering firm Kiefner & Associates, Inc. (Kiefner) to investigate the rupture cause, including metallurgical testing. At the time of the accident, TET was owned by Duke Energy Gas Transmission (DEGT). DEGT did not perform a

[25] Some reports have the rupture location as MP 501.76; MP 501.72 is sourced from PHMSA documentation.

root cause failure analysis (RCFA) to determine the accident cause and all contributing factors; Enbridge documentation states that RCFA was "not common practice" at the time. However, DEGT did investigate and took actions it determined necessary to address the failure, including a close interval survey in the area around the rupture.

1.4.3 Prior Incident Investigation – 2019 ESD at Danville CS

On May 8, 2019, the Danville Compressor Station experienced an unplanned emergency shutdown (ESD). An ESD is designed to protect a compressor station and its personnel from threats. During an ESD, automated block valves isolate the station from the main pipeline system and automated blow-off valves release the isolated gas to bring the pressure in the station down to atmospheric pressure (0 psig). The ESD on May 8, 2019 was caused by a shorted wire in a direct-current circuit, which, after a series of events, caused a buildup of pressure at the station, which triggered the ESD.

After the incident, Enbridge performed a root cause failure analysis. Enbridge's investigation found that had the station operator "reviewed the station HMI, he would have concluded that valve 10-296 remained open during the ESD event." The report states that the station operator displayed "a lack of understanding of the ESD system" by failing to confirm all valves had operated as intended. Additionally, the investigation found that the gas controller and station operator did not communicate effectively, resulting in the station operator "attempting to manipulate valves that were irrelevant to the event."

Enbridge's investigation contained two recommendations to be completed by January 7, 2020 that were relevant to the station operator's actions:

1. Provide training on station-specific ESD Systems,
2. Develop training material for gas controllers and station operators on how to identify specific valves for better communication.

No further information regarding the completion status of the two Enbridge recommendation action-items, as cited above, has been forthcoming from Enbridge, as of the date of this report.

Enbridge's operator qualification program states that if their internal investigation of an accident finds the employee's performance of a covered task contributed to an accident, that employee "will be deemed disqualified" for that task(s).

2.0 Enbridge - Guidance Documentation to Address Emergency Preparedness / Emergency Response

2.1 Public Awareness Program

2.1.1 Background / Overview

Pursuant to the requirements of 49 CFR 192.616 [titled] Public awareness, a transmission pipeline operator is required to compile a documented Public Awareness Program (PAP), in which, pursuant to the criteria of 49 CFR 192.616(a), “… each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162”, which is “incorporated by reference” in 49 CFR 192.616.

As promulgated in API Recommended Practice 1162 for Public Awareness Programs for Pipeline Operators (as had been described in the SF Factual Report § 1.6.1), generally described, as relevant to the investigation, a PAP involves the effort by, and activities of the pipeline owner / operator, to communicate (distribute) appropriate safety information, in the form of outreach activities, to the jurisdictional emergency services agencies, and to property owners that are situated along the length of the common pipeline ROW. As depicted in the Recommended Practice 1162, the purpose of the PAP is to help assure that the recipients of the distributed safety information become better informed about:

[1] how the pipeline functions,

[2] the responsibilities of the public to help prevent damage to a pipeline, and

[3] measures that can be employed by the recipients of the information to help avoid damage or injury should an anomaly occur in the operation of the pipeline.[26]

2.1.2 Enbridge PAP – Message Content

Enbridge documented to the investigation[27], that it developed, and utilizes, a formal, documented PAP, which is documented in a publication [of the company] titled “Enterprise-Wide Public Awareness Program Plan (External Communications Plan)”, revision dated June 5, 2019.

Review by the investigation of the subject PAP document, indicated that Section 5.0 [titled] Messages, stated the following.

> “The basic message conveyed to the intended stakeholder audiences shall provide information that will enable the Company to meet the PAP objectives. Those objectives include keeping Company employees and the key stakeholder groups identified in Section 4.1 apprised of:
>
> - Presence of pipeline(s) 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,

[26] Source: select narrative elements extracted from API RP 1162 (rev [dated] 2003).

[27] Source: a document, having the e-document filename “DR22A Public Awareness Program Plan 060519_Final.pdf”, was made available to the SF investigation during the on-scene phase of the investigation, via transfer to the NTSB Accellion FTP [secure transmittal] website, in which it was observed that the document contained a notation CONTAINS CONFIDENTIAL INFORMATION in the header of each page.

- Damage reporting process,
- Pipeline location information,
- Summary of HCA and Integrity Management Plans (applicable to [USA] only)
- Right-of-Way encroachment prevention,
- [language applicable to Enbridge Canadian operations is omitted as irrelevant to this investigation],
- Regulatory requirements,
- Security,
- Related facility purpose,
- 811/One Call services and locate request requirements,
- Pipeline location information and availability of the National Pipeline Mapping System (NPMS),
- How to get additional information,
- Emergency and non-emergency contact information,
- Description of pipeline markers and signage.

Information relating to specific line size and/or pressure can be included in the baseline mailing, dependent upon the asset, due to the varying sizes/pressure on Enbridge’s pipelines. This information is provided upon request by contacting [language applicable to Enbridge Canadian operations is omitted as irrelevant to this investigation] or in the U.S by calling the public awareness hotline at 877-799-2650 or emailing USpublicawareness@enbridge.com or Uspublicawareness@vectorpipeline.com.”

Review by the investigation of the PAP pamphlets as distributed to the “affected public” (civilian residential properties), and the PAP pamphlets as distributed to the local emergency services agencies, both as situated proximate to the pipeline right-of-way (ROW), identified that information indicating that the ROW contained three, large (30 inch) diameter, high-pressure (in excess of 900 psi) pipelines, was not cited in the PAP pamphlets. Regulation under 49 CFR 192.616(d) requires five specific items to be included in public awareness materials: 1) information on one-call and other damage prevention activities, 2) possible hazards of a release, 3) physical indications of a release, 4) steps for public safety in the event of a release, and 5) procedures for reporting events.

Debriefing interviews conducted by the SF investigation identified that both the “affected public” (a canvas of residents proximate to the release site), and senior officials of the local emergency services agencies (i.e., the fire departments), indicated that they were unaware of the fact that the pipeline ROW contained three pipelines, in which the pipelines were large (30 inch) diameter, and that the pipelines were operating at high-pressure (in excess of 900 psi).

2.2 Emergency Preparedness and Response Procedures – Measures / Plans

2.2.1 Background / Overview

Pursuant to the requirements of 49 CFR 192.615 [titled] Emergency plans, a transmission pipeline operator is required to compile documented emergency plans, to address the hazard resulting from a gas pipeline emergency. Such plans should include, but are not limited to the elements of communication, a prompt and effective response, fire, explosion, rupture, availability of resources, response actions, emergency shutdown and pressure reduction, notification of appropriate [local] emergency services agencies, establish and maintain liaison with appropriate [local] emergency services agencies and other public officials, among other criteria.

Specific language of 49 CFR 192.615, as applicable to the methodologies / processes / practices to be employed, when an emergency response action is required to be executed by technical personnel of the pipeline operator (i.e., an urgent shutdown of the product flow through the transmission pipelines in the common ROW, as occurred proximate to the accident site), indicates the following.

> "(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
>
> (11) Actions required to be taken by a controller during an emergency in accordance with [49 CFR] §192.631."

2.2.2 Area Emergency Response Plan

Review by the investigation of Volume 5, Emergency Response and Common Procedures, indicated that it contained a series of procedural guidance documents, which included a document [which incorporates a procedure by the title of] *Area Emergency Response Procedures,* Procedure Number: 5-2010.

Review of the Procedure Number: 5-2010 content indicated that, in Section 1.0, "Each operating Area shall develop an Area Emergency Response Plan that is site-specific keeping in mind that facility design and operation vary throughout the system.".

The Stanford Area Emergency Response Plan provides specific details on what activities a station operator should take in response to an ESD for each individual compressor station. For Danville CS, it lists the valves which should be operated during an ESD, both automatically and manually (see Figure 2). There is also a list of activities the station operator should perform to bring the station back online after an ESD.

The Stanford Area Emergency Response Plan also outlines what actions the station operator should take in the event of a rupture, as well as during other abnormal operations. Section 3 provides details on which valves must be closed to isolate specific pipeline segments, along with maps, written directions and detailed schematics of the various valve stations and compressor stations (see Figure 3).

EMERGENCY SHUTDOWN SYSTEM - ACTIVATION

DANVILLE

- Valves that close automatic
  - ⇒ Station suction valves (30") 10-292, 15-393, 25-512
  - ⇒ Station discharge valves (30") 10-296,15-421, 25-530
- Valves that open automatic
  - ⇒ Station blow down SBD-1 (6") Line 10
  - ⇒ Station blow down SBD-2 (8") Line 15
  - ⇒ Station blow down SBD-3 (8") Line 25
- Manually operated valves to open
  - ⇒ (30") Bypass valves - Lines 10, 15, 25

Figure 2. Excerpt from Stanford Area Emergency Response Plan on ESD at Danville CS. Courtesy Enbridge.

LINE	ISOLATION LOCATION		VALVE SIZE	VALVE DESCRIPTION	VALVE #	ACTION
#15	HWY 49 VALVES	M.P. 408.48	30"	M/L VALVE	15-382	CLOSE
			10" X 8"	CROSS OVER	10-281	CK CLOSED
			10" X 8"	CROSS OVER	15-384	CK CLOSED
			10" X 8"	CROSS OVER	25-479	CK CLOSED
			10" X 8"	CROSS OVER	10-279	OPEN
			10" X 8"	CROSS OVER	15-381	OPEN
			10" X 8"	CROSS OVER	25-476	OPEN
	DANVILLE STATION	M.P. 427.20	30"	PLUG VALVE	15-393	CLOSE
			10" X 8"	RECEIVING LN	15-583	CK CLOSED
			10" X 8"	RECEIVING LN	15-395	CK CLOSED
			30" X 24"	BY-PASS	15-409	CK CLOSED
			30"	PIG TRAP	15-387	OPEN

Figure 3. Isolation plan within Stanford Area Emergency Response Plan. Courtesy Enbridge.

D. Authorship

Compiled by: // s // Date July 13, 2021

Alexandria Colletti
Pipeline Investigator
Pipeline Operations and Integrity Management – Technical Working Group Chairperson, and Investigator in Charge (IIC)
Pipeline and Hazardous Materials Division (RPH-20)

Compiled by: // s // Date July 13, 2021

Richard M. Downs, Jr., P.E.
Mechanical Engineer (Crashworthiness)
Survival Factors – Technical Working Group Chairperson
System Safety Division (RPH-40)

-- End of Report --