October 13, 2023

VIA ELECTRONIC MAIL TO: tom.long@energytransfer.com

Thomas Long
Chief Executive Officer
Energy Transfer, LP
8111 Westchester Drive
Dallas, Texas 75225

CPF No. 4-2023-007-CAO

Dear Mr. Long:

Enclosed please find a Corrective Action Order (CAO or Order) issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), in the above-referenced case. It requires Enable Gas Transmission, LLC, a subsidiary of Energy Transfer, LP, to take certain corrective actions with respect to a pipeline rupture that occurred on October 4, 2023, on its 24-inch natural gas transmission pipeline near Jessieville, Arkansas.

Service of the CAO by electronic transmission is deemed complete upon transmission and acknowledgement of receipt, or as otherwise provided under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon completion of service.

Thank you for your cooperation in this matter.

Sincerely,

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Enclosure: CAO

cc: Linda Daugherty, Deputy Associate Administrator for Field Operations, Office of Pipeline Safety, PHMSA
Bryan Lethcoe, Director, Southwest Region, Office of Pipeline Safety, PHMSA

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CONFIRMATION OF RECEIPT REQUESTED

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	
Enable Gas Transmission, LLC, a subsidiary of Energy Transfer, LP,	**CPF No. 4-2023-007-CAO**
Respondent.	

CORRECTIVE ACTION ORDER

Purpose and Background

This Corrective Action Order (CAO or Order) is being issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), under the authority of 49 U.S.C. § 60112 and 49 C.F.R. § 190.233, to require Enable Gas Transmission, LLC (Enable), a subsidiary of Energy Transfer, LP (together "Respondent"), to take the necessary corrective actions to protect the public, property, and the environment from potential hazards associated with the October 4, 2023, failure of its 24-inch natural gas transmission pipeline in Jessieville, Arkansas (Incident). The Incident occurred near Arkansas Highway 298, in a rural area with few buildings.

Respondent's Malvern AR-7 Pipeline System at the Jessieville Junction Station in Garland County, Arkansas, includes the following pipelines that share a common right-of-way: BT-1-AN (24-inch), BT-1 (30-inch), BT-1 (16-inch), and BT-1-AS (16-inch) pipeline. Respondent's BT-1-AN 24-inch pipeline runs approximately 40 miles between the Dunn Compressor Station and Jessieville Junction Station.

At approximately 4:43 p.m. CDT, Respondent's control room personnel received a call from a member of the public reporting a loud noise and fire in the vicinity of the failure. Respondent's control room personnel reviewed BT-1-AN's operating indications and noted pressure dropping with flow increasing. At approximately 4:45 p.m. and 4:47 p.m. CDT, the control room personnel notified Russellville and Malvern pipeline technicians, respectively, of the indication of pressure loss and the information relayed by the public. At approximately 4:48 p.m. CDT, control room personnel received a rate-of-change alarm for the BT-1-AN pipeline, indicating a rapid loss of line pressure. At approximately 4:49 p.m. CDT, pipeline technicians notified the Malvern OPS supervisor of a possible pipeline failure near Jessieville, Arkansas. At approximately 4:53 p.m. CDT, pipeline technicians were dispatched to the reported failure site, and to pipeline isolation valves upstream and downstream of the reported failure location. At approximately 5:29 p.m. CDT, a pipeline technician arrived at the failure site in Jessieville, Arkansas, and confirmed a pipeline failure. At approximately 5:31 p.m. CDT, the downstream isolation valve (Gate 88 Valve) was manually shut approximately 12 miles south of the failure site. At approximately 6:15 p.m. CDT, Respondent determined that the following pipeline segments were impacted: BT-1-AN (24-inch), BT-1 (16-inch), BT-1-AS (16-inch), and BT-1 (30-inch). At approximately 6:30 p.m. CDT, the upstream isolation valve (Dry Fork Valve) was manually shut approximately 13 miles north of the failure site, which isolated BT-1 and BT-1-AN. The failure location was determined to be Respondent's BT-1-AN 24-inch natural gas transmission pipeline at approximately mile post (MP) 3830+51 to 3831+28 (Jessieville Junction Station) in Jessieville, Arkansas. The failure resulted in the ejection of at least two portions of pipe: approximately 34 feet of pipe, which landed on the yard fence towards the northeast approximately 55 feet from the failure location, and approximately 9 feet of pipe, which landed on the other side of the dirt road towards the east approximately 180 feet from the failure location. Other pipeline equipment located at the failure site, including a launching station and associated equipment, was damaged or destroyed. The rupture ignited and resulted in a large fire at the rupture site and smaller fires in the surrounding forest, along the road, and adjacent property. A nearby deer blind and pine trees along the right-of-way were destroyed. Two occupants of a home approximately one mile from the failure site were temporarily evacuated from the residence.

Pursuant to 49 U.S.C. § 60117, PHMSA, OPS, initiated an onsite investigation of the Incident. The preliminary findings of PHMSA's ongoing investigation are outlined below.

Preliminary Findings

- On October 4, 2023, at approximately 4:43 p.m. CDT, Respondent received a call from a member of the public reporting a loud noise and fire in the vicinity of the failure. At approximately 4:44 p.m. CDT, Respondent's control room personnel observed a dropping pressure and increasing flow on the SCADA screen, indicating a possible failure of Respondent's pipeline. At approximately 4:45 p.m. and 4:47 p.m. CDT, the control room personnel notified Russellville and Malvern Team pipeline technicians, respectively, of a possible pipeline failure. At approximately 4:48 p.m. CDT, the control room personnel received a rate-of-change alarm indicating a rapid loss of line pressure.

- At approximately 4:49 p.m. CDT, the Malvern Team pipeline technician notified the Operations Supervisor (OPS supervisor) of a possible pipeline failure with a fire near Jessieville, Arkansas. At approximately 4:50 p.m. CDT, control room personnel notified the Gas Control Manager of the potential failure and requested support. At approximately 4:53 p.m. CDT, the OPS supervisor notified the Senior Director of Operations of a potential failure on the BT pipeline system, and Malvern pipeline technicians were dispatched to the failure site near Jessieville, Arkansas, and Dry Fork Valve and Gate 88 Valve upstream and downstream of the failure site, respectively.

- At 5:04 p.m. CDT, the Gas Control Manager notified the Senior Director of Gas Control and System Planning of the potential failure. At approximately 5:13 p.m. CDT, the Gas Control Manager notified the Lead Mechanic of the Dunn Team and requested on-site support at the Dunn Compressor Station. At approximately 5:19 p.m. CDT, the Senior Director of Operations set up a Teams conference bridge with stakeholders to assist in facilitating the isolation and control of the potential failure.

- At approximately 5:29 p.m. CDT, the pipeline technician arrived at the failure site and confirmed a pipeline failure with a fire at Jessieville Junction. At approximately 5:31 p.m. CDT, a Malvern pipeline technician isolated the BT-1-AS 16-inch pipeline at downstream Gate 88 Valve.

- At approximately 6:15 p.m. CDT, Respondent determined that the BT-1-AN 24-inch, BT-1 16-inch, BT-1-AS 16-inch, and BT-1 30-inch pipelines were impacted by the failure, and the BT-1 16-inch pipeline was isolated at downstream Gate 88 Valve. At approximately 6:30 p.m. CDT, a pipeline technician isolated BT-1 and BT-1-AN at upstream Dry Fork Valves. At approximately 11:05 p.m. CDT, Respondent's on-site personnel confirmed that the fire at the failure site had significantly diminished and was under control. Respondent's personnel remained overnight at the location of the failure, Gate 88 Valve, and Dry Fork Valves.

- At approximately 7:44 a.m. CDT on October 5, 2023, Respondent confirmed that the fire at the failure site was extinguished. At approximately 8:00 a.m. CDT, Respondent initiated the operation of air movers at both the Dry Fork Valve and Gate 88 Valve. At approximately 12:55 p.m. CDT, the failure site was cleared for access.

- Both BT-1-AN 24-inch and BT-1 16-inch pipelines were isolated from approximately 13 miles upstream (north of failure location) at Dry Fork Valve and 12 miles downstream (south of failure location) at Gate 88 Valve. All pipelines entering and leaving the Jessieville Junction Station remain in a shutdown condition.

- The failure occurred at approximately mile post (MP) 3830+51 to 3831+28 at Jessieville Junction Station on Respondent's Malvern AR-7 Pipeline System BT-1-AN 24-inch line in Jessieville, Arkansas.

- Respondent reported the Incident to the National Response Center (NRC) at 5:44 p.m. CDT on October 4, 2023 (NRC Report No. 1380909), indicating there was a fire and release of gas of approximately 99,860 MCF.

- The natural gas was released to the atmosphere with no injuries or fatalities associated with this incident. Two occupants of a home approximately one mile from the failure location were temporarily evacuated from the residence. The failure resulted in an explosion and fire when the gas ignited and caused the ejection of at least two portions of pipe: approximately 34 feet of 24-inch pipe, which landed on the yard fence towards the northeast direction approximately 55 feet from the failure location, and approximately 9 feet of 24-inch pipe, which landed on the other side of the dirt road towards the east direction approximately 180 feet from the failure location. A third small piece of pipe was discovered approximately 90 feet to the southwest of the failure site. It is currently unknown whether the third piece was ejected as a result of the pipeline failure.

- Launching equipment for the 16-inch BT-1 pipeline was destroyed in the rupture.

- The maximum allowable operating pressure (MAOP) of BT-1-AN is 1000 pounds per square inch gauge (psig), which was determined by hydrostatic testing under 49 C.F.R. § 192.619(a)(2). The operating pressure before the Incident was 960 psig, and 562 psig immediately after the failure. The maximum operating pressure between September 28, 2023, and October 4, 2023, was recorded at 978 psig. The discharge pressure at the Dunn Compressor Station is set at 780 psig.

- The MAOP of BT-1 (16-inch) is 1000 pounds per square inch gauge (psig), which was determined by hydrostatic testing under 49 C.F.R. § 192.619(a)(2). The normal operating pressure is 960 psig.

- Respondent shut the downstream Gate 88 Valve, approximately 12 miles south of the Incident, at 5:31 p.m. CDT, and shut the upstream Dry Fork Valve, approximately 13 miles north of the Incident at 6:30 p.m. CDT. Respondent also shut in the parallel line at similar distances.

- The BT-1-AN pipeline was constructed of 24-inch OD x 0.281-inch w.t., X-60 double submerged arc welded (DSAW) pipe manufactured by U.S. Steel in 1967. The coating type of the failed BT-1-AN pipeline segment is unknown. The pipeline is cathodically protected.

- The BT-1 pipeline was constructed of 16-inch OD x 0.25-inch w.t., X-46 electric resistance welded (ERW) pipe constructed in 1984. The coating type of the 16-inch BT-1 pipeline segment is unknown. The pipeline is cathodically protected.

- Respondent's BT-1 (16- and 30-inch), BT-1-AN (24-inch), and BT-1-AS (16-inch) pipelines are gas pipeline facilities subject to the pipeline safety laws in 49 U.S.C. chapter 601 and 49 C.F.R. part 192.

- BT-1-AN is one of two parallel natural gas transmission pipelines in a common right-of-way. The two parallel pipelines are comprised of four separately named pipelines that connect at a common manifold at Jessieville Junction Station. BT-1-AN runs from Dunn Compressor Station to Jessieville Junction Station for approximately 40 miles. BT-1 16-inch pipeline runs parallel with BT-1-AN between Dunn Compressor Station and Jessieville Junction Station. BT-1-AS runs from Jessieville Junction Station to the Gate 88 Valve. BT-1 30-inch pipeline runs parallel with BT-1-AS between Jessieville Junction Station and Gate 88 Valve.

- BT-1-AN, BT-1-AS, and BT-1 (16- and 30-inch) traverse mostly Class 1 and 2 locations. The Incident occurred in a heavily forested area with potential impacts to wildlife.

- A visual inspection of the failed pipe segment by Respondent's on-site personnel appeared to show an area of extensive external corrosion with one area reading 0.130-inches or 46% remaining wall thickness. The rupture and ignition of the pipeline caused extensive damage to nearly all aboveground piping and appurtenances at the Jessieville Junction Station.

- Respondent has begun preparation to transport pipe samples from the failed segment to a third-party lab for examination. Respondent began excavation of the two ends of the ruptured pipe at approximately 4:00 p.m. CDT on October 6, 2023. On October 7, 2023, the two known ejected pieces (34-feet, 9-feet), and the small piece that is of unknown origin, were loaded onto a truck and shipped to Houston, Texas, for testing. The two ends of the pipe that the ejected piece broke away from will be shipped out on a later truck.

- On May 2, 2019, Respondent's Malvern AR-7 BT-1 30-inch pipeline (5.67 miles south of the Incident) ruptured due to near-neutral pH stress corrosion cracking in an area of external corrosion. On November 24, 2014, Respondent's Malvern AR-7 BT-1-AN 24-inch pipeline (1.25 miles north of the Incident) cracked due to near-neutral pH stress corrosion cracking.

Determination of Necessity for Corrective Action Order and Right to Hearing

Section 60112 of Title 49, United States Code, authorizes PHMSA to determine that a pipeline facility is or would be hazardous to life, property, or the environment and if there is a likelihood of serious harm, to issue an order without prior notice to the operator of the facility to take necessary corrective action, including suspended or restricted use of the facility, physical inspection, testing, repair, replacement, or other appropriate action. An order issued without notice must provide an opportunity for a hearing as soon as practicable after the order is issued.

In deciding whether to issue an order, PHMSA must consider the following, if relevant: (1) the characteristics of the pipe and other equipment used in the pipeline facility, including the age, manufacturer, physical properties, and method of manufacturing, constructing, or assembling the equipment; (2) the nature of the material the pipeline facility transports, the corrosive and deteriorative qualities of the material, the sequence in which the material are transported, and the pressure required for transporting the material; (3) the aspects of the area in which the pipeline facility is located, including climatic and geologic conditions and soil characteristics; (4) the proximity of the area in which the natural gas pipeline facility is located to environmentally sensitive areas; (5) the population density and population and growth patterns of the area in which the pipeline facility is located; (6) any recommendation of the National Transportation Safety Board made under another law; and (7) other factors PHMSA may consider appropriate.

After evaluating the foregoing preliminary findings of fact, and having considered the age of the pipelines, the material properties of the pipelines, the hazardous nature of the product transported, the proximity of the pipelines to heavily forested areas and a residential home, the pressure required for transporting the material, the uncertainty as to the cause of the failure, the uncertainty of potential impacts of the Incident to the parallel pipeline (BT-1 16-inch), the destruction of launching equipment associated with BT-1 (16-inch), a prior failure on this pipeline (BT-1-AN) in 2014 approximately 1.25 miles north of the Incident location due to near-neutral pH stress corrosion cracking, a more recent failure in 2019 downstream of the Incident (BT-1 30-inch) also due to near-neutral pH stress corrosion cracking, and the possibility that the same condition(s) that may have caused the October 4, 2023, failure remain present in the pipeline that failed and parallel pipeline (16-inch BT-1 & BT-1-AS), I find that continued operation of the pipeline without corrective measures is or would be hazardous to life, property, or the environment, and that failure to issue this Order without notice would result in the likelihood of serious harm.

Accordingly, under 49 C.F.R. § 190.233(b), this Order mandating immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, with a copy to the Director, Southwest Region, PHMSA (Director). If a hearing is requested, it will be held in accordance with 49 C.F.R. § 190.211.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken. Respondent will be notified of any additional measures required and, if appropriate, PHMSA will consider amending this Order. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Actions

<u>Definitions:</u>

Affected Pipelines – The *"Affected Pipelines"* means Respondent's 16-inch (BT-1) and 24-inch (BT-1-AN) natural gas transmission pipelines upstream of Jessieville Junction Station (from Dunn Compressor Station to Jessieville Junction Station) and the 16-inch (BT-1-AS) and 30-inch (BT-1) natural gas transmission pipelines downstream of Jessieville Junction Station (from Jessieville Junction Station to the Gate 88 Valve).

Isolated Segments **–** The "*Isolated Segments*" means both the 16-inch (BT-1) and the 24-inch (BT-1-AN) segments upstream of Jessieville Junction Station (from Dry Fork Valve to Jessieville Junction Station) and the 16-inch (BT-1-AS) and 30-inch (BT-1) downstream of the Jessieville Junction Station (from Jessieville Junction Station to the Gate 88 Valve).

Director – The Director, Southwest Region, Office of Pipeline Safety, PHMSA, 8701 S. Gessner, Suite 630 Houston Texas 77074.

Pursuant to 49 U.S.C. § 60112, I hereby order Respondent to immediately take the following corrective actions:

1. ***Shutdown of the Isolated Segments.*** The *Isolated Segments* are currently out of service. The *Isolated Segments* must remain shut-in and may not be operated until authorized to be restarted by the Director in accordance with the terms of this Order.

2. ***Operating Pressure Restriction.*** Respondent must reduce and maintain a twenty percent (20%) pressure reduction in the actual operating pressure along the entire length of the *Affected Pipelines* such that the operating pressure along the *Affected Pipelines* will not exceed eighty percent (80%) of the actual operating pressure in effect along the *Affected Pipelines* immediately prior to the Incident.

   a. This pressure restriction is to remain in effect until written approval to increase the pressure or return the pipeline to its pre-failure operating pressure is obtained from the Director. This written approval may be obtained on an individual pipeline basis within the *Affected Pipelines*.

   b. Within 15 days of receipt of this Order, Respondent must provide the Director the actual operating pressures of each compressor station and each main line pressure regulating station on the *Affected Pipelines* at the time of failure and the reduced pressure restriction set-points at these same locations.

   c. This pressure restriction requires any relevant remote or local alarm limits, software programming set-points or control points, and mechanical over-pressure devices to be adjusted accordingly.

   d. When determining the pressure restriction set-points, Respondent must take into account any in-line inspection (ILI) features or anomalies present in the *Affected Pipelines* to provide for continued safe operation while further corrective actions are completed.

   e. Respondent must review the pressure restriction monthly by analyzing the operating pressure data, taking into account any ILI features or anomalies present in the *Affected Pipelines.* Respondent must immediately reduce the operating pressure further to maintain the safe operations of the *Affected Pipelines*, if warranted by the monthly review. Further, Respondent must submit the results of the monthly review to the Director including, at a minimum, the current discharge set-points (including any additional pressure reductions), and any pressure exceedance at discharge set-points. Submittals must be made quarterly, in accordance with Item 14 below.

3. ***Restart Plan.*** Prior to resuming operation of the *Isolated Segments,* develop and submit a written *Restart Plan* to the Director for prior approval.

   a. The Director may approve the *Restart Plan* incrementally without approving the entire plan, but the *Isolated Segments* cannot resume operation until the *Restart Plan* is approved in its entirety.

   b. Once approved by the Director, the *Restart Plan* will be incorporated by reference into this Order.

   c. The *Restart Plan* must provide for adequate patrolling of the *Isolated Segments* during the restart process and must include incremental pressure increases during start up, with each increment to be held for at least two hours.

   d. The *Restart Plan* must include sufficient surveillance of the pipeline during each pressure increment to ensure that no leaks are present when operation of the line resumes.

   e. The *Restart Plan* must specify a day-light restart and include advance communications with local emergency response officials.

   f. The *Restart Plan* must provide for a review of the *Isolated Segments* for conditions similar to those of the failure including a review of construction, operating and maintenance (O&M) and integrity management records such as ILI results, hydrostatic tests, root cause failure analysis of prior failures, aerial and ground patrols, corrosion, cathodic protection, excavations, and pipe replacements. Respondent must address any findings that require remedial measures to be implemented prior to restart.

   g. The *Restart Plan* must also include documentation of the completion of all mandated actions, and a management of change plan to ensure that all procedural modifications are incorporated into Respondent's O&M procedures manual.

   h. The *Restart Plan* must provide for hydrostatic pressure testing of the *Isolated Segments.*

4. ***Return to Service.*** After the Director approves the *Restart Plan*, Respondent may return the *Isolated Segments* to service but the operating pressure must not exceed the pressure restrictions in accordance with Item 2 above.

5. ***Removal of Pressure Restriction***.

   a. The Director may allow the removal or modification of the pressure restriction upon a written request from Respondent demonstrating that restoring the pipeline to its pre-failure operating pressure is justified based on a reliable engineering analysis showing that the pressure increase is safe considering all known defects, anomalies, and operating parameters of the pipeline.

   b. The Director may allow the temporary removal or modification of the pressure restrictions upon a written request from Respondent demonstrating that temporary mitigative and preventive measures are implemented prior to and during the temporary removal or modification of the pressure restriction. The Director's determination will be based on available information, including the failure cause and provision of evidence that preventative and mitigative actions taken by the operator provide for the safe operation of the *Affected Pipelines* during the temporary removal or modification of the pressure restriction. Appeals to determinations of the Director in this regard will be decided by the Associate Administrator for Pipeline Safety.

6. ***Mechanical and Metallurgical Testing***. Within 45 days of receipt of this Order, Respondent must complete mechanical and metallurgical testing and failure analysis of the failed pipe, including an analysis of soil samples and any foreign materials. Mechanical and metallurgical testing must be conducted by an independent third-party approved by the Director, and must document the decision-making process and all factors contributing to the failure. Respondent must complete the testing and analysis as follows:

a. Document the chain-of-custody when handling and transporting the failed pipe section and other evidence from the failure site.

b. Within 10 days of receipt of this Order, develop and submit the testing protocol and the proposed testing laboratory to the Director for prior approval.

c. Prior to beginning the mechanical and metallurgical testing, provide the Director with the scheduled date, time, and location of the testing to allow for an OPS representative to witness the testing.

d. Ensure the testing laboratory distributes all reports whether draft or final in their entirety to the Director at the same time they are made available to Respondent.

7. ***Root Cause Failure Analysis.*** Within 90 days following receipt of this Order, complete a root cause failure analysis (RCFA) and submit a final report of this RCFA to the Director. The RCFA must be supplemented or facilitated by an independent third-party approved by the Director and must document the decision-making process and all factors contributing to the failure. The final report must include findings and any lessons learned and whether the findings and lessons learned are applicable to other locations within Respondent's pipeline system.

8. ***Remedial Work Plan (RWP)***.

a. Within 90 days following receipt of this Order, Respondent must submit a *remedial work plan* (RWP) to the Director for approval.

b. The Director may approve the RWP incrementally without approving the entire RWP.

c. Once approved by the Director, the RWP will be incorporated by reference into this Order.

d. The RWP must specify the tests, inspections, assessments, evaluations, and remedial measures Respondent will use to verify the integrity of the *Affected Pipelines*. It must address all known or suspected factors and causes of the Incident. Respondent must consider the risks and consequences of another failure to develop a prioritized schedule for RWP-related work along the *Affected Pipelines.*

e. The RWP must include a procedure or process to:

i. Identify pipe in the *Affected Pipelines* with characteristics similar to the contributing factors identified for the Incident, including the age and manufacturer of the entire length of the *Affected Pipelines*.

ii. Gather all data necessary to review the failure history (in service and pressure test failures) of the *Affected Pipelines* and to prepare a written report containing all the available information such as the locations, dates, and causes of leaks and failures.

iii. Integrate the results of the metallurgical testing, root cause failure analysis, and other corrective actions required by this Order with all relevant pre-existing operational and assessment data for the *Affected Pipelines.* Pre-existing operational data includes, but is not limited to, design, construction, operations, maintenance, testing, repairs, prior metallurgical analyses, and any third-party consultation information. Pre-existing assessment data includes, but is not limited to, ILI tool runs, hydrostatic pressure testing, direct assessments, close interval surveys, and DCVG/ACVG surveys.

iv. Determine if conditions similar to those contributing to the Incident are likely to exist elsewhere on the *Affected Pipelines.*

v. Conduct additional field tests, inspections, assessments, and evaluations to determine whether, and to what extent, the conditions associated with the Incident and other failures from the failure history (see (e)(ii) above) or any other integrity threats are present elsewhere on the *Affected Pipelines*. At a minimum, this process must include hydrostatic pressure testing of the *Isolated Segments*, must consider all failure causes and must specify the use of one or more of the following:

1) ILI tools that are technically appropriate for assessing the pipeline system based on the cause of Incident and that can reliably detect and identify anomalies;
2) Close-interval surveys;
3) Cathodic protection surveys, to include interference surveys in coordination with other utilities (e.g. underground utilities, overhead power lines, etc.) in the area;
4) Coating surveys;
5) Stress corrosion cracking surveys;
6) Selective seam corrosion surveys; and
7) Other tests, inspections, assessments, and evaluations appropriate for the failure causes.

Note: Respondent may use the results of previous tests, inspections, assessments, and evaluations if approved by the Director, provided the results of the tests, inspections, assessments, and evaluations are analyzed with regard to the factors known or suspected to have caused the Incident.

vi. Describe the inspection and repair criteria Respondent will use to prioritize, excavate, evaluate, and repair anomalies, imperfections, and other identified integrity threats. Include a description of how any defects will be graded and a schedule for repairs or replacement.

vii. Based on the known history and condition of the *Affected Pipelines,* describe the methods Respondent will use to repair, replace, or take other corrective measures to remediate the conditions associated with the Incident and to address other known integrity threats along the *Affected Pipelines*. The repair, replacement, or other corrective measures must meet the criteria specified in (e)(vi) above.

viii. Implement continuing long-term periodic testing and integrity verification measures to ensure the ongoing safe operation of the *Affected Pipelines* considering the results of the analyses, inspections, evaluations, and corrective measures undertaken pursuant to the Order.

f. Include a proposed schedule for completion of the RWP.

g. Respondent must revise the RWP as necessary to incorporate new information obtained during the failure investigation and remedial activities, to incorporate the results of actions undertaken pursuant to this Order, and to incorporate modifications required by the Director.

   i. Submit any plan revisions to the Director for prior approval.

   ii. The Director may approve plan revisions incrementally.

   iii. All revisions to the RWP after it has been approved and incorporated by reference into this Order will be fully described and documented in the *CAO Documentation Report*.

h. Implement the RWP as it is approved by the Director, including any revisions to the plan.

9. ***Instrumented Leakage Survey***. Within 30 days of receipt of this Order, Respondent must perform an aerial or ground instrumented leakage survey of the *Affected Pipelines.* Respondent must investigate all leak indications and remedy all leaks discovered. Respondent must submit documentation of this survey to the Director within 45 days of receipt of this Order.

10. ***Records Verification***. Respondent must verify the records for the *Affected Pipelines* that were used to establish the MAOP in accordance with § 192.619, including any adjustments needed for the current class locations per §§ 192.609 and 192.611. Respondent must submit documentation of this records verification to the Director within 45 days of receipt of this Order.

11. ***CAO Documentation Report (CDR)***. Respondent must create and revise, as necessary, a CAO Documentation Report (CDR). When Respondent has concluded all the items in this Order it will submit the final CDR in its entirety to the Director. This will allow the Director to complete a thorough review of all actions taken by Respondent with regards to this Order prior to approving the closure of this Order. The intent is for the CDR to summarize all activities and documentation associated with this Order in one document.

    a. The Director may approve the CDR incrementally without approving the entire CDR.

    b. Once approved by the Director, the CDR will be incorporated by reference into this Order.

    c. The CDR must include, but is not necessarily limited to, the following:

       i. Table of Contents;

       ii. Summary of the Incident and the response activities;

       iii. Summary of pipe data, material properties and all prior assessments of the *Affected Pipelines*;

       iv. Summary of all tests, inspections, assessments, evaluations, and analysis required by the Order;

       v. Summary of the mechanical and metallurgical testing as required by the Order;

       vi. Summary of the RCFA with all root causes as required by the Order;

vii. Documentation of all actions taken by Respondent to implement the RWP, the results of those actions, and the inspection and repair criteria used;

viii. Documentation of any revisions to the RWP including those necessary to incorporate the results of actions undertaken pursuant to this Order and whenever necessary to incorporate new information obtained during the failure investigation and remedial activities;

ix. Lessons learned while completing this Order;

x. A path forward describing specific actions Respondent will take on its entire pipeline system as a result of the lessons learned from work on this Order; and

xi. Appendices (if required).

Other Requirements:

12. ***Approvals.*** With respect to each submission that under this Order requires the approval of the Director, the Director may: (a) approve, in whole or part, the submission; (b) approve the submission on specified conditions; (c) modify the submission to cure any deficiencies; (d) disapprove in whole or in part, the submission, directing that Respondent modify the submission, or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Director, Respondent shall proceed to take all action required by the submission as approved or modified by the Director. If the Director disapproves all or any portion of the submission, Respondent must correct all deficiencies within the time specified by the Director and resubmit it for approval.

13. ***Extensions of Time.*** The Director may grant an extension of time for compliance with any of the terms of this Order upon a written request timely submitted demonstrating good cause for an extension.

14. ***Reporting.*** Submit quarterly reports to the Director that: (1) include all available data and results of the testing and evaluations required by this Order; and (2) describe the progress of the repairs or other remedial actions being undertaken. The first quarterly report is due on November 30, 2023. The Director may change the interval for the submission of these reports.

15. ***Documentation of the Costs.*** It is requested but not required that Respondent maintain documentation of the costs associated with implementation of this Corrective Action Order. Include in each monthly report submitted, the to-date total costs associated with: (1) preparation and revision of procedures, studies, and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.

Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. § 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

In your correspondence on this matter, please refer to "CPF No. 4-2023-007-CAO" and for each document you submit, please provide a copy in electronic format whenever possible. The actions required by this Order are in addition to and do not waive any requirements that apply to Respondent's pipeline system under 49 C.F.R. Parts 190 through 199, under any other order issued to Respondent under authority of 49 U.S.C. Chapter 601, or under any other provision of federal or state law.

Respondent may appeal in writing any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator shall be final.

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 U.S.C. § 60120.

The terms and conditions of this Order are effective upon service in accordance with 49 C.F.R. § 190.5.

________________________________ October 13, 2023

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Date Issued