



U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

February 18, 2022

VIA ELECTRONIC MAIL TO: kenneth_grubb@kindermorgan.com

Mr. Kenneth Grubb
Chief Operating Officer
1001 Louisiana St.
Suite 1000
Houston, Texas 77002

Re: CPF No. 2-2022-007-CAO

Dear Mr. Grubb,

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 Southern Natural Gas Co., a subsidiary of Kinder Morgan, Inc., to take certain corrective actions with respect to a pipeline failure that occurred on February 13, 2022, on the 18-inch South Main Line in Perry County, Alabama.

Service of the CAO by electronic mail is effective upon the date of transmission and acknowledgment of receipt as provided under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon completion of service.

Sincerely,

ALAN KRAMER MAYBERRY
Digitally signed by ALAN
KRAMER MAYBERRY
Date: 2022.02.18
14:21:30 -05'00'

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Enclosure: CAO

cc: Mr. James Urisko, Director, Southern Region, Office of Pipeline Safety, PHMSA
Mr. Jaime Hernandez – Director – Engineering: Codes and Standards, Kinder Morgan,
jaime_hernandez@kindermorgan.com

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)	
)	
)	
Southern Natural Gas Co.,)	
a subsidiary of Kinder Morgan, Inc.)	CPF No. 2-2022-007-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, to require Southern Natural Gas Co. (SNG or Respondent), a subsidiary of Kinder Morgan, Inc.,¹ to take necessary corrective actions to protect the public, property, and the environment from potential hazards associated with the February 13, 2022, natural gas pipeline failure that occurred on the 18-inch South Main Line at mile post 155.7, resulting in a rupture and fire, in Perry County, Alabama (Incident).

The South Main System consists of approximately 504 right-of-way (ROW) miles of the 18-inch and 16-inch South Main Line and multiple large diameter loop lines traversing from Gwinville, Mississippi (MP 0) to Aiken, South Carolina (MP 504). The South Main System is in Mississippi, Alabama, Georgia, and South Carolina. Approximately 379 miles of the 16- and 18-inch South Main Line were declared in-service in 1951, including the failed pipe. The 18-inch portion of the South Main Line terminates and transitions to the 16-inch diameter South Main Line at the Elmore Compressor Station in Elmore, Alabama. SNG's above-referenced loop lines in the common ROW at the failure location are the South Main Loop, South Main 2nd Loop, and South Main 3rd Loop.

At approximately 04:42 PM Central Standard Time (CST) the pipeline ruptured, ejecting a five-foot section of the pipe approximately 72 feet and initiating a fire that burned nearby vegetation. A Perry County, Alabama, resident called the Kinder Morgan Gas Control to report a fire had been observed on SNG's pipeline ROW.

¹ Southern Company, Kinder Morgan Enter Southern Natural Gas Pipeline Strategic Venture, Kinder Morgan (July 10, 2016), <https://ir.kindermorgan.com/news/news-details/2016/Southern-Company-Kinder-Morgan-Enter-Southern-Natural-Gas-Pipeline-Strategic-Venture/default.aspx>.

Upon being notified of the Incident, Respondent's personnel isolated the line at mainline valve (MLV) #1 located at Gate #18 and MLV #1 located at Gate #19, upstream and downstream, respectively, of the failure location to depressurize the line and extinguish the fire. Subsequently, SNG personnel isolated the adjacent 18-inch South Main Loop line and performed an inspection of the pipeline failure site. Respondent estimated a volume release of 171,159 MCF of natural gas.

The pressure was not reduced on the remaining adjacent lines (the South Main 2nd Loop and the South Main 3rd Loop). The pressure in the 18-inch South Main Loop has been restored to normal operating pressure. The failed 18-inch South Main Line is currently shut-in.

Pursuant to 49 U.S.C. § 60117, PHMSA initiated an investigation of the Incident. The preliminary findings of the Agency's ongoing investigation are as follows:

Preliminary Findings

- At approximately 04:42 PM CST on February 13, 2022, a natural gas pipeline failure occurred on the 18-inch South Main Line at Mile Post (MP) 155.7, resulting in rupture and fire in Perry County, Alabama. The town nearest to the location of the Incident is Uniontown, Alabama.
- The rupture ejected a five-foot section of the pipe approximately 72 feet and initiated a fire that burned nearby vegetation. The Incident occurred in a Class 1 area and a non-high consequence area (HCA). There were no reported fatalities, injuries, or evacuations.
- A Perry County, Alabama, resident called Kinder Morgan Gas Control to report a fire had been observed on SNG's pipeline right-of-way.
- Respondent reported the Incident to the National Response Center (NRC) at 06:34 PM Eastern Standard Time (EST) on February 13, 2022. SNG gave an updated report to the NRC at 02:25 PM EST on February 15, 2022.
- After being notified of the Incident, SNG personnel closed main line valves on the South Main Line at MLV #1 at Gate #18 and MLV #1 at Gate #19, upstream and downstream, respectively, of the failure location to depressurize the line and extinguish the fire.
- After extinguishing the fire, SNG personnel isolated the adjacent 18-inch South Main Loop line and performed an inspection of the pipeline failure site. Respondent estimated a volume release of 171,159 MCF.
- The pressure was not reduced on the remaining loop lines: the South Main 2nd Loop and the South Main 3rd Loop.
- The pressure in the 18-inch South Main Loop line has been restored to normal operating pressure. The failed South Main Line is currently shut-in.

- The South Main Line was manufactured in 1951. It is an A.O. Smith pipe with flash weld longitudinal seam, 0.312 wall thickness, API 5L grade X52 (52,000 pounds per square inch specified minimum yield strength), with coal tar enamel coating.
- Approximately 379 miles of the 16- and 18-inch South Main Line were declared in-service in 1951, including the failed pipe.
- Prior to the failure, the 18-inch South Main Line operated at a pressure of 1170 pounds per square inch gauge (psig).
- The maximum allowable operating pressure (MAOP) of the 18-inch South Main Line is 1200 psig.
- In March 2008, in Sumter County, Alabama, the 18-inch, 1951 A.O. Smith flash weld pipe (X52) on the South Main Line experienced a girth weld failure. The girth weld failed due to high tensile stresses likely due to improper backfill from recent excavation. Metallurgical analysis revealed the girth weld was found to be deficient from the original construction.
- This line was assessed in 2014 with a magnetic flux leakage in-line inspection tool.
- The cause of the Incident is currently unknown. While probable cause has not yet been established, the failed pipe was 1951 vintage, manufactured by A.O. Smith with a flash weld longitudinal seam, which has a history of being susceptible to significant anomalies due to inconsistent weld seam quality and hard spots. Additionally, pipe having low-frequency, flash-welded longitudinal seams are a known threat to pipeline integrity under certain conditions.
- Pre-1970 low-frequency electric resistance weld (ERW) pipe, including flash welded pipe, has been the focus of many studies and reviews. A final report *TTO Number 5, Integrity Management Program Delivery Order DTRS56-02-D-70036, Integrity Management Program regarding Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation* (Revision 3) was prepared by Michael Baker in association with Kiefner and Associates, Inc., CorrMet Engineering Services, PC, in April 2004. The report was written to support the importance of operators correctly selecting integrity assessment methods capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
- The Battelle Memorial Institute issued a report on the integrity characteristics of vintage pipelines in 2005. The Battelle study stated that hard spots develop during hot rolling of a steel plate when an uncontrolled jet of water locally cools a portion of the plate too quickly. The water-quenched areas form untampered martensite, with hardness levels locally much higher than the remainder of the pipe. If the coating does not have good adhesion or has been damaged, it can be exposed to hydrogen. If cathodic protection (CP) levels are above or below certain voltage levels, hydrogen can be generated. Typically, this occurs in pipelines that operate at higher stress levels.
- ERW pipe manufactured prior to 1970 has a history of increased risk of seam failures. PHMSA issued two advisory bulletins (ALN-88-01 on January 28, 1988, and ALN-89-01

on March 8, 1989) regarding factors contributing to operational failures of pipelines constructed with ERW pipe manufactured prior to 1970. PHMSA identified selective corrosion of the ERW seam as a contributing cause of failure in a significant number of these accidents. Other failures have occurred due to the growth of manufacturing defects in ERW seams. The advisory bulletins recommended that operators reevaluate the potential for safety problems on their high-pressure pre-1970 ERW pipelines by hydrostatic testing on those pipelines, ensuring the effectiveness of cathodic protection systems, and taking additional safety measures.

- Under 192.917(e), if a covered pipeline segment contains ERW pipe, lap welded pipe, or other conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The failure location appears to be a non-covered pipeline segment.

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 expeditiously order 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 expeditiously 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, manufacture, 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 is 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 hazardous liquid 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) any other factors PHMSA may consider as appropriate.

After evaluating the foregoing preliminary findings of fact, and having considered the characteristics of the pipeline, including the prior failure of the pipeline and the known issues with 1951 A.O. Smith pipe with a flash weld longitudinal seam; the known threat to pipeline integrity from pipe having low-frequency, flash-welded longitudinal seams; the hazardous nature of the material (natural gas) transported; the uncertainty as to the root cause of the Incident; the impacts to property, the environment, and wildlife, and the risk of additional, related incidents; and the possibility that the same condition(s) that may have caused the failure remain present in

the pipeline; I find that continued operation of the *Affected Pipeline*, as defined below, without corrective measures is or would be hazardous to life, property, or the environment, and that failure to issue this Order expeditiously would result in the likelihood of serious harm.

Accordingly, this Order mandating immediate corrective action is issued expeditiously 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, PHMSA, OPS Southern Region. 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

Definitions:

Affected Pipeline – The “*Affected Pipeline*” means approximately 221 miles of SNG’s South Main pipeline that contains the 18-inch diameter, 1951 vintage A.O. Smith X52 pipe from Gwinville Compressor Station in Gwinville, Mississippi (MP 0) to Elmore Compressor Station in Elmore, Alabama (MP 221.6). The “*Affected Pipeline*” traverses the following counties in Mississippi: Jefferson Davis, Simpson, Smith, Jasper, Clarke, and Lauderdale; and the following counties in Alabama: Sumter, Marengo, Hale, Perry, Dallas, Autauga, and Elmore.

Isolated Segment – The “*Isolated Segment*” means the approximately 8.3-mile segment of SNG’s South Main Line that contains the 18-inch 1951 vintage A.O. Smith X52 pipe from Gate #18 (MP 150.783) to Gate #19 (MP 159.054). It is the portion of the “*Affected Segment*” that was shut-in after the failure on February 13, 2022, and must remain shut-in until a restart plan is approved by the “Director.”

Director – The “*Director*” means the Director, PHMSA, OPS Southern Region.

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

1. ***Shutdown of the Isolated Segment.*** The *Isolated Segment* 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.*** SNG must reduce and maintain a twenty percent (20%) pressure reduction in the actual operating pressure along the entire length of the *Affected Pipeline* such that, upon restart, the operating pressure along the *Affected Pipeline* will not exceed eighty percent (80%) of the actual operating pressure in effect

at the failure location immediately prior to the failure on February 13, 2022.

- 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.
 - b. Within 15 days of receipt of the CAO, SNG must provide the Director the actual operating pressures of each compressor station and each main line pressure regulating station on the *Affected Pipeline* 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, SNG must take into account any in-line inspection (ILI) features or anomalies present in the *Affected Pipeline* to provide for continued safe operation while further corrective actions are completed.
 - e. SNG must review the pressure restriction monthly by analyzing the operating pressure data, taking into account any ILI features or anomalies present in the *Affected Pipeline*. SNG must immediately reduce the operating pressure further to maintain the safe operations of the *Affected Pipeline*, if warranted by the monthly review. Further, SNG 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 may be made quarterly, in accordance with Item 15 below.
3. ***Instrumented Leakage Survey.*** Within 30 days of receipt of the CAO, SNG must perform an aerial or ground instrumented leakage survey of the *Affected Pipeline*. SNG must investigate all leak indications and remedy all leaks discovered. SNG must submit documentation of this survey to the Director within 45 days of receipt of the CAO.
4. ***Records Verification.*** SNG must verify the records for the *Affected Pipeline* 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. SNG must submit documentation of this record verification to the Director within 45 days of receipt of the CAO. See PHMSA Advisory Bulletin 2012-06 for additional information regarding records verification.
5. ***Review of Prior In-line Inspection (ILI) Results.***
- a. Within 30 days of receipt of the CAO, SNG must conduct a review of any previous ILI results of the *Affected Pipeline*. In its review, SNG must re-evaluate all ILI results from the past 10 calendar years, including a review of the ILI vendors' raw data and analysis. SNG must determine whether any features were present in the failed pipe joints from the February 13, 2022, failure. Also, SNG must determine if any features with similar characteristics are present elsewhere on the *Affected Pipeline*. SNG must submit documentation of this ILI review to the Director within

45 days of receipt of the CAO, as follows:

- i. List all ILI tool runs, tool types, and the calendar years of the tool runs.
- ii. List, describe (type, size, wall loss, etc.), and identify the specific location of all ILI features present in the failed joint and other pipe removed.
- iii. List, describe (type, size, wall loss, etc.), and identify the specific location of all ILI features with similar characteristics present elsewhere on the *Affected Pipeline*.
- iv. Explain the process used to review the ILI results and the results of the reevaluation.

6. ***Mechanical and Metallurgical Testing.*** Within 45 days of receipt of the CAO, SNG 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 acceptable to the Director, and must document the decision-making process and all factors contributing to the failure. SNG 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 the CAO, 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 SNG.

7. ***Root Cause Failure Analysis.*** Within 90 days following receipt of the CAO, 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 acceptable to 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 SNG's pipeline system.

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

- a. Within 90 days following receipt of the CAO, SNG 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 SNG will use to verify the integrity of the *Affected Pipeline*. It

must address all known or suspected factors and causes of the February 13, 2022, failure. SNG must consider the risks and consequences of another failure to develop a prioritized schedule for RWP-related work along the *Affected Pipeline*.

- e. The RWP must include a procedure or process to:
 - i. Identify pipe in the *Affected Pipeline* with characteristics similar to the contributing factors identified for the February 13, 2022, failure, including the age and manufacture of the entire length of the *Affected Pipeline*.
 - ii. Gather all data necessary to review the failure history (in service and pressure test failures) of the *Affected Pipeline* 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 Pipeline*. 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 failure on February 13, 2022, are likely to exist elsewhere on the *Affected Pipeline*.
 - v. Conduct additional field tests, inspections, assessments, and evaluations to determine whether, and to what extent, the conditions associated with the failure on February 13, 2022, and other failures from the failure history (see (e)(ii) above) or any other integrity threats are present elsewhere on the *Affected Pipeline*. At a minimum, this process must consider all failure causes and 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 failure on February 13, 2022, and that can reliably detect and identify anomalies,
 - 2) Hydrostatic pressure testing,
 - 3) Close-interval surveys,
 - 4) Cathodic protection surveys, to include interference surveys in coordination with other utilities (e.g., underground utilities, overhead power lines, etc.) in the area,
 - 5) Coating surveys,
 - 6) Stress corrosion cracking surveys,
 - 7) Selective seam corrosion surveys; and
 - 8) Other tests, inspections, assessments, and evaluations appropriate for the failure causes.

Note: SNG 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 February 13, 2022, failure.

- vi. Describe the inspection and repair criteria SNG 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 Pipeline*, describe the methods SNG will use to repair, replace, or take other corrective measures to remediate the conditions associated with the pipeline failure on February 13, 2022, and to address other known integrity threats along the *Affected Pipeline*. 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 Pipeline* 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. SNG 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. ***CAO Documentation Report (CDR)***. SNG must create and revise, as necessary, a CAO Documentation Report (CDR). When SNG 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 SNG 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 pipeline failure of February 13, 2022, and the response activities;

- iii. Summary of pipe data, material properties and all prior assessments of the *Affected Pipeline*;
- 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 SNG 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 SNG will take on its entire pipeline system as a result of the lessons learned from work on this Order; and
- xi. Appendices (if required).

10. ***Restart Plan.*** Prior to resuming operation of the *Isolated Segment*, 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 Segment* 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 Segment* during the restart process and must include incremental pressure increases during start up, with each increment to be held for at least 2 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 daylight restart and include advance communications with local emergency response officials and adjacent landowners.
- f. The *Restart Plan* must provide for a review of the *Isolated Segment* 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. SNG 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 SNG's O&M procedures manual.

11. ***Return to Service.*** After the Director approves the *Restart Plan*, SNG may resume operation of the *Isolated Segment* according to the terms of the *Restart Plan*, but the operating pressure must not exceed the limit in accordance with Item 2 above.

12. ***Removal of Pressure Restriction.***

- a. The Director may allow the removal or modification of the pressure restriction upon a written request from SNG 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 SNG 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 Pipeline* 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.

Other Requirements:

- 13. ***Approvals.*** With respect to each submission under this Order that 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.
- 14. ***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.
- 15. ***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 March 31, 2022. The Director may change the interval for the

submission of these reports.

16. ***Documentation of the Costs.*** It is requested that Respondent maintain documentation of the costs associated with implementation of this CAO. 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. 2-2022-007-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 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.

ALAN KRAMER MAYBERRY
Digitally signed by ALAN KRAMER MAYBERRY
Date: 2022.02.18 14:19:26 -05'00'

February 18, 2022

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Date Issued