



Pipeline Safety
Enable Midstream Partners
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November 2, 2021

Mary McDaniel
Director, Southwest Region
PHMSA Pipeline Safety
8701 S. Gessner Dr.
Suite 1110
Houston, TX 77074

Subject: Enable Gas Transmission, LLC - Response to PHMSA Notice of Probable Violation and Proposed Compliance Order CPF 4-2021-001

Dear Ms. McDaniel,

Enable Gas Transmission, LLC (EGT) hereby responds to acknowledge receipt of the Notice of Probable Violation (NOPV) and Proposed Compliance Order issued by Pipeline and Hazardous Materials Safety Administration (PHMSA) on October 4, 2021. On the bases of PHMSA's inspection performed from April 13, 2020 through October 2, 2020, alleged violations were identified as seen below in the excerpt from Notice of Probable Violation CPF 4-2021-001.

Item 1: § 192.481 – Atmospheric corrosion control: Monitoring.

(a)...

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by Sec.192.479.

Enable failed to remediate damaged coating identified during its atmospheric corrosion inspections for four consecutive calendar years, 2017 through 2020. Enable's written procedure OM-235 Pipe Inspection, Section 2.9.6 (Effective Date: 9/27/2018) states, "If coating is other than 'Good,' remove deteriorated coating sufficiently to allow for visual inspection of pipe surface." Furthermore, Section 2.9.8 of the same procedure states, "If there are no defects visually evident...recoat the pipe in accordance with Construction Specifications (Book 2)" and "install pipeline markers on both sides of the exposure."

PHMSA inspectors reviewed Enable's Pipe Inspection History reports from calendar years January 2017 through July 2020 and found multiple areas where the pipeline was exposed and the completed inspection report noted the condition of the coating as "Damaged," "Local Disbondment," or "Extensively Disbonded." PHMSA requested to review the records of any remedial actions that were taken to address the findings; however, no such records were provided by Enable.

Item 2. § 192.739 - Pressure limiting and regulating stations: Inspection and testing.

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is-

Enable failed to inspect and test its pressure limiting stations, relief devices, and pressure regulating stations and its equipment at five (5) Compressor Station locations in accordance with § 192.739(a).

Enable's written Operations and Maintenance procedure Engineering Standards, ES-010, Design Requirements for Pressure Protection of Gas Piping Systems (Effective Date: 1/23/2020) and Operating & Maintenance Plan, OM-304, Inspection and Testing of Relief and Automatic Shutdown Devices Compressor Stations (Revisions Date: 1/23/2020) provides that unit relief devices, pressure limiting devices, and automatic shutdown devices will be inspected and tested at intervals not exceeding 15 months, but at least once at each calendar year.

During the field records review of Enable's relief and automatic shutdown devices, PHMSA inspectors found that the testing and inspection of several devices and equipment at the following compressor stations had not been performed in accordance with § 192.739(a):

- 1. Stateline (East Texas) Compressor Station on Line CP - relief valves, transmitters, and shutdown switches on compressor units 1, 2, and 4 were not tested or inspected in calendar years 2019 and 2020 for each of these compressor units;*
- 2. Panola Compressor Station on Line CP - the compressor discharge transmitters on compressor units 1, 2, and 3 were not tested or inspected for calendar years 2017, 2018, and 2019 for each of these compressor units;*
- 3. Westdale Compressor Station on Line CP - the compressor discharge transmitters on compressor units 1 and 2 were not tested or inspected for calendar years 2017, 2018, and 2019 for each of these compressor units;*
- 4. Vernon Compressor Station on Line CP - the compressor discharge transmitters on compressor units 1, 2, and 3 were not tested or inspected for calendar years 2017, 2018, and 2019 for each of these compressor units; and*
- 5. Alto Compressor Station on Line CP - the shutdown switch on compressor unit 1 was not tested or inspected for calendar years 2017, 2018, and 2019.*

Item 3. § 192.619 - Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under § 192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, one of the following pressures is to be used as design pressure:

- (i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, see § 192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or**
- (ii) If the pipe is 12 3/4 inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).**

(2) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction as follows:

- (i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.**
- (ii) For steel pipe operated at 100 psi (689 kPa) gage or more, the test pressure is divided by a factor**

determined in accordance with the Table 1 to paragraph(a)(2)(ii):

TABLE 1 TO PARAGRAPH (a)(2)(ii)

Class location	Installed before (Nov. 12, 1970)	Factors, ^{1 2} segment -		
		Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under §192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

¹ For offshore pipeline segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

² For a component with a design pressure established in accordance with § 192.153(a) or (b) installed after July 14, 2004, the factor is 1.3.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
-Onshore gathering line that first became subject to this part (other than § 192.612) after April 13, 2006. -Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.	March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
Offshore gathering lines.	July 1, 1976	July 1, 1971.
All other pipelines.	July 1, 1970	July 1, 1965

(4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with § 192.607, if applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure.



Enable failed to establish a Maximum Allowable Operating Pressure (MAOP) and provide records to demonstrate the establishment of the MAOP for its Line ST-1 and Line AM-5 pipelines that were placed in service prior to calendar year 1970 in accordance with § 192.619(a).

According to its written procedure Operating & Maintenance Plan, OM-210, Maximum Allowable Operating Pressure MAOP (Revision Date: 1/23/2020), the MAOP will be established for each pipeline segment based on design, materials, pressure test, operating history, or other factors.

During the MAOP records review, PHMSA inspectors concluded that Enable's MAOP verification form for Line ST-1 (which was originally constructed circa 1954 and had segments replaced in 1959), was errantly overridden to 950 psig, instead of an actual MAOP of 632 psig.

For Line AM-5, Enable has not established the MAOP by one or more of the required methods outlined in § 192.619. Enable does not possess a pressure test per § 192.619(a)(2) or "grandfather" pressure records per § 192.619(c) to establish the MAOP.

Enable is not contesting the alleged findings and is taking actions necessary to address and/or remediate issues described herein. Please note that the line listed as Line AM-5 is incorrect, it should read Line AM-50. If you have any questions concerning the information contained in this response, please do not hesitate to contact me.

Sincerely,

A handwritten signature in blue ink, appearing to read "Cary Watson".

Cary Watson
Vice President, Safety, Environmental and Technical Programs
Enable Midstream Partners, LP