



U.S. Department
of Transportation

Pipeline and Hazardous Materials
Safety Administration

FEB 24 2020

1200 New Jersey Ave., SE
Washington, DC 20590

Mr. John Pettigrew
Chief Executive Officer
National Grid, PLC
1-3 Strand
London WC2N 5EH, United Kingdom

Re: CPF No. 1-2018-3005

Dear Mr. Pettigrew:

Enclosed please find the Final Order issued in the above-referenced case. It withdraws the allegation in the Notice of Probable Violation issued on June 12, 2018. Accordingly, this case is now closed. Service of the Final Order by certified mail is effective upon the date of mailing as provided under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Robert Burrough, Director, Eastern Region, Office of Pipeline Safety, PHMSA
Mr. Ross Turrini, Senior Vice President, Gas Process and Engineering, National Grid,
PLC, 40 Sylvan Road, Waltham, Massachusetts 02451
Mr. David C. Lodemore, Esq., Senior Counsel, National Grid, PLC, 40 Sylvan Road,
Waltham, Massachusetts 02451

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

¹ Pipeline Safety Violation Report (Violation Report), (June 12, 2018) (on file with PHMSA), at 1.

WITHDRAWAL OF ALLEGATION

The Notice alleged that Respondent violated 49 C.F.R. Part 193, as follows:

Item 1: The Notice alleged that Respondent violated 49 C.F.R. § 193.2635(d), which states:

§ 193.2635 Monitoring corrosion control.

Corrosion protection provided as required by this subpart must be periodically monitored to give early recognition of ineffective corrosion protection, including the following, as applicable:

(a)...

(d) Each component that is protected from atmospheric corrosion must be inspected at intervals not exceeding 3 years.

The Notice alleged that Respondent violated 49 C.F.R. § 193.2635(d) by failing to inspect each component that is protected from atmospheric corrosion at intervals not exceeding three years. Specifically, the Notice alleged that Niagara failed to inspect insulated piping for the glycol system and three insulated vaporizers for atmospheric corrosion at its Providence LNG Plant for the 2014 to 2017 period.

In its Response and at the hearing, Niagara contested the allegation. Niagara argued that while the facility piping was generally subject to the three-year atmospheric corrosion inspection requirement, the regulation did not expressly require the piping that was covered by thermal insulation to be inspected. Niagara pointed out that the atmospheric corrosion inspection provisions for natural gas pipelines in 49 CFR Part 192 (§ 192.481) and for hazardous liquid pipelines in 49 CFR Part 195 (§ 195.583) both expressly require inspecting under thermal insulation, but the cited regulation in Part 193 for LNG facilities does not. Respondent believes this may have been a purposeful omission. Respondent cited *United States v. Approximately 64,695 Pounds of Shark Fins* to argue that it was reasonable to presume that PHMSA acted intentionally when the agency did not include an express requirement to inspect LNG facility piping under insulation in § 193.2635(d).²

In response to this argument, OPS explained that Niagara's comparison of the pipeline regulations in Parts 192 and 195 to the LNG facility regulations in Part 193 failed to observe a key distinction. Both §§ 192.481 and 195.583 are distinguishable from § 193.2635 because they concern pipelines that are "exposed to the atmosphere," whereas § 193.2635 contemplates inspection of "each component that is protected from atmospheric corrosion." OPS argued that this distinction reflects the differences in the types of facilities being regulated. LNG is natural gas that has been cooled to a liquid state, at or below -260° F. LNG facility piping is almost always protected with insulation or jacketing to protect the pipe from atmospheric corrosion, to prevent heat transfer due to the ambient temperature being hundreds of degrees higher, and to protect the people working in the facility from cryogenic temperatures. In comparison to the treatment of insulation by the Part 192 and 195 code drafters, the Part 193 code drafters would

² 520 F. 3d 976, 983 (9th Cir. 2008).

have been well aware that LNG facility piping was generally insulated requiring removal for visual inspection of the protected piping.³ OPS is correct that it follows from the Part 193 language that the material to be inspected is the protected material, even if it is underneath insulation or jacketing. Moreover, there is no rationale for the proposition that insulated LNG piping should receive lesser inspections than aboveground natural gas and hazardous liquid pipes that are insulated.

Niagara further argued that it had not received “fair notice” of PHMSA’s application of § 193.2635(d).⁴ Niagara noted that in contrast to PHMSA’s approach under Parts 192 and 195, it made no compliance guidance on atmospheric corrosion inspections under Part 193 available to operators.⁵ In response, OPS noted that the DC Circuit stated in *General Electric Company v. US EPA* that where a party argues that an agency is providing notice of interpretation through an enforcement action, the relevant question is, “whether the regulated party received, or should have received notice of the agency’s interpretation in the most obvious way of all: by reading the regulations.”⁶

Having considered these arguments, I find that PHMSA did provide such notice to LNG operators. The regulation states:

(d) Each component that is protected from atmospheric corrosion must be inspected at intervals not exceeding 3 years.

Component is defined by § 193.2007, to include:

“any part, or system of parts functioning as a unit, including, but not limited to, piping, processing equipment, containers, control devices, impounding systems, lighting, security devices, fire control equipment, and communication equipment, whose integrity or reliability is necessary to maintain safety in controlling, processing, or containing a hazardous fluid.”

Thus, the regulation itself provides fair notice that operators must inspect each component that is protected from atmospheric corrosion at intervals not exceeding three years. Niagara acknowledged that its asbestos insulation and aluminum jacketing served as thermal insulation and protection against atmospheric corrosion.⁷ Insulation is not a component protected from atmospheric corrosion. Rather, insulation protects the component in question from atmospheric corrosion. To comply with § 193.2635(d), an operator must “inspect” the component being

³ OPS also pointed out that in *Shark Fins*, the court analyzed subsections within the same regulation, specifically 50 CFR § 600.1204(b) and (c). Conversely, the LNG regulation § 193.2635 is in a completely different Part of title 49 from the parts dealing with natural gas and hazardous liquid pipelines, Parts 192 and 195.

⁴ Post-hearing submission, at 3.

⁵ Post-hearing submission, at 6.

⁶ 53 F. 3d 1324, 1329 (D.C. Cir. 1995).

⁷ Pre-hearing submission, at 3.

protected. While non-destructive examination methods can be utilized, if visual inspection is the method of inspecting the exterior surface of a component for atmospheric corrosion, the requirement to inspect these components requires operators to actually look at the condition of the component being protected from atmospheric corrosion which by definition would involve visual inspection of enough of the pipe surface under the insulation to confirm the absence of atmospheric corrosion. In this case, Niagara was required to visually inspect enough of the glycol system piping and the vaporizers that were protected by asbestos insulation and aluminum jacketing to confirm the absence of atmospheric corrosion.⁸

Niagara then argued in the alternative that even if § 193.2635(d) does require the operator of an LNG facility to inspect under thermal insulation, certain activities that it conducted at the Providence LNG Plant during the relevant period should be considered to have satisfied any such requirement.⁹ Niagara explained that the facility had an ongoing program of replacing the asbestos insulation with polycarbonate insulation whenever the asbestos insulation was found to be in a deleterious condition. Niagara stated that atmospheric corrosion inspections were performed on the pipe surface exposed by the removal of the old asbestos insulation during this insulation replacement program. During the hearing, Niagara provided photos of portions of the glycol system and vaporizers with insulation removed demonstrating that the pipe surface was inspected. Niagara further explained that these visual atmospheric corrosion inspections were supplemented with ultrasonic readings of the 8-inch glycol pipe and other sections of piping.¹⁰

OPS conceded that it may be possible to “conduct atmospheric corrosion inspections and achieve compliance with § 193.2635(d) during the performance of other field activities.”¹¹ However, OPS maintained that although deteriorated insulation could be a factor to consider for prioritizing locations for atmospheric corrosion inspection, none of the 2014, 2015, 2016, or 2017 asbestos insulation removal locations were identified in Niagara’s records as locations that corresponded to a risk-based assessment of the portions of the glycol lines or vaporizers with the greatest risk of atmospheric corrosion.

The issue to be determined in this case is whether the regulation at issue allowed Niagara to conduct its atmospheric corrosion inspections in the manner described. Under § 193.2635(d), an LNG facility operator has wide latitude in developing the procedures by which its atmospheric corrosion inspections will be conducted. The regulations permit an operator to determine the appropriate manner of inspection for its particular facility so long as the procedures account for the presence of piping that is not visually accessible such as insulated piping. For example, operators that utilize visual inspection as the primary method can establish procedures for

⁸ In a highly similar case from 2012, for example, PHMSA alleged that Transco, an LNG operator, failed to inspect any pipe under the thermal insulation on its steel piping during atmospheric corrosion surveys. The operator was found to have violated § 193.2635(d), ordered to pay a civil penalty of \$48,400, and ordered to comply with compliance terms. *In the Matter of Transcontinental Gas Pipe Line Company, LLC*, CPF No. 1-2012-3002, Final Order, 2012 WL 6892766 (D.O.T., Oct. 26, 2012).

⁹ Post-hearing submission, at 8-12.

¹⁰ Reply, at 2.

¹¹ Region recommendation, at 6.

removing select portions of the insulation or clamps or developing a program whereby visual inspections occur in predetermined critical inspection locations by creating inspection ports. They can also supplement visual inspections with non-destructive methods such as ultrasonic or radiographic testing.

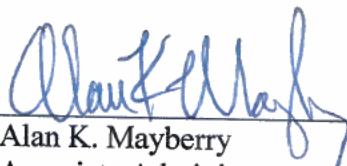
OPS is correct that Respondent did not utilize a rigorous risk-based approach for planning and conducting its atmospheric corrosion inspections on the insulated piping and that its written procedures in this area were not ideal. Respondent correctly pointed out, however, that the regulation does not require a risk-based atmospheric corrosion inspection program. Niagara reasoned that the areas it did visually inspect where the insulation had deteriorated would tend to correspond to the higher risk areas for atmospheric corrosion.¹² Moreover, in this case the sheer extent of Niagara's insulation replacement program resulted in hundreds of linear feet of the insulation on piping being replaced and hundreds of square feet of insulation on the vaporizers being replaced during the 2014 to 2017 period. As a result, Respondent may well have inspected a greater amount of the pipe surface under the insulation at its facility than an operator that has pre-designated its inspection locations typically inspects. While Niagara would be well advised to clarify and enhance its atmospheric corrosion inspection procedures, in this case OPS did not establish that the inspections under the insulation that Respondent did conduct were so inadequate that they constituted non-compliance with the minimum requirements in the regulation.

Based upon the foregoing, I hereby order that this allegation be withdrawn.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to the alleged violation of 49 C.F.R. § 193.2635(d). Because the allegation has been withdrawn, the compliance terms are also withdrawn.

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



Alan K. Mayberry
Associate Administrator
for Pipeline Safety

FEB 24 2020

Date Issued

¹² Reply, at 4.