Before the
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety
Washington, D.C.

In the Matter of	)	
	)	CPF No. 5-2023-003-NOPV
Kinder Morgan, LLC[1]	)	Notice of Probable Violation
	)	
Respondent.	)	
	)	

<u>Kinder Morgan, Inc. Post-Hearing Brief</u>

[1] The NOPV was issued to Kinder Morgan, LLC, and should have been Kinder Morgan, Inc. SFPP is an indirect subsidiary of KM and the owner and operator of the LS-120 pipeline at issue.

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I. PHMSA Should Withdraw the NOPV.

SFPP, LP (SFPP or the Company) and the Pipeline and Hazardous Materials Safety Administration's (PHMSA or the Agency) Western Region (the Region) convened an in-person informal administrative hearing on February 14, 2024, in Lakewood, Colorado in the above-referenced Notice of Probable Violation (NOPV) where the Region alleged a violation of 49 C.F.R. § 195.583(c) regarding atmospheric corrosion protection. As follow-up to that hearing, SFPP timely files this post-hearing submission to emphasize the overwhelming and uncontroverted evidence in the record that supports withdrawal of the NOPV in its entirety and to address unsubstantiated generalizations and assertions raised for the first time by the Region in its pre-hearing submission and/or the hearing.

SFPP prioritizes pipeline safety and integrity, which drives the Company's approach to pipeline operations and maintenance, including without limitation corrosion control. Toward that end, SFPP requires recoating where, among other things, a pipeline exhibits "any degree of pitting or scale corrosion where a measurable amount of wall loss has occurred."[2] The crux of this appeal is that SFPP, after numerous comprehensive investigations of the areas at issue both before and after the Region's audit, did not find any evidence whatsoever of pitting, scale, metal loss, or any condition that would affect the safe operation of the pipeline. Additional testing, inspection, and evaluation by a renowned and experienced independent corrosion expert supports SFPP's findings. Further, SFPP continues to safely operate the pipeline facilities at issue without incident.

The pipeline facilities at issue exhibit only a light surface oxide in certain limited areas, which PHMSA regulations expressly except from remediation based on a demonstration by test, investigation, or experience appropriate to the environment. The intent of this exception is to allow operators flexibility in prioritizing risk so as not to compel remediation solely for aesthetic reasons. To sustain its allegations, the Region must prove that atmospheric corrosion requiring protection before the next scheduled inspection existed on the pipeline at the locations at issue. SFPP's comprehensive investigation, analysis, testing, and measurements, however, directly refute the Region's limited observations, unsubstantiated interpretations, and mischaracterizations. For these reasons, SFPP respectfully requests that PHMSA withdraw the NOPV in its entirety.

II. NOPV Allegations, Proposed Penalty, PCO, and Applicable Background.

This matter presents a straightforward factual issue: whether actionable atmospheric corrosion existed at the locations identified in the NOPV. Since the underlying PHMSA audit in 2022, the Company coordinated with the Region in a responsive, transparent, and forthcoming manner. When the Region raised potential concerns during the November 2022 audit, SFPP quickly performed a supplemental inspection to identify any actionable atmospheric corrosion in January 2023. SFPP's comprehensive investigation and testing confirmed, however, that PHMSA's concerns were cosmetic only: the pipeline exhibited a light surface oxide film with no evidence of metal loss, pitting, or scaling of the pipe steel.

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[2] *Pre-Hearing Brief Attachment B: SFPP L-O&M Procedure 918.*

The Region's April 11, 2023, NOPV alleged a probable violation of 49 C.F.R. § 195.583(c) related to atmospheric corrosion on the Compton Creek span of SFPP's LS-120 pipeline in southern California, as follows (emphasis added):

> during the PHMSA field inspection, atmospheric corrosion on LS-120 was identified, at a span crossing Compton Creek (MP 1.85), including excessive corrosion with pitting…After finding the atmospheric corrosion during the inspection, KM failed to provide protection against corrosion as required by § 195.581. Despite the prevalence of atmospheric corrosion on its line, KM failed to adequately clean and coat the pipeline pursuant to § 195.581(a).

In an associated footnote, the Region opined that "[t]his does not fall within an exception in § 195.581(c) because this is not light surface oxide nor is it corrosion that otherwise would not affect the safe operation of the pipeline before the next scheduled inspection," asserting that safe operation of the pipeline is impacted simply because the pipeline is located in a high consequence area.[3] The Region identified additional alleged "areas of concern" at the Colton Terminal Station in Bloomington, California, which appear to be separate and apart from the NOPV allegations. Notably absent from the NOPV and the underlying pipeline safety violation report (PSVR) are the Region's after the fact allegations put forward in its pre-hearing filing and at the hearing, including the completeness of SFPP's inspections, consideration of SFPP's corrosion procedure L-O&M 918, and the possibility of corrosion underneath disbonded coating.[4]

The Region proposed a civil penalty of $81,500 for the alleged violation. Finally, the Region proposed a compliance order (PCO) to require SFPP to "conduct an atmospheric corrosion inspection to include soil to air interface to determine the amount of corrosion and then follow their procedures for the proper repair method."[5] These are the very actions SFPP proactively undertook to vet PHMSA's concerns communicated during the audit, even prior to issuance of the NOPV, as evidenced by its January 26, 2023, atmospheric inspection.[6] That inspection, conducted by a highly qualified and experienced corrosion technician with the use of a pit gauge and an ultrasonic wall loss measurement tool, confirmed the results of SFPP's inspections preceding PHMSA's audit: some portions of the span exhibited only a light surface oxide with no metal loss, pitting, or condition that would affect the safe operation of the pipeline before the next scheduled inspection. In-line inspection (ILI) results from 2017 and 2022 further affirmed the complete lack of evidence of metal loss with state-of-the-art tools designed specifically to identify metal loss.

Given these facts, SFPP hoped to resolve the issues through informal settlement meetings, including – at the Agency's request – further inspection and testing of areas in November 2023 with an ultrasonic wall loss measurement tool. Although the Company confirmed unequivocally

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[3] NOPV, p. 2, n. 1.

[4] The NOPV and the PSVR do not mention these allegations or cite to L-O&M 918, which were first asserted in the pre-hearing submission, in part, and at the hearing.

[5] The Region inaccurately summarized the PCO at the hearing as follows "in addition to a compliance order requiring Kinder Morgan to clean and coat the pipeline to address the corrosion." Test. A. Iorio, Hr'g Tr. 12:20-22.

[6] *See Request for Hearing, Attachment A: Compton Creek Inspection Report* [hereinafter Compton Creek Inspection Report]; *Pre-Hearing Brief Attachment E: Affidavit of Micheal Pyle (Feb. 4, 2024)* at ¶ 15-17, Exhibit B [hereinafter M. Pyle Aff.].

through measurements from multiple tools that no pitting, metal loss, or scaling of the pipe steel existed, ultimately settlement could not be reached.

III. Atmospheric Corrosion Does Not Require Protection in All Circumstances.

The pipeline safety regulations are rooted in ensuring pipeline integrity and public safety. In keeping with those foundations, PHMSA corrosion control regulations are based on the science of corrosion, consideration of the pipeline environment (e.g., whether the pipeline is exposed to the atmosphere or "buried"), and technical industry standards, including National Association of Corrosion Engineers (NACE) Standard SP0169-2007 specific to external corrosion on underground or submerged metallic pipelines and NACE Standard SP0502-2010 regarding external corrosion direct assessment methodology for buried onshore pipelines.[7] The corrosion regulations are not driven by aesthetics or cosmetics. Corrosion requirements differ significantly based on the pipeline environment due to the susceptibility of pipe steel when buried (defined to mean "covered or in contact with soil") as compared to when it is exposed to the atmosphere.[8] As such, operators must monitor for external corrosion or atmospheric corrosion, depending on the pipeline environment, and separately for internal corrosion.

For pipelines exposed to the atmosphere, 49 C.F.R. § 195.581(c) provides a longstanding exception to the requirement to protect against atmospheric corrosion at 49 C.F.R. § 195.583. The exception is clear, and it has remained unchanged since it was issued. Section 195.581(c) provides (emphasis added):

> [Operators] need not protect against atmospheric corrosion any pipeline for which [it] demonstrates by <u>test</u>, <u>investigation</u> <u>or</u> <u>experience appropriate to the environment</u> of the pipeline that <u>corrosion</u> will:
>
> (1) Only be a <u>light surface oxide</u> <u>or</u>
> (2) <u>Not affect the safe operation of the pipeline before the next scheduled inspection</u>.

The regulation expressly allows three different methods (i.e., testing, investigation, or experience), without mandating any specific one over another, for an operator to demonstrate that corrosion will only be a light surface oxide or will not affect the safe operation of the pipeline before the next inspection. PHMSA regulations leave it in the operator's discretion as to how to make this demonstration in their corrosion control programs and there is no clarifying guidance.

In issuing this rule, PHMSA's predecessor agency understood the mechanics of atmospheric corrosion of pipe steel, that it is dependent on the presence of certain factors, and even then, that it is a slow process.[9] PHMSA's predecessor intended that the regulations provide operators with the "flexibility" to decide whether and when to recoat under these circumstances. Accordingly, PHMSA's predecessor agency explained:

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[7] 49 C.F.R. § 195.3. Since 1993, NACE is now the Association of Materials for Protection and Performance (AMPP).
[8] 49 C.F.R. Part 195, Subpart H, Corrosion Control.
[9] Final Rule, *Controlling Corrosion on Hazardous Liquid and Carbon Dioxide Pipelines*, 66 Fed. Reg. 66994, 67001 (Dec. 27, 2001).

> Final § 195.581 gives operators flexibility when deciding to coat pipelines where atmospheric corrosion will be limited to a light surface oxide, or will not affect the safe operation of the pipeline before the next scheduled inspection.[10]

In response to a commenter's complaint that the regulation would allow pipe to "remain unprotected and unrepaired," PHMSA's predecessor responded:

> [T]he need for coating would be reviewed again in 3 years. A 3-year delay in coating a pipeline judged to be safe should not jeopardize public safety, considering that atmospheric corrosion generally progresses at a slow rate.[11]

PHMSA's corrosion enforcement guidance expressly clarifies what a light surface oxide means: "general oxidation of the metal where there is no associated loss of metal" or "the slow rusting of pipe which is not yet considered to be atmospheric corrosion because there is no evidence of metal loss."[12] PHMSA has explained "that a light surface oxide is a non-damaging form of corrosion that does not need remedial action" and that it "believes operators should have the option of assigning resources to problems that pose a higher near-term risk."[13] PHMSA has also recognized that some experts consider a light surface oxide to be beneficial and protective of the pipe surface.[14]

In contrast to light surface oxide or corrosion that will not impact the safe operation of the pipeline before the next inspection, PHMSA guidance has clarified that atmospheric corrosion warranting remediation is "an area of metal loss due to general corrosion, localized corrosion pitting, or peeling scale on the steel surface that has damaged the pipe*.*"[15] PHMSA guidance makes no reference to the color or texture of the oxide film; the key factor is metal loss that results in damage to the pipe steel.

Accordingly, PHMSA has issued enforcement based on evidence of pitting, peeling scale of the pipe steel (not peeling of the paint coating), and severe corrosion.[16] Further, PHMSA has not

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[10] *Id*. (emphasis added).
[11] *Id.* (emphasis added); *see also PHMSA Decision on Petition for Reconsideration, In re: Express Holdings*, CPF No. 3-2020-5005 (Jul. 26, 2021) (evaluating 49 C.F.R. 195.583(b) and stating that "atmospheric inspections are conducted on a three-year cycle because corrosion is a long-term process").
[12] *PHMSA Corrosion Enforcement Guidance Part 195* at 87, 90 (Jun. 22, 2016) (emphasis added).
[13] *See* Final Rule, *Further Regulatory Review: Gas Pipeline Safety Standards*, 68 Fed. Reg. 53895, 53897-98 (Sept. 15, 2003) (discussing the corollary regulation in Part 192); *see also* Notice of Proposed Rulemaking, *Controlling Corrosion on Hazardous Liquid and Carbon Dioxide Pipelines*, 65 Fed. Reg. 76968, 75978 (Dec. 8, 2000) (explaining "[t]he intent of the recommendation is to distinguish harmless rust from serious metal loss").
[14] *See PHMSA Corrosion Enforcement Guidance Part 195*, p. 90 (Jun. 22, 2016) ("Some corrosion experts consider a light surface oxide to be protective to the metal surface.").
[15] *Id.* at 87 (emphasis added).
[16] *See, e.g., Warning Letter, In re: Chevron*, CPF 5-2019-5003W (Jan. 27, 2019) (alleging a warning item under 49 C.F.R. § 195.581 based on a pipeline "without coating and with severe atmospheric corrosion" and appears to have existed for several years) (emphasis added); *Warning Letter, In re: Conoco Phillips Alaska, Inc.*, CPF 5-2017-6030W (Aug. 15, 2017) (alleging a warning item under 49 C.F.R. § 195.583 based on the presence of oxidation "as well as scaling and pitting") (emphasis added).

issued enforcement to an operator solely for peeling paint or harmless rust of the pipe, with conclusions of law based on the exception at 49 C.F.R. § 195.581(c).[17]

Finally, while relevant only because the Region raised it at the hearing, the PHMSA regulations specify requirements for the use of direct assessment on *buried* pipe "to evaluate the effects of external corrosion or stress corrosion cracking."[18] External corrosion direct assessment (ECDA) includes pre-assessment as a first step in the analysis that incorporates by reference portions of NACE SP0502, and where reassessment intervals are calculated based on analysis of corrosion growth rates.[19] NACE SP0502 expressly states that the ECDA process covered in the standard is specific to "buried" pipelines and corrosion rates referenced therein has no application to atmospheric corrosion.[20] This regulation and this standard is not applicable to pipelines exposed to the atmosphere, however, because operators can regularly investigate the pipeline firsthand for signs of corrosion in contrast to buried pipe.

IV. <u>PHMSA's Case Consists Solely of Observations, Interpretations, and Limited Experience</u>.

To support the allegations of "excessive corrosion with pitting," the Region relies primarily on 10 photographs taken of the Compton Creek span during the November 2022 audit,[21] the speculative observations by a Region inspector who was present during the audit, and after-the-fact supposition of two Agency personnel reviewing those photographs. The Region provided no basis in any actual investigation, testing, or evaluation to support its visual observations of these difficult to access areas, the Region has not referenced any technical data or industry standards to support its conclusions. Without explanation or rebuttal, the Region completely dismisses the findings presented by SFPP's more experienced corrosion technicians, third-party expert analysis and

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[17] The Region's pre-hearing submission cites a single dated enforcement action for the proposition that PHMSA has made a finding of violation of 195.583(c) "for having pipelines in the same condition as the span over Compton Creek." *Final Order, In re: ConocoPhillips Pipe Line Company,* CPF. 4-2008-5011 (December 17, 2009). The uncontested allegations and finding of violation (which does not contain conclusions of law) in the *ConocoPhillips* Final Order have no precedential value, and PHMSA has failed to demonstrate that the facts are even remotely similar to those presented in this matter. Whether remediation is required under the regulations is a fact-specific determination based on the pipeline facility at issue, the evaluation, investigation and any testing by the operator, and the environment of the pipeline. The minimal information in the Agency's enforcement transparency website for the *ConocoPhillips* Final Order confirms the differences from the SFPP matter at hand, including the nature of the product transported by ConocoPhillips (HVLs), the areas at issue (primarily exposed pipeline components, including block valves), and the environment (Texas). Further, unlike SFPP, no demonstration made by the operator that the conditions were no more than a light surface oxide or would not impact the safe operation of the pipeline.

[18] 49 C.F.R. § 195.588, What standards apply to direct assessment?

[19] *Id*.

[20] *Id*.; see also 49 C.F.R. 195.3(g)(2) (incorporating NACE SP0502-2010 by reference). NACE SP0502-2010 states in its scope "1.1 This standard covers the NACE external corrosion direct assessment process for buried onshore ferrous pipeline systems."

[21] The PSVR contains 10 photographs of the Compton Creek span associated with Ms. Leanna Green, PHMSA General Engineer, who was one of the inspectors for the Western Region in the underlying audit. The PSVR also contains 12 photographs associated with the areas of concern alleged at the Colton Terminal Station, which are also associated with Ms. Green. Notably absent from the case file is a photograph exhibited during the Region's testimony at the hearing and which was not previously provided to SFPP and was only provided upon request by counsel after the hearing. Test. D. Hubbard, Hr'g Tr. 150:3-25; 151:1-25; 153:1-9; 155:17. PHMSA counsel admitted this photograph was not part of the NOPV or the case file provided to SFPP. It is unknown to SFPP if there are other photographs which were not provided to SFPP.

evaluation, as well as their collective testing and measurements with industry accepted tools which demonstrate the absence of measurable metal loss. Instead, the Region argues, "[w]e can and should trust our experienced investigators and experts who know corrosion when they see it."[22]

A. The Region's Firsthand Observations Are Speculative.

Only two PHMSA inspectors saw this pipe in person, from a distance, and their experience in corrosion control and identification is not established in the record or at the hearing. Mr. Williams, an Agency inspector for the Region, testified at the hearing that he started with PHMSA in 2019, and has since performed approximately 30 inspections.[23] Mr. Williams is not certificated by AMPP (formerly NACE International), nor does he maintain other relevant corrosion control qualifications. The other inspector in the field, whose name appears associated with the photographs in the case file, did not testify at the hearing,[24] and the record is devoid of her qualifications or experience both generally and specific to corrosion.

Mr. Williams described what he considered to be evidence of pitting on the Compton Creek span based on dark discoloration ("darker spots," "darker in color," "areas that look like pitting," "maybe in the darker – almost black in a spot in the upper left-hand corner is an area where we believe to be some evidence of pitting," "where it's getting pretty – pretty much black, and it shows that it could be pitting up there") and texture ("I don't know if we can see it on here, but some areas, if you zoom in, you can kind of see little crevices or cavities").[25] His testimony equivocated with qualifiers such as "sort of," "it looks like," "it could be."[26] Mr. Williams did not touch the pipe or perform any measurement or testing to confirm his visual observations.[27] As it relates to the Colton Station, the Region admits in the NOPV that it was "unable to determine the severity of the atmospheric corrosion"[28] while performing the audit because the valves at issue were located in vaults. Mr. Williams conceded that he did not personally observe the Colton Station pipeline facilities identified in the NOPV as "areas of concern."[29]

B. PHMSA's Accident Investigator Provided Only Generalizations.

The Region also elicited testimony from an Accident Investigator without any firsthand experience with the pipeline locations at issue.[30] Dr. Rodriguez received a PhD in Chemical Engineering and joined the Agency in 2019. Outside of accident investigations, he has participated in only "five to

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[22] Test. A. Iorio, Hr'g Tr. 14:16-18.
[23] Test. J. Williams, Hr'g Tr. 16:19-22.
[24] Remarks during the hearing by Region counsel appeared to indicate that Mr. Williams took the photographs at issue. *See e.g.* Hr'g Tr. 19:1-3 ("And about how far away from, you know, the pipelines were you at when you took this picture?"). However, the PSVR associates all of the photographs provided as evidence of a violation with Ms. Green, the other PHMSA inspector who participated in the audit of SFPP and who did not testify at the hearing. Further, the Region's purported corrosion expert attributed them to Ms. Green. Test. A. Rodriguez, Hr'g Tr. 148:18-19.
[25] Test. J. Williams, Hr'g Tr. 20:20-22, 21:4-9, 21:25, 22:1, 22:11-13, 23:11-13.
[26] *Id*.
[27] *Id*. at 144:17-19, 145:9-19.
[28] NOPV, p. 2.
[29] Test. J. Williams, Hr'g Tr. 144:20 – 145:8, 145:20 – 146:8.
[30] Test. A. Rodriguez, Hr'g Tr. 148:9-12 (confirming that he "[has] not been firsthand to any of the areas referenced in the NOPV.").

ten" pipeline inspections and he became involved in this matter some time last year.[31] Although Dr. Rodriguez did not inspect the Compton Creek span or the Colton Station, he nevertheless opined that "in some areas it's evident that pitting is happening" on the Compton Creek span "[o]f which extent, it's up to the person that is conducting the investigation."[32] Without citing any authority or attribution, he further stated that the pitting needs to be evaluated prior to sanding and noted there are different ways to measure pitting by instrumentation or ILI tool.[33]

Despite his involvement in this matter, Dr. Rodriguez testified that he had not reviewed any of SFPP's evidence in the record prior to the hearing, including photographs, reports, results of the testing for pitting employed by hook probe, pit gauge and ultrasonic wall loss measurement tool, ILI, and SFPP's independent third-party expert evaluation, report, and testing results.[34] Instead, his testimony relied solely on photographs taken by another PHMSA inspector at some distance from the pipeline and his own expertise.[35] While Dr. Rodriguez testified about conditions that may cause atmospheric corrosion generally (i.e., amount of moisture, acid rain or other pollution, temperature changes, UV radiation, and salt), he provided no analysis of whether those conditions were present at the specific locations at issue in the NOPV.[36] As such, his testimony and opinion are limited at best given the lack of consideration or knowledge of SFPP's scientifically supported evidence relating to atmospheric corrosion conditions of the areas at issue in the NOPV, most notably the absence of measurable metal loss, pitting, or scaling of the pipe steel.

C. The Region Lacks Evidence of Measurable Metal Loss or Pitting.

Notwithstanding the Region's insistence that pitting existed on the Compton Creek span, no concrete evidence supports this assertion. Actual measurements are the only definitive evidence of metal loss or pitting, which the Region's case lacks. The Region inspector, Mr. Williams, confirmed that he did not touch the pipe locations in question or use measurement tools on the Compton Creek span during the audit.[37] The PHMSA Accident Investigator, Dr. Rodriguez, similarly testified that his opinion was based on limited information, consisting solely of the photographs taken by another inspector and his expertise.[38] Without the benefit of a single measurement, the Region is unable to demonstrate with any scientific certainty that metal loss,

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[31] Test. A. Rodriguez, Hr'g Tr. 147:3-5, 148:1-8.
[32] *Id*. at 32:24-25; 33:1.
[33] *Id*. at 33:4-23.
[34] *Id*. at 148:13- 149:9 ("Q. What did you review in advance of your testimony today to inform your opinions? A. Procedures, *some* of the evidence, photographs. Q. Whose photographs? A. I believe they are Leanna's photographs…[a] [p]ipeline inspector with the Western Region. Q. Did you review the results of any UT testing or any – did you see any photographs with measurement tools? A. Only the photographs that were presented here with one of the pitting gauges. Q. So is it fair to say you did not review any of SFPP's photographs taken since – or I guess that are in the record? A. Only the photographs that were presented and were also part of the affidavit. **Q. Am I understanding correctly that you are basing your opinion that atmospheric corrosion or pitting exists based on two-dimensional photographs taken by PHMSA's inspector in 2022? A. Yes, and expertise**.") (emphasis added).
[35] *Id.*
[36] *Id*. at 34:15 – 35:18. Dr. Rodriguez was asked to explain how these factors mattered in this case, but he did not provide any opinion or analysis as to their presence or effect on the specific pipe span in question. Instead, Dr. Rodriguez opined generally about environmental factors and atmospheric corrosion.
[37] Test. J. Williams, Hr'g Tr. 145:9-19.
[38] Test. A. Rodriguez, Hr'g Tr. 148:9-14.

pitting, peeling, or scaling of the pipe material existed, or further that the pipeline could not be safely operated until the next scheduled inspection.

V. SFPP's Extensive Evidence in the Record is Uncontroverted.

Given the absence of the critical feature of actionable atmospheric corrosion (measurable metal loss damaging the steel surface), the Region's case by itself is not sufficient to establish a violation. Further, the Region does not rebut SFPP's extensive experience, investigations, and actual testing and measurements in the record. SFPP's evidence indisputably confirms that the pipeline locations at issue exhibited nothing more than a light oxide and there was no condition that would affect the safe operation of the pipeline before the next inspection. Under SFPP's procedures and consistent with 49 C.F.R. §§ 195.583(c) and 195.581(c), a requirement to recoat or repair the coating was not and is not triggered today.

Knowledgeable, trained, and experienced SFPP corrosion engineers and technicians certificated by AMPP in coatings, corrosion assessments, cathodic protection, and corrosion control practices performed comprehensive atmospheric corrosion inspections on the areas at issue (see Table 1). The corrosion technicians maintain operator qualifications (OQs) in atmospheric corrosion monitoring, inspection of coatings, surface preparation, application and repair, and they received extensive initial refresher, and on-the-job training from SFPP. "[T]hey, through the year, will conduct [100s], if not [1,000s] of individual site inspections across the region."[39] Their conclusions were based on investigation, testing, and experience with this very pipeline at this exact location and environment in arid southern California, as evidenced by SFPP's atmospheric corrosion control procedures and criteria, corrosion technician training and qualifications, and results of regular atmospheric corrosion monitoring.[40]

In contrast to PHMSA's cursory visual observations, the detailed inspections conducted by qualified SFPP technicians were performed in close proximity to the pipe, in consideration of their experience with the pipeline environment, and with access to measurement tools as needed (pit gauge, fine tip hook probe, ruler, sandpaper). The supplemental inspections performed after PHMSA's audit involved digital ultrasonic wall loss measurement tools to further confirm that there is no metal loss or pitting on the pipe surface, with close attention to the areas identified by PHMSA (see Table 2). SFPP's thorough inspections documented only limited instances of light surface oxide without any evidence of metal loss, pitting, or scaling of the pipe steel, which precisely meets the clear and unambiguous language of the exception at 49 C.F.R. § 195.581(c) and relevant PHMSA guidance.

Most recently, an independent third-party corrosion expert, Kevin Garrity with Mears Group, Inc., personally inspected the areas identified in the NOPV on January 11, 2024, in consideration of the

[39] Test. R. Galisky, Hr'g Tr. 91:25, 92:1-2.

[40] PHMSA does not specify in the regulations or guidance any requirements to inform the operator's specific testing, investigations, or experience appropriate to the environment of the pipeline beyond the plain language of 49 C.F.R. § 195.581(c). PHMSA guidance and enforcement suggest that operators have wide latitude in using a test, investigation, or experience to satisfy the exception at 49 C.F.R. § 195.583(c). Final Rule, 71 Fed. Reg. 13289, 13295 (Mar. 15, 2006) (explaining that "operators do not have to protect aboveground pipelines from atmospheric corrosion if they demonstrate the corrosion will have certain characteristics. We require operators to demonstrate grounds for exceptions when they are the best source of information on which the exception is based.").

Region's NOPV allegations and PSVR.[41] Mr. Garrity is a highly regarded expert by both industry and government with over 40 years of experience in corrosion control and decades of experience with pipeline safety regulations. In his report, Mr. Garrity summarized his analysis of SFPP's inspection and testing results, along with his own independent inspection and evaluation, opining that "[t]o date, the corrosion observed during the inspections of the SFPP piping referenced by PHMSA is only cosmetic in nature, not potentially injurious to safety and does not adversely affect the safe operation of these assets."[42]

Table 1: Relevant Inspections of LS-120 Compton Creek Span[43]

Date	Corrosion Engineer	AMPP Certifications (Y/N)	"Test, Investigation, or Experience Appropriate to the Environment of the Pipeline"	Evidence of Metal Loss, Pitting, or Scaling (Y/N)
2017	NA	NA	✓ ILI MFL-C	No.
8/13/19	B. Mars	Yes.	✓	No.
9/24/20	B. Mars	Yes.	✓	No.
12/3/21	B. Mars	Yes	✓	No.
2022	NA	NA	✓ ILI MFL-C and MFL-A	No.
1/26/23	M. Pyle	Yes.	✓	No.
11/13/23	W. Yarbrough	Yes.	✓	No.
1/11/24	K. Garrity	Yes.[44]	✓	No.

[41] Mr. Garrity reviewed numerous materials in support of his investigation and his conclusions. These materials include, but are not limited to: 49 C.F.R. Part 195 and associated Corrosion Enforcement Guidance (2016); PHMSA CPF 5-2023-003-NOPV (4/11/2023); 52023003 NOPV Pipeline Safety Violation Report (4/11/2023); PSVR Photos; SFPP Response to 2022 PHMSA Field Inspection Request for Information SFPP WATSON AZ AUDIT YEARS 2019 – 2021; 2022 PHMSA FIELD INSPECTION OF SFPP WATSON AZ AUDIT YEARS 2019 – 2021; SFPP Atmospheric Corrosion Inspection Report -Compton Creek Bridge Span-11/27/23; SFPP Compton Creek Inspection Report (01/31/23); SFPP Atmospheric Corrosion Survey Report _LS-1230 Compton Creek (11/13/23); SFPP L-O&M 918 Inspecting for Atmospheric Corrosion 09-11-2019 and 2023; Mears 01/11/2024 Site Visits Photographic documentation and Sampling Results; and Atmospheric Corrosion, C. Leygraf, I.O. Walinder, J. Tidblad, T. Graedel (Second Edition- The Electrochemical Society). *See Pre-Hearing Brief Attachment G: Mears Atmospheric Corrosion Evaluation for SFPP Performed by K. Garrity (Feb. 2, 2024)*, p. 5 [hereinafter Mears Report].

[42] *Id.* at p. 9.

[43] As reflected in the record, SFPP qualified corrosion technicians performed regular atmospheric corrosion monitoring inspections at Colton Station, including Britt Mars and Micheal Pyle. *See SFPP Pre-Hearing Brief, Attachment C: Summary of Colton Station Atmospheric Corrosion Inspections (2019-Present)* [hereinafter Colton Station AC Inspection Chart]*; Pre-Hearing Brief Attachment D: Affidavit of Britt Mars (Feb. 4, 2024)* at ¶ 32-39, Exhibit B [hereinafter B. Mars Aff.]; M. Pyle Aff. ¶ 29-33. The corrosion technicians did not identify any evidence of pitting, scaling, or metal loss through the use of ultrasonic wall loss and other tools. AMPP (formerly NACE International) certified corrosion expert, Kevin Garrity also inspected and evaluated the locations at Colton Station. Mr. Garrity confirmed that no evidence of metal loss, pitting, or scaling was present. Mears Report, p. 18-19.

[44] Mr. Garrity is a registered AMPP Cathodic Protection Specialist and has obtained a CP4 from AMPP (formerly NACE International). NACE has merged with SSPC to become AMPP.

A. SFPP Atmospheric Corrosion Inspections Rated as "Fair" (2019, 2020, and 2021).

SFPP Corrosion Technician Britt Mars has worked in the corrosion industry for 15 years, is certified by AMPP as a Cathodic Protection Technician (CP2) and Corrosion Technologist, and spent 8 years inspecting this pipeline span prior to PHMSA's audit.[45] On August 13, 2019, he "perform[ed] a satisfactory visual examination on the atmospheric condition of the pipe by walking the span from above and below, along with examining the air-to-soil transition on both sides."[46] As Mr. Mars explained, "we are looking for visual cues that could indicate a 'poor' atmospheric, and this location, through my visual inspections, did not indicate any of those visual cues."[47] Mr. Mars observed only "a light surface oxide with no visual pitting."[48]

On September 24, 2020, Mr. Mars performed another "satisfactory visual examination of the atmospheric condition of the pipe by walking the span, from above and below and examining air-to-soil transitions on both sides."[49] Explaining further that "there was no roughness or deformities; there was also not a presence of heavy surface oxide; and then, most importantly, there was no 3D-dimensional pitting present on the pipe," Mr. Mars concluded that the atmospheric corrosion grading was "Fair."[50]

On December 3, 2021, Mr. Mars returned to the span to perform another atmospheric corrosion inspection, which he described as "another satisfactory visual examination of the atmospheric condition of the pipe by walking the span, once again, from above and below, along with examining the air-to-soil transitions on both sides."[51] Once again, based on observations that "no roughness or deformities, no heavy surface oxide nor visual 3D-dimensional pitting," Mr. Mars rated the span as "Fair."[52] Mr. Mars' demonstration, based on his extensive experience, unequivocally determined that this pipeline only had light surface oxide and it was safe to operate until the next scheduled inspection.[53]

B. SFPP Supplemental Atmospheric Corrosion Inspection Confirmed "Fair" Rating (Jan. 26, 2023).

In response to the potential concerns raised by PHMSA during the audit in November 2022, SFPP quickly returned to the span to conduct an additional inspection on January 26, 2023, by another

[45] Test. B. Mars, Hr'g Tr. 105:10-13 ("The entire eight years I was there, it was under my responsibility for providing and documenting the LOP surveys, along with atmospheric grading of that span for eight years."); *see also* B. Mars Aff. ¶ 2, 4, 7-8.
[46] *Id*. at 106:8-12 (discussing Aug. 2019 inspection); *see also* B. Mars Aff. ¶ 15.
[47] *Id*. at 106:19-24; *see also* B. Mars Aff. ¶ 10, 15, 22.
[48] *Id*. at 106:19-20.
[49] *Id.* at 107:18-22; *see also id.* at 110: 3-6. (Sept. 2020 inspection).
[50] *Id*. at 109:8-12; *see also* B. Mars Aff. ¶ 17-18.
[51] *Id*. at 110:23 - 111:2.
[52] *Id*. at 111:6, 9-10.
[53] Mr. Mars also performed atmospheric corrosion inspections of one or more Colton Station breakout tanks and associated piping on February 6, 2019; January 28, 2020; and February 14, 2022, in accordance with SFPP L-O&M 918 procedures and guidelines. B. Mars Aff. ¶ 33. Mr. Mars "did not identify any measurable pitting or general wall loss or conditions that would affect the safe operation of the pipeline before the next scheduled inspection per SFPP's procedures" during any of the inspections. *Id*. at ¶ 37.

experienced corrosion engineer, Micheal Pyle.[54] Mr. Pyle has over 9 years in the corrosion industry and is certificated by AMPP as a Cathodic Protection Technologist (CP3) and Corrosion Technologist.[55] He considered the areas of concern identified by PHMSA on the Compton Creek span during the audit, explaining "[p]rior to my hands on inspection, I did review [PHMSA's 2022 audit] photos and made sure we put hands on those sites."[56] With the use of a ladder,

> I went up to the pipe to perform a 360-degree view of the pipeline across the entire span of that bridge. Anywhere that there was a light surface oxide, I took sandpaper, lightly sanded that down, just to remove the light surface oxide and be able to check the remaining wall thickness, looks for pits utilizing the analog pit gauge, and then used the fine tip hook knife to feel for any kind of etching, bulging, or dents in the pipe. [. . .] Looking for any kind of anomaly along the pipes here. [. . .] I found nothing more than light surface oxide and some bare pipe along [. . .] portions of the entire span.[57]

The grading of the atmospheric corrosion condition of the pipeline remained "Fair" and again nothing more than a light surface oxide was identified. Further, "there was no visible pitting, no measurable pitting with the analog pit gauge, and no measurable wall loss with the ultrasonic thickness gauge."[58]

C. SFPP Additional Atmospheric Corrosion Inspection Further Validated "Fair" Rating (Nov. 13, 2023).

During subsequent discussions, the Region requested that SFPP collect ultrasonic wall loss measurement tool readings across the span,[59] expressly to reconfirm that there was no metal loss.[60] Even though the regulations allow for a demonstration based on investigation, test, or experience, SFPP nevertheless performed this testing in good faith on November 13, 2023, in conjunction with qualified SFPP corrosion technician Walter Yarbrough's atmospheric corrosion inspection performed under the direct supervision of Mr. Galisky, a qualified corrosion supervisor.[61] Mr.

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[54] Inexplicably, PHMSA counsel characterized SFPP's re-inspections as "post hoc rationalizations." Test. A. Iorio, Hr'g Tr. 14:7. Subsequent confirmations of Mr. Mars' initial demonstration of compliance are not rationalizations after the fact. They are not rationalizations at all, but independent validation of SFPP's initial determination based on investigation, testing, and experience by separate qualified and trained corrosion engineers and technicians.

[55] Test. M. Pyle, Hr'g Tr. 115:6-7; *see also* M. Pyle Aff. In preparation for his inspection, Mr. Pyle reviewed photographs provided to SFPP PHMSA's preliminary inspection findings, which appear to be the same photographs in the PSVR.

[56] *Id*. at 122:5-13.

[57] *Id*. at 116:5-23. Despite Dr. Rodiguez's opinion that measurement should be conducted before sanding, surface preparation and cleaning is necessary prior to using a hand pit gauge. *See also infra* Section VI.C.2.

[58] *Id*. at 121:3-6.

[59] SFPP corrosion technicians and third-party corrosion expert also collected such measurements and conducted additional testing at Colton Station. *See* Colton Station AC Inspection Chart*;* Mears Report, p. 9-10.

[60] These readings were documented and confirmed no metal loss on the pipe span. *See Pre-Hearing Brief, Attachment F: Affidavit of Walter Yarbrough (Feb. 2, 2024)*, Exhibit C (Attachment 1 includes a Field Measurements Table containing atmospheric inspection bare spot measurements) [hereinafter W. Yarbrough Aff.]. Ultrasonic wall loss measurement tools were also employed by SFPP Technicians and corrosion expert Mr. Garrity at certain areas of concern at Colton Station. *See* Colton Station AC Inspection Chart; Mears Report, p. 9-10.

[61] W. Yarbrough Aff. (and associated exhibits); *see also* Test. W. Yarbrough, Hr'g Tr. 130-134.

Yarbrough has worked in the corrosion industry for 9 years, is certificated by AMPP as a Cathodic Protection Technician (CP2), and began working with SFPP in 2022.[62]

Mr. Yarbrough explained his use of a ladder and proximity to the pipe: "I'm over the pipe, and my – face and my camera are a foot away from these spots. I'm closer than anybody besides Mike [Pyle] has been to these spots, and there was no – no – no evidence of corrosion in any way."[63] He documented the locations identified by PHMSA with as-found photographs and used a "square" of sandpaper to loosen and wipe clean the light surface oxide to measure for evidence of wall loss.[64] Employing a hook probe designed to identify metal loss and a calibrated ultrasonic wall loss measurement tool, Mr. Yarbrough's evaluation and testing identified no evidence of metal loss, pitting, or condition that would affect the condition of the pipe before the next scheduled inspection.[65] The pipe condition rating was confirmed as "Fair."[66]

D. Third-Party Expert Evaluation Confirmed Light Surface Oxide and No Impact to Safe Operation (Jan. 11, 2024).

Independent third-party corrosion expert Mr. Garrity conducted a review of the extensive inspection and testing undertaken by SFPP, PHMSA's case file and associated photographs, and performed his own thorough on-site evaluation of the LS-120 span and Colton Station.[67] As part of Mr. Garrity's on-site direct examination of the relevant pipeline locations on January 11, 2024, he measured the areas at issue, took photograph documentation, and performed Surface Contaminant Acceptability Testing (SCAT) on bare pipe surfaces and peeled coating samples.[68] Based on that review and evaluation, combined with his extensive corrosion experience, Mr. Garrity concluded that PHMSA's allegations cannot be substantiated given the lack of definitive evidence of corrosion pitting.[69] Specifically, Mr. Garrity determined that,

[62] Test. W. Yarbrough, Hr'g Tr. 123:16-22.
[63] *Id*. at 133:23-25; 134:1-2.
[64] *Id*. at 131-133.
[65] *Id*. Additional testing also confirmed the same at the Colton Station areas of concern. *See* Colton Station AC Inspection Chart*;* Mears Report, p. 9-10.
[66] A report summarizing this analysis, the results, the calibration certification for the ultrasonic wall loss measurement tool, among other factors considered in the examination are included as Exhibit C to Mr. Yarbrough's affidavit included with the Pre-Hearing Brief.
[67] Mears Report, p. 5. In addition to his January 2024 site visit, photographs, and sampling results, Mr. Garrity also considered and relied upon his review and analysis of PHMSA regulations, the NOPV issued to SFPP, underlying PSVR and exhibits including photographs, SFPP's responses to PHMSA requests for information, field inspection notes, SFPP atmospheric corrosion inspection and survey reports, SFPP procedures.
[68] Mears Report, p. 14 (The SCAT testing was used to assess the environmental conditions in the area through analyzing the presence of chlorides and the pH of liquid extracts from the pipe and coatings)*; see also* Test. K. Garrity, Hr'g Tr. 60:12-20 ("I … performed an inspection January 11 of 2024. I was up close to the pipe, using harnesses and ladders, and I did not see any evidence of pitting. Certainly, I had a Starrett pit gauge with me for the purposes of measuring any pitting that I found, and I couldn't find anything in the areas that I looked at. The only thing I found was light surface oxide.").
[69] *See* Mears Report, p. 18 ("Mears concludes that PHMSA's allegations cannot be substantiated given the lack of definitive evidence of excessive corrosion pitting."); *id.* at 14 ("Based on the inspection of Line 120-1 and PHMSA areas of concern at Colton Station, only surface oxide was detected, and no evidence of corrosion pitting or metal loss was found."); *see also* Test. K. Garrity, Hr'g Tr. 77:1-2 ("Is there evidence of pitting corrosion? No, there isn't."); 77:9-11 ("Based on the evidence presented, are the allegations of a violation sustainable? In my opinion, the answer

> Based on the inspection of Line 120-1 and PHMSA areas of concern at Colton Station, only surface oxide was detected, and no evidence of corrosion pitting or metal loss was found. ... No chlorides were detected and the pH of the liquid extract from the SCAT testing had pH values consistent with the deionized water used for the extract. These results indicate that chemical constituents that may contribute to atmospheric corrosion were not present in the samples obtained.[70]

During the hearing, Mr. Garrity provided further testimony which expanded upon his conclusions and clarified that that the presence of peeling paint was not indicia of corrosion:

> There's no question that the paint is peeling on this [Compton Creek] span, but truth be told, this span doesn't even need a paint or a coating. <u>It has no measurable wall loss. It's not in an environment that's conducive to any type of accelerated atmospheric corrosion, and nothing has been found by either SFPP or PHMSA that would suggest that there is a condition that adversely affects the safe operation of that pipeline</u>, and the same is true for what I looked at […] Colton Station.[71]

Mr. Garrity also addressed PHMSA's substantial and misplaced reliance on photographs, explaining that "corrosion is three-dimensional. So when we're looking at photographs…there needs to be a recognition that it's very difficult to identify metal loss from a photograph unless there's a significant cavity or reduction in the wall loss itself."[72] Further, Mr. Garrity clarified in his report and at the hearing that the mechanism of corrosion resulting in external metal loss beneath disbonded coating is not feasible:

> It also important to note that under the observed peeling coating conditions, the mechanism of corrosion resulting in external metal loss under disbonded coatings is not feasible due to the absence of a capillary path between an anaerobic anodic condition under the coating and an adjacent oxygenated cathodic condition where the coating has peeled off.[73]

As part of his overall analysis and as reflected in his report, Mr. Garrity explored the corrosion growth rate of atmospheric corrosion in carbon steel pipelines.[74] During the hearing, Mr. Garrity described the calculations and assumptions involved in order to estimate the time in which

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to that is no."); 79:10-16 ("There is no evidence, in my opinion, that supports the allegations in the PHMSA NOPV. That's based on numerous field investigations, testing, and other evidence, the fact that there's not metal loss, no pitting, no scaling…").

[70] *Id*. at 14.

[71] Test. K. Garrity, Hr'g Tr. at 68:5-14 (emphasis added); *see also id.* at 157:20-25 (where Mr. Garrity provided further explanation regarding his efforts to vet whether water could be beneath disbonded coating, an *ad hoc* suggestion by PHMSA during the hearing, offering that "I took a lot of these sections … and I peeled the painting off, the coating off – I'll call it a coating – and I did not find any evidence of corrosion underneath it apart from what we've been talking about, which is the light surface oxide").

[72] *Id.* at 56:20 – 57:2; *see also id.* at 56:7-19 ("…as we look at photographs and we try to judge from those photographs…a few things are important to consider. One, color doesn't really tell us anything about what's going on underneath the corrosion film…").

[73] Mears Report, p. 10*;* Test. K. Garrity, Hr'g Tr. at 156:9-157:1 (explaining "there is no electrolyte here, so even if there's moisture underneath the disbonded coating [. . .] there isn't a capillary path that's going to allow corrosion to take place in a manner similar to the way it would in an underground application.").

[74] Mears Report, p. 9.

corrosion could grow to the point it could adversely affect the safe operation of a pipeline.[75] The purpose of the calculations, as explained by Mr. Garrity, was to "assure [himself] of the fact that what we were observing on the span was not going to adversely affect safety before the next inspection cycle."[76] Mr. Garrity ran an atmospheric corrosion growth rate equation assuming environmental conditions harsher than those in Compton or Bloomington, California.[77] The calculations confirmed that it would take 60 years with the pipe exposed before any actionable atmospheric corrosion develops under environmental conditions that are more conducive corrosion than the actual atmospheric pipeline environment in Compton, California.[78] Mr. Garrity reiterated that routine inspections would continue to occur at the requisite regulatory interval over that timeframe to monitor for signs of actionable atmospheric corrosion and to remediate detected measurable metal loss, as necessary.[79]

Notably, Mr. Garrity remarked that the Region did not present any testimony or evidence suggesting that the conditions at the locations at issue "at this point in time affect the safe operation of the pipeline before the next scheduled inspection," per the regulation at 49 C.F.R. § 195.581(c).[80] Mr. Garrity went on to explain that under the PHMSA regulations,

> You are obligated to clean and coat pipeline that's exposed to the atmosphere, but that there are exceptions, and one exception is if the corrosion that's observed is only a light surface oxide or if it will not affect the safe operation of the pipeline before the next scheduled inspection. … I think it's also important to recognize that the [PHMSA] enforcement guidelines identify the metal loss that's contemplated in atmospheric corrosion; that due to general corrosion, localized corrosion, pitting, or peeling, scale, and the steel surface has been damaged. So the concept is that … <u>they've actually succeeded in damaging the actual pipe surface, the steel surface</u>. Further, <u>if a light surface oxide exists, it's a slow rusting process</u>, according to the enforcement guidelines, <u>and it's not yet considered to be atmospheric corrosion because there's actually no evidence of metal loss at this time</u>.[81]

As explained in the hearing and in his report, Mr. Garrity's expert opinion is that "all evidence indicates" that while there is peeling paint, (1) the observed corrosion is light surface oxide; (2) the extent of corrosion will not affect safe operation of the pipeline; and (3) "SFPP has satisfied the requirements for testing and investigations and can clearly demonstrate that it satisfies both conditions set forth in the regulations."[82]

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[75] Test. K. Garrity, Hr'g Tr. at 136:19 – 137:7.
[76] *Id*. at 137:8-11.
[77] *Id*. at 137:12-21 ("So the parameters that I input into the equation were a relative temperature of 25 degrees C, which is roughly 75 degrees Fahrenheit….humidity 95 percent that would exist 24 hours a day, 365 days a year, which we know is not the condition in Compton or Bloomington. Even though I didn't detect any chlorides, I entered 30 parts per million chlorides into the equation…").
[78] *Id*. at 137:22 – 138:7
[79] *Id*. at 138:21 – 139:2.
[80] *Id*. at 51:16-25; 52:1.
[81] *Id*. at 52:4-25 – 53:6 (emphasis added).
[82] Mears Report, p. 12.

E. ILI Data Further Substantiates No Measurable Wall Loss.

To supplement the comprehensive inspections performed by the experienced SFPP corrosion technicians (and third-party corrosion expert in this case), SFPP regularly performs ILI on its pipeline facilities. Metal loss ILI tools performed in 2017 and 2022 on the Compton Creek span confirmed that there was no metal loss on the span at or near MP 1.82.[83] PHMSA proffered no evidence to refute the results of these ILI inspections.

Table 2: SFPP Evaluation of Areas Identified by PHMSA on Compton Creek Span[84]

PHMSA PSVR Photograph[85]	Atmospheric Corrosion Inspection Jan. 26, 2023 (M. Pyle)[86]	Atmospheric Corrosion Inspection Nov. 13, 2023 (W. Yarbrough)[87]	Third-Party Atmospheric Corrosion Evaluation Jan. 11, 2024 (K. Garrity)[88]
Photo A-1	✓	✓	✓
Photo A-2	✓	✓	✓
Photo A-3	✓	✓	✓
Photo A-4	✓	✓	✓
Photo A-5	✓	✓	✓
Photo A-6	✓	✓	✓
Photo A-7	✓	✓	✓
Photo A-8	✓	✓	✓
Photo A-9	✓	✓	✓
Photo A-10	✓	✓	✓

[83] *Pre-Hearing Brief Attachment H: Compton Creek 2017 & 2022 ILI Results.*

[84] A checkmark indicates that the SFPP or a third-party expert engaged by SFPP personally evaluated the area of concern identified in the corresponding PHMSA Audit Photograph.

[85] PSVR, Exhibits A1-A10.

[86] M. Pyle ¶ 15-16, 28, Exhibit B; Hr'g Tr. 122:1-13 (Pyle confirming that he "visually examined and put hands and tools on all of the sites depicted in PHMSA's exhibit to its Pipeline Safety Violation Report" and reiterating that "[p]rior to my hands-on inspection, I did review those photos and made sure we put hands on those sites, yes.").

[87] W. Yarbrough Aff. ¶ 13, 21, Exhibit C.

[88] Mears Report, p. 14-18, Appendix A; *see also* Hr'g Tr. 80:2-8 ("All areas of – identified by NOPV…demonstrated by the corrosion technicians' implementation of procedures, investigation of the pipe, and experience examining the areas in the environment for atmospheric corrosion.").

VI. PHMSA's Post Hoc Generalizations and Assertions Are Unsupported.

A. The Region Mischaracterizes SFPP's Atmospheric Corrosion Inspections.

In an attempt to bolster its case, PHMSA asserted at the hearing that the SFPP's atmospheric corrosion inspections were not complete, that SFPP determined that recoat was required, and that SFPP's own procedures required recoat. As methodically addressed by SFPP at the hearing and born out in the documentation, these assertions are unsupported, and they are directly refuted by testimony from the experienced individuals who performed the inspections and completed the associated inspection documentation.

Direct testimony by Mr. Mars, SFPP Level 5 Corrosion Technician, and Mr. Galisky, SFPP Corrosion Manager, confirms the comprehensive nature and completeness of the inspections performed prior to the Region's audit.[89] In addition, SFPP's voluntary recommendation to consider upgrading the coating of the span was not tied to any regulations or procedures based on the rating of the pipe material (i.e., it was not mandatory).[90] SFPP clarified its L-O&M 918 procedure criteria for rating the atmospheric condition of pipe as "Poor," and representative photographs which PHMSA mischaracterized in the hearing.[91] Specifically, PHMSA neglected to mention the procedure's detailed text associated with the photographic examples of a "Poor" rating, both of which specify that the rating in the example was based on actual pitting measurements at <u>depths of 20 Mils</u>.[92] As such and consistent with the PHMSA regulations, this rating is not applicable to the areas at issue in the NOPV because there are no signs or measurements of pitting or metal loss and there is no condition that would impact the safe operation of the pipeline before the next inspection.

B. Pitting on *Buried Pipe Below Grade* Has No Bearing on Pipe *Exposed to the Atmosphere.*

In its pre-hearing submission and at the hearing, PHMSA argued that SFPP's identification of pitting on buried pipe below grade underneath a different type of coating and in contact with a link seal on either end of the span – well after PHMSA's underlying audit and issuance of the NOPV – further supports the Region's case, calling it an "admission" of atmospheric corrosion.[93] PHMSA's own regulations and the factual record, however, refute this assertion.

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[89] Test. B. Mars, Hr'g Tr. 109:13-25; Test. R. Galisky, Hr'g Tr. 100:10-21. *See also* B. Mars Aff. ¶ 22 ("During each of the 3 inspections I performed of the SFPP Compton Creek span, my investigation and testing confirmed that the pipe span had experienced no metal loss or pitting. No measurable pitting, general wall loss, or roughness was detected. All inspections were completed and graded per L-O&M 918 procedures and guidelines.").

[90] Test. R. Galisky, Hr'g Tr. 96:24 - 98:12.

[91] Test. J. Williams, Hr'g Tr. 26:11 – 27:23.

[92] *Pre-Hearing Brief Attachment B: SFPP Procedure L-O&M 918, Inspection for Atmospheric Corrosion (Rev 9-11-2019)* at 11 ("The presence of any degree of <u>pitting</u> or scale corrosion where a <u>measurable amount of wall loss has occurred</u>.") (emphasis added); *id*. at 12 ("Photograph 5 <u>shows pitting</u> around the air/ground interface of the <u>pipe that measured approximately 20 mils in depth</u>") (emphasis added); *id*. at 13 (explaining that "Photograph 6 shows [. . .] "[p]itting depths <u>were measured approximately 20 mils in depth</u>" with the title "Photograph 6 – <u>the pitting with wall loss is the criteria</u> that places this site into the poor category") (emphasis added); *see also* Test. R. Galisky, Hr'g Tr. 86:20 - 87:1, 88:24 - 89: 5; Test. K. Garrity, Hr'g Tr. 76:1-15.

[93] Test. D. Hubbard, Hr'g Tr. 39:13-20; Test. J. Williams, Hr'g Tr. 25:22-25.

As detailed above, the PHMSA federal corrosion control regulations specify different regulatory requirements for pipelines based on whether they are exposed to the atmosphere or buried.[94] The corrosion monitoring and remediation requirements are entirely distinct for atmospheric corrosion as compared to external corrosion because of the elements required for corrosion to occur and to accelerate vary greatly depending on the pipeline environment.[95]

The buried pipe inspection report, Pipeline Inspection Repair Report (PIRR), and pictures contained therein clearly show that the portion of the pipeline where SFPP identified pitting was buried, surrounded by soil and concrete, and correlates to a link seal in contact with the pipeline below grade.[96] Nowhere in the PIRR is there a reference to atmospheric corrosion pitting.[97] Instead, it clearly identifies the location as "beneath the seal link" and a check by "external corrosion." Atmospheric inspections would never have identified this below grade pitting on buried pipe.[98]

As Mr. Garrity explained with regard to the pitting identified below grade and the potential for pitting on the span exposed to the atmosphere,

> They're in no way related to each other. This subsurface or underground pitting was at an area where the pipe had a coating fault or holiday, but it was in constant contact with an electrolyte that is necessary for the corrosion to take place. That condition does not exist above grade in the atmospheric section.[99]

The general assertion that "if you have pitting in one area, it's in the exact same environment, the same grade of pipe, very likely you could have pitting in other areas" may be true in some circumstances.[100] That simply is not what occurred here: the below grade pitting was in a completely different environment than the portion of the span exposed to the atmosphere at issue in the NOPV. Further, the argument that corrosion identified in a different pipeline service and environment is indicative of another, is scientifically incorrect.[101] SFPP has acknowledged the existence of this pitting below grade on either end of the buried portion of span, but SFPP unequivocally denies that it has any bearing on this matter. PHMSA's assertion that the pitting identified – after the underlying audit and issuance of the NOPV – on a portion of the pipeline buried in soil and surrounded by concrete proves the existence or even a susceptibility to atmospheric corrosion on the span is illogical and unsupported.

C. SFPP Post-Audit Atmospheric Corrosion Inspections Were Consistent with PHMSA Regulations and Industry Standards.

The Region lodged several unsubstantiated and puzzling critiques of the atmospheric corrosion review performed by SFPP and its third-party expert following PHMSA's audit, including the

[94] 49 C.F.R. Part 195, Subpart H Corrosion Control; *see also* Section III. *supra*.
[95] *Compare* 49 C.F.R. § 195.572, "What must I do to monitor external corrosion?"; *with* 49 C.F.R. § 195.583, "What must I do to monitor atmospheric corrosion control?".
[96] W. Yarbrough Aff. Exhibit B; *see also* Test. W. Yarbrough, Hr'g Tr. 123-130.
[97] *Id*.
[98] Test. W. Yarbrough, Hr'g Tr. 128:21-24.
[99] Test. K. Garrity, Hr'g Tr. 134:23- 135:4.
[100] Test. D. Hubbard, Hr'g Tr. 39:13-20.
[101] Test. K. Garrity, Hr'g Tr. 134:19 - 135:4 ("They're in no way related to each other…").

steps and tools employed to identify and measure for evidence of wall loss and pitting. SFPP and its third-party expert reviewed and analyzed the entire Compton Creek span exposed to the atmosphere (as well as areas of Colton Station) inclusive of the areas identified by PHMSA during its audit and in the PSVR. The steps employed were consistent with widely accepted technical industry standards in corrosion assessment and PHMSA regulations. Further, these steps starkly contrast with PHMSA's attempt to classify wall loss or pitting <u>without taking these steps</u>.

1. SFPP Analyzed Every Area Identified by the Region.

At the hearing, the Region complained of difficulty in matching the locations photographed by SFPP after the audit, without identifying a single location where SFPP did not perform a one-to-one comparison.[102] This assertion is directly contradicted by testimony of the SFPP corrosion technicians conducting the post-audit evaluation of the span. As the inspection reports and testimony clearly show, SFPP took care after PHMSA's audit to perform a one-to-one comparison of each of the areas on the pipeline span photographed by the Region and provided to SFPP.[103] SFPP's testing and investigation included additional areas for a thorough evaluation and assessment of the atmospheric condition of the span. Independent third-party review and evaluation of the span also considered every one of the Region's photographs that were provided to SFPP as part of the PSVR.[104] Any differences in the vantage point of the areas photographed are because SFPP and its third-party expert performed much closer inspections than the Region, through the use of a ladder and harness in order to evaluate the atmospheric condition of the pipe and to facilitate hands-on inspections and the use of direct measurement tools.[105]

Further, SFPP can only perform a one-to-one comparison of the areas identified by the Region and for which it has fair notice and an opportunity to respond. It became apparent after the hearing, that the Region has one, if not more, photos of the Compton Creek span which are not part of the case file, one of which was exhibited during the Region's testimony at the hearing.[106] This photograph was not previously provided to SFPP and was only made available to SFPP upon request after the hearing, without attribution as to its source, date, or verification of its location. As discussed at the hearing, this photo shows nothing more than disbonded coating, and the Region did not identify a single location on the span with measurable pitting or wall loss.[107]

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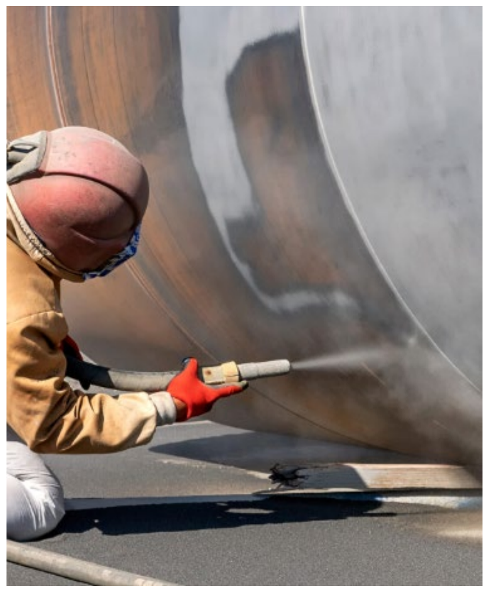
[102] Test. D. Hubbard, Hr'g Tr: 140:9-25.
[103] This is illustrated above in Table 2.0.
[104] See Section V.D, *supra*.
[105] Test. M. Pyle, Hr'g Tr. 116:11-14; M. Pyle Aff. ¶ 18; Test. W. Yarbrough Hr'g Tr. 132:23-24; W. Yarbrough Aff. ¶ 15; Test. K. Garrity, Hr'g Tr. 59:12-15.
[106] Test. D. Hubbard, Hr'g Tr. 150:3-25; 151:1-25; 153:1-9; 155:17.
[107] PHMSA's inspector testified they did not take any measurements to identify or confirm pitting or wall loss. Test. J. Williams, Hr'g Tr. 145:18-19, 146:7-8. As Mr. Garrity has explained, "[the span] has no measurable wall loss…There's nothing measurable from the standpoint of a pit depth or wall loss at this location." Test. K. Garrity, Hr'g Tr. 68:7-8, 68:24 – 69:1. As Mr. Galisky explained, PHMSA's photographs did not identify any wall loss on the span as "[t]he only way that [pitting] can be identified is actually through measurement…but it's not properly demonstrated within that particular picture." Test. R. Galisky, Hr'g Tr. 88:17-21.

2. SFPP Used Sandpaper to Facilitate Accurate Wall Loss Measurements Consistent with Industry Standards.

The Region boldly states – without any supporting evidence – that SFPP sandblasted or otherwise removed (or repaired) evidence of pitting or metal loss.[108] The span was not subject to grit blasting or sandblasting, which requires use of a power tool. In response to the concerns expressed by PHMSA during the 2022 audit, qualified SFPP corrosion engineers and technicians, Mr. Pyle and Mr. Yarbrough, used a piece of sandpaper to lightly clean the areas to evaluate the pipeline more closely for evidence of metal loss, pitting, or scaling of the pipe steel, of which they found none.[109] The sandpaper employed has very low level of grit, as compared to a heavy power tool which would be used to grind or blast the pipe metal.

Figure 1: Sandpaper as Compared to Abrasive Blasting (E.g., Sandblasting)[110]



[108] Test. D. Hubbard, Hr'g Tr. 37:5-20 ("…what we're seeing here is beyond a light surface oxide…then some of the photos you'll see where the corrosion was sanded down, sandblasted down to get down to the bare metal. If that was just the light surface oxide, you wouldn't need to that. You wouldn't have -- you wouldn't have the pitting. You wouldn't see the shadows in the photos showing that irregular surface. You don't that smooth surface that you would expect."); *id.* at 81:1-22 ("When you were in the field identifying or working on these areas, were the – the patches of corrosion that we're discussing here, had they been sanded or repaired ahead of time, or what were you seeing? Were you seeing the raw states of the corrosion that we saw in our photos when we were in the field?...But some of those locations, it had been removed?").

[109] Test. W. Yarbrough, Hr'g Tr. 131: 23-24 ("I went up there with – with sandpaper, hand tools, no power tools, and lightly sanded down a portion…"); Test. K. Garrity, Hr'g Tr. 57:3-19 ("This span was not subjected to grit blasting or sandblasting. It was subjected to sandpaper…") and Tr. 135:12-15 ("That's… impossible to do [to sand out pits on a pipeline]. You can grind a pit with a grinding tool, a mechanical grinding tool, but not with a piece of sandpaper that we would use on a piece of wood or drywall."); *id.* at 81:19-21. Sandblasting is more accurately referred to as abrasive blasting given that silica sand is no longer used today because of industrial health concerns. Nevertheless, SFPP uses the term sandblasting to track the Region's assertion.

[110] Compare general purpose sandpaper sheets (available at https://www.uline.com/BL_2340/3M-Sandpaper-Sheets) to SSPC & NACE, *Surface Preparation Standards Photograph (available at* https://galvatech2000.com/sspc-nace-surface-preparation-standards/?lang=en).

The use of light sandpaper to clean and prepare the pipe surface for further evaluation is consistent with technical industry standards for direct examination of coating damage, corrosion defects, and corrosion depth measurements.[111] Those standards expressly provide for the important initial step of cleaning and surface preparation of any anomalies, stating "accurate assessment of external corrosion anomalies can only be accomplished after thorough cleaning of the affected area."[112] Further, "the objective of the pipe preparation process is to remove coating residue and corrosion deposits to optimize the effectiveness of the inspection. The steel pipe surface must be clean, dry, and free of surface contaminants such as dirt, oil, grease, corrosion products, and coating remnants."[113]

SFPP's corrosion expert reiterated that during his investigation and testing he observed "some areas that had been sanded for the <u>purposes of looking for pitting by the technicians and also for the UT measurements</u>, but there were other areas [he examined] that had not been subjected to any of the sanding."[114] Further, corrosion pitting, which exhibits cavities or holes in the pipe metal, cannot be hand-sanded out with sandpaper.[115]

3. SFPP Employed Ultrasonic Wall Loss Measurement Tools Per PHMSA Regulations and Industry Standards.

During the hearing, the Region also questioned the capabilities of the ultrasonic wall loss measurement tool, a tool that the Region itself requested and which SFPP proactively employed.[116] Specifically, SFPP utilized a calibrated ultrasonic wall loss measurement tool pursuant to the applicable manufacturer specifications, the results for which were within the stated tool tolerance.[117] PHMSA integrity management regulations 49 C.F.R. Part 195 and associated guidance expressly authorize use of this tool: "[m]etal Loss Tools (Ultrasonic and Magnetic Flux Leakage) for determining pipe wall anomalies, e.g., wall loss due to corrosion."[118] In addition, technical industry standards expressly cite "ultrasonic wall loss probes" and "pit depth gauges" as

[111] NACE SP0502-2010, Pipeline External Corrosion Assessment Methodology, Appendix B, Direct Examination – Coating Damage and Corrosion Depth Measurements, Section B6 Assessment of Corrosion Defects and Other Anomalies, Section B6.2 Cleaning/Surface Preparation. While portions of the NACE standard are incorporated by reference at 49 C.F.R. Part 195, Appendix B is not. 49 C.F.R. §§ 195.3(g)(2); 195.588(b).
[112] *Id*.
[113] *Id.*; *see also* ASME/ANSI B31-G-1991, Manual for Determining the Remaining Strength of Corroded Pipelines (incorporated by reference at 49 C.F.R. §§ 195.452(h); 195.587; 195.588(c)) (as Step 3 of performing a remaining strength calculation of corroded pipe, operators are to "clean the corroded pipe surface to bare metal").
[114] Test. K. Garrity, Hr'g Tr. 81:9-12 (emphasis added).
[115] *Id.* at 135:8-23.
[116] Test. D. Hubbard, Hr'g Tr. 38:4-21 (acknowledging receipt of the thickness measurements on the areas at issue in the NOPV, while citing concerns with UT tool measurements and asserting that an operator can only identify metal loss by measuring the corrosion rate "over a succession of years.").
[117] W. Yarbrough Aff. Exhibit C (Atmospheric Corrosion Inspection of Compton Creek Bridge Span (Nov. 27, 2023), Attachment 4 – UT Meter Calibration Certificate from Valley Instrument dated 07.24.2023).
[118] *See e.g.* Appendix C to Part 195—Guidance for Implementation of Integrity Management Program at 7(IV), Types of internal inspection tools to use.

"techniques" to measure corrosion anomalies for wall loss.[119] Accordingly, the industry widely uses these tools to measure for wall loss.

The Region's further suggestion that an operator should consider corrosion growth rate over time during atmospheric inspections is perplexing, by alluding to the performance of some sort of pre-assessment "baseline" necessary prior to cleaning the pipeline to confirm the extent of atmospheric pitting.[120] No such requirement exists in the regulations or incorporated industry standards, and SFPP is not aware that any operator in the industry takes such action. PHMSA regulations also directly contradict the Agency's suggestion that a pipeline's nominal wall thickness as specified by the pipe manufacturer is not reliable, requiring that "only the specified nominal wall thickness shall be used for uncorroded wall thickness" when calculating the remaining strength of corroded pipelines.[121]

As it relates to calculating remaining life during direct assessment PHMSA regulations incorporate industry standards, which while applicable to buried pipe, provide: "[i]f no corrosion defects are found, no remaining life calculation is needed: the remaining life may be taken as the same for new pipe."[122] Moreover, as confirmed by the tools employed (including ILI in 2017 and 2022), there is no measurable corrosion growth to quantify in this instance on the pipeline locations at issue. Corrosion growth rate is not meaningful if there is no corrosion.

D. Prior SFPP Enforcement and Incidents Are Irrelevant.

As a final attempt to prop up its case in the hearing, the Region pointed to enforcement issued to SFPP in 2011, a 2017 incident on the SFPP system in New Mexico, and incidents caused by localized pitting generally. [123] The Region's assertions are incorrect, they are not relevant to this matter (as evidenced by the fact that they were not cited to in the Region's PSVR), and they have no bearing on whether the Compton Creek span (or the areas at Colton Station) exhibited atmospheric corrosion requiring protection.

1. Prior Dated SFPP Enforcement is Distinguishable.

The enforcement issued to SFPP over a decade ago in 2011 differs markedly from the facts before the Agency in this NOPV. In that prior enforcement, historical atmospheric corrosion inspections from 2004 identified external corrosion on pipe partially covered in soil that worsened, which

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[119] NACE SP0502-2010, Pipeline External Corrosion Assessment Methodology, Appendix B, Direct Examination – Coating Damage and Corrosion Depth Measurements, Section B6 Assessment of Corrosion Defects and Other Anomalies, Section B6.2 Cleaning/Surface Preparation. While portions of this standard are incorporated by reference at 49 C.F.R. Part 195, Appendix B is not. 49 C.F.R. §§ 195.3(g)(2); 195.588(b).

[120] Test. A. Rodriguez, Hr'g Tr. 33:9-19; 33:24-34:7.

[121] 49 C.F.R. § 195.587, 195.588(c), 195.452(h) (incorporating by reference ASME B31G-1991, Manual for Determining the Remaining Strength of Corroded Pipelines which states "only the specified nominal wall thickness shall be used for the uncorroded wall thickness when conducting a Level 0 evaluation").

[122] 49 C.F.R. § 195.588(b) (incorporating by reference NACE SP0502, Pipeline External Corrosion Assessment Methodology, Section 6.2 Remaining Life Calculation, Section 6.2.1).

[123] Test. A. Iorio, Hr'g Tr. 13:2-4 (arguing that SFPP "has been cited for the same issue in the past"); PHMSA Pre-Hearing Submission, p. 5 (citing CPF No. 5-2011-5012).

corrosion personnel rated as "Poor" in 2010 and described the corrosion as "excessive."[124] PHMSA's allegations also noted the existence of mechanical damage and the presence of dents, and the Agency premised its finding of violation in that instance on the fact that SFPP "did not submit any documented test or investigation demonstrating that the atmospheric corrosion on its pipeline was only light surface oxide and will not affect safe operations."[125] In the present matter, SFPP has demonstrated that actionable atmospheric corrosion does not exist on the span through application of its grading criteria by qualified inspections as documented in the Company's maintenance records, which SFPP and a third-party expert further confirmed since the NOPV. Further, there is no evidence that the pipeline locations at issue are partially covered in soil or exhibit evidence of mechanical damage or dents.

2. SFPP Incident in Anthony, New Mexico is Irrelevant.

At the hearing, the Region also inaccurately stated that a failure caused by "atmospheric corrosion" occurred on the SFPP system in 2017 near Anthony, New Mexico.[126] The facts and the cause associated with the 2017 incident are entirely distinct from the pipeline locations at issue. The 2017 incident was caused by external corrosion, an entirely different corrosion failure mechanism as compared to atmospheric corrosion.[127] In addition, the incident was associated with a different pipeline (LS-18 in New Mexico), different type of coating (tape coating), different location (partially buried air to soil interface in a small agricultural drainage ditch subject to being submerged in water), and entirely distinct corrosion environment.[128] The incident is, therefore, not relevant to this matter and has no bearing on the atmospheric condition of the LS-120 Compton Creek highway span or Colton Station piping in California.[129]

3. Atmospheric Corrosion is Not a Leading Cause of Serious Incidents.

At the Hearing, the Region asserted that "some of the most serious accidents that we've had have been from pitting corrosion," noting that it is the "primary driver for accidents" outside of third-party damage.[130] Respectfully, SFPP believes that this is a mischaracterization. Based on

[124] *Final Order, In re SFPP, CPF No. 5-2011-5012 (Dec. 14, 2011)*. The Region incorrectly states that this enforcement was resolved through a consent order issued in 2012, but rather a compliance order accompanied the Final Order in 2011.

[125] *Id.*

[126] Test. D. Hubbard, Hr'g Tr. 158:16-25; 159:10-12 (referencing a 2017 incident in Anthony, New Mexico).

[127] *See* PHMSA Failure Investigation Report – Santa Fe Pacific Pipeline LP External Corrosion (Jun. 17, 2020) ("The failure was caused by external corrosion at the 5:00 o'clock position (looking downstream), in the area of the soil-to-air interface. The rupture opening measured 22-inches long, and was approximately 5-inches wide at the center of the opening. Disbonded polyethylene (PE) tape coating contributed to the development of corrosion anomalies" and describing the area as [a]gricutural [a]rea – [d]rainage [c]anal"). As detailed in PHMSA's report, this incident was caused by external corrosion, not atmospheric corrosion.

[128] *Id.*

[129] *Id.*

[130] *See* Test. D. Hubbard, Hr'g Tr. 40:14-22 ("Some of the most serious accidents that we've had have been from pitting corrosion. Outside of third-party damage, that's the primary driver for accidents.").

PHMSA's published data regarding pipeline incidents,[131] there has been only 1 serious[132] incident associated with localized pitting going back to 2010. That incident involved galvanic corrosion (in contrast to atmospheric) associated with stray current that shielded the pipe from cathodic protection caused the pitting which occurred on a buried gas gathering pipeline in Mayport, Pennsylvania in 2019.[133] PHMSA provided no actual incident data to support its claims, and even if the Region could provide that general data, the fact remains that the Region provided no demonstrable proof that the locations at issue in this NOPV represent a pipeline integrity concern requiring remediation.

VII. PHMSA Has Not Met its Burden of Proof.

The Region has the burden of proof, presentation, and persuasion in this enforcement action.[134] The Region may not impermissibly shift this burden of proof to SFPP and it is the Region who must prove all elements of a probable violation in an enforcement proceeding.[135] As such, "a violation may be found only if the evidence supporting the allegation outweighs the evidence and reasoning presented by Respondent in its defense."[136]

If the Region "does not produce evidence supporting the allegation [which] outweighs the evidence and reasoning presented by Respondent in its defense," the allegation of violation must be withdrawn.[137] Further, where "the evidence for and against the occurrence of a fact necessary to show a violation [. . .] is essentially equal, OPS cannot meet its burden of persuasion and the allegation of probable violation must be withdrawn."[138]

In this case, the Presiding Official cannot simply trust that PHMSA's representatives "know corrosion when they see it."[139] The preponderance of the evidence must be considered.[140] In order

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[131]Available for download at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-20-year-trends.

[132] Incidents are identified as "serious" if they involved a fatality or injury. *See* PHMSA, *National Pipeline Performance Measures*, https://www.phmsa.dot.gov/data-and-statistics/pipeline/national-pipeline-performance-measures.

[133] *Id.*

[134] 49 U.S.C. § 60117(b)(1)(F); 5 U.S.C. § 556(d).

[135] *See e.g., Final Order, In re ANR Pipeline Co, CPF No. 3-2011- 1011 (Dec. 31, 2012). See also, Final Order, In re: Tennessee Gas Pipeline Company*, CPF 1-2018-1001 (Nov. 14, 2019) (Administrator rejecting PHMSA's attempt to shift the burden to the operator to demonstrate effectiveness of leak detection method). Courts will reject agency attempts to improperly shift the burden. *See e.g. GPA Midstream Assn. v. U.S. Dept. of Transportation*, 67 F.4th 1188, 1199 (D.C. Cir. 2023) (dismissing PHMSA's arguments in a rulemaking challenge "[b]ecause this argument would impermissibly shift the burden of proof to the petitioners and other operators, we must reject it.").

[136] *Final Order, In the Matter of Butte Pipeline Co., CPF No. 5-2007-5008 (Aug. 17, 2009).*

[137] *Id.*

[138] *Decision on Petition for Reconsideration, In re: Alyeska Pipeline Service Company*, CPF No. 5-2005-5023 (Dec. 16, 2009); see also *EQT Corp., CPF 1-2006-1006, Final Order (May 13, 2010)* ("While [the operator's] efforts to address unavailable data may have been inadequate, in the absence of a more detailed allegation or relevant evidence, the record in this case does not support a finding of violation.").

[139] Test. A. Iorio, Hr'g Tr. 14:16-18; 154:6-16.

[140] *See e.g., Final Order, In re: Sunoco Pipeline, LP, CPF No. 1-2019-5006 (Jun. 26, 2020)* (considering "the preponderance of the evidence" and finding that the Region's justification was neither necessary nor reasonable in light of the operator's documentation in the record); *Final Order, In re: Golden Pass Pipelines LLC, CPF No. 4-2008-1017* (Mar. 22, 2011) ("OPS bears the burden of proving by a preponderance of the evidence that's its interpretation [. . .] is the correct one).

for the Region's alleged violation to stand under 49 C.F.R. § 195.583(c), the Region must prove that (1) atmospheric corrosion existed on the areas at issue; and (2) that SFPP has not met the longstanding exception in 49 C.F.R. § 195.581(c), as follows:

> A demonstration "by test, investigation, or experience appropriate to the environment of the pipeline" that corrosion will:
> (1) "Only be a light surface oxide," **or**
> (2) "Not affect the safe operation of the pipeline before the next scheduled inspection."[141]

The burden is upon the Region to establish that measurable wall loss, pitting, or scaling has occurred at the locations at issue to sustain its allegation that actionable corrosion requiring protection before the next scheduled inspection existed on the pipeline.[142] It has failed to satisfy this burden.[143] The Region's case is limited to photographs and the testimony of three representatives, only one of whom saw the pipeline locations at the Compton Creek span in person, and even then, only from a distance. The Region has not further substantiated its allegations as set forth in the NOPV of "excessive corrosion with pitting" through any wall loss or pit depth measurements. Moreover, the Region has not produced any support whatsoever that the conditions observed on the span – a light surface oxide with no measurable wall loss, pitting, or scaling of the pipe steel – require further atmospheric corrosion protection before the next scheduled inspection. Instead, the Region raises unsupported assertions and generalizations as a substitute for actual evidence.

Meanwhile, SFPP has clearly and indisputably refuted the Region's claims. Given the absence of any actionable corrosion and in accordance with PHMSA regulations and its own procedures, SFPP has the flexibility to decide when and whether to recoat the Compton Creek span. SFPP's knowledgeable, trained, and qualified corrosion technicians closely inspected the Compton Creek span and Colton Station areas at issue for signs of metal loss and pitting. They demonstrated by investigation and experience with the very locations at issue that there was nothing more than a light surface oxide present and there were no conditions which would impact the safe operation of the pipeline before the next inspection. The absence of any measurable wall loss, pitting, or scaling on the pipeline locations at issue was further confirmed by ILI results and additional SFPP and third-party inspections that employed a variety of tools, including ultrasonic wall loss measurement tools.

VIII. <u>PHMSA May Not Articulate New Rules Through Enforcement</u>.

The Region cannot manufacture allegations of atmospheric corrosion pitting to compel SFPP to recoat peeling paint that has no bearing on the condition of the underlying pipe steel and which is allowed under the regulations. If upheld in a Final Order, PHMSA's NOPV raises serious due

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[141] 49 C.F.R. § 195.581(c) (emphasis added).
[142] *See e.g. Final Order, In re: Tennessee Gas Pipeline Company, CPF 1-2018-1001 (Nov. 14, 2019)* ("[I]n the absence of a reason to believe that the [operator's] method was ineffective [. . .], it is OPS that has the burden of proof in showing that Respondent's methods were not effective.")
[143] *See, e.g.*, *Final Order, In the Matter of ExxonMobil Pipeline Co., CPF 5-2013-5007 (Jan. 23, 2015)* (finding that PHMSA failed to meet its "burden of proving the measures alleged in the Notice were, in fact, required[.]").

process concerns and constitutes arbitrary and capricious decision making and an abuse of discretion. PHMSA may not articulate new rules for the first time through enforcement.

SFPP prepares and implements its procedures in reliance on PHMSA regulations, enforcement, and guidance. If PHMSA intends to expand the atmospheric corrosion regulations to require repainting of pipe with only light surface oxide that does not impact the integrity of the pipeline before the next scheduled inspection, thereby nullifying a longstanding exception at 49 C.F.R. § 195.581(c), it must go through notice and comment rulemaking required by the Administrative Procedure Act to provide fair notice and due process under the U.S. Constitution.[144]

The U.S. Constitution and the Administrative Procedure Act require that a regulation provide a regulated entity with fair notice of the obligations it imposes and be issued pursuant to notice and comment rulemaking.[145] Fair notice requires the agency to have "state[d] with ascertainable certainty what is meant by the standards [it] has promulgated. [...] must give [a party] fair warning of the conduct it prohibits or requires, and it must provide a reasonably clear standard of culpability to circumscribe the discretion of the enforcement authority and its agents."[146]

An agency may not enforce regulations according to "what an agency intended but did not adequately express...."[147] "Even if the [Agency's] interpretation were reasonable, announcing it for the first time in the context of this adjudication deprives Petitioners of fair notice. Where, as here, a party first receives actual notice of a proscribed activity through a citation, it implicates the Due Process Clause of the Fifth Amendment."[148] Regulated entities are not obligated to "divine the agency's interpretations in advance or else be held liable when the agency announces its interpretations for the first time in an enforcement proceeding and demands deference."[149] If the Agency has made a policy decision to require operators to address cosmetics or aesthetics of aboveground piping, it must go through notice and comment rulemaking to provide fair notice and due process to the industry and to SFPP in this instance.

IX. <u>Conclusion and Request for Relief</u>.

As clearly laid out in the PHMSA regulations, the rulemaking preamble, and associated PHMSA guidance, the locations at issue in the NOPV do not require further protection from atmospheric corrosion at this time. PHMSA has not met its burden to prove otherwise. Accordingly, and for the addition reasons identified in this Post-Hearing Brief, the hearing, SFPP's prior filings in this matter, and for other reasons as justice may require, SFPP respectfully requests that the NOPV be withdrawn in its entirety, including the proposed civil penalty of $81,500, and the associated PCO obligations.

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[144] Perhaps due to the fact that SFPP has already completed the PCO requirements contained in the NOPV, the Region incorrectly recited the PCO as follows, "in addition to a compliance order requiring Kinder Morgan to clean and coat the pipeline to address the corrosion." Test. A. Iorio, Hr'g Tr. 12:20-22.

[145] *The Constitution of the United States, Amendment 5;* 5 U.S.C. § 554(b).

[146] *ExxonMobil Pipeline* Co *v. U.S. DOT*, 867 F.3d 564, 578 (5th Cir. 2017) (citing *Diamond Roofing Co*., *Inc. v. OSHRC,* 528 F.2d at 645, 649 (5th Circ. 1976)).

[147] *Gates v. Fox* Co., *Inc. v. OSHRC,* 790 F.2d 154, 156 (D.C. Cir. 1986).

[148] *Fabi Constr. Co. v. Sec'y of Labor*, 508 F.3d 1077, 1088 (D.C. Cir. 2007).

[149] *Christopher v. SmithKline Beecham Corp*., 132 S. Ct. 2156, 2167 (2012).

Respectfully submitted,

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