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

1200 New Jersey Avenue, SE
Washington, DC 20590

May 21, 2024

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

Thomas E. Long
Chief Executive Officer
Energy Transfer LP
1300 Main Street
Houston, Texas 77002

Re: CPF No. 4-2022-032-NOPV

Dear Mr. Long:

Enclosed please find the Final Order issued in the above-referenced case to Florida Gas Transmission Company, LLC, a subsidiary of Energy Transfer LP. It withdraws one of the allegations of violation, makes other findings of violation, and assesses a civil penalty of $409,400. The penalty payment terms are set forth in the Final Order. This enforcement action closes automatically upon receipt of payment. Service of the Final Order by e-mail is effective upon the date of transmission and acknowledgement of receipt as provided under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

ALAN KRAMER MAYBERRY
Digitally signed by ALAN KRAMER MAYBERRY
Date: 2024.05.20 08:53:34 -04'00'

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Bryan Lethcoe, Director, Southwest Region, Office of Pipeline Safety, PHMSA
Mr. Greg McIlwain, Executive Vice President of Operations, Energy Transfer LP, gregory.mcilwain@energytransfer.com

Mr. Eric Amundsen, Senior Vice President of Operations, Energy Transfer LP, eric.amundsen@energytransfer.com
Mr. Todd Stamm, Senior Vice President of Operations, Energy Transfer LP, todd.stamm@energytransfer.com
Ms. Jennifer Street, Senior Vice President of Operations Services, Energy Transfer LP, jennifer.street@energytransfer.com
Ms. Heidi Murchison, Chief Counsel, Energy Transfer LP, heidi.murchison@energytransfer.com
Mr. Leif Jensen, Vice President of Tech Services, Energy Transfer LP, leif.jensen@energytransfer.com
Mr. Todd Nardozzi, Director of Regulatory Compliance, Energy Transfer LP, todd.nardozzi@energytransfer.com
Ms. Susie Sjulin, Director of Regulatory Compliance, Energy Transfer LP, susie.sjulin@energytransfer.com
Mr. Vince Murchison, Esq., Outside Counsel for Florida Gas Transmission Co., Murchison Law Firm, PLLC, vince.murchison@pipelinelegal.com

CONFIRMATION OF RECEIPT REQUESTED

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

In the Matter of	)	
Florida Gas Transmission Company, LLC, a subsidiary of Energy Transfer LP,	)	**CPF No. 4-2022-032-NOPV**
Respondent.	)	

FINAL ORDER

From September 13, 2020 through September 23, 2021, pursuant to 49 U.S.C. § 60117, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), conducted an on-site pipeline safety inspection and investigation of the facilities and records of Florida Gas Transmission Company, LLC's (FGT or Respondent) 12-inch diameter Sanford Lateral natural gas transmission pipeline following a rupture of the Sanford Lateral that occurred on September 10, 2020, in Sanford, Florida.[1]

The escaping natural gas ignited and burned an area measuring approximately 515 by 100 feet. The burn also damaged and knocked down three overhead powerlines owned by Duke Energy and about 32 homes and 93 businesses had to be evacuated. There were no reported injuries or fatalities. On September 18, 2020, PHMSA issued a Corrective Action Order (CAO) to FGT (CPF 4-2020-008-CAO) that required a shutdown of the pipeline segment and required a records review and verification, a review of prior inline inspection results, a metallurgical laboratory examination of the ruptured pipe, a root cause failure analysis, a pressure restriction upon restart, and a remedial work plan. With PHMSA's Southwest Region oversight, FGT repaired the pipe at the rupture site and returned the Sanford Lateral to service on December 7, 2020, under the terms of the CAO.

As a result of the inspection and investigation, the Director, Southwest Region, OPS (Director), issued to Respondent, by letter dated July 22, 2022, a Notice of Probable Violation and Proposed Civil Penalty (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that FGT committed three violations of 49 C.F.R. Part 192 and proposed assessing a total civil penalty of $834,400 for the alleged violations.

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[1] FGT is a large interstate natural gas pipeline company that operates approximately 5,300 miles of gas transmission lines that originate in Galveston Bay and extend through various states including Florida. FGT is owned by Citrus Corporation, a joint venture between Energy Transfer LP and Kinder Morgan, Inc. Energy Transfer LP website, Natural Gas, *available online at* https://www.energytransfer.com/natural-gas (last accessed Jan. 30, 2024).

FGT responded to the Notice by letter dated September 30, 2022 (Response), as supplemented by material submitted on March 13, 2023 (Pre-hearing Submission). FGT contested the allegations and requested an informal hearing. A hearing was subsequently held on March 22, 2023, in Houston, Texas, before a Presiding Official from the Office of Chief Counsel, PHMSA. At the hearing, Respondent was represented by counsel. After the hearing, Respondent provided additional written material for the record by letter dated April 21, 2023 (Post-hearing submission). The Director provided a recommendation on May 22, 2023 (Recommendation) and FGT submitted a reply to the Recommendation on June 12, 2023 (Reply).

FINDINGS OF VIOLATION

The Notice alleged that Respondent violated 49 C.F.R. Part 192, as follows:

Item 1: The Notice alleged that Respondent violated 49 C.F.R. § 192.619(a)(3), which states:

> **§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.**
> (a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:
> (1) …
> (3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
(i) Onshore regulated gathering pipeline (Type A or Type B under § 192.9(d)) that first became subject to this part (other than §192.612) after April 13, 2006	March 15, 2006, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
(ii) Onshore regulated gathering pipeline (Type C under § 192.9(d)) that first became subject to this part (other than § 192.612) on or after May 16, 2022	May 16, 2023, *or date pipeline becomes subject to this part, whichever is later*	5 years preceding applicable date in second column.

(iii) Onshore transmission pipeline that was a gathering pipeline not subject to this part before March 15, 2006	March 15, 2006, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
(iv) Offshore gathering pipelines	July 1, 1976	July 1, 1971.
(v) All other pipelines	July 1, 1970	July 1, 1965.

The Notice alleged that Respondent violated 49 C.F.R. § 192.619(a)(3) by failing to establish a maximum allowable operating pressure (MAOP) for its Sanford Lateral in accordance with § 192.619(a)(3). Specifically, the Notice alleged that FGT did not have records to substantiate the highest actual operating pressure that the segment was subjected to during the five years prior to MAOP establishment.

In its Response and at the hearing, FGT contested the allegation and provided information concerning the history of the pipeline going back to 1959 indicating that former owners and operators of the pipeline considered the MAOP in 1970 to be 713 psig. Respondent explained that it maintained a one-page historical record from 1989 referred to by FGT as the "Gold Sheet" that in its view substantiated the current MAOP for the Sanford Lateral,[2] and argued that the regulations did not require it to have records to substantiate the MAOP indicated on the Gold Sheet or otherwise substantiate the highest actual operating pressure that the segment was subjected to during the five years prior to MAOP establishment. FGT further argued that the Notice should have alleged a violation under the MAOP Reconfirmation section in § 192.624 which was added to Part 192 in 2019, and not establishment of MAOP under § 192.619.

At the hearing, OPS maintained that it was unable to verify or substantiate, based on FGT records, that the Sanford Lateral was subjected to 713 psig during the five-year period prior to July 1, 1970. FGT argued that "[n]o indication exists that Sanford Lateral *was not* subjected to a highest pressure of 713 psig between 1965 and 1970."[3] OPS stated that Respondent did not provide any records that would substantiate the establishment of an MAOP of 713 psig and that the first pressure records provided to substantiate the MAOP were from the 2020 hydrostatic test conducted pursuant to the CAO.

To demonstrate compliance with § 192.619(a)(3), operators are required to have records that enable PHMSA to "verify that the entire pipeline was subjected to that pressure sometime during the five-year period prior to July 1, 1970."[4] Consistent with this requirement, PHMSA issued

[2] PHMSA Violation Report, Exhibit A.

[3] Post-hearing Submission, at 18.

[4] West Texas Gas, Final Order, CPF No. 4-2004-1007, at 6 (Sept. 13, 2006).

enforcement guidance in 2017 reminding operators that a probable violation may be found if an operator cannot provide records to "substantiate the established MAOP."[5]

With regard to the 1989 Gold Sheet, FGT acknowledged that it did not have pressure logs or other such records of pressure readings associated with it, but suggested that Enron, the former operator of the Sanford Lateral, must have reviewed such records when creating the Gold Sheet. That assertion, however, does not take the place of records necessary to verify MAOP.[6] Respondent also provided a declaration from a current FGT employee who had recently reviewed the specifications of various valves and other components of the pipeline.[7] The declaration stated that "no component on the pipeline at the time of the September 10, 2020 incident had, and no component on the pipeline currently has, a design pressure that is less than 713 psig which is the established MAOP of the pipeline." However, this affidavit is insufficient to satisfy § 192.619(c) because it failed to include any operating pressure readings from July 1, 1965 – July 1, 1970. In addition, OPS has advised operators that affidavits on their own are not verifiable records sufficient to meet the requirement to establish MAOP.[8] Without actual pressure logs or similar records demonstrating actual pressures experienced during this five-year time period, OPS cannot verify that the MAOP was properly established.

At the hearing, FGT also contended that even though the Gold Sheet does not reflect any actual historical operating pressure readings, it is in some sense a record of the overall "limiting factor" on the Sanford Lateral.[9] Thus, it appears FGT accepts that 713 psig is not a reflection of the actual operating pressure from 1965 to 1970, but instead reflects MAOP established under § 192.619(a)(1). The Gold Sheet, however, cannot be both. FGT also acknowledged that the Gold Sheet may itself be inaccurate. FGT stated that "[i]t would not be unreasonable to conclude" that the MAOP Authorization Sheet "inadvertently chose '619(c)."[10] Because FGT failed to substantiate its MAOP with § 192.619(c), it cannot rely on § 192.619(c) as a defense to the alleged violation of § 192.619(a)(3). For the same reasons that the records fail to demonstrate compliance with § 192.619(c), FGT failed to provide records to substantiate its

[5] PHMSA, Operations & Maintenance Enforcement Guidance Part 192 Subparts L and M, at 81 (July 21, 2017), *available online at* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/regulatory-compliance/pipeline/enforcement/5776/o-m-enforcement-guidance-part-192-7-21-2017.pdf.

[6] PHMSA's enabling statute requires operators to "make" and "maintain records" to demonstrate compliance with the pipeline safety laws and regulations. *See* 49 U.S.C. § 60117(c). The failure to maintain records, by itself, can be a violation of the pipeline safety regulations. *See* 49 C.F.R. § 192.619(f).

[7] Post-hearing Submission, Exhibit 3.

[8] Pipeline Safety: Verification of Records: ADB-2012-06, 77 Fed. Reg. 26,822, 26,823 (May 7, 2012) ("In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by an individual who would have reason to be familiar with the test or inspection.").

[9] Post-hearing Submission, at 17.

[10] Post-hearing Submission, at 18.

establishment of MAOP in accordance with § 192.619(a)(3).[11] If the Gold Sheet does in fact reflect uncertainty about whether it was intended to apply for purposes of subsection (a) or subsection (c), that only reinforces the conclusion that it does not substantiate the establishment of MAOP.

With respect to the consistency of this case with PHMSA's position in prior proceedings, in the above-referenced *West Texas Gas* proceeding the agency found that, "PHMSA must be able to verify" that a pipeline was subjected to the pressure if MAOP was established under § 192.619(c). In *West Texas Gas*, the Acting Associate Administrator found that two single documents, each with different MAOPs, were insufficient to establish MAOP because neither number could be corroborated with other records.[12] Similarly in the present case, FGT has failed to provide any corroborating records (i.e., operating pressure records) that support the selection of 713 psig on the MAOP Authorization Sheet. In fact, FGT suggested that 713 psig was selected based on the design pressure, and not historical operating pressure.[13] This uncertainty supports finding this violation as PHMSA cannot verify how MAOP was established. This point is further emphasized by FGT's efforts spent speculating on what the prior operator may or may not have reviewed in creating the MAOP Authorization Sheet.[14]

Similarly, in the *El Paso Natural Gas Company, LLC* proceeding, OPS alleged that the operator failed to establish MAOP in accordance with § 192.619(a)(3). In the final order, the Associate Administrator for Pipeline Safety found the operator in violation of 192.619(a)(3) for failing to have records in support of its (pre-1970) MAOP establishment. Thus, the final order found the operator in violation of § 192.619(a)(3) under the same charge as alleged here in this proceeding.[15] In both the West Texas Gas and El Paso proceedings cases, the operators had established an MAOP using historical operating pressure, but could not provide any operating pressure records to support that number. Thus, OPS is correct that its position in this case is consistent with the outcome of both prior proceedings.

Finally, FGT argued that any allegation of non-compliance should have cited the MAOP reconfirmation requirements in § 192.624 because it was a newer regulation and "obviated" the provisions in § 192.619(c).[16] FGT cited the above referenced *El Paso* proceeding as support for

[11] FGT suggested it established MAOP under other provisions of § 192.619(a) and that it is PHMSA's burden to demonstrate § 192.619(a)(3) is the lowest of the options in subparagraph (a). However, the absence of any one calculation under § 192.619(a)(1)-(4) renders the whole analysis unsubstantiated. If the MAOP "established" under § 192.619(a)(3) cannot be verified or substantiated it cannot form the basis for a valid MAOP.

[12] West Texas Gas, Final Order, CPF No. 4-2004-1007, at 6 (Sept. 13, 2006).

[13] Post-hearing Submission, at 18.

[14] *Id.,* at 17-18.

[15] El Paso Natural Gas Company, LLC, Notice of Probable Violation, CPF No. 4-2019-1010, at 2 (Oct. 1, 2019).

[16] Post-hearing Submission at 25; *see* Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 Fed. Reg. 52,180 (Oct. 1, 2019).

its position that MAOP reconfirmation obviated section 192.619.[17] Section 192.624 was promulgated, in part, to address a congressional mandate in sction 23 of the 2011 Pipeline Safety Act that "requires the verification of records for pipe in Class 3 and Class 4 locations, and high consequence areas in Class 1 and Class 2 locations, to ensure they accurately reflect the physical and operational characteristics of the pipelines and confirm the established MAOP of the pipelines."[18] Section 192.624, however, is complementary to, but does not replace, § 192.619. MAOP reconfirmation instead reiterated the importance of verifiable documentation to support MAOP establishment. Operators are required to establish MAOP under § 192.619 and then, if the criteria in § 192.624(a) are met, operators must reconfirm MAOP according to that section. Nothing in the MAOP reconfirmation regulatory record suggests that this regulation replaced the MAOP establishment requirements.[19]

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 192.619 by failing to establish an MAOP for its Sanford Lateral in accordance with § 192.619(a)(3).

Item 2: The Notice alleged that Respondent violated 49 C.F.R. § 192.917(a)(1), which states:

> **§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**
> (a) Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S incorporated by reference, see § 192.7), section 2, which are grouped under the following four categories:
> (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

The Notice alleged that Respondent violated 49 C.F.R. § 192.917(a)(1) by failing to identify and evaluate all potential threats to each covered pipeline segment in its natural gas pipeline systems in accordance with § 192.917(a)(1). Specifically, the Notice alleged that FGT failed to include the Sanford Lateral as part of its stress corrosion cracking (SCC) program prior to the September 10, 2020 incident.

In its Response and at the hearing, FGT contested the allegation and explained that while it was generally aware of the potential of SCC to be an integrity threat, after appropriate application of the relevant factors it had insufficient reason to include the Sanford Lateral in its SCC program. Respondent stated that the only indication of SCC on Sanford Lateral came after the September 10, 2020 incident when the post-incident metallurgical report was received.[20]

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[17] *See* El Paso Natural Gas Company, LLC, Final Order, CPF No. 4-2019-1010 (July 22, 2020).

[18] 84 Fed. Reg., at 52,234.

[19] The MAOP Reconfirmation Rule made conforming changes to § 192.619 and revised the test pressure factors but otherwise retained each provision. *See id.* Thus, FGT's assertions that MAOP Reconfirmation replaced MAOP Establishment is unsupported by the regulatory record.

[20] *Id*., at 29-30.

As the basis for its allegation that the Sanford Lateral should have been included in FGT's SCC program, OPS stated that Respondent has 30 pipelines and 13 laterals in its SCC program with pipe specifications it believed were similar to the Sanford Lateral, and that SCC had been found on pipelines in the vicinity. Respondent strongly disagreed. Respondent's Director of Pipeline Integrity testified that the 30 pipelines and 13 laterals OPS mentioned are not in fact the same as Sanford Lateral and that they have different seam type and coating, different grade steel, different vintage (age), different manufacturer, and different wall thickness and diameter. FGT correctly noted that just because one pipeline may have some of the same characteristics as another does not automatically mean that all of them will be susceptible to SCC. FGT argued that PHMSA's inference that all of those pipelines are in the vicinity of the Sanford Lateral was also incorrect and explained that some were hundreds of miles distant.[21]

With regard to OPS' contention that, prior to the incident, the Sanford Lateral should have been included in Respondent's SCC program, FGT argued that the Sanford Lateral simply did not meet the applicable criteria to be subjected to the program. Respondent's Director of Pipeline Integrity testified that its pipelines are evaluated for SCC all the time, and, had SCC been found or had Sanford Lateral been determined to be susceptible to SCC, it would have been added to the program, as occurred after the 2020 incident.[22]

Respondent noted that section 192.917(a), Threat Identification, directs operators to identify and evaluate all potential threats to each covered pipeline segment, including but not limited to those identified in ASME/ANSI B31.8S-2004 (B31.8S), section 2. Of the four categories established in Section 192.917(a)(1)-(4), OPS alleged a violation of only subsection (1), "time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking."[23] Section 2.3.3 of B31.8S, Risk Assessment, refers the reader to a prescriptive approach presented in Appendix A. Section A3.3 of Appendix A provides that each segment should be assessed for risk for the possible threat of SCC if **all** of the following criteria are present:

ASME B31.8S-2004 - SCC Threat Susceptibility Review

(a) Operating stress > 60% SMYS

(b) Operating temperature > 100^{o} Fahrenheit

(c) Distance from compressor station ≤ 20 miles

(d) Age ≥ 10 years

(e) All corrosion coating systems other than fusion-bonded

[21] Post-hearing Submission, at 30-31.

[22] *Id*., at 31.

[23] *Id*., at 27.

epoxy (FBE).[24]

Respondent explained that the Sanford Lateral fails to meet three of those five criteria. The only two criteria met are d) age ≥ 10 years given that Sanford Lateral was constructed in 1959, and (e) all corrosion coating systems other than fusion-bonded epoxy given that the greater proportion of Sanford Lateral is coated with Polyken tape coating.[25] With regard to the first of the three criteria that the Sanford Lateral does not meet, criterion (a) operating stress > 60% SMYS, Respondent presented information showing that the Sanford Lateral operates at a maximum stress level of 49% SMYS. Second, regarding criterion (b) operating temperature > 100º Fahrenheit, Respondent's Vice President of Operations for the Southeast Division testified that Sanford Lateral over the last six years has operated between 61 and 84 degrees Fahrenheit and that this temperature range is typical for operating conditions on the Sanford Lateral. Regarding criterion c) distance from compressor station ≤ 20 miles, Respondent presented information showing that the beginning of Sanford Lateral at the takeoff is approximately 39 miles from the upstream compressor station.[26] Respondent is correct that B31.8S indicates that only if "all" criteria of Section A3.3 of Appendix A are met is a segment "to be assessed for risk of the possible threat of SCC" but only two were met.[27]

While they are not mandatory criteria, B31.8S contains additional factors that an operator must consider for determining whether a segment of pipeline is susceptible to the SCC threat. Those are: (a) one or more service incidents was caused by either high pH SCC or near neutral pH SCC; and (b) one or more hydrostatic test breaks or leaks was caused by one of the two types of SCC. Respondent's witnesses testified that no service incident was caused by either type of SCC prior to the 2020 incident, and no hydrostatic test leaks or breaks were experienced on the Sanford Lateral.[28] B31.8S also requires an operator to consider previous SCC history. Respondent showed that the only indication of SCC on Sanford Lateral came after the incident, when the post-incident metallurgical report was received.[29]

Unlike a component widely known to have manufacturing defects that can be identified by an operator in various ways, SCC is an issue that can take decades to develop and typically needs to be confirmed by metallurgical analysis. As FGT correctly noted, many pipelines never experience SCC at all. While OPS is correct that a pipeline operator is obligated to address the potential for SCC on its pipelines, the issue to be determined here is whether a violation of the code as it currently exists has been proven. Under circumstances in which a pipeline segment has no history of SCC ever being identified and does not have substantially the same material

[24] Case File Exhibit 5, PSVR Ex. C, ASME B31.8S, at 43 (PDF p. 176).

[25] Post-hearing Submission, at 28.

[26] *Id*.

[27] *Id*., at 29.

[28] *Id*.

[29] *Id*., at 29-30.

and operating characteristics as pipe that has been deemed susceptible to SCC,[30] OPS has the burden of establishing that such a segment should have been treated as an SCC segment in a given operator's SCC program.[31] In this instance, the evidence presented by OPS fell short of meeting that burden.

Accordingly, after considering all of the evidence, I find that OPS did not establish that Respondent was out of compliance with the cited regulation. Based upon the foregoing, I hereby order that Item 2 be withdrawn.

Item 3: The Notice alleged that Respondent violated 49 C.F.R. § 192.937(c)(1), which states:

> **§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?**
> (a) ...
> (c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* § 192.917), or by confirmatory direct assessment under the conditions specified in § 192.931.
> (1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (ibr, *see* § 192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.[32]

The Notice alleged that Respondent violated 49 C.F.R. § 192.937(c)(1) by failing to follow B31.8S, section 6.2 in selecting the appropriate internal inspection tools for each covered segment. Specifically, the Notice alleged that although the Sanford Lateral consisted largely of low-frequency electric-resistance welded (LF-ERW) pipe manufactured by Youngstown Sheet & Tube of 1959 vintage known to be susceptible to axial seam defects, FGT used an in-line inspection (ILI) tool for its ILI runs in 2014 and 2019 that was designed primarily to evaluate circumferential defects rather than axial defects.

In its Response and at the hearing, FGT contested the allegation and argued that although the Sanford Lateral largely did consist of LF-ERW pipe, no assessment for this threat was prompted by 49 C.F.R. § 192.937(c)(1).[33] FGT argued that the cited regulation should be read together

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[30] Respondent's Director of Pipeline Integrity testified that the 30 pipelines and 13 laterals OPS mentioned are not in fact the same as Sanford Lateral and that they have different seam type and coating, different grade steel, different vintage (age), different manufacturer, and different wall thickness and diameter.

[31] Of course, now that near-neutral pH SCC has been identified in connection with FGT's analysis of the September 10, 2020 incident, Respondent is not disputing the need to include the Sanford Lateral in its SCC program going forward.

[32] Section 192.937(c) and (d) were amended on October 1, 2019, after FGT conducted its 2014 and 2019 ILIs.

[33] Post-hearing Submission, at 37-38.

with § 192.917(e)(4).[34] This provision states that if a covered pipeline segment contains LF-ERW pipe, lap welded pipe, or other conditions specified in B31.8S, Appendices A4.3 and A4.4, any covered or noncovered segment in the pipeline system with such pipe must have experienced a pressure increase over MAOP or a seam integrity failure during the preceding five years in order for an operator to be required to select an assessment technology capable of detecting and measuring longitudinal seam defects.[35] Respondent argued that the Sanford Lateral had not experienced such a pressure increase or a seam integrity failure prior to the 2019 tool run and as a result, its LF-ERW pipe was not considered susceptible to failure and use of an ILI tool with axial capability in 2019 was not required. OPS disagreed and stated that there was a history of seam integrity failures on Respondent's system including an actionable axial seam defect identified in 2014 on the Sanford Lateral.

The axial seam failure threat posed by older LF-ERW pipe, has been a safety issue in the natural gas and hazardous liquid pipeline industry for decades due to the known occurrence of manufacturing defects or inclusions in the weld seam. A widely-referenced report on the integrity threat presented by LF-ERW pipe discusses the types of inclusions in older LF-ERW pipe that make the material susceptible and states that "The likely causes of seam failures that could necessitate a seam-integrity assessment are pressure cycle-induced fatigue and selective (grooving) corrosion of the bondline region of the seam."[36] OPS has consistently identified LF-ERW pipe as being subject to failures in the longitudinal seam because of manufacturing defects. Pipeline accidents involving seam failures can be much more serious than failures involving smaller leaks because a failed seam can propagate longitudinally for some distance along the pipe and blow-out a large rupture of the pipeline resulting in a large volume of flammable product being released. OPS issued Alert Notices on January 28, 1988, and again on March 8, 1989, to inform pipeline operators of the problem. Failures of the longitudinal seam of the pipe have been caused by the growth over time of manufacturing defects in the LF-ERW seams. As summarized in the CAO:

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[34] OPS disagreed, noting that § 192.917(a) outlines the process operators must follow to determine which threats their pipelines are susceptible to. However, section 192.917(e)(4) sets forth specific *actions* an operator must take to address known issues with ERW pipe. Section 192.917(e)(4) does not prescribe an exclusive list of criteria for use in determining appropriate assessment tools. OPS maintained that the Notice alleged that FGT failed to use appropriate *assessment methods*, it did not allege that FGT failed to take one of the specific actions listed in § 192.917(e)(4).

[35] Section 192.917(e)(4) states, in relevant part, "Electric Resistance Welded (ERW) pipe. If a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0 as defined in § 192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding 5 years (including abnormal operation as defined in § 192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies."

[36] *See* PHMSA, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation (Apr. 2004), *available online at* https://www.phmsa.dot.gov/pipeline/gas-transmission-integrity-management/low-frequency-erw-and-lap-welded-longitudinal-seam-evaluation, at page 1; Post-Hearing Brief, at 60.

> PHMSA has issued Advisory Bulletins on the safety risks of Low-Frequency Welded ERW and Flash-welded Pipe manufactured prior to 1970. It also issued Alert Notice, ALN-88-01, in January 1988, advising owners and operators of natural gas and hazardous liquids pipelines to consider the threat from ERW pipe manufactured prior to 1970. The operators were advised to determine whether their pipelines were susceptible to ERW seam failures and address the potential impact on pipeline integrity.[37]

In determining susceptible threats, an operator is required to consider its prior history and internal inspection records.[38] Prior to the 2019 tool run, FGT has experienced axial seam issues on the 15.9-mile length of the Sanford Lateral as well as on the larger 654-mile FGT pipeline unit of which the Sanford Lateral is a part. With respect to the Sanford Lateral, FGT's 2014 ILI run identified an anomaly that was found to be selective seam weld corrosion, a type of axial defect.[39] As stated in the CAO:

> The operator reported that it performed ILI runs of the Sanford Lateral in 2014 and 2019. ILI correlation data from these runs show corrosion growth rates as high as 17 thousandths of an inch per year. The 2019 ILI run had a large amount of corrosion indications in the vicinity of rupture, many over forty percent (40%).
>
> Most of the pipeline ROW appears to be located in swamp areas with heavy vegetation along its borders, making the 12-inch line more susceptible to active external corrosion than other locations.[40]

Moreover, FGT remediated such defects in 2015.[41] According to the Root Cause Failure Analysis (RCFA):

> 2015: Integrity digs are performed in response to the 2014 ILI run, none of these digs were within the Black Bear Wilderness Area. One as-found anomaly is classified as selective seam weld corrosion (SSWC), however contrary to an understood practice at that time (but not procedurally or best-practice documented), no hydrostatic test was performed on the line. Instead this anomaly was remediated with a Class B sleeve. (105, 109, interviews)

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[37] Florida Gas Transmission Company, Amended Corrective Action Order, CPF No. 4-2020-008-CAO, at 4 (Oct. 1, 2020).

[38] 49 C.F.R. § 192.917(b) (Apr. 6, 2004).

[39] Root Cause Failure Analysis (RCFA), at 13; PHMSA Violation Report, Exhibit B, at page 32.

[40] Florida Gas Transmission Company, Amended Corrective Action Order, CPF No. 4-2020-008-CAO, at 3 (Oct. 1, 2020).

[41] RCFA, at 13; PHMSA Violation Report, Exhibit B, at page 32.

There were three anomaly digs in total with repairs made on all three.[42]

The 2014 ILI results and the 2015 sleeve installation to repair the identified failure of axial seam integrity occurred within the five-year period preceding the 2019 ILI tool run and was sufficient to trigger the requirement to change the 2019 tool selection to one that reliably detects axial defects such as selective seam corrosion. However, FGT did not change the tool selection. Instead, in 2019 FGT used a tool that, according to section 6.2 of B31.8S, is "not reliable" for detecting the types of axial defects identified and addressed in 2014-2015.[43]

With regard to the larger 654-mile FGT pipeline unit of which the Sanford Lateral is a part, FGT has experienced LF-ERW seam failures as well. For example, on May 4, 2009, Respondent's 18-inch line also composed of LF-ERW pipe of the same vintage and manufacture as the Sanford Lateral pipe experienced an axial seam rupture along the Florida Turnpike near a high school resulting in the ejection of a 113-foot long section of pipe.[44] On December 26, 2012, Respondent's 20-inch line also composed of LF-ERW pipe of the same vintage and manufacture as the Sanford Lateral pipe experienced an axial seam rupture near Melbourne, Florida resulting in the ejection of an approximately 20-foot long section of pipe.[45] While there is no allegation that these failures involved regulatory violations, and these failures did not occur on the 12-inch portion of the 15.9 mile Sanford Lateral, operators generally apply their system-wide experience with LF-ERW in making decisions about ILI tools. Integrity management is intended to address systemic risk and prevent failures before they occur. In the absence of a systemic approach, unfortunately an operator may wait for the LF-ERW seam to fail on each individual pipe section putting the public at risk which would be inconsistent with the nature and purpose of the integrity management regulations. In other words, it goes without saying that an operator would treat LF-ERW pipeline as susceptible to failure after a seam failure. Saying that available means to detect a known manufacturing defect need not be used until after a seam failure occurs would render the regulations pointless. At a minimum, the system's LF-ERW history should have been data points that, together with the 2014 ILI results and the 2015 sleeve installation, informed FGT when it made its decision not to change ILI tools when it conducted its 2019 tool run.

FGT then argued that even if it had used a tool designed to detect axial defects such as the MFL-C, it was not a certainty that the defect associated with the September 10, 2020 incident would have been identified. Under section 192.937(c)(1), FGT is required to use an "appropriate internal inspection tool" that is "capable of detecting corrosion, and any other threats to which the covered segment is susceptible." In selecting this tool, "operator[s] must follow ASME/ANSI B31.8S (ibr, see § 192.7), section 6.2." Section 6.2.1(e) of B31.8S states that MFL-C "is more sensitive to axially aligned metal-loss defects." Conversely, section 6.2.1(a) states that MFL-A is "not reliable for detection or sizing of axially aligned metal-loss defects."

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[42] *Id.*

[43] Recommendation, at 13.

[44] Florida Gas Transmission Company, Corrective Action Order, CPF No. 2-2009-1002H (May 7, 2009).

[45] Florida Gas Transmission Company, Corrective Action Order, CPF No. 2-2012-1005H (Dec. 28, 2012). FGT apparently experienced another LF-ERW rupture in 2014 in Port St. John, Florida.

Thus, the MFL-C tool should have been selected for its increased sensitivity and likelihood of detecting axial defects despite the fact that there are no absolute guarantees that any individual defect will be identified.

Based on the preponderance of the evidence that the results of the 2014 ILI results led to the 2015 sleeve installation to repair a failure of axial seam integrity, I find, in accordance with B31.8S, that MFL-C was the appropriate and more reliable tool to detect axial defects in future ILI runs on the covered segments of the Sanford Lateral. Therefore, I find that FGT should have selected and used the MFL-C or other ILI tool with similar axial capability for the 2019 ILI tool run.

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 192.937(c)(1) by failing to follow ASME/ANSI B31.8S, section 6.2 in selecting the appropriate internal inspection tools for the 2019 tool run.

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to an administrative civil penalty not to exceed $200,000 per violation for each day of the violation, up to a maximum of $2,000,000 for any related series of violations.[46]

In determining the amount of a civil penalty under 49 U.S.C. § 60122 and 49 C.F.R. § 190.225, I must consider the following criteria: the nature, circumstances, and gravity of the violation, including adverse impact on the environment; the degree of Respondent's culpability; the history of Respondent's prior offenses; any effect that the penalty may have on its ability to continue doing business; the good faith of Respondent in attempting to comply with the pipeline safety regulations; and self-disclosure or actions to correct a violation prior to discovery by PHMSA. In addition, I may consider the economic benefit gained from the violation without any reduction because of subsequent damages, and such other matters as justice may require. The Notice proposed a total civil penalty of $834,400 for the violations cited above.

Item 1: The Notice proposed a civil penalty of $46,600 for Respondent's violation of 49 C.F.R. § 192.619(a)(3), for failing to establish a MAOP for its Sanford Lateral in accordance with § 192.619(a)(3).

Respondent argued that the proposed civil penalty amount in the Notice for Item 1 should be reduced or eliminated. With respect to the nature, circumstances, and gravity of this violation, ensuring the MAOP of a gas pipeline was properly established and supported by traceable and verifiable records is a key part of safe operations because MAOP has direct impact on pipeline stresses. OPS' experiences with pipeline accidents nationwide has shown the importance of

[46] These amounts are adjusted annually for inflation. *See* 49 C.F.R. § 190.223 for adjusted amounts.

MAOP verification to an operator's ability to safely operate a pipeline. With respect to culpability, the proposed penalty amount in the Notice was at the low end of the range and did not reflect any heightened level of egregiousness or deliberate decision not to comply. As to good faith, Respondent presented no circumstances beyond its control that would have prevented it from complying. Therefore, there is no justification for a good faith or other matters as justice may require credit.

With respect to the statute of limitations, the calculation of the civil penalty did not violate the statute of limitations because the Notice alleged a violation of § 192.619(a)(3) that was not cured until late 2020 when a hydrostatic test was conducted. Therefore, the violation last occurred in 2020, well within the five-year period preceding issuance of the Notice and commencement of the case.

While PHMSA's statute and regulations do not constrain it in this way, PHMSA's practice has been to apply the statutory maximum penalty limits applicable on the most recent date of the violation, as indicated in Part E5 of the Pipeline Safety Violation Report.[47] Thus, the statutory maximum penalty limit is selected based on "the most recent date listed on the violation report" and not when the violation started or was discovered. This is a reasonable approach to penalty calculations. Compliance was restored when FGT ran a hydrotest under the terms of the CAO to establish its MAOP.

Respondent has presented no information or arguments that would warrant a reduction of the proposed civil penalty amount in the Notice for this item. I find that the record supports the civil penalty amount proposed in the Notice. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $46,600 for violation of 49 C.F.R. § 192.619(a)(3).

Item 2: The Notice proposed a civil penalty of $362,800 for Respondent's alleged violation of 49 C.F.R. § 192.917(a)(1). Since this alleged violation has been withdrawn, the proposed penalty is not assessed.

Item 3: The Notice proposed a civil penalty of $425,000 for Respondent's violation of 49 C.F.R. § 192.937(c)(1), for failing to follow ASME/ANSI B31.8S, section 6.2 in selecting the appropriate internal inspection tools for each covered segment.

Respondent argued that the proposed civil penalty amount in the Notice for Item 3 should be reduced or eliminated. With respect to the nature and circumstances of this violation, an operator with LF-ERW pipe in its system is obligated to make sound risk management program decisions including decisions about the capability of the ILI tools they select to detect the types of defects that it has reason to believe may be present. With respect to gravity, FGT argued that its failure to use an ILI tool with axial capability in 2019 was not a causal factor in the September 10, 2020 incident. However, I find that Respondent's failure to use the appropriate assessment method was a causal factor in the failure because the rupture occurred in the longitudinal seam and FGT failed to use the appropriate tool in 2019 to address longitudinal

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[47] *See* 49 U.S.C. § 60122(a); 49 C.F.R. § 190.223.

seam failure, an axial defect.[48] As discussed above, an MFL-C tool is more sensitive to this type of defect and therefore more likely to detect it whereas the tool used was unreliable for this purpose. With respect to culpability, the proposed penalty amount in the Notice did not reflect any heightened level of egregiousness or deliberate decision not to comply. As to good faith, Respondent presented no circumstances beyond its control that would have prevented it from complying. Therefore, there is no justification for a good faith or other matters as justice may require credit.

Respondent questioned whether the civil penalty amount proposed in the Notice for Item 3 was consistent with the five-year statute of limitations in 28 U.S.C. 2462 and correctly pointed out that the Notice alleged that both the 2014-2015 ILI tool run and sleeve repair and the 2019 ILI tool run failed to comply with the requirement that the tool be capable of detecting axial seam defects as two instances of violation. With respect to the number of instances of violation for Item 3, I agree with Respondent that only the 2019 ILI run should be considered in the penalty calculation, not the 2014-2015 ILI tool run and sleeve repair. OPS also acknowledged that only the 2019 tool run constituted an instance of violation within the five-year period preceding issuance of the Notice, and the Director agreed that the 2014-1015 events were simply part of the fact pattern.

Accordingly, having reviewed the record and considered the assessment criteria, based upon the foregoing, I assess Respondent a reduced civil penalty of $362,800 for one instance of violation of 49 C.F.R. § 192.937(c)(1).

Constitutional/Due Process Arguments

FGT's written submissions in this matter go on to make a litany of assertions regarding due process and the fairness of the PHMSA's regulations governing its enforcement procedures and its authority to use informal administrative proceedings to assess civil penalties for violations.

PHMSA agrees Federal governmental agencies must act within the scope of the Constitution in carrying out their statutory duties, and PHMSA has complied with all applicable Constitutional requirements in this proceeding. Notably, the U.S. Court of Appeals for the Sixth Circuit recently issued a decision on June 2, 2023, denying a pipeline operator's petition for review of a PHMSA pipeline safety enforcement civil penalty matter.[49] In that case, the Court upheld PHMSA's assessment of civil penalties in a contested pipeline safety enforcement case, in which a hearing was also held, under the same procedural statutes and regulations which govern here.[50] That decision underscores the archetype that DOT's safety enforcement agencies, including PHMSA, have long carried out their statutory duties. PHMSA follows the enforcement regime set forth by Congress at 49 U.S.C. 60122 and codified at 49 C.F.R. Part 190. These statutory safety enforcement processes continue in lawful operation today.

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[48] RCFA, at 4.

[49] *See Wolverine Pipe Line Company v. DOT, PHMSA*, Case No. 21-3405 (6th Cir., June 2, 2023); *available online at* https://www.govinfo.gov/content/pkg/USCOURTS-ca6-21-03405/pdf/USCOURTS-ca6-21-03405-0.pdf.

[50] *Id.*

With regard to PHMSA's enforcement procedures generally, FGT argued that the case file provided by OPS prior to the hearing failed to comply with 49 U.S.C. § 60117(b)(1)(C) and violates due process. I disagree. Section 60117(b)(1)(C) requires PHMSA to ensure its enforcement procedures state that the case file "include all agency records pertinent to the matters of fact and law asserted." PHMSA not only has compliant enforcement procedures but also a regulation at § 190.209 that defines the case file to include the notice of probable violation, violation report (including exhibits), all materials submitted by a respondent, hearing materials, and the Region Director's recommendation. PHMSA enforcement procedures define the case file and affirm that it includes all agency records pertinent to the matters of fact and law asserted.[51] In other words, PHMSA's regulation and procedures comply with § 60117(B)(1)(C) and the 2020 PIPES Act, which did not expand the scope of the case file but reaffirmed the existing scope. Further PHMSA's authorizing statutes and the corresponding regulations issued thereunder provide for checks and controls in order to comply with the Administrative Procedure Act, not the least of which is notice and comment on regulations, separation of functions, and the ability to seek judicial review of various agency actions.

Finally, FGT contended the case file did not comply with § 60117(b)(1)(C) and due process, in part,[52] because PHMSA did not provide upon request the Proposed Civil Penalty Worksheet in Excel format, even though the Southwest Region provided the Proposed Civil Penalty Worksheet in PDF form. The PDF worksheet provides a detailed chart with point values applied to each selected civil penalty assessment factor. These point values correspond to the civil penalty assessment factors PHMSA is required to consider.[53] Those factors are further defined in the Violation Report, which FGT received a copy of. FGT was also provided the Civil Penalty Summary document which provides civil penalty ranges for each statutory assessment factor.[54] Combined, these documents provide a clear and reasoned basis for PHMSA's calculation of the proposed civil penalties. By reading these documents, Respondent knows for example the culpability level associated with the initially proposed penalty amount and points that were assigned to each penalty factor and can see how they add up to the total number of points corresponding to the final proposed penalty amount for each violation. As such, FGT is able to understand, and in fact has made numerous arguments to mitigate, the proposed civil penalties under the penalty assessment factors. While FGT claimed that the "per-point values" are obscured within the Excel spreadsheet, PHMSA notes that FGT has identified and made arguments concerning the "per-point values" based on the documents in its possession.[55]

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[51] *See* PHMSA, Pipeline Safety Enforcement Procedures: Section 4, at 19 n.4 (Dec. 9, 2022), *available online at* https://www.phmsa.dot.gov/regulatory-compliance/pipeline/enforcement/section-4-administrative-enforcement-processes.

[52] With respect to FGT's discussion of other documents not in the case file, the Southwest Region emphasizes that the case file includes all necessary evidence to sustain each allegation of violation and complies with 49 C.F.R. § 190.209.

[53] *See* 49 U.S.C. § 60122.

[54] *See* PHMSA, Civil Penalty Summary (Jan. 23, 2023), *available online at* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-01/Civil-Penalty-Summary-01-23-2023.pdf.

[55] Post-Hearing Brief, at 68.

Finally, it is worth noting that because Respondent's arguments were in fact persuasive to a significant extent such that Item 2 was withdrawn entirely and Item 3 was reduced from two instances of violation to one. The final penalty amount ended up being less than half of the total amount initially proposed in the Notice. This is itself indicative of the fairness of PHMSA's enforcement program, Respondent's ability to present its case during the informal hearing process, and the degree of transparency in how the civil penalties were assessed. Therefore, FGT's arguments that it is denied due process without the Excel version of the Proposed Civil Penalty Worksheet are without merit.

In summary, having reviewed the record and considered the assessment criteria for each of the Items cited above, I assess Respondent a total civil penalty of **$409,400**.

Payment of the civil penalty must be made within 20 days after receipt of this Final Order. Federal regulations (49 C.F.R. § 89.21(b)(3)) require such payment to be made by wire transfer through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMK-325), Federal Aviation Administration, Mike Monroney Aeronautical Center, 6500 S MacArthur Blvd, Oklahoma City, Oklahoma 79169. The Financial Operations Division telephone number is (405) 954-8845.

Failure to pay the civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9 and 49 C.F.R. § 89.23. Pursuant to those same authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Furthermore, failure to pay the civil penalty may result in referral of the matter to the Attorney General for appropriate action in a district court of the United States.

Under 49 C.F.R. § 190.243, Respondent may submit a Petition for Reconsideration of this Final Order to the Associate Administrator, Office of Pipeline Safety, PHMSA, 1200 New Jersey Avenue, SE, East Building, 2nd Floor, Washington, DC 20590, with a copy sent to the Office of Chief Counsel, PHMSA, at the same address. The written petition must be received no later than 20 days after receipt of the Final Order by Respondent. Any petition submitted must contain a brief statement of the issue(s) and meet all other requirements of 49 C.F.R. § 190.243. The filing of a petition automatically stays the payment of any civil penalty assessed. The other terms of the order, including any corrective action, remain in effect unless the Associate Administrator, upon request, grants a stay. If Respondent submits payment of the civil penalty, the Final Order becomes the final administrative decision and the right to petition for reconsideration is waived.

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

ALAN KRAMER MAYBERRY
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May 21, 2024

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Date Issued