

October 1, 2020

VIA ELECTRONIC MAIL TO: matthew.ramsey@energytransfer.com

Mr. Matthew Ramsey
Chief Operating Officer
Energy Transfer Partners, LP
8111 Westchester Drive
Dallas, Texas 75225

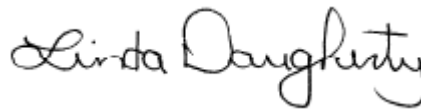
CPF No. 4-2020-008-CAO

Dear Mr. Ramsey:

Enclosed please find an Amended Corrective Action Order (ACAO) issued by the Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, in the above-referenced case to Florida Gas Transmission Company (FGT), which is operated by Energy Transfer Partners, LP. The ACAO requires FGT to take corrective actions with respect to a rupture that occurred on September 24, 2020 on FGT's 18-inch FLMEA-21 pipeline located in Lake Worth, Florida, in addition to those actions previously ordered on September 18, 2020, with respect to an incident that occurred on the 12-inch Sanford Lateral on September 10, 2020.

Service of the ACAO by electronic transmission is deemed complete upon transmission and acknowledgement of receipt, or as otherwise provided under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon completion of service.

Sincerely,



Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Enclosure: ACAO

cc: Ms. Linda Daugherty, Deputy Associate Administrator for Field Operations, OPS
Ms. Mary L. McDaniel, P.E., Director, Southwestern Region, OPS
Mr. Eric Amundsen, Senior Vice President, Energy Transfer Partners, LP,
eric.amundsen@energytransfer.com

CONFIRMATION OF RECEIPT REQUESTED

¹ FGT is an approximately 5,300-mile system that transports natural gas from South Texas to South Florida. FGT is owned by Florida Gas Transmission Company, LLC, a 100 percent owned subsidiary of Citrus Corp. Citrus Corp is a 50/50 joint venture between Kinder Morgan, Inc. and Energy Transfer Partners, LP. FGT is operated by Energy Transfer. See <https://www.kindermorgan.com/Operations/Natural-Gas/Index> (last accessed September 14, 2020).

Incident 2: At approximately 9:50 am EDT on September 24, 2020, FGT's FLMEA-21 18-inch pipeline ruptured and ejected multiple pieces of pipeline into the air. FGT's gas control was notified by a representative of the Lake Worth Drainage District that their pipeline was blowing natural gas. FGT's representative confirmed the leak on the 18-inch pipeline and the line was isolated between FGT's two compressor stations (FGT CS 21 and CS 21.5). At the incident site, FGT found a 13-foot portion of ejected pipeline that landed approximately 400 feet downstream from the rupture site on the median of Lake Worth Road, and an additional 8.3-foot piece of ejected pipeline was located approximately 200 feet east of the rupture site in a retaining pond behind a Florida Turnpike toll booth. The outside lane of northbound traffic on the Florida Turnpike was closed while FGT assessed the damage and initiated repairs. A mobile phone emergency alert was sent to those within a half-mile of the gas rupture notifying those persons to shelter-in-place or evacuate. An unknown number of people were evacuated from commercial businesses and a nearby elementary school. Evacuees were allowed to return to the area once the gas flow at the rupture site was secured.

Pursuant to 49 U.S.C. § 60117, PHMSA, Office of Pipeline Safety (OPS), initiated investigations of both Incident 1 and Incident 2. The preliminary findings of the agency's ongoing investigations are as follows:

Preliminary Findings for Incident 1:

- FGT initially reported Incident 1 to the National Response Center (NRC) at 2:24 am EDT on September 10, 2020 (NRC Report No. 1286952), indicating that Reverse 911 notified 800 area homes and that the local sheriff reported the evacuation of 20 homes when the 12-inch Sanford Lateral ruptured and ignited a fire. FGT provided an update to NRC after 48 hours that indicated an estimated release of 22 million cubic feet (MMCF) of natural gas and caused the evacuation of 20 homes. FGT also reported that all evacuees had returned to their homes.
- There were no injuries or fatalities associated with Incident 1; however, there is burn damage to the surrounding vegetation measuring 515 feet by 100 feet. Additionally, three overhead powerlines owned by Duke Energy, that shared the right-of-way (ROW), were damaged and knocked down.
- The rupture occurred near Mile Post 15 on the 12-inch Sanford Lateral (12-inch line or Sanford Lateral) that feeds a Duke Energy Power Plant and a Sanford Florida Public Utilities (FPU) meter station.
- The Sanford Lateral was constructed in 1959 with a 12-inch nominal diameter, 0.219-inch wall thickness, X-42 grade pipe that was manufactured by Youngstown Sheet and Tube. The pipe has a low-frequency electric resistance welded (LF ERW) seam and is coated with a tape coating. The length of the 12-inch Sanford Lateral was measured at 15.9 miles by a 2019 in-line inspection (ILI) run. The Sanford Lateral is part of a larger FGT unit with a total of 654 miles.

- The Sanford Lateral was manually shut in between upstream Valve 17-22U and downstream Valve 17-22ERB. On the evening of September 10, 2020, FGT cut the failed 12-inch pipeline and installed a pre-tested weld cap downstream from the lateral to Sanford FPU meter station. The weld cap location is approximately 0.5 miles upstream of rupture location and downstream of an FPU lateral to two customers (Sanford West and Sanford FPU) line, allowing a return to service of the remainder of the line.
- Service has been restored to all 125 customers that initially lost service. The isolated segment of pipeline, including the site of the rupture, is approximately 1.4 miles in length and remains out of service.
- The Maximum Operating Pressure of the 12-inch Sanford Lateral is 713 psig. The operating pressure at the time of the rupture was 695 psig. The portion of the Sanford Lateral that resumed operations is currently operating at 344 psig, which is fifty percent (50%) of operating pressure at the time of rupture. This pressure restriction was put into place by FGT.
- 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. The line also reportedly has river weights in the vicinity of the rupture, and throughout the entire area where high corrosion rates are present.
- Aerial mapping and alignment sheets show a mix of sparsely populated swamp and residential and commercial properties in close proximity to ROW.
- There have been no previous reportable incidents on the Sanford Lateral. FGT reports that a 2012 rupture occurred in Melbourne, Florida and a 2014 rupture occurred in Port St. John, Florida. Both were on different pipelines in the unit that includes the Sanford Lateral. The 2012 rupture involved 20-inch 1959 vintage Youngstown Tube and Steel LF ERW pipe and was classified as original manufacturing related (not weld). The 2014 rupture involved an 8-inch 1962 vintage LF ERW pipe manufactured by Lonestar, and was also classified original manufacturing related (not weld).
- Pre-1970 LF ERW pipe has been the focus of many studies and reviews. A final report *TTO Number 5, Integrity Management Program Delivery Order DTRS56-02-D-70036, Integrity Management Program regarding Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation* (Revision 3) was prepared by Michael Baker in association with Kiefner and Associates, Inc., CorrMet Engineering Services, PC in

April 2004.² The report was written to support the importance of operators correctly selecting integrity assessment methods capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

- 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.

Preliminary Findings for Incident 2:

- FGT initially reported Incident 2 to the NRC at 10:53 am EDT on September 24, 2020 (NRC Report No. 1288141), indicating that a rupture, with no fire, occurred on FGT's 18-inch FLMEA-21 pipeline. FGT provided an update to NRC (NRC Report No. 1288281) after 48 hours that indicated an estimated release of 12 MMCF of natural gas. There were no injuries or fatalities associated with Incident 2.
- The rupture occurred approximately 350 feet north of the intersection of the Florida Turnpike and Lake Worth Road in Lake Worth, Florida. The rupture location is about six miles south of FGT's upstream compressor station, and 24 miles north of FGT's downstream compressor station.
- The FLMEA-21 pipeline was constructed in 1959 with an 18-inch nominal diameter, 0.25-inch wall thickness, X-52 grade pipe that was manufactured by Youngstown Sheet and Tube. The pipe has an LF ERW seam and is coated with cold applied tape. The length of the FLMEA-21 pipeline is 67.04 miles.
- The FLMEA-21 pipeline supplies gas to three power plants and four regulator stations that supply natural gas to local distribution systems. The 18-inch FLMEA-21 pipeline shares the ROW with FGT's 24-inch, FLMEB-21 pipeline, which runs parallel to the FLMEA-21 pipeline and is located approximately 20 feet away. The FLMEB-21 pipeline experienced no apparent collateral damage due to Incident 2.
- The FLMEA-21 pipeline is currently shut in between FGT's Main Line Valve (MLV) 20-3 and MLV 20-4, approximately 15 miles. At MLV 20-3 there is a crossover to the FLMEB-21 24-inch and another crossover at MLV 20-4 to revert back to the FLMEA-21 18-inch. The segment continues to remain out of service.
- The Maximum Operating Pressure of the FLMEA-21 is 866 psig. The operating pressure at the time of the rupture was 846 psig.

² See <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/hazardous-liquid-integrity-management/64376/tto5lowfrequencyerwfinalreportrev3april2004.pdf> (last accessed September 14, 2020).

- In 2018, FGT performed an ILI of the FLMEA-21 pipeline with no actionable indications of anomalies reported within the area near the Florida Turnpike exit ramp and Lake Worth Blvd.
- Much of FGT's FLMEA-21 pipeline shares the ROW with FGT's FLMEB-21 pipeline and the Florida Turnpike.
- Aerial mapping shows heavily populated and travelled area in the vicinity of the pipeline. The pipeline is parallel and in close proximity (4 to 5 feet) from a retaining wall for the Florida Turnpike. The retaining wall was severely damaged as a result of this incident.
- There have been two reportable incidents on the FLMEA-21 pipeline since 2009 that were attributed to Stress Corrosion Cracking (SCC). The first was in May 2009 in Palm City, Florida, which resulted in a rupture of the pipeline. The second was a leak on the pipeline that occurred in December 2012 in Lake Worth, Florida. The 2012 leak was approximately 400-feet south of the rupture site for Incident 2.
- PHMSA issued Corrective Action Orders (CPF Nos. 2-2009-1002H and 2-2012-1005H) for each of the previous two failures on the FLMEA-21 pipeline.
- As discussed in the Preliminary Findings for Incident 1, pre-1970 LF ERW pipe has been the focus of many studies and reviews, including those reports cited above. PHMSA has also issued notices, including Advisory Bulletins and Alert Notices, on the safety risks of LF ERW and Flash-welded Pipe manufactured prior to 1970, as well as advising operators to determine whether their pipelines were susceptible to ERW seam failures and address the potential impact on pipeline integrity.

Determination of Necessity for Corrective Action Order and Right to Hearing:

Section 60112 of title 49, United States Code, authorizes PHMSA to determine that a pipeline facility is or would be hazardous to life, property, or the environment and, if there is a likelihood of serious harm, to expeditiously order the operator of the facility to take necessary corrective action, including suspended or restricted use of the facility, physical inspection, testing, repair, replacement, or other appropriate action. An order issued expeditiously must provide an opportunity for a hearing as soon as practicable after the order is issued.

In deciding whether to issue an order, PHMSA must consider the following, if relevant: (1) the characteristics of the pipe and other equipment used in the pipeline facility, including the age, manufacture, physical properties, and method of manufacturing, constructing, or assembling the equipment; (2) the nature of the material the pipeline facility transports, the corrosive and deteriorative qualities of the material, the sequence in which the material are transported, and the pressure required for transporting the material; (3) the aspects of the area in which the pipeline facility is located, including climatic and geologic conditions and soil characteristics;

(4) the proximity of the area in which the hazardous liquid pipeline facility is located to environmentally sensitive areas; (5) the population density and population and growth patterns of the area in which the pipeline facility is located; (6) any recommendation of the National Transportation Safety Board made under another law; and (7) other factors PHMSA may consider appropriate.

After evaluating the foregoing preliminary findings of fact, I find that the continued operation of the Affected Pipelines, as defined below, without corrective measures is or would be hazardous to life, property and the environment. Given that both Incident 1 and Incident 2 involved pre-1970 LF ERW pipe, and that there is an increased likelihood that there are other locations along the pipelines subject to the same operational cycles and fatigue, there is a heightened risk for imminent failures along the pipe. Furthermore, given that the area of the rupture for Incident 1 appears to be at a low point in the line which is located in a swamp, there is an increased possibility of the presence of moisture that may increase the likelihood of increased external corrosion. In fact, recent ILI data of the Sanford Lateral showed indications of increased corrosion in the vicinity of the rupture. As for Incident 2, the location of the pipeline and the rupture site is in close proximity to populated areas, including the Florida Turnpike. Therefore, after considering the age of the pipelines, the manufacturing methods, the hazardous nature of the products being transported, the pressure required for transporting the materials, and the attributes of the ROWs for each pipeline, as well as the uncertainties as to the causes of the incidents and the ongoing investigation, I find that a failure to issue this Order expeditiously to require immediate corrective action would result in likely serious harm to life, property, and the environment.

Accordingly, this ACAO mandating immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, with a copy to the Director, Southwest Region, PHMSA (Director). If a hearing is requested, it will be held in accordance with 49 C.F.R. § 190.211.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken. Respondent will be notified of any additional measures required and, if appropriate, PHMSA will consider amending this Order. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Actions:

Definitions for Incident 1:

Incident 1 Affected Pipeline³ – Means the entire 15.9 miles of the 12-inch Sanford Lateral operated by Florida Gas Transmission that transports natural gas from FGT’s 26-inch mainline to the Sanford West and Sanford FPU meter station.

Incident 1 Isolated Segment – Means the portion of the Incident 1 Affected Pipeline between the weld cap location (approximately MP 14.8) and Valve 17-22ERB that remains out of service.

Definitions for Incident 2:

Incident 2 Affected Pipeline – Means the entire 67.04 miles of the 18-inch FLMEA-21 pipeline and the 60.2 miles of the 24-inch FLMEB-21 pipeline.

Incident 2 Isolated Segment– Means the approximate 15 miles of the 18-inch FLMEA-21 pipeline (i.e. Incident 2 Affected Pipeline) between FGT’s MLV 20-3 and FGT’s MLV 20-4.

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

1. ***Shutdown of the Isolated Segments.*** The Incident 1 Isolated Segment and Incident 2 Isolated Segment (collectively Isolated Segments) are currently out of service and must remain shut down until its restart in accordance with this Order.
2. ***Operating Pressure Restriction of the Affected Pipelines.*** FGT must maintain a fifty percent (50%) pressure reduction in the actual operating pressure along the entire length of the Incident 1 Affected Pipeline such that the operating pressure along the pipeline will not exceed fifty percent (50%) of the actual operating pressure in effect immediately prior to the failure on September 10, 2020. FGT must initiate and maintain a twenty percent (20%) pressure reduction in the actual operating pressure along the entire length of the Incident 2 Affected Pipeline such that the operating pressure along the pipeline will not exceed twenty percent (20%) of the actual operating pressure in effect immediately prior to the failure on September 24, 2020.
 - a. This pressure restriction is to remain in effect until written approval to increase the pressure or return the pipelines to their pre-failure operating pressure is obtained from the Director.
 - b. FGT must provide the Director by October 2, 2020 for Incident 1 and 14 calendar days of receipt of this ACAO for Incident 2, the actual operating pressures of each compressor station and each main line pressure regulating station on the Incident 1 Affected Pipeline and Incident 2 Affected Pipeline (collectively Affected Pipelines)

³ The Corrective Action Order issued on September 18, 2020, referred to this pipeline as the “Affected Segment.” To avoid confusion with the “Isolated Segment,” the pipeline is hereafter referred to as the “Incident 1 Affected Pipeline.”

at the time of failure and the reduced pressure restriction set-points at these same locations.

- c. This pressure restriction requires any relevant remote or local alarm limits, software programming set-points or control points, and mechanical over-pressure devices to be adjusted accordingly.
 - d. When determining the pressure restriction set-points, FGT must take into account any ILI features or anomalies present in the Affected Pipelines to provide for continued safe operation while further corrective actions are completed.
 - e. FGT must review the pressure restriction monthly by analyzing the operating pressure data. FGT must take into account any ILI features or anomalies present in the Affected Pipelines and immediately reduce the operating pressure to maintain the safe operations of the Affected Pipelines, if warranted by the monthly review.
3. ***Repair/Restart Plan.*** Prior to resuming operation of the Isolated Segments, FGT must develop and submit a written Repair/Restart Plan for each of the Isolated Segments to the Director for approval.
- a. The Director may approve the Repair/Restart Plan incrementally without approving the entire plan, but the Isolated Segments cannot resume operation until the Repair/Restart Plan is approved in its entirety.
 - b. Once approved by the Director, the Repair/Restart Plan will be incorporated by reference into this Order.
 - c. The Repair/Restart Plan must provide plans and procedures for the repair of the isolated segment of the pipelines.
 - d. The Repair/Restart Plan must provide for adequate patrolling of the Isolated Segment during the restart process and must include incremental pressure increases during start up, with each increment to be held for at least two hours.
 - e. The Repair/Restart Plan must include sufficient surveillance of the pipeline during each pressure increment to ensure that no leaks are present when operation of the line resumes.
 - f. The Repair/Restart Plan must specify a day-light restart and include advance communications with local emergency response officials.
 - g. The Repair/Restart Plan must provide for a review of the Isolated Segments for conditions similar to those of the failure, including a review of construction, operating and maintenance and integrity management records such as ILI results, hydrostatic pressure tests, root cause failure analysis of prior failures, aerial and ground patrols, corrosion, cathodic protection, excavations and pipe replacements. FGT must address any findings that require remedial measures to be implemented prior to restart.

- h. The Repair/Restart Plan must also include documentation of the completion of all mandated actions, and a management of change plan to ensure that all procedural modifications are incorporated into FGT's operations and maintenance procedures manual.
 - i. The Repair/Restart Plan must provide for hydrostatic pressure testing of the Isolated Segments.
- 4. ***Return to Service.*** After the Director approves the Repair/Restart Plan, FGT may return the Isolated Segments to service, but the operating pressures must not exceed the pressure restriction in accordance with Item 2 above.
- 5. ***Removal of Pressure Restriction.*** The Director may allow the removal or modification of the pressure restriction in Item 2 above upon a written request from FGT demonstrating that restoring the pipeline to its pre-failure operating pressure is justified based on a reliable engineering analysis showing that the pressure increase is safe considering all known defects, anomalies, and operating parameters of the pipeline.
 - a. The Director may allow the temporary removal or modification of the pressure restrictions upon a written request from FGT demonstrating that temporary mitigative and preventive measures are implemented prior to and during the temporary removal or modification of the pressure restriction. The Director's determination will be based on the known or suspected failure cause and provision of evidence that preventative and mitigative actions taken by the operator provide for the safe operation of the Affected Pipelines during the temporary removal or modification of the pressure restriction. Appeals to determinations of the Director in this regard will be decided by the Associate Administrator for Pipeline Safety.
- 6. ***Instrumented Leakage Survey.*** By October 18, 2020 for Incident 1, and within 30 calendar days of receipt of this Order for Incident 2, FGT must perform an aerial or ground instrumented leakage survey of the Affected Pipelines. FGT must investigate all leak indications and remedy all leaks discovered. FGT must submit documentation of this survey to the Director by November 2, 2020 for Incident 1, and within 45 calendar days of receipt of this Order for Incident 2.
- 7. ***Records Verification.*** As recommended in PHMSA Advisory Bulletin 2012-06, FGT must verify the records for the Affected Pipelines to confirm the maximum allowable operating pressure. FGT must submit documentation of this record verification to the Director by November 2, 2020 for Incident 1, and within 45 calendar days of receipt of this Order for Incident 2.
- 8. ***Review of Prior Inline Inspection Results.*** By October 18, 2020 for Incident 1, and within 30 calendar days of receipt of this Order for Incident 2, FGT with the assistance of an outside third party, approved by PHMSA, conduct a review of any previous ILI results of the Affected Pipelines to re-evaluate all ILI results from the past five calendar years, include a review of the ILI vendors' raw data and analysis, and determine whether any features were present in the failed pipe joint and any other pipe removed. Also, determine if any features with similar characteristics are present elsewhere on the Affected

Pipelines. FGT must submit documentation of this ILI review to the Director by November 2, 2020 for Incident 1, and within 45 calendar days of receipt of this Order for Incident 2.

- a. List all ILI tool runs, tool types, and the calendar years of the tool runs. Provide ILI results data, as requested, to PHMSA.
 - b. List, describe (type, size, wall loss, etc.), and identify the specific location of all ILI features present in the failed joint and/or other pipe removed.
 - c. List, describe (type, size, wall loss, etc.), and identify the specific location of all ILI features with similar characteristics present elsewhere on the Affected Pipelines.
 - d. Explain the process used to review the ILI results and the results of the reevaluation.
9. ***Mechanical and Metallurgical Testing.*** By November 2, 2020 for Incident 1, and within 45 calendar days of receipt of this Order for Incident 2, FGT must submit for approval a plan for mechanical and metallurgical testing and failure analysis of the failed pipe, including an analysis of soil samples and any foreign materials, by an approved independent third-party laboratory. Complete the testing and analysis as follows:
 - a. Document the chain-of-custody when handling and transporting the failed pipe sections and other evidence from the failure sites.
 - b. Within 10 calendar days of receipt of this Order for Incident 2, FGT must develop and submit the testing protocol and the proposed testing laboratory to the Director for prior approval.
 - c. Prior to beginning the mechanical and metallurgical testing, provide the Director with the scheduled date, time, and location of the testing to allow for an OPS representative to witness the testing.
 - d. Ensure the testing laboratory distributes all reports whether draft or final in their entirety to the Director at the same time they are made available to FGT.
10. ***Root Cause Failure Analysis.*** By December 17, 2020 for Incident 1, and within 90 calendar days of receipt of this Order for Incident 2, FGT must complete a root cause failure analysis (RCFA) and submit a final report of this RCFA to the Director. The RCFAs must be supplemented or facilitated by an independent third-party acceptable to the Director and must document the decision-making process and all factors contributing to the failure. The final reports must include findings and any lessons learned and whether the findings and any lessons learned are applicable to other locations within FGT's pipeline system.
11. ***Remedial Work Plan.***
 - a. By December 17, 2020 for Incident 1, and within 90 calendar days of receipt of this Order for Incident 2, FGT must submit Remedial Work Plan(s) (RWP) to the Director for approval. The Director may approve the RWPs incrementally without approving the entire RWP. FGT may also submit one RWP for both Incidents by December 17, 2020.

- b. Once approved by the Director, the RWP(s) will be incorporated by reference into this Order, and FGT must implement the RWP(s) as it is approved by the Director, including any revisions to the plan.
- c. The RWP(s) must specify the tests, inspections, assessments, evaluations, and remedial measures FGT will use to verify the integrity of the Affected Pipelines. It must address all known or suspected factors and causes of the September 10, 2020 and September 24, 2020 failures. FGT should consider both the risk of another failure and the consequence of another failure to develop a prioritized schedule for RWP related work along the Affected Pipelines.
- d. The RWP must include a procedure or process to:
 - i. Identify pipe in the Affected Pipelines and other pipelines in the FGT operating areas with characteristics similar to the contributing factors identified for the September 10, 2020 and September 24, 2020 failures.
 - ii. Gather all data necessary to review the failure history (in service and pressure test failures) of the Affected Pipelines and to prepare a written report containing all the available information such as the locations, dates, and causes of leaks and failures.
 - iii. Integrate the results of the metallurgical testing, root cause failure analysis, and other corrective actions required by this Order with all relevant pre-existing operational and assessment data for the Affected Pipelines. Pre-existing operational data includes, but is not limited to, manufacturing and construction, operations, maintenance, testing, repairs, prior metallurgical analyses, and any third-party consultation information. Pre-existing assessment data includes, but is not limited to, ILI tool runs, hydrostatic pressure testing, direct assessments, close interval surveys, and direct or alternating current voltage gradient surveys.
 - iv. Determine if conditions similar to those contributing to the failures on September 10, 2020 and September 24, 2020 are likely to exist elsewhere on FGT's operational pipelines.
 - v. Conduct additional field tests, inspections, assessments, and/or evaluations necessary to determine whether, and to what extent, the conditions associated with the failures on September 10, 2020 and September 24, 2020, and other failures from the failure history in Item 11(d)(ii) above or any other integrity threats are present elsewhere on the Affected Pipelines or other systems operated by FGT. At a minimum, this process must consider all failure causes and specify the use of one or more of the following:
 - 1. ILI tools that are technically appropriate for assessing the pipeline system based on the cause of failures on September 10, 2020 and September 24, 2020, and that can reliably detect and identify anomalies;

2. Hydrostatic pressure testing;
3. Close-interval surveys;
4. Cathodic protection surveys, to include interference surveys in coordination with other utilities (e.g. underground utilities, overhead power lines, etc.) in the area;
5. Coating surveys;
6. Stress corrosion cracking surveys;
7. Selective seam corrosion surveys; and
8. Other tests, inspections, assessments, and evaluations appropriate for the failure causes.

FGT may use the results of previous tests, inspections, assessments, and evaluations if approved by the Director, provided the results of the tests, inspections, assessments, and evaluations are analyzed with regard to the factors known or suspected to have caused the September 10, 2020 and September 24, 2020 failures.

- vi. Describe the inspection and repair criteria FGT will use to prioritize, excavate, evaluate, and repair anomalies, imperfections, and other identified integrity threats. Include a description of how any defects will be graded and a schedule for repairs or replacement.
 - vii. Based on the known history and condition of the Affected Pipelines, describe the methods FGT will use to repair, replace, or take other corrective measures to remediate the conditions associated with the pipeline failures on September 10, 2020 and September 24, 2020, and to address other known integrity threats along the Affected Pipelines. The repair, replacement, or other corrective measures must meet the criteria specified in Item 11(d)(vi) above.
 - viii. Implement continuing long-term periodic testing and integrity verification measures to ensure the ongoing safe operation of the Affected Pipelines considering the results of the analyses, inspections, evaluations, and corrective measures undertaken pursuant to the Order.
- e. The RWP must include a schedule for completion.
 - f. FGT must revise the RWP(s) as necessary to incorporate new information obtained during the failure investigation and remedial activities, to incorporate the results of actions undertaken pursuant to this Order, and to incorporate any modifications required by the Director.
 - i. Submit any plan revisions to the Director for prior approval.

- ii. The Director may approve plan revisions incrementally.
- iii. Any and all revisions to the RWP(s) after it has been approved and incorporated by reference into this Order will be fully described and documented in the CAO Documentation Report (CDR).

12. **CAO Documentation Report.** When FGT has concluded all the items in this Order, it will submit the final CDR in its entirety to the Director. This will allow the Director to complete a thorough review of all actions taken by FGT with regards to this Order prior to approving the closure of this Order. The intent is for the CDR to summarize all activities and documentation associated with this Order in one document.

- a. The Director may approve the CDR incrementally without approving the entire CDR.
- b. Once approved by the Director, the CDR will be incorporated by reference into this Order.
- c. The CDR must include, but is not necessarily limited to, the following elements:
 - i. Table of Contents;
 - ii. Summary of the pipeline failures of September 10, 2020 and September 24, 2020, and the response activities;
 - iii. Summary of pipe data/properties and all prior assessments of the Affected Pipelines;
 - iv. Summary of all tests, inspections, assessments, evaluations, and analysis required by the Order;
 - v. Summary of the Mechanical and Metallurgical Testing as required by the Order;
 - vi. Summary of the RCFA with all root causes as required by the Order;
 - vii. Documentation of all actions taken by FGT to implement the RWP(s), the results of those actions, and the inspection and repair criteria used;
 - viii. Documentation of any revisions to the RWP(s) including those necessary to incorporate the results of actions undertaken pursuant to this Order and whenever necessary to incorporate new information obtained during the failure investigation and remedial activities;
 - ix. Lessons learned while completing this Order;
 - x. A path forward describing specific actions FGT will take on its entire pipeline system as a result of the lessons learned from work on this Order; and
 - xi. Other Appendices as required.

Other Requirements:

13. **Approvals.** With respect to each submission that under this Order requires the approval of the Director, the Director may: (a) approve, in whole or part, the submission; (b) approve the submission on specified conditions; (c) modify the submission to cure any deficiencies; (d) disapprove in whole or in part, the submission, directing that Respondent modify the submission, or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Director, Respondent shall proceed to take all action required by the submission as approved or modified by the Director. If the Director disapproves all or any portion of the submission, Respondent must correct all deficiencies within the time specified by the Director, and resubmit it for approval.
14. **Extensions of Time.** The Director may grant an extension of time for compliance with any of the terms of this Order upon a written request timely submitted demonstrating good cause for an extension.
15. **Reporting.** Submit quarterly reports to the Director that: (1) include all available data and results of the testing and evaluations required by this Order; and (2) describe the progress of the repairs or other remedial actions being undertaken. The first quarterly report is due on December 31, 2020. The Director may change the interval for the submission of these reports.
16. **Documentation of the Costs.** It is requested but not required that Respondent maintain documentation of the costs associated with implementation of this ACAO. Include in each monthly report submitted, the to-date total costs associated with: (1) preparation and revision of procedures, studies and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.

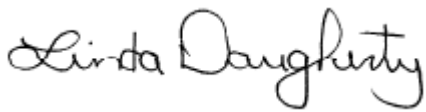
Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. § 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

In your correspondence on this matter, please refer to “CPF No. 4-2020-008-CAO” and for each document you submit, please provide a copy in electronic format whenever possible. The actions required by this Order are in addition to and do not waive any requirements that apply to Respondent’s pipeline system under 49 C.F.R. Parts 190 through 199, under any other order issued to Respondent under authority of 49 U.S.C. Chapter 601, or under any other provision of Federal or State law.

Respondent may appeal any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator shall be final.

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 U.S.C. § 60120.

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



October 1, 2020

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Date Issued