U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

ENVIRONMENTAL ASSESSMENT
and
FINDING OF NO SIGNIFICANT IMPACT

Special Permit Information:

Docket Number:	PHMSA-2021-0118
Requested By:	Florida Gas Transmission Company, LLC
Operator ID#:	5304
Original Date Requested:	November 17, 2021
Issuance Date:	April 4, 2022
Code Section(s):	49 CFR 192.611(a) and (d) and 192.619(a)

I. Background:

The National Environmental Policy Act (NEPA), 42 U.S.C. 4321 – 4375 et seq., Council on Environmental Quality Regulations, 40 CFR 1500-1508, and U.S. Department of Transportation (DOT) Order No. 5610.1C, requires the Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS)[1] to analyze a proposed action to determine whether the action will have a significant impact on the human environment. PHMSA analyzes special permit requests for potential risks to public safety and the environment that could result from our decision to grant, grant with additional conditions, or deny the request. As part of this analysis, PHMSA evaluates whether a special permit will impact the likelihood or consequence of a pipeline failure as compared to the operation of the pipeline in

1 Throughout this special permit the usage of "PHMSA" or "PHMSA OPS" means the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety.

full compliance with the Federal pipeline safety regulations. PHMSA's environmental review associated with the special permit application is limited to impacts that would result from granting or denying the special permit. PHMSA developed this assessment to determine what effects, if any, our decision would have on the environment.

Pursuant to 49 U.S.C. 60118(c) and 49 Code of Federal Regulations (CFR) 190.341, PHMSA may only grant special permit requests that are not inconsistent with pipeline safety. PHMSA will impose conditions in the special permit if we conclude they are necessary for safety, environmental protection, or are otherwise in the public interest. If PHMSA determines that a special permit would be inconsistent with pipeline safety or is not justified, the application will be denied.

The purpose of this Final Environmental Assessment (FEA) is to comply with National Environmental Policy Act (NEPA) for the Florida Gas Transmission Company, LLC (FGT)[2] special permit to waive compliance from 49 CFR 192.611(a) and (d) and 192.619(a) for one (1) ***special permit segment*** and one (1) ***special permit inspection area*** along the FGT natural gas transmission pipeline system in Florida. This FEA assesses the pipeline special permit request, in accordance with 49 CFR 190.341, and is intended to specifically analyze any environmental impact associated with the waiver of certain federal pipeline safety regulations found in 49 CFR 192.611(a) and (d) and 192.619(a). This permit requires FGT to implement additional conditions on the operations, maintenance, and integrity management (IM) of the approximately 0.978 miles (***special permit segment***) on the 26-inch Mainline Loop CMPR STA 18-19 (Pipeline) and approximately 73.7 miles (***special permit inspection area***) of the FGT natural gas transmission pipeline system located in Brevard County, Florida.

II. Introduction:

Pursuant to 49 U.S.C. 60118(b) and 49 CFR 190.341, FGT submitted a special permit application to PHMSA on November 17, 2021, requesting that PHMSA waive the requirements of 49 CFR 192.611(a) and (d) and 192.619(a) to permit FGT to maintain the maximum

[2] Florida Gas Transmission Company, LLC is owned by Energy Transfer and Kinder Morgan, Inc.

allowable operating pressure (MAOP) for one (1) ***special permit segment*** where the class location has changed from Class 1 to Class 3 located in in Brevard County, Florida.

PHMSA is granting a special permit to waive certain regulatory requirements where it is not inconsistent with pipeline safety. A special permit is typically conditioned on the performance of additional measures beyond minimum Federal pipeline safety regulations, in accordance with 49 CFR 190.341.

III. Regulatory Background:

PHMSA regulations at 49 CFR 192.611(a) require that an operator confirm or revise the MAOP of a pipe segment that is in satisfactory condition when the hoop stress of the segment is no longer commensurate with class location. Under 49 CFR 192.611(a), an operator may be required to reduce the operating pressure of a pipe segment, or alternatively, may have to replace the pipe in order to maintain the MAOP. Below is the relevant text of 49 CFR 192.611(a):

49 CFR 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

3) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(iii) For pipeline operating at an alternative maximum allowable operating pressure per §192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

49 CFR 192.619 What is the maximum allowable operating pressure for steel or plastic pipelines?

(a)(2)(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Table 1 to Paragraph (a)(2)(ii)

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

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

(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:

Section 192.619(a) requires Class 3 location pipe to be pressure tested to 1.5 times MAOP.

IV. Purpose and Need

FGT requested a waiver from the requirements of 49 CFR 192.611(a) and (d) and 192.619(a) for the ***special permit segment*** consisting of approximately 0.978 miles of natural gas transmission pipeline listed below in **Table 1 – Special Permit Segment**. Without a special permit, the cited regulations require that FGT complete pipe replacement, hydrotest, and pressure reduction, based on population changes in the vicinity of the ***special permit segment***. FGT must apply the special permit conditions to one (1) ***special permit segment*** to provide an equivalent margin of safety and environmental protection to meet the requirements of 49 CFR 192.611, as outlined in the special permit conditions.

The special permit establishes enhanced IM procedures to maintain pipe integrity and protect both the public and the environment for the class location units in which the ***special permit segment*** is located for the length of pipeline covered by the special permit. In addition, FGT must comply with conditions as provided in the terms of the special permit for all the impacted ***special permit segments*** and the ***special permit inspection area*** in the special permit.

The special permit authorizes future class changes within the ***special permit inspection area*** (***special permit segment extensions***) under the special permit, providing the ***special permit segment extensions*** meet the special permit conditions applicable to the ***special permit segment***. In that case, FGT must also notify PHMSA and update this FEA/FONSI.

V. Site Description

The ***special permit segment*** consists of 5,162 feet (approximately 0.978) of the 26-inch diameter Mainline Loop CMPR STA 18-19 Pipeline located in Brevard County, Florida. The ***special permit inspection area*** extends approximately 73.7 miles of the pipeline.

VI. Special Permit Segments and Special Permit Inspection Areas

<u>Special Permit Segment</u>:

This special permit applies to the ***special permit segment*** identified in **Table 1 – Special Permit Segment** and are identified using the FGT survey station (SS) references.

Table 1 – Special Permit Segment

Special Permit Segment Number	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (SS)	End Survey Station (SS)	County, State	Year Installed	Seam Type	MAOP (psig)
182069	26	26-inch Mainline Loop STA 18 - STA 19	5,162	3241+20	3292+82	Brevard, FL	1968	DSAW	977

<u>Special Permit Inspection Area</u>:

The ***special permit inspection area*** is defined as the area that extends 220 yards on each side of the centerline along approximately 79.7 miles of 26-inch diameter Mainline Loop pipeline. A summary of ***special permit inspection area*** is included in **Table 2 – Special Permit Inspection Area**.

Table 2 – Special Permit Inspection Area

Special Permit Inspection Area Name	Special Permit Segment Number(s)	Outside Diameter (inches)	Line Name	County, State	Start Survey Station (MP)	End Survey Station (MP)	Length (miles)
FLMEB-18	182069	26	Mainline Loop STA18-STA19	Brevard, FL	668.8	742.5	73.7

Attachment B1 is a general map that includes the pipeline route map showing the ***special permit segment*** and ***special permit inspection area***.

PHMSA is granting this special permit request based on this document and the "Special Permit Analysis and Findings" document, which is incorporated by reference into this document and can be read in its entirety in Docket No. PHMSA-2021-0118 in the Federal Docket Management System (FDMS) located on the internet at www.regulations.gov.

VII. Alternatives

Alternative 1: "No Action" Alternative

If PHMSA were to select the "no action" alternative, PHMSA would deny FGT's special permit request, FGT would be required to fully comply with 49 CFR 192.611(a) and (d) and 192.619(a). In order to maintain the existing MAOP, FGT would be required to replace the 0.978 miles (5,162 feet) of pipe in the ***special permit segment*** or FGT would be required to reduce pressure on the segment. FGT stated that it would choose to replace the ***special permit segment*** to maintain the MAOP because a pressure reduction would prevent it from meeting its contractual obligations to deliver natural gas to its customers.

Alternative 2: "Selected" Alternative – Issuance of the special permit

PHMSA is granting the special permit with the below conditions, and FGT is allowed to continue to operate at the current maximum allowable operating pressure (MAOP) of 977 pounds per square inch gauge (psig) in the Class 3 location without replacing pipe while complying with the special permit conditions, as described below.

VIII. Overview of Special Permit Conditions

The special permit conditions are designed to prevent leaks and ruptures such that the Special Permit is not inconsistent with pipeline safety. This section provides an overview of the special permit conditions. For FGT specific technical requirements, see **Attachment C - Special Permit Conditions**.

1) **Current Status of Pipe in the Ground**

   To ensure that key characteristics of the pipe currently installed in each ***special permit segment*** is known, FGT must provide records that confirm pipe specifications, successful pressure tests, and girth weld non-destructive tests are required. Should records be unavailable or unacceptable, additional activities as detailed in the special permit must be completed. If FGT does not complete these additional activities are not completed or should pipe be discovered that does not meet specific requirements of eligibility, the ***special permit segment*** must be replaced.

2) **Operating Conditions**

The ***special permit inspection area*** must continue to be operated at or below the existing MAOP until a restoration or uprating plan has been approved, if allowed by the special permit. To ensure compliance with special permit conditions, the operator's Operations and Maintenance Manual (O&M), IMP, and Damage Prevention (DP) program must be modified to implement the special permit conditions. In addition, PHMSA must approve any long-term flow reversals that would impact the ***special permit segment***.

3) **Threat Management**

Threats are factors that can lead to the failure of a pipeline. Activities are required to identify, assess, remediate, and monitor threats to the pipeline.

a) **General activities.** The permit holder must perform annual data integration and identification of threats to which the ***special permit inspection area*** is susceptible. These activities must include integrity assessments with specific inline inspection tools, strict anomaly repair criteria, and appropriate environmental assessment and permitting. Additional integrity assessment methodologies may be used if allowed by the special permit. Integrity assessments must then be conducted periodically at an interval determined in the special permit for each threat identified.

b) **External corrosion control requirements**. The special permit requires additional activities to monitor and mitigate external corrosion. These activities include installation and annual monitoring of cathodic protection (CP) test stations, periodic close interval surveys (CIS), and clearing or remediating shorted casings that may impede CP effectiveness. These activities ensure the appropriate level of CP is reaching the pipeline in areas where coating loss or damage has occurred in order to prevent or mitigate external corrosion. In addition, FGT will be required to develop and implement a plan that identifies and remediates interference from alternating or direct current (AC/DC) sources (such as high-voltage powerlines) that could adversely impact the effectiveness of CP.

c) **Internal corrosion control requirements.** The special permit includes gas quality specifications to mitigate internal corrosion because internal corrosion is highly dependent on the quality of the gas transported within the pipeline and.

d) **Stress corrosion cracking (SCC) requirements.** To ensure that SCC is discovered and remediated, any time a pipe segment is exposed during an excavation the permit holder must examine coating to determine type and condition. If the coating is in poor condition, FGT must conduct additional SCC analysis. If SCC is confirmed, FGT must implement additional special permit defined remediation and mitigation.

e) **Pipe seam requirements.** FGT must perform an engineering integrity analysis to determine susceptibility to seam threats. The permit holder must re-pressure test any ***special permit segments*** with an identified seam to ensure the issue is not systemic in nature.

f) **External pipe stress requirements.** Upon identification of any source of external stress on the pipeline (such as soil movement), FGT must develop procedures to evaluate and periodically monitor these stresses.

g) **Third-party specific requirements.** To assist in identifying the pipeline location and minimizing the chance of accidental pipeline strikes, FGT must install and maintain line-of-site markers for the pipeline. FGT must perform mitigation activities for any location where a depth-of-cover survey shows insufficient soil cover.

4) **<u>Consequence Mitigation</u>**

To ensure quick response and decreased adverse outcome in the event of a failure, each side (upstream and downstream) of the ***special permit segment*** must have and maintain operable automatic shutdown valves (ASV) or remote-controlled valves (RCV). FGT must monitor valves through a control room with a supervisory control and data acquisition (SCADA) system. In addition to the mainline valves, should a crossover or lateral connect between the valve locations, additional isolation valves may be required.

5) **<u>Post Leak or Failure</u>**

If the ***special permit inspection area*** experiences an in-service or pressure test leak/failure, FGT must conduct a root cause analysis to determine the cause. If the cause is determined to be systemic in nature, the permit holder must implement a remediation plan or the ***special permit segment*** must be replaced, as determined by the special permit specific conditions.

6) **<u>Class Location Study and Potential Extension of Special permit segment</u>**

FGT must conduct a class location study at an interval specified in the special permit. This allows the permit holder to quickly identify extended locations that must comply with the ***special permit segment*** requirements. FGT may extend the ***special permit segment*** with proper notification, update of the Final Environmental Assessment, and implementation of all requirements in the special permit.

7) **<u>PHMSA Oversite and Management</u>**

PHMSA maintains oversight and management of each special permit. This includes annual meetings with executive level officers on special permit implementation status, written certification of the special permit, special permit required notification of planned activities, notification of root cause analysis results, and notification prior to certain excavation activities so that PHMSA may observe.

8) **<u>Gas Leakage Surveys and Remediation</u>**

The ***special permit segment*** and ***special permit inspection area*** have requirements in the special permit to conduct leakage surveys more frequently than is presently required in 49 CFR 192.706. Gas leakage surveys using instrumented gas leakage detection equipment must be conducted along each ***special permit segment*** and at all valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher, and ILI receiver facilities in each ***special permit inspection area*** at least twice each calendar year, not to exceed 7½ months. The type of leak detection equipment used, survey findings, and remediation of all instrumented gas leakage surveys must be documented by operator. The special permit will require a three-step grading process with a time interval for remediation based upon the type of leak.

9) **<u>Documentation</u>**

FGT must maintain documentation that supports compliance with special permit conditions for the life of the pipeline.

IX. Affected Resources and Environmental Consequences

A. Affected Resources and Environmental Consequences of the Granted Action and the No Action Alternatives

FGT is granted a special permit that waives compliance with 49 CFR 192.611(a) and (d) and 192.619(a) for a ***special permit segment*** totaling 5,162 feet (approximately 0.978 miles) located within the ***special permit inspection area*** totaling approximately 73.7 miles. FGT must comply with the special permit conditions within the ***special permit segment***.

Potential risks from the regulatory waiver to pipeline integrity will be analyzed for each ***special permit segment*** to evaluate the potential for impacts or increased risk to safety or environmental resources.

Aesthetics**:** The visual character of the ***special permit segment*** and the ***special permit inspection area*** will not be changed by the approval of this special permit request. The objective of the special permit is to avoid construction or ground disturbances in the pipeline ROW that would be necessitated if the special permit was not granted. Therefore, the issuance of the requested special permit will result sporadic and temporary aesthetic impacts due to increased monitoring, maintenance, and repair activities along the affected ***special permit segment*** or ***special permit inspection area***.

Denial of the special permit request would require the replacement or pressure testing of all the pipeline segments associated with this special permit request. Pipe replacement would require removal of the existing pipe and installation of a new pipe. This would result in the use of heavy equipment and ground disturbance. Furthermore, pressure testing would also require disturbances along the pipeline ROW.

Agricultural Resources**:** This special permit request will not impact agricultural resources in the pipeline ROW where the ***special permit segment*** or the ***special permit inspection area*** are located, as there are none in adjacent areas.

Air Quality**:** Air Quality Control Regions (AQCRs) are areas for which implementation plans describe how ambient air quality standards would be achieved and maintained. AQCRs are defined by the U.S. Environmental Protection Area (EPA) and state agencies in accordance with the Clean Air Act of 1970 (CAA). The 1977 CAA Amendments in Section 107 require EPA and states to identify by category those AQCRs meeting and not meeting the U.S. National Ambient Air Quality Standards (NAAQS) which are standards for harmful pollutants. Areas meeting the NAAQS are designated "attainment areas," and areas not meeting the NAAQS are designated "nonattainment areas". The designation of an area is made on a pollutant-by-pollutant basis. The ***special permit segment*** occurs in areas that are designated attainment areas for all pollutants.

This special permit will not significantly affect the air quality of the ***special permit segment*** or the ***special permit inspection area***, as increased monitoring, maintenance, and repair activities and associated vehicles and equipment will only have sporadic and temporary air impacts caused by fuel combustion. The objective of the special permit is to avoid construction or ground disturbances in the pipeline ROW that would be necessitated if the special permit was not granted.

If the special permit request is not granted, pipe replacement and hydrotesting would be required. This would necessitate blowing down the pipeline which releases unburned natural gas into the atmosphere, which is an aggressive greenhouse gas. Furthermore, pipe replacement and/or pressure testing would be required which would require the temporary use of heavy equipment, which result in release of air pollutants.

Biological Resources*:** The "Selected" Alternative will not impact vegetation (including wetlands), wildlife (including threatened and endangered species), or fishery resources in the pipeline ROW where the ***special permit segment or the ***special permit inspection area*** are located.

The low-growing herbaceous cover within the pipeline ROW may provide sources of food and nesting sites for various birds, as well as cover for mammals, invertebrates, reptiles, and amphibians. The area has been disturbed previously and is located between Interstate 95 (I-95) and a man-made drainage canal. Furthermore, the pipeline ROW is maintained in an herbaceous state by routine mowing and clearing activities using mechanical equipment. Therefore, the wildlife found in the vicinity of the ***special permit segment*** will most likely be tolerant of human disturbance. A discussion of water resources (wetlands and waterbodies) crossed by the ***special permit segments*** is provided in this document. A discussion of listed species and sensitive areas (i.e., conservation land) is provided below.

Listed Species

The U. S. Fish and Wildlife Service (USFWS) Information, Planning, and Conservation System (IPaC) was utilized to identify the federally and state listed threatened and endangered species that could potentially inhabit or traverse the ***special permit segment*** (USFWS, 2021). **Table 3** provides a list of the federally and state listed threatened and endangered species potentially occurring in the ***special permit segment***. A total of 13 listed species (5 birds, 6 reptiles, and 2 plants) were identified as potentially occurring in the ***special permit segment***.

The objective of the special permit is to avoid construction or ground disturbance in the pipeline ROW. Therefore, the "Selected" Alternative will not disturb wildlife habitat resulting in "*No effect*" to listed species. However, if the special permit request is not granted by selection of the "No Action" Alternative, then pipe replacement and/or pressure testing would be required, which would disturb vegetation and wildlife habitat in the vicinity of the existing pipeline ROW, which could potentially disturb listed species such as gopher tortoises and gopher tortoise commensal species (i.e., Eastern indigo snake) in the ***special permit segment***.

Any inspection activities related to the ***special permit segment*** will be conducted within the boundaries of the previously disturbed pipeline ROW. FGT has received a categorical exclusion blanket clearance from the USFWS for minor pipeline construction and maintenance projects within FGT's existing ROW. The Florida USFWS Ecological Services Field Office has determined in its categorical exclusion blanket clearances that work within FGT's existing ROW is unlikely to adversely impact federally listed species and their habitats.

TABLE 3
Federally and State Listed Threatened and Endangered Species Potentially Occurring within the Special Permit Segment Areas in Brevard County, Florida

Species	Federal Status	State Status	Habitat Description	Determination of Effect / Rationale
Birds				
Audubon's Crested Caracara (*Polyborus plancus audubonii*)	T	T	Occurs in dry or wet prairie areas with scattered cabbage palms (*Sabal palmetto*). It may also be found in lightly wooded areas.	**No effect** / No suitable habitat is present in the special permit project areas (maintained pipeline ROW).
Eastern Black Rail (*Laterallus jamaicensis* ssp. *Jamaicensis*)	T	T	Typically found in salt and brackish marshes with dense cover.	**No effect** / No suitable habitat is present in the special permit project areas (maintained pipeline ROW).
Everglade Snail Kite (*Rostrhamus sociabilis plumbeus*)	E	E	Habitat includes salt and brackish marshes with dense cover.	**No effect** / No suitable habitat is present in the special permit project areas (maintained pipeline ROW).
Red-Cockaded Woodpecker (*Picoides borealis*)	E	E	Mature 80-120-year-old longleaf or loblolly pine forest.	**No effect** / No mature 80 to120-year-old longleaf or loblolly pine

TABLE 3 Federally and State Listed Threatened and Endangered Species Potentially Occurring within the Special Permit Segment Areas in Brevard County, Florida				
Species	**Federal Status**	**State Status**	**Habitat Description**	**Determination of Effect / Rationale**
				forest present in the special permit project areas (maintained pipeline ROW).
Wood Stork (*Mycteria Americana)*	T	T	Inhabits emergent wetland, mixed hardwood swamps, sloughs, mangroves, and cypress domes. Nesting trees range from low shrubs to cypress.	**No effect** / No preferred suitable nesting habitat present in the special permit project areas (maintained pipeline ROW).
R**eptiles**				
Eastern Indigo Snake (*Drymarchon couperi)*	T	T	Species prefers xeric longleaf pine sandhills with gopher tortoise burrows and requires very large tracts of land. Commensal species with gopher tortoise burrows. FGT will adhere to USFWS Standard Protection Measures for the Eastern Indigo Snake if excavations are required in an area containing burrows.	**No effect** / Although suitable habitat is present within the pipeline ROW (i.e., gopher tortoise burrows), the special permit will allow FGT to avoid construction in the pipeline ROW avoiding impacts to this species.
Gopher tortoise (*Gopherus Polyphemus)*	C	T	Inhabits well-drained soils types with sparse tree canopy such as pine flatwoods, longleaf pine /xeric oak, and xeric oak scrub. Habitat includes disturbed soils within utility and road ROWs.	**No effect** / Although suitable habitat is present within the pipeline ROW, the special permit will allow FGT to avoid construction in the pipeline ROW avoiding impacts to this species.
Green Sea Turtle (*Chelonia mydas*)	T	T	Found in shallow waters (except when migrating) inside reefs, bays, and inlets with an abundance of seagrass. Beaches are required for nesting.	**No effect** / No coastal habitat is present in the special permit project areas
Hawksbill Sea Turtle (*Eretmochelys imbricate*)	E	E	Primarily found in tropical coral reefs. Nesting occurs on undisturbed deep-sand beaches in the tropics.	**No effect** / No coastal habitat is present in the special permit project areas
Leatherback Sea Turtle (*Dermochelys coriacea*)	E	E	Found primarily in the ocean. Requires sandy nesting beaches backed with vegetation for nesting.	**No effect** / No coastal habitat is present in the special permit project areas.
Loggerhead Sea Turtle (*Caretta caretta*)	T	T	Florida's sandy Atlantic and Gulf of Mexico beaches are preferred habitat for nesting.	**No effect** / No coastal habitat is present in the special permit project areas (maintained pipeline ROW).
Flowering Plants				
Carter's Mustard (*Warea carteri*)	E	E	Sandhill, scrubby flatwoods, inland and coastal scrub.	**No effect /** Preferred suitable habitat not present in special permit project areas (maintained pipeline ROW).

TABLE 3 Federally and State Listed Threatened and Endangered Species Potentially Occurring within the Special Permit Segment Areas in Brevard County, Florida				
Species	**Federal Status**	**State Status**	**Habitat Description**	**Determination of Effect / Rationale**
Lewton's Polygala (*Polygala lewtonii*)	E	E	Oak scrub, sandhill, and transition zones between high pine and turkey oak barrens.	**No effect /** Preferred suitable habitat not present in special permit project areas (maintained pipeline ROW).
Source: USFWS, 2021a. Notes: E - Endangered T - Threatened C - Candidate Species				

Conservative Land*:** The Florida Natural Areas Inventory (FNAI) maintains an inventory of the state's conservation land holdings (FNAI, 2021). The ***special permit segment does not cross conservation land holdings.

Climate Change*:** The scope and duration of any activities associated with the ***special permit segment, including maintenance and repair activities will have minimal impact on climate change. A benefit of the “Selected” Alternative is that it will avoid methane venting, construction, or ground disturbances in the pipeline ROW. The “No Action” Alternative would not grant a special permit, requiring the pipe replacement and/or hydrotesting would be required, which would necessitate the use of heavy equipment during construction and blowing down the pipeline releasing natural gas, a known greenhouse gas. Pipeline operators can and should mitigate blowdowns through pressure reductions and capture and storage of natural gas during pipeline work. However, PHMSA does not currently have authority to mandate these mitigation measures.

The “Selected” alternative will result in emissions that result from increased maintenance, monitoring, and repair requirements for the duration of the special permit. These emissions would be expected to be significantly less than the replacement associated with the “No Action” alternative.

Cultural Resources*:** Neither the “No Action” nor the “Selected” alternative will have an effect on cultural resources. Any inspection activities associated with the ***special permit segment and ***special permit inspection area*** will be conducted within the boundaries of FGT’s existing aboveground facilities (i.e., compressor stations) and maintained pipeline ROW. FGT was granted a categorical exclusion blanket clearance certificate from the Florida Division of

Historical Resources for activities to be undertaken within its existing, previously disturbed ROW to ensure compliance with the National Historic Preservation Act of 1966, as amended (NHPA). The Florida State Historic Preservation Office (SHPO) concurred with its categorical exclusion for work within existing ROW and stated that "no known historic properties will be affected by this undertaking."

Environmental Justice**:** The special permit alternative associated with this special permit will not have an adverse impact on the population along the pipeline including local, minority, low income, or limited English proficiency populations as shown below in **Table 4 - Demographic Information for Special Permit Segment – Using EPA EJScreen**.

The special permit is intended to maintain or increase safety with the implementation of safety conditions in the ***special permit segment***. Many special permit conditions also apply to the ***special permit inspection area*** and will not have a disparate impact on any minority, low income, or limited English proficiency populations. This special permit will also reduce climate change impacts, which are understood to disproportionately affect low-income and minority communities. Therefore, consistent with DOT Order 5610.2C ("Department of Transportation Actions to Address Environmental Justice in Minority Populations and Low-Income Populations") and Executive Orders 12898 ("Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations"), 13985 ("Advancing Racial Equity and Support for Underserved Communities Through the Federal Government"), 13990 ("Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis"), 14008 ("Tackling the Climate Crisis at Home and Abroad"), 12898 and DOT Order 5610.2(a), and Department of Transportation Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, PHMSA does not anticipate that the special permit will result in disproportionately high and adverse effects on minority or low-income populations.

Table 4 - Demographic Information for Special Permit Segments – Using EPA EJScreen						
Special Permit Segment No.	State	County	Total Population (Along Special Permit Segment)	Minority*/ People of Color** Population	Low Income Population	Linguistically Isolated
182069	FL	Brevard	2,313	21%	13%	0%
Minority*: The term minority is used in the currently active DOT Environmental Justice Order 5610.2(a), available at: https://www.fhwa.dot.gov/environment/environmental_justice/ej_at_dot/orders/order_56102a/index.cfm People of Color**: The term people of color is used in the EPA's Environmental Justice Screening and mapping tool (EJSCREEN). An overview of demographic indicators through EJSCREEN is available at: https://www.epa.gov/ejscreen/overview-demographic-indicators-ejscreen						

Geology and Soils*:** The general characteristics of the ***special permit segment consists of relatively flat terrain. The project area is located in the Atlantic Plain physiographic region of the U.S. Major Land Resource Areas (MLRAs) are geographically associated land resource units, usually encompassing several thousand acres, characterized by a particular pattern of soils, geology, climate, water resources, and land uses. The ***special permit segment*** crosses the Southern Florida Flatwoods MLRA and the ***special permit inspection area*** crosses the Southern Florida Flatwoods and Southern Florida Lowlands MLRAs (USDA NRCS, 2021a). The soils within the Southern Florida Flatwoods and Southern Florida Lowlands MLRAs are deep or very deep, poorly drained or very poorly drained, and loamy or sandy (USDA NRCS, 2021b).

The objective of the special permit is to avoid construction or ground disturbances in the pipeline ROW that will be necessitated if the special permit was not granted. Therefore, the "Selected" Alternative will not result in soils impacts to the affected ***special permit segment*** or ***special permit inspection area***. Furthermore, no changes to geologic conditions would occur.

Denial of the special permit request will require the replacement and/or pressure testing of the pipeline segments associated with this special permit request. Pipe replacement would require vegetation clearing, removal of the existing pipe, and installation of a new pipe. The removal of the vegetative cover and ground disturbance exposes soils to the effects of wind and water which increases the potential for soil erosion and the transport of sediment to sensitive resource areas. Furthermore, pressure testing would also expose the soil to water which increases the potential for soil erosion and transport of sediment to sensitive areas along the pipeline ROW.

Mineral Resources*:** Florida's mineral commodities include limestone, sand, gravel, clay, heavy minerals, phosphate, and peat. The ***special permit segment is located along FGT's existing pipeline system and do not cross any areas mined for mineral resources.

Seismic Hazards: Seismic hazards include earthquakes, surface faulting, and soil liquefaction. The U.S. Geological Survey's (USGS's) National Earthquake Hazard Program has developed a series of maps that depict the estimated probability for seismic hazards. The Program's National Seismic Hazard Maps are derived from seismic hazard curves calculated on a grid of sites across the U.S. that describe the annual frequency of exceeding a set of ground motions. Based on the latest long-term model, 2018, the ***special permit inspection area*** is characterized as falling into the category of the lowest hazard potential (USGS, 2018a). The USGS has also produced a 2018 one-year (short-term) probabilistic seismic hazard forecast for the central and eastern U.S. from induced and natural earthquakes. Again, the ***special permit inspection area*** falls within the category of lowest potential with a less than 1-percent chance of potentially minor-damage ground shaking in 2018 (USGS, 2018b). The low seismic risk in the ***special segment inspection area*** is also a limiting factor for liquefaction to occur. As a result, the likelihood of soil liquefaction to occur in the ***special permit inspection area*** is low.

Subsidence: Ground subsidence is the local downward movement of surface material with little or no horizontal movement. Karst is a landscape formed by the dissolution of soluble bedrock that is conducive to land subsidence that exists in many areas in Florida. The Florida Department of Environmental Protection (FDEP) Map Direct database includes a public mapping spatial data library with locational information on known subsidence incidents. Review of FDEP's subsidence database indicates no karst features are located within 500 feet of the ***special permit segment*** (FDEP, 2021).

Indian Trust Assets*:** Any work associated with the ***special permit segment will have no impact on Native Americans or any land owned or otherwise administered by Native American tribes. The "Selected" Alternative will have little to no effect or impact on the socioeconomics in the vicinity of the project area. No tribal land exists along the ***special permit segment*** thus tribal coordination is not required.

Land Use*: **Land use within the ***special permit segment consists of maintained pipeline ROW. Land use adjacent to the ROW in the vicinity of the ***special permit segment*** includes transportation ROW, open space, wetland and waterbodies, and residential/industrial land.

The "Selected" Alternative will avoid or minimize construction or ground disturbances in the pipeline ROW that would be necessitated if the special permit was not granted. Therefore, this special permit will not impact land use or planning. Further, FGT will avoid disturbing the adjacent property owners to the pipeline ROW.

Any inspection activities associated with the ***special permit segment*** and ***special permit inspection area*** will be conducted within the boundaries of FGT's existing aboveground facilities (i.e., compressor station and regulator stations) and maintained pipeline ROW. Therefore, the "Selected" Alternative will not require permitting above and beyond what is required for normal pipeline operation and maintenance activities. However, if the special permit request was not granted then pipe replacement and pressure testing would be required, which would disturb land uses adjacent to the ***special permit segment***.

Noise*: **The presence of equipment and personnel along the ***special permit segment and ***special permit inspection area*** could increase noise levels somewhat for short durations due to monitoring, maintenance, and repair activities required for the "Selected" Alternative. However, if the special permit request is not granted ("No Action" Alternative) then pipe replacement and/or pressure testing would be required, which would result in more significant and longer duration though temporary increases in noise during construction of these activities.

Recreation*: **The ***special permit segment is not located in a designated state, county or local park, recreation area, state forest campground, or wildlife management area. The scope and duration of any activities associated with the ***special permit segment*** and ***special permit inspection area*** will have little to no impact on recreation in the vicinity of the pipeline. Denial of the special permit would have resulted in greater impacts to any recreational activities within the ***special permit segment.***

***Safety*: **Class locations are based upon the population (dwellings for human occupancy) within a "class location unit" which is defined as an onshore area that extends 220 yards on either side of the centerline of any continuous one-mile of pipeline. These locations are determined by surveying the pipeline for population growth. The more conservative safety factors are required as the number of dwellings for human occupancy (population growth) increase near the pipeline. Pipeline operators must conduct surveys and document population growth within 220 yards on either side of the pipeline. A higher population along the pipeline may trigger any of the following for the pipeline segment with the higher population: a reduced MAOP, a new pressure test at a higher pressure, or new pipe with either or both heavier walled or higher-grade pipe.

The special permit enhanced integrity management conditions are designed to identify and mitigate integrity threats that could threaten the ***special permit segment*** and cause failure. The effect of the monitoring and maintenance requirements in the special permit conditions will ensure the integrity of the pipe and protection of the population living near the pipeline segment to a similar degree of a lower MAOP, new pressure test, or a thicker walled or higher-grade pipe that would not have the enhanced integrity management protections.

Under the "Selected" Alternative of granting a special permit, PHMSA will require increase integrity management inspections for ***special permit inspection area*** adjacent to the ***special permit segment***, which will lower the risk in areas beyond the ***special permit segment***. FGT must implement the conditions in ***special permit inspection area*** for the duration of the special permit.

PHMSA analyzed the integrity conditions and history of the FGT natural gas transmission pipeline system, and PHMSA determined that the pipeline is in satisfactory condition for the issuance of the special permit. Details about the pipeline's integrity and compliance history are provided in the Special Permit Analysis and Findings document, which is available in the docket.

Performance of the conditions in the special permit provides an equivalent level of safety for the public and environment; and imposes no additional safety risks as a result of the waived regulation. As already noted, the pipeline ***special permit segment*** included under the special permit will be treated as HCAs with the additional risk analysis and remedial activities associated with this designation. The special permit also includes a number of conditions that address potential safety risks. Among these are incorporation of these segments into the FGT Integrity Management Program, close interval corrosion surveys, implementation of a cathodic protection reliability improvement plan, an in-line inspection program with intervals not to exceed seven years, anomaly evaluation and repair meeting more stringent criteria, additional testing and remediation of interference currents caused by induced alternating current sources, pipe seam evaluations, criteria for the identification of pipe properties, installation of line-of-sight markers, and the integration of all inspection and remediation data.

a. Will operation under a special permit change the risk of rupture or failure?

Operation under the special permit will not be expected to have an impact on the risk of failure or rupture as the operating conditions of the ***special permit segment*** have not changed. The special permit will require inspections at intervals similar to IM program intervals, which will maintain the integrity of the ***special permit segment*** over the life of the special permit.

b. If a failure occurred, will consequences and spill or release volumes be different if PHMSA granted the permit***?***

The consequences of any spill or release will not be impacted as a result of the special permit and the potential for such an event is expected to be less likely with the added safety programs noted above.

If PHMSA denied the special permit request and FGT opted to lower the pressure, the PIR would be smaller in the event of a pipeline failure. However, FGT's contractual obligations would not allow for a lowering of pressure and therefore, FGT would need to replace the existing pipeline.

c. Will the Potential Impact Radius (PIR) of a rupture change under the special permit? Please calculate and provide the PIR data, if applicable. Would more people be affected by a failure if PHMSA granted the permit?

As compared to current operation, the PIR as calculated in accordance with 49 CFR § 192.903 will not change under the special permit since maximum operating pressure and pipe diameter will not change, thus there will be no additional impact on the public.

d. Will operation under the special permit have an effect on pipeline longevity or reliability? Will there be any life cycle or maintenance issues?

Operation under the special permit conditions will provide a positive impact on pipeline longevity and reliability. PHMSA does not anticipate any deleterious life cycle or maintenance issues related to operation of the pipeline special permit segment by implementation the special permit by FGT.

Socioeconomics: This special permit request will not be situated in, or disproportionately impact, any predominantly low-income populations. The population characteristics for the county crossed by the ***special permit segment*** is shown in **Table 6-3**. Based on U.S. Census 2019 data, the total population is 601,942 with a median household income for Brevard County is $56,775. The percent of population in poverty in Brevard County is 9.4 percent (U.S. Census, 2021).

Implementing enhanced inspection and assessment practices throughout the ***special permit inspection area***, in lieu of replacing the small sections of pipe experiencing the class location changes, extends pipeline safety benefits to a much greater area, and thus will not have an adverse impact on the local population. In addition, avoiding pipe excavation, replacement, and pressure testing will minimize costs to the operator, will avoid delivery interruptions and supply shortages, and avert environmental disturbance. Thus, the increased safety measures associated with the special permit will benefit local populations.

TABLE 5 - Population Characteristics of the County Crossed by the Special Permit Segments

County	Total Population [a]	Population Percentage [a]	Percent Non-English Language Population [b]	Median Household Income (Dollars)	Percent of Population in Poverty [b,c]
Brevard	601,942	White: 83.2 Black or African American: 10.8 American Indian and Alaska Native: 0.5 Asian: 2.6 Native Hawaiian/Pacific Islander: 0.1 Other Race: 2.8	10.6	56,775	9.4

Source: U.S. Census Bureau, 2021.
Notes:
[a] 2019 Estimate
[b] 2015 - 2019 Estimates, U.S Census Bureau
[c] Based on all people (i.e., all age groups)

Topography: The topography of the area surrounding the requested ***special permit segment*** is flat terrain mainly consisting of developed land, transportation ROW, and wetlands. The average elevation in the area is approximately 30 feet above sea level (Topographic-Maps.com, 2021).

The topography of the ***special permit segment*** and the ***special permit inspection area*** will not be changed by implementing the "Selected" Alternative. The objective of the special permit is to avoid construction or ground disturbances in the pipeline ROW that would be necessitated if the special permit was not granted.

Denial of the special permit request would have required the replacement and pressure testing of all the pipeline segments associated with this special permit request. Pipe replacement would require removal of the existing pipe and installation of a new pipe. Effects from construction could include disturbance of the natural topography along the pipeline ROW due to trenching and grading activities. Furthermore, pressure testing would also require disturbances along the pipeline ROW. However, following construction, all areas would be restored as close as practicable to their preconstruction contours.

Transportation*:** In the event that the ***special permit segment needs to be accessed in order to perform required tasked under the special permit of the "Selected" Alternative, existing ROW access points will be used. The "Selected" Alternative will not increase traffic or require additional roads to be constructed or more frequently maintained. The objective of the special permit is to avoid construction or ground disturbances in the pipeline ROW that would be necessitated if the special permit was not granted. Temporary increases in traffic could occur in the area if PHMSA denied the special permit application and FGT was required to replace the pipeline segments that underwent class location change.

Water Resources*:** According to USFWS National Wetland Inventory (NWI) mapping data, the ***special permit segment does not cross wetlands (USFWS, 2021b). The ***special permit segment*** does not cross any waterbodies. A man-made drainage canal parallels the west side of the ***special permit segment***.

Drinking Water Aquifers

The ***special permit inspection area*** is underlain by the surficial aquifer system and the Floridan aquifer system. The surficial aquifer system is an unconfined groundwater system with freshwater storage concentrated in the vicinity of the Atlantic Coastal Ridge parallel to the coastline. In Brevard County, two units comprise the sediments of the surficial aquifer system: a lower marl which is 50 to 150 feet thick and an upper sand which is 0 to 50 feet thick (Williams, 1995). Groundwater in the surficial aquifer generally flows from areas of higher elevation towards the coast or streams where it can discharge as baseflow. In Brevard County, municipal drinking water is obtained from the surficial aquifer system.

Underlying the surficial aquifer system is an upper confining unit and the Floridan aquifer system. The Floridan aquifer system one of the most productive aquifers in the world and overlies the entire State of Florida. The Floridan aquifer system is composed of the Upper and Lower Floridan aquifers and the middle semi-confining unit (Williams, 1995). A thick sequence of carbonate rocks (limestone and dolomite) of Tertiary age comprises the system which generally thickens seaward from a thin edge near its northern limit.

The EPA defines a sole source aquifer as one where the aquifer supplies at least 50 percent of the drinking water for its service area; and there are no reasonably available alternative drinking water sources should the aquifer become contaminated. There are no EPA sole source aquifers located within the vicinity of the ***special permit segment*** (U.S. EPA, 2021).

Aquifers will not be disturbed by implementing the "Selected" Alternative by the grant of the special permit. However, if the special permit request is not granted then pipe replacement and/or pressure testing would be required, which could temporarily disturb the surficial aquifer system during construction.

B. Comparative Environmental Impacts of Alternatives

As PHMSA recognized in its June 29, 2004, Federal Register Notice (69 FR 38948), implementing additional preventative and mitigative measures enables a pipeline operator to improve its knowledge and understanding of the pipeline's integrity, accelerate the identification and repair of actionable anomalies, and better manage and mitigate threats to the public and environment. Implementing enhanced inspection and assessment practices throughout the ***special permit segment*** and ***special permit inspection area***, in lieu of replacing small segments of pipe experiencing the class location change, extends pipeline safety benefits to a much greater area along the pipeline. In addition, avoiding pipe excavation and replacement will minimize costs to FGT, will avoid delivery interruptions and supply shortages, and avert environmental disturbance.

While the granting of the special permit avoids the full replacement of affected pipe, the special permit conditions require monitoring and maintenance that could lead to minor excavations and repair or replacement of some pipe. The effect of the monitoring and maintenance requirements in the special permit conditions will ensure the integrity of the pipe and protection of the population living near the ***special permit segment*** to a similar degree of a lower MAOP, new pressure test, or a thicker walled or higher-grade pipe without the enhanced IM protections.

Performance of the special permit conditions provides an equivalent level of safety for the public and environment; and imposes no additional safety risks as a result of the waived regulation. As already noted, all the ***special permit segment*** included in the special permit will be treated as HCAs with the additional risk analysis and remedial activities associated with this designation. The special permit also includes a number of conditions that address potential safety risks.

In the event that PHMSA denied the special permit, it would have no authority to decide whether FGT achieved full compliance with 49 CFR Part 192 through pressure reduction or pipeline segment replacement. Nonetheless, FGT reports that its contractual obligations would not allow the operating pressure of the pipe to be lowered. Thus, the PIR of a pipeline failure will be the same whether the pipe operates under a special permit, is replaced, or pressure tested. Likewise, human safety as a result of pipeline failure would not be affected differently under either the action or no-action alternatives. Furthermore, the special permit enhanced IM conditions are designed to identify and mitigate integrity issues that could threaten the ***special permit segment*** and cause failure.

FGT will evaluate the potential environmental consequences and affected resources of land disturbances and adjacent waterbody impacts caused by construction activities (including adding, modifying, replacing, or removing any facility) associated with any FGT activity. These activities are regulated by the Federal Energy Regulatory Commission (FERC) under Section 7 of the Natural Gas Act (NGA) and are subject to Federal, State, and local environmental authorizations and require a review by FGT Environmental Services staff prior to the start of work, incorporation of environmental requirements into the project implementation, and ensuring outstanding (environmental) requirements are incorporated into facility operation.

The ”Selected” Alternative approval of the special permit will have a positive impact to landowners and negligible, if any, environmental impact for the ***special pipeline segment*** that does not require pressure testing or replacement. FGT will avoid disturbing the ROW of property owners except for the additional inspections that may be required to satisfy the conditions of the special permit such as those related to the IMP for HCAs, and potential anomaly evaluations/repairs. If the special permit was not granted, 49 CFR 192.611(a) and (d) and 192.619(a) would require pipe replacement and pressure testing. This would result in temporary disturbances to the natural environment in the ***special permit segment***. The consequences of any spill or release will not be changed as a result of the special permit and the potential for such an event is expected to be less likely with the added safety programs noted above.

X. Consultation and Coordination

The following FGT employees were consulted in the preparation of this document:

- Eric Amundsen, Senior VP Operations
- Chris Lason, VP of Asset Integrity
- Dave Shellhouse, VP of Operation
- Mike Teal, Director of Technical Operations
- Robert Fleming, Senior Manager, Engineering and Construction
- Bob Bouchard, Staff Engineer, Pipeline Integrity
- Eric Hildebrand, Senior Engineer, Pipeline Integrity
- Eric Williams, Senior Engineer, Engineering and Construction
- Kristin Benbow, Environmental Scientist

The following PHMSA employees were involved in the preparation of this document:

- Amelia Samaras, PHMSA, US DOT
- Joshua Johnson, PHMSA, US DOT
- Steve Nanney, PHMSA, US DOT

XI. Response to Public Comments Placed on Docket PHMSA-2021-0118

PHMSA published the special permit request in the Federal Register (87 FR 6648) for a 30-day public comment period from February 4, 2022, through March 7, 2022. The special permit application from FGT, draft environmental assessment, and draft special permit conditions were available in Docket No. PHMSA-2021-0118 at: www.regulations.gov for public review.

PHMSA received no public comments concerning this special permit renewal request through March 7, 2022.

XII. Finding of No Significant Impact

In consideration of the special permit conditions explained above, pipeline condition, and safety history, PHMSA finds that no significant negative impact will result from the issuance and full implementation of the above-described special permit to waive the requirements of 49 CFR 192.611(a) and (d) and 192.619(a) for one (1) ***special permit segment***, which consists of approximately 0.978 miles of 26-inch diameter pipelines located in Brevard County, Florida. This permit will require FGT to implement additional conditions on the operations, maintenance, and integrity management of the ***special permit segment*** and ***special permit inspection area***.

XIII. Bibliography

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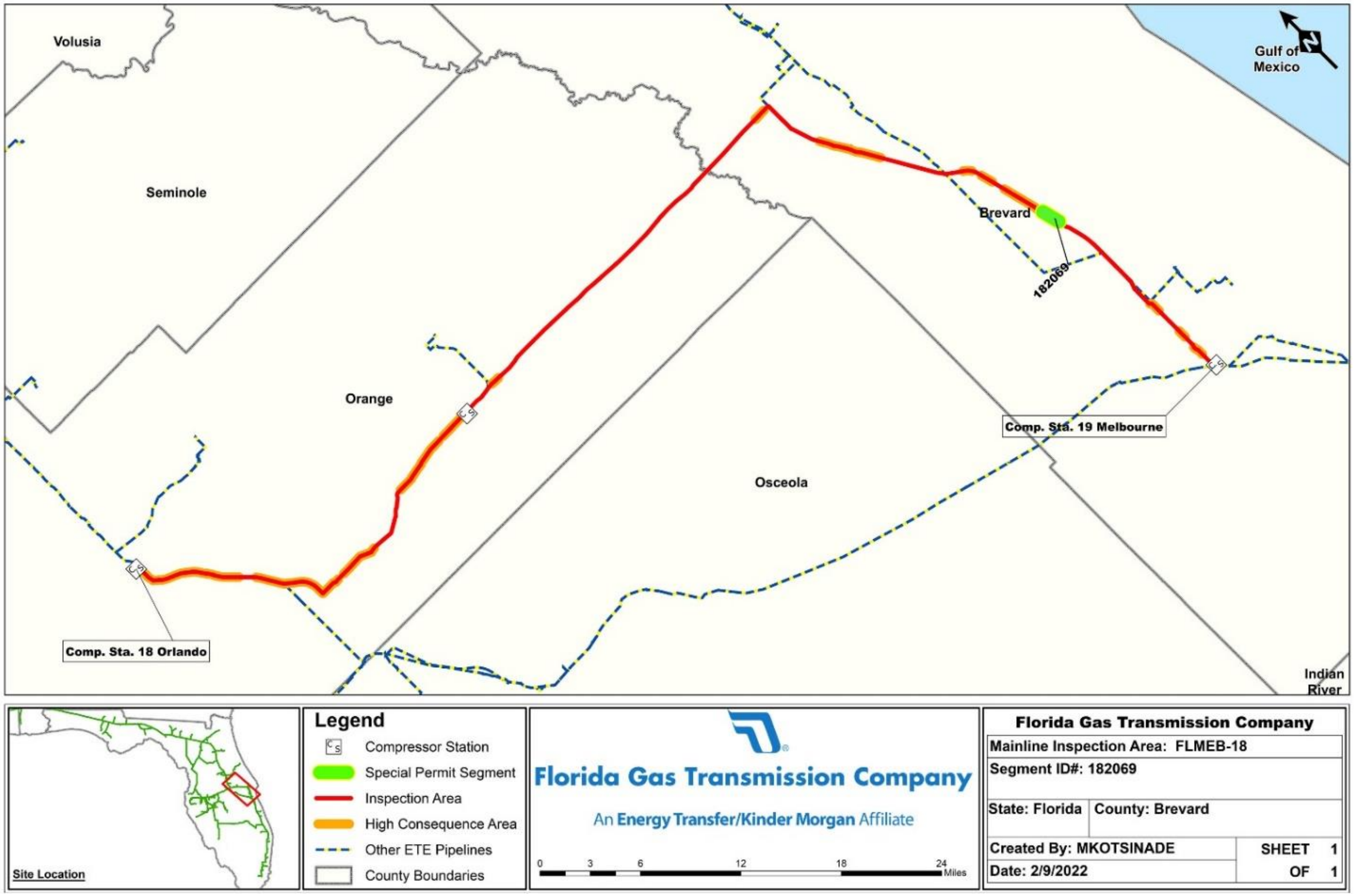
USGS. 2018. Short-term Induced Seismicity Models, 2018 One-Year Model. Available online at: https://earthquake.usgs.gov/hazards/induced/index.php#2018. Accessed October 2019.

Completed by PHMSA in Washington, DC on: **April 4, 2022**

Attachment B-1 - FGT Route Map - Special Permit Segment and Special Permit Inspection Area



Attachment C – Special Permit Conditions

1) **<u>Condition 1 - Maximum Allowable Operating Pressure</u>**

   a) **<u>Maximum Allowable Operating Pressure</u>**: FGT must continue to operate each ***special permit segment*** and ***special permit inspection area*** at or below the existing MAOP of 977 pounds per square inch gauge (psig) (Mainline Loop).

   b) **<u>Pressure Test</u>**: FGT must identify previous pressure tests for each ***special permit segment***. Pressure test records for each ***special permit segment*** must meet 49 CFR 192.517(a) and be traceable, verifiable, and complete (TVC)[3] as required in 49 CFR 192.624(a)(1).

      i) FGT must furnish TVC pressure test records to the Director, PHMSA Engineering and Research Division, and to the Director, PHMSA Southwest Region, within 60 days of the grant of the special permit. The pressure test records must be compliant with **Condition 1(b)**.[4] FGT must receive a "no objection" letter from the Director, PHMSA Southwest Region, that the TVC pressure test records are compliant with 49 CFR 192.517(a), 192.624(a)(1), and 192.619(a)(1) through (a)(4) for a Class 1 location, or FGT must pressure test the ***special permit segment*** in accordance with **Condition 1(b)(ii)**.[5]

      ii) If FGT does not have a TVC record of a 1.25 times the MAOP hydrotest in accordance with Subpart J, or the ***special permit segment*** requires an updated

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3 TVC procedures and records must follow the following: 1) "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments"; 84 FR 52218 to 52219; October 1, 2019; and 2) PHMSA Advisory Bulletin: Pipeline Safety: Verification of Records; 77 FR 26822; May 7, 2012; <u>https://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf</u>.

4 The pressure test records must cover the entire length of the ***special permit segment***, regardless of when the pipeline, single or multiple pipe joints, or other pipeline components were installed. Affidavits for a pressure test are not acceptable TVC pressure test records.

5 FGT has furnished TVC pressure test records to PHMSA for the ***special permit segment*** that meets **Condition 1(b)**.

pressure test, the ***special permit segment*** must be hydrostatically tested[6] to a minimum of 1.39 times the MAOP for eight (8) continuous hours in accordance with 49 CFR Part 192, Subpart J, within 18 months of the grant of this special permit.[7]

c) **MAOP Restoration or Uprating of Previously De-rated Pipe**: MAOP restoration or uprating is not approved for this special permit.

2) **Condition 2 - Procedure Updates**

Within 90 days of the grant of the special permit, FGT must develop and maintain procedures in accordance with 49 CFR 192.603 and 192.605 that incorporate the special permit condition requirements as follows:

a) **Operations and Maintenance Manual**: FGT must amend the applicable sections of its Operations and Maintenance (O&M) manual(s) and procedures to incorporate the special permit conditions.

b) **Integrity Management Program**:

i) FGT must incorporate each ***special permit segment*** into its written integrity management (IM) program procedures as if the ***special permit segment*** is a "covered segment" as defined in 49 CFR 192.903, except for the reporting requirements contained in 49 CFR 192.945.[8] A ***special permit inspection area*** outside of a ***special permit segment*** is not required to be included as "covered segments" in accordance with 49 CFR 192.903.

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[6] For all in-service and pressure test failures, FGT must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. FGT must provide the written results of this root cause analysis to the Director, PHMSA Southwest Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

[7] The grant of this special permit, as used throughout, is the signed issuance date of the special permit.

[8] FGT must follow the reporting requirements in **Condition 15 – Annual Report** as well as those noted throughout the conditions contained herein.

ii) The ***special permit inspection area*** and ***special permit segment*** must have integrity threats identified, assessed, and remediated in accordance with these special permit conditions, 49 CFR 192.917, and 49 CFR Part 192, Subpart O.

iii) Any high consequence area (HCA) in either a ***special permit segment*** or a ***special permit inspection area*** must be assessed and remediated for threats in accordance with these special permit conditions and 49 CFR Part 192, Subpart O.

iv) All permit conditions that are applicable to a ***special permit segment*** or to a ***special permit inspection area*** are applicable to HCAs where the HCA overlaps a ***special permit segment*** or a ***special permit inspection area***.

v) All special permit conditions that are applicable to a ***special permit inspection area*** are also applicable to the ***special permit segment***. A ***special permit segment*** must meet the requirements of 49 CFR 192, Subpart O, if Subpart O is more stringent than the special permit conditions.

vi) The ***special permit inspection area*** must be able to be assessed using inline inspection (ILI) tools, including tethered or remotely controlled tools, in accordance with 49 CFR 192.150 and 192.493.

c) **Damage Prevention Program**: FGT must incorporate within a ***special permit inspection area*** the applicable best practices of the Common Ground Alliance (CGA)[9] in its damage prevention (DP) program.

3) **Condition 3 – Corrosion Control**

FGT must promptly address any corrosion control deficiencies in a ***special permit segment*** that are indicated by the inspection and testing programs required under 49 CFR 192.463 and 192.465.

a) **Cathodic Protection Test Station Spacing**: At least one (1) cathodic protection (CP) pipe-to-soil test station must be located within each ***special permit segment***, with a spacing not to exceed ½ mile between CP pipe-to-soil test stations. In cases where

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[9] Common Ground Alliance. (March 2020). Best Practices Guide. Retrieved from: https://commongroundalliance.com/BPguide.

obstructions or restricted areas prevent such test station placement, the test station must be placed in the closest practical location, not to exceed a 3,000-foot spacing. CP pipe-to-soil test stations must be installed within 12 months of the grant of this special permit.

b) **Annual Monitoring of Test Station Potential Measurements**: At least once every calendar year, not to exceed 15 months, FGT must monitor CP pipe-to-soil test stations to meet 49 CFR 192.463 and 192.465 for the ***special permit segment*** and must include "on and off" potential measurements. Test station readings (pipe-to-soil potential measurements) must comply with Appendix D – Section I.A. (1) of 49 CFR Part 192 or remediation detailed in paragraph (c) of this condition is required. For hard spots identified with a Brinell Hardness (HB) of 300 HB or greater, CP voltage levels must be maintained more electro-positive than minus 1.2 volts direct current (DC).

c) **Inadequate Cathodic Protection Level Determination**:

   i) In instances where inadequate potentials are a result of an electrical short to an adjacent foreign structure, a rectifier malfunction, an interruption of power source, or an interruption of CP current due to other non-systemic or location-specific causes, FGT must document and repair these instances. A close interval survey (CIS) will not be required.

   ii) All other instances must be assessed as detailed in **Condition 4 – Close Interval Surveys**.

d) **Remedial Action Plans**:

   i) Within six (6) months of identifying a deficiency, FGT must develop a remedial action plan to restore CP to meet 49 CFR 192.463. Within two (2) months of the finding, FGT must apply for any necessary environmental permits (federal or state).

   ii) FGT must complete the remediation and confirm restoration of adequate CP over the entire area where inadequate CP levels were detected within 12 months of the deficiency finding or as soon as practicable after obtaining the necessary permits.

4) **<u>Condition 4 – Close Interval Surveys</u>**

a) **<u>Survey Methodology and Boundaries</u>**:

i) FGT must perform an "on and off" current CIS at a maximum 5-foot spacing along the entire length of each ***special permit segment***.[10]

ii) FGT must evaluate each ***special permit segment*** in accordance with 49 CFR 192.463.

iii) For inadequate CP level determination described in **Condition 3(c)(ii)**, FGT must conduct a CIS in both directions from the test station with an inadequate CP reading with the CIS ending at the adjacent test stations.

b) **<u>Survey Intervals</u>**: FGT must perform the CIS within the following timeframes:

i) Initial assessment must be completed for each newly incorporated and extended ***special permit segment*** within 12 months after the grant of the special permit. For a ***special permit segment*** renewal, the CIS may be conducted at the next reassessment interval.[11]

ii) Reassessments must be conducted every five (5) years not to exceed 66 months. CISs within the reassessment interval are not required to be performed in the same year as ILI reassessments.

c) **<u>Survey Remediation and Remedial Action Plans</u>**:

i) If a ***special permit segment*** requires the use of 100 millivolt shift criteria[12] or the installation of linear anodes along the ***special permit segment*** to meet the CP requirements of 49 CFR 192.463, it is not eligible to operate with a Class 1 pipe in a

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[10] Each condition in this special permit that requires FGT to perform an action with respect to the ***special permit inspection area*** also requires FGT to perform that action on each ***special permit segment*** within the area.

[11] A CIS survey conducted in 2020 for a ***special permit segment*** that is permit condition compliant would not need to be resurveyed in 2021 but could wait until the next CIS survey reassessment time.

[12] A.W. Peabody, "Peabody's Control of Pipeline Corrosion," second edition, "Criteria for Cathodic Protection." "The 100mV polarization criterion should not be used in areas subject to stray current because 100 mV of polarization may not be sufficient to mitigate corrosion in these areas. This criterion also should not be used in areas where the intergranular form of external SCC, also referred to as high-pH or classical SCC, is suspected. The potential range for cracking lies between the native potential and -850 mV (CSE) such that application of the 100mV polarization criterion may place the potential of the structure in the range for cracking."

Class 3 location. FGT must either: (1) replace the pipe in the ***special permit segment*** with Class 3 location standard (design factor) pipe (see 49 CFR 192.111(a)); (2) recoat the pipe with non-shielding external coating within 12 months of the finding; or (3) lower the MAOP to meet 49 CFR 192.611.

ii) Within four (4) months of identifying a deficiency, FGT must develop a remedial action plan to restore CP to meet 49 CFR 192.463. Within two (2) months of the remedial action plan being developed, FGT must apply for any necessary environmental permits (federal or state).

iii) FGT must complete remediation of each ***special permit segment*** and confirm restoration of adequate CP over the entire area where inadequate CP levels were detected within 12 months of the survey or as soon as practicable after obtaining the necessary permits.[13]

5) **<u>Condition 5 – Inline Inspection</u>**

a) **<u>Threat Identification</u>**: FGT must implement data integration and identify integrity threats in the ***special permit inspection area*** at least once each calendar year, with intervals not to exceed 15 months, in accordance with 49 CFR 192.917 and **Condition 13(c) – Data Integration**. The stress corrosion cracking (SCC) threat assessment for the ***extended special permit segment***,[14] must be conducted using the current incorporated by reference (IBR) edition of the American Society of Mechanical Engineers (ASME) Standard B31.8S, "Managing System Integrity of Gas Pipelines" (ASME B31.8S) Appendix A3 and National Association of Corrosion Engineers (NACE) Standard Practice (SP) 0204-2008, "Stress Corrosion Cracking Direct Assessment Methodology," Sections 1.2.1.1 and 1.2.2.

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[13] If remediation based upon the findings of the CIS is not practicable within 12 months of the CIS survey, FGT must submit a schedule and justify the delay 60 days prior to the 12-month completion requirement to the Director, PHMSA Southwest Region. FGT must receive a “no objection” letter from the Director, PHMSA Southwest Region, prior to a pipe coating remediation schedule extension.

[14] The ***extended special permit segment*** is defined as the ***special permit segment*** and the five (5) contiguous miles past each endpoint.

b) **<u>Inline Inspection Methodology</u>**: FGT must conduct instrumented ILI integrity assessments in accordance with 49 CFR 192.493, for each ***special permit inspection area*** for all threats identified in accordance with 49 CFR 192.919 and 192.921.

i) At a minimum, FGT must conduct ILI assessments for corrosion and denting with high-resolution (HR) magnetic flux leakage (HR-MFL) and HR deformation tools with deformation-extended sensor arms not limited by pig cups.

ii) For near-neutral or high-pH SCC (cracking threat), FGT must use an ILI tool[15] that will identify tight cracks.[16]

iii) A ***special permit segment*** with electric flash-welded (EFW) pipe must have an ILI tool assessment run for hard spots and cracking from hard spots.

iv) In a ***special permit inspection area*** that has experienced pipe or girth weld leaks or ruptures due to soil movement or the threat has been identified, FGT must run inertial measurement unit (IMU) and HR-deformation ILI tools for detection and remediation of strains and denting of the pipe body and girth welds from soil or pipe movements that impair pipeline integrity. Remediation must be conducted as determined by **Condition 13(j) – Pipe and Soil Movement**.

c) **<u>Inline Inspection Assessment Intervals</u>**: FGT must conduct initial assessments and reassessments for the ***special permit inspection area*** in accordance with the following:

i) Initial ILI assessments must be conducted as follows:

(1) If the ***special permit segment*** has EFW pipe, it must be assessed for hard spots within 18 months of the special permit grant date.

(2) If cracking has been identified as a threat for the ***extended special permit segment***, it must be assessed within 18 months of the special permit grant date.

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15 The crack ILI tool must be comparable to an electro-magnetic acoustic transducer (EMAT) ILI tool.

16 FGT may propose an alternative assessment method for SCC (such as spike hydrostatic testing in accordance with 49 CFR 192.506) to the Director, PHMSA Southwest Region, with a copy of the proposal to the Director, PHMSA Engineering and Research Division. FGT must receive a “no objection” letter from the Director, PHMSA Southwest Region, prior to implementing any alternative assessment methods for SCC.

(3) All other identified threats must be assessed within two (2) years of the special permit grant date.

(4) For newly identified threats, assessments must be completed within two (2) years of identification.

(5) Previous ILI assessments may be applied if **Condition 8 – Anomaly Evaluation and Remediation** is completed and the **Condition 5(c)(ii)** reassessment interval is maintained.

ii) Reassessments must be completed in accordance with the shortest interval of the following:

(1) 49 CFR 192.939(a);

(2) Intervals of five (5) calendar years not to exceed 66 months, if the ***special permit segment*** contains any of the following:

(a) low-frequency electric resistance welded (LF-ERW) or EFW pipe,

(b) hard spots,

(c) shorted carrier pipe to the casing,

(d) susceptible to SCC, or

(e) pipe or soil movement; or

(3) The engineering critical assessment (ECA) determined interval, if applicable.

iii) After conducting two (2) assessments of a threat, one (1) of which must be after the grant of this special permit, FGT may request reassessment intervals up to seven (7) years for that threat assessment. FGT must submit for and receive a "no objection" letter from the Director, PHMSA Southwest Region, prior to implementing this change.

iv) If factors beyond FGT's control prevent the completion of an assessment within the required timeframe or reassessment interval, FGT must perform the assessment as soon as practicable, and FGT must submit a letter justifying the delay and provide the anticipated date of completion to the Director, PHMSA Southwest Region, no later than two (2) months prior to the end the timeframe or interval. FGT must receive a “no objection” letter from the Director, PHMSA Southwest Region, for the delay or must lower the MAOP of the ***special permit segment*** in accordance with 49 CFR 192.611.

d) **Remediation**: Anomaly assessments must be evaluated and remediated in accordance with **Condition 8 – Anomaly Evaluation and Remediation**.

6) **Condition 6 - Girth Welds**

a) **Construction Girth Weld Non-Destructive Test Records**: FGT must provide records to PHMSA that demonstrate the girth welds in the ***special permit inspection area*** were either:

i) Non-destructively tested (NDT) at the time of construction in accordance with the federal pipeline safety regulations at the time the pipelines were constructed, or

ii) At least 1% of the girth welds and a minimum of two (2) girth welds in each ***special permit segment*** were NDT after initial construction and prior to the special permit application. FGT must demonstrate these welds were excavated, NDT, and repaired, if the welds do not meet federal pipeline safety regulations at the time the pipelines were constructed.

b) **Missing Records**: If FGT cannot provide girth weld records to PHMSA to demonstrate compliance with **Condition 6(a)**, FGT must complete either **Condition 6(b)(i)** or both **Conditions 6(b)(ii)** and **(iii)** within 12 months of the grant of this special permit as follows:

i) Certify to PHMSA, in writing, that there have been no in-service leaks or breaks in the girth welds in the ***special permit inspection area*** for the life of the pipeline; or

ii) Evaluate the terrain along each ***special permit segment*** for threats to girth weld integrity from soil or settlement stresses, perform NDT, and remediate all such integrity threats;[17] and

iii) Excavate,[18] visually inspect, and perform NDT on at least two (2) girth welds on each ***special permit segment*** in accordance with the applicable American Petroleum Institute Standard 1104, "*Welding of Pipelines and Related Facilities*" (API 1104) as follows:

(1) Using the edition of API 1104 current at the time the pipeline was constructed;

(2) Using the edition of API 1104 IBR in the federal pipeline safety regulations at the time the pipeline was constructed; or

(3) Using the edition of API 1104 currently IBR in 49 CFR 192.7.

c) **Defective Girth Welds**: If any girth weld in a ***special permit segment*** is found unacceptable in accordance with the API 1104 IBR Edition at the time of pipeline construction, FGT must repair the girth weld immediately and then prepare an inspection and remediation plan for all remaining girth welds in the ***special permit segment*** based upon the repair findings and the threat to the ***special permit segment***. FGT must submit the inspection and remediation plan for girth welds to the Director, PHMSA Southwest Region, and must receive a "no objection" letter for the girth weld remediation plan prior to its implementation.[19] FGT must remediate girth welds in the ***special permit segment***

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[17] If a ***special permit segment*** has not had girth weld NDT to meet **Condition 6** – **Girth Welds** and has experienced pipe or girth weld leaks or ruptures due to soil movement or the threat has been identified, then **Condition 5(b)(iv)** must be conducted within 12 months of the finding.

[18] FGT must evaluate the pipe for SCC any time the ***special permit inspection area*** is uncovered or excavated in accordance with **Condition 8(b) or (c)** of this special permit. Pipe with fusion bonded epoxy coating does not require SCC evaluation when excavated unless SCC has been identified as a threat in the ***special permit inspection area***.

[19] The Director, PHMSA Southwest Region, must respond to FGT's submittal letter within 90 days of receipt with a decision letter, or either give FGT a request for additional information or a need of additional time for PHMSA to review the request.

in accordance with the inspection and remediation plan within 90 days of the "no-objection" letter receipt.[20]

7) **Condition 7 - Stress Corrosion Cracking Threat**

FGT must evaluate the entire length of each ***special permit inspection area***[21] for SCC as follows:

a) **Threat Assessments**: FGT must complete the SCC threat assessment as detailed in **Condition 5(a) – Threat Assessment**.

b) **SCC Integrity Assessment**: If the threat assessment required under **Condition 7(a)** indicates the ***extended special permit segment***[22] is susceptible to either near-neutral or high-pH SCC, FGT must perform an SCC assessment on the ***extended special permit segment*** in accordance with **Condition 5 – Inline Inspection**. SCC integrity assessment using spike pressure testing is not approved for this special permit.[23]

c) **Examination of Pipe**: If the threat of SCC exists in the ***extended special permit segment*** as determined in **Condition 7(a)**, FGT must directly examine the pipe for SCC when the coating has been identified as poor during the pipeline examination. The examination must be conducted using an accepted crack detection practice in accordance with 49 CFR 192.710(c)(4), (d), and **Condition 7(d)** when the extended ***special permit segment*** is uncovered for any reason to comply with the special permit and IM activities, not including One Call activities (49 CFR 192.614).

d) **Inspection of Pipe at Excavations**: Except for pipe coated with non-shielding coatings (fusion-bonded or liquid-applied epoxy coatings) and excavations performed in accordance with 49 CFR 192.614(c), FGT must directly examine the pipe for SCC using

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[20] FGT must include any plan requirements or comments received from the Director, PHMSA Southwest Region, into the remediation plan.

[21] FGT has documented zero (0) occurrences of SCC in the ***special permit inspection area***.

[22] The ***extended special permit segment*** is defined as the ***special permit segment*** and the five (5) contiguous miles past each endpoint.

[23] FGT may propose an alternative assessment method for SCC (such as spike hydrostatic testing in accordance with 49 CFR 192.506) to the Director, PHMSA Southwest Region, with a copy of the proposal to the Director, PHMSA Engineering and Research Division. FGT must receive a "no objection" letter from the Director, PHMSA Southwest Region, prior to implementing any alternative assessment methods for SCC.

non-destructive examination methods appropriate for the type of pipe and integrity threat conditions in the ditch. FGT must use appropriate methods for crack detection, such as phased array ultrasonic testing (PAUT), inverse wavefield extrapolation (IWEX), or magnetic particle inspection (MPI),[24] when an ***extended special permit segment*** is uncovered, and the coating has been identified as poor during the pipeline examination. Visual inspection is not sufficient to determine "poor coating." FGT must "jeep" the excavated segment to determine the coating condition. Examples of "poor coating" include, but are not limited to, a coating that has become damaged and is losing adhesion to the pipe which is shown by falling off the pipe and/or shields the CP. FGT must keep coating records[25] at all excavation locations in the ***special permit inspection area*** to demonstrate the coating condition.

e) **<u>Discovery of SCC</u>**: If FGT discovers SCC[26] activity by any means within the ***extended special permit segment*** in similar pipe vintage (manufacturer, manufacturing time or age, diameter, wall thickness, grade, and seam type) and pipe coating vintage (in accordance with 49 CFR 192.917(e)), or the ***extended special permit segment*** has had an in-service or hydrostatic test SCC failure or leak,[27] the ***special permit segment*** must be further assessed and mitigated, within 18 months of finding SCC and reassessed every five (5) calendar years or less[28] based upon the evaluated growth of the SCC, using <u>one (1) of the following methods</u>:

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[24] When MPI finds cracking, another method must be used to size the crack unless the crack can be completely ground out and still meet the pipeline MAOP.

[25] The records must include, at a minimum, a description of FGT's detection procedures, records of finding, and mitigation procedures implemented for the excavation.

[26] "SCC" activity shall be defined as greater than 20 percent wall thickness depth and 2-inches in length.

[27] For all in-service and pressure test failures, FGT must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. FGT must provide the written results of this root cause analysis to the Director, PHMSA Southwest Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

[28] FGT has the option to submit a written request to the Director, PHMSA Southwest Region, with a copy to the Director, PHMSA Engineering and Research Division, for extension of the crack assessment interval to seven (7) years, as defined in 49 CFR 192.939(a), if the ECA shows that five (5) calendar year assessments are not required. FGT must receive a "no objection" letter from the Director, PHMSA Southwest Region, prior to extending the assessment interval to seven (7) calendar years.

i) **Spike Hydrostatic Test Program**:[29]

(1) FGT must perform its SCC spike hydrostatic test program in an ***extended special permit segment*** in accordance with 49 CFR 192.506 and include an ECA of the results that includes a determination of the reassessment interval, and

(2) If a joint of pipe in an ***extended special permit segment*** leaks or ruptures during a hydrostatic test due to SCC, FGT must replace the pipe joint that does not meet 49 CFR 192.611 in the ***extended special permit segment*** with new pipe. FGT must complete a successful SCC hydrostatic test prior to returning the ***extended special permit segment*** to operational service;

ii) **Crack Detection Tool Assessment**: FGT must run an electro-magnetic acoustic transducer (EMAT) ILI tool or other equivalent crack detection ILI tool in the ***extended special permit segment***;

iii) **MAOP Lowered**: FGT must lower the MAOP of the ***special permit segment*** to 60% specified minimum yield strength (SMYS);

iv) **Pipe Replacement**: FGT must replace all pipe and comply with 49 CFR 192.611 and 192.619 in the ***special permit segment***; or

v) **Operating Pressure Lowered**: FGT must lower the operating pressure of the ***special permit segment*** to 20% below the maximum pressure during the preceding 90-day operating interval until FGT conducts an ECA and remediates the ***special permit segment***.

f) **SCC Remediation Plan**: If FGT discovers any SCC activity in the ***extended special permit segment***, FGT must submit an SCC remediation plan to the Director, PHMSA

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[29] FGT may propose an alternative assessment method for SCC (such as spike hydrostatic testing in accordance with 49 CFR 192.506) to the Director, PHMSA Southwest Region, with a copy of the proposal to the Director, PHMSA Engineering and Research Division. FGT must receive a "no objection" letter from the Director, PHMSA Southwest Region, prior to implementing any alternative assessment methods for SCC.

Southwest Region, and send a copy to the Director, PHMSA Engineering and Research Division, no later than 90 days after the finding of SCC.[30] The plan must:

i) Meet **Condition 7(e)** and include an SCC remediation/repair plan with SCC characterization and timing; or

ii) Include a technical justification that shows that FGT is addressing the threat for SCC in the ***special permit segment***.

8) **Condition 8 - Anomaly Evaluation and Remediation**

a) **General**: FGT must use the procedures specified in the special permit conditions, 49 CFR 192.712, and **Attachment A** when evaluating anomalies. FGT must account for ILI tool tolerance and corrosion growth rates in determining scheduled response times and repairs and must document and justify the values used.

i) **ILI Tool Accuracy**: FGT must demonstrate ILI tool tolerance accuracy for each ILI tool run by using calibration excavations and unity plots that demonstrate ILI tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10% accuracy for 80% of the time). FGT must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool and includes that tolerance in determining the size of each anomaly feature reported to FGT. FGT must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently overcalling or under-calling, the remaining ILI features must be re-graded accordingly. ILI tools used must be calibrated as follows:

(1) **General ILI Tool Calibration**: ILI tool calibrations must use ILI tool run results and anomaly calibrations from either the ***special permit inspection area*** or from the complete ILI tool run segment if the continuous ILI segment is longer than the ***special permit inspection area***. ILI calibration excavations may include previously excavated anomalies or recent anomaly excavations with

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[30] For FGT to go forward with the technical justification for addressing the SCC threat, FGT must receive a "no objection" letter from the Director, PHMSA Southwest Region.

known dimensions that were field measured for length, depth, and width, externally re-coated, CP maintained, and documented for ILI calibrations prior to the ILI tool run. A minimum of four (4) calibration excavations must be used for unity plots.[31]

(2) **<u>EMAT ILI Tool Calibration</u>**:

(a) ILI calibration for EMAT ILI Tools must be based upon excavation results of a minimum of the two (2) most severe anomalies from a combined review of crack depth and length. If the EMAT tool identifies only one (1) anomaly, the anomaly must be excavated and assessed. FGT can propose alternative EMAT ILI Tool evaluation procedures to the Director, PHMSA Southwest Region, but must receive a "no objection" letter prior to usage of these procedures.

(b) If the EMAT ILI tool does not identify any cracking anomalies above the minimum length and depth criteria for 90% probability of detection, FGT must provide the following to the Director, PHMSA Southwest Region:

(1) EMAT ILI service provider report with any FGT provided reporting thresholds for cracking;

(2) Calibration data showing the ILI tool meets API Standard 1163 IBR - *Sections 6 - Qualification of Performance Specifications*, *Section 7 -*

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[31] Other known and documented pipeline features that are appropriate for the type of ILI tool used may be used as calibration excavations for ILI tool calibration with technical documentation of their validity. To use other known and documented pipeline features as calibration excavations for ILI tool calibration, FGT must complete the following: (1) submit a plan for using known and documented pipeline features such as calibration excavation data, to the Director, PHMSA Southwest Region, with a copy to the Director, PHMSA Engineering and Research Division. The plan must include at least the following information: a) reason that known and documented pipeline features will be used in place of anomalies on the pipelines; b) the pipeline features that will be used for the ILI tool calibration; and c) the technical justification for using the pipeline features for ILI tool calibration; (2) receive a "no objection" letter from the Director, PHMSA Southwest Region, prior to performing the ILI tool calibration using pipeline features; (3) submit a report to the Director, PHMSA Southwest Region, with a copy to the Director, PHMSA Engineering and Research Division, and with the results of the use of pipeline features for the ILI tool calibration that includes technical documentation establishing the validity of using the pipeline features for the ILI tool calibration.

System Operational Verification, and *Section 8 - System Results Validation*, as applicable; and

(3) Previous in-ditch non-destructive examination records showing no SCC findings.

(4) FGT must receive a "no objection" letter from the Director, PHMSA Southwest Region, that no excavation is required for the EMAT ILI tool calibration.

ii) **Unity Plots**: The unity plots must show actual anomaly depth versus predicted depth.

iii) **ILI Tool Evaluations**: ILI tool evaluations for metal loss must use "6t x 6t"[32] interaction criteria for determining anomaly failure pressures and response timing.

iv) **Discovery Date**: The discovery date[33] must be within 180 days of any ILI tool run for each type of ILI tool (e.g., HR-geometry, HR-deformation, HR-MFL, EMAT, IMU, or other equivalent ILI tools).

b) **Remediation schedule for "special permit inspection area"**: FGT must remediate the ***special permit inspection area***[34] as follows:

i) **Immediate repair conditions for a "*special permit inspection area*"**: FGT must repair the following conditions immediately upon discovery in a ***special permit inspection area***:

(1) Metal loss anomaly where the calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with 49 CFR 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

32 "6t" means pipe wall thickness times six (6).

33 Discovery date is the day, month, and year that FGT receives the ILI tool run results from the ILI tool service provider.

34 Throughout this special permit, the ***special permit inspection area*** includes the ***special permit segment***, so any anomalies found in a ***special permit segment*** must be remediated to meet the requirements for a ***special permit inspection area*** in addition to the requirements of this condition for a ***special permit segment***. The ***special permit segment*** has additional remediation criteria in later sections of this special permit condition.

(2) Metal loss greater than 80% of nominal wall, regardless of dimensions.

(3) Metal loss preferentially affecting a detected pipe weld seam, and the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is less than 1.25 times the MAOP or the metal loss is greater than 50% of pipe wall thickness.[35]

(4) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(5) A crack or crack-like anomaly meeting any of the following criteria:

  (a) Crack depth plus any metal loss is greater than 50% of pipe wall thickness;

  (b) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

  (c) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with 49 CFR 192.712(d), that is less than 1.25 times the MAOP.

(6) An indication or anomaly that, in the judgment of FGT, requires immediate action.

ii) **<u>One-year conditions – Hard Spots for a "special permit inspection area"</u>**: FGT must repair by installation of a Type B sleeve or cut-out and recoat within 12 months of discovery, any hard spots found in the pipe body of EFW pipe discovered after the grant of the special permit with a hardness on the Brinell Hardness scale (HB) of either (1) 300 HB or greater and 2-inches in length or width; (2) 300 HB or greater

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[35] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

with any cracking or metal loss over 10% of wall thickness; or (3) a single reading of 320 HB or greater at any location.

iii) **<u>One-year conditions – dents, metal loss, and cracks for a "special permit inspection area"</u>**: FGT must repair the following conditions within 12 months of discovery in a ***special permit inspection area***:

(1) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(2) A dent with a depth greater than 2% of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(3) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(4) Metal loss anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with 49 CFR 192.712(b), at the location of the anomaly less than or equal to 1.39 times the MAOP for Class 2 locations, and 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations outside of the ***special permit segment*** with a predicted failure pressure greater than 1.1 times the MAOP, FGT must follow the remediation schedule specified in ASME/ANSI B31.8S, Section 7, Figure 4.

(5) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, with a predicted failure pressure determined in accordance with 49 CFR 192.712 less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.

(6) Metal loss preferentially affecting a detected pipe weld seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0 (49 CFR 192.113), and where the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[36]

(7) A crack or crack-like anomaly that has a predicted failure pressure determined in accordance with 49 CFR 192.712(d) that is less than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, and 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.

iv) **<u>Two-year condition for crack repairs for a "special permit inspection area"</u>**: FGT must remediate any crack or crack-like anomaly that has a crack depth greater than 40% of the pipe wall thickness within two (2) years of discovery that are in the ***special permit inspection area*** and area outside of the ***special permit segment***.

(v) **<u>Monitored conditions for a "special permit inspection area"</u>**: FGT does not have to schedule the following conditions for remediation but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored conditions are the least severe and

[36] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

will not require examination and evaluation until the next scheduled integrity assessment.

(1) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe), and engineering analyses of the dent conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(2) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and engineering analyses of the dent conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(3) A dent with a depth greater than 2% of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and engineering analyses conducted in accordance with 49 CFR 192.712 and **Attachment A** to demonstrate the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(4) A dent that has metal loss, cracking, or a stress riser, and an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** to demonstrate the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(5) Metal loss preferentially affecting a detected pipe weld seam and where the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is greater than or equal to 1.39 times the MAOP for Class 1 locations or where

Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[37]

(6) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with 49 CFR 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[38] The crack depth is less than 40% of the pipe wall thickness.

c) **Remediation schedule for a "special permit segment"**: In addition to the requirements in paragraphs (a) and (b) of **Condition 8** for a ***special permit inspection area***, FGT must remediate conditions in a ***special permit segment*** as follows:[39]

i) **One-year conditions for a "special permit segment"**: FGT must repair the following conditions within one (1) year of discovery in a ***special permit segment***:

(1) **Pipe Wall**: Pipe wall thickness metal loss greater than 40%.

(2) **Weld Metal**: Girth weld metal loss greater than 30% of pipe wall thickness or pipe weld seam metal loss greater than 15% of pipe wall thickness.[40]

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[37] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

[38] Failure stress pressure and crack growth analysis of cracks and crack-like defects must be determined using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other). Examples of technically proven models include but are not limited to: for the brittle failure mode, the Raju/Newman Model; for the ductile failure mode, Modified LnSec, API RP 579-1/ASME FFS-1, June 15, 2007, (API 579-1, Second Edition) – Level II or Level III, CorLas™, PAFFC, and PipeAccess™. All crack fracture mechanic evaluation models must be used within the assessment limits of the model.

[39] The ***special permit inspection area*** includes the ***special permit segment***, so any anomalies found in a ***special permit segment*** must be remediated to meet the requirements for a ***special permit inspection area*** in addition to the requirements in this condition. The ***special permit segment*** must also be remediated to meet all additional remediation requirements specifically for the ***special permit segment*** as required in the special permit conditions.

[40] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

(3) **<u>Class 1 pipe</u>**: Any anomaly with a predicted failure pressure less than 1.39 times the MAOP.

(4) **<u>Class 2 pipe</u>**: Any anomaly with a predicted failure pressure less than 1.67 times the MAOP.

(5) **<u>Class 3 pipe</u>**: Any anomaly with a predicted failure pressure less than 2.0 times the MAOP.

ii) **<u>One-year crack repair conditions for a "special permit segment</u>**": FGT must repair all anomalies with a predicted failure pressure determined in accordance with 49 CFR 192.712(d) that is less than 1.39 times the MAOP, or a crack depth that is greater than 40% of the pipe wall thickness.

iii) **<u>Un-cleared shorted casing for a "special permit segment</u>**": FGT must repair within 12 months of discovery any identified corrosion, cracking or other anomaly that is shorted to a casing that is greater than 30% of the pipe wall thickness.

iv) **<u>Monitored conditions for a "special permit segment</u>**": FGT does not have to schedule the following conditions for remediation but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation in a ***special permit segment***. Monitored conditions are the least severe and will not require examination and evaluation until the next scheduled integrity assessment.

(1) **<u>Class 1 pipe</u>**: Any anomaly with a predicted failure pressure greater than or equal to 1.39 times the MAOP and an anomaly depth less than or equal to 40% wall thickness loss.

(2) **<u>Class 2 pipe</u>**: Any anomaly with a predicted failure pressure greater than or equal to 1.67 times the MAOP and an anomaly depth less than or equal to 40% wall thickness loss.

(3) **<u>Class 3 pipe</u>**: Any anomaly with a predicted failure pressure greater than or equal to 2.0 times the MAOP and an anomaly depth less than or equal to 40% of pipe wall thickness.

9) **<u>Condition 9 - Pipe Casings</u>**

FGT must identify all shorted casings within a ***special permit segment*** no later than six (6) months after the grant of this special permit and classify any shorted casings as either having a "metallic short" (the carrier pipe and the casing are in metallic contact) or an "electrolytic short" (the casing is filled with an electrolyte) using a commonly accepted method such as the Panhandle Eastern, Pearson, Direct Current Voltage Gradient (DCVG), Alternating Current Voltage Gradient (ACVG), or AC Attenuation.

a) **<u>Clear Shorted Casings</u>**: Where practical, FGT must clear shorted casings identified within a ***special permit segment*** no later than 12 months after the grant of this special permit as follows:

   i) **<u>Metallic Shorts</u>**: FGT must clear any metallic short on a casing in a ***special permit segment*** no later than 12 months after the short is identified.

   ii) **<u>Electrolytic Shorts</u>**: FGT must remove the electrolyte from the casing/pipe annular space on any casing in a ***special permit segment*** that has an electrolytic short within 12 months of identifying the short. If FGT identifies any shorts after uprating, they must be cleared no later than 12 months after identification.

   iii) **<u>All Shorted Casings</u>**: FGT must install external corrosion control test leads on both the carrier pipe and the casing in accordance with 49 CFR 192.471 to facilitate the future monitoring for shorted conditions. FGT may then choose to fill the casing/pipe annular space with a high dielectric casing filler or other material that provides a corrosion-inhibiting environment provided FGT completed an assessment and all necessary repairs.

b) **<u>Remediation of Un-cleared Casing Shorts</u>**: If it is impractical for FGT to clear a shorted casing within a ***special permit segment***, FGT must document the actions taken to remediate the shorted casing and must receive a "no objection" letter from the Director, PHMSA Southwest Region, to use ILI assessments instead of clearing the short.[41, 42] In addition to the notification, FGT must conduct the following:

i) A ***special permit segment*** with shorted casings must be assessed with the appropriate ILI tools (<u>a minimum of HR-MFL and HR-Deformation ILI and with EMAT ILI when a ***special permit segment*** is susceptible to SCC</u>) on a five (5) calendar year assessment schedule, not to exceed 66 months.

ii) FGT must remediate any identified corrosion, cracking, or other anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**.

10) **<u>Condition 10 - Pipe - Seam Evaluations</u>**

FGT must conduct engineering integrity assessments to identify any pipe in the ***extended special permit segment*** that may be susceptible to pipe seam leak, rupture, or other failure issues because of the vintage of the pipe, the manufacturer of the pipe, other physical or operational characteristics, or unknown pipe characteristics as follows:

a) **<u>Identify and Test Pipe Seam Issues</u>**:

i) Within 12 months of the special permit grant, FGT must perform an engineering integrity analysis to determine if the pipe seam is susceptible to seam threats located in the ***extended special permit segment***.[43] This engineering integrity analysis must follow and document the processes listed herein along with other relevant materials:

(1) "M Charts" in "Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines," by Kiefner and Associates (updated April 26, 2007), under PHMSA Contract DTFAA-COSP02120; and

(2) Figure 4.2, "Framework for Evaluation with Path for the Segment Analyzed Highlighted" from TTO-5, "Low Frequency ERW and Lap Welded Longitudinal

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[41] The Director, PHMSA Southwest Region, must respond to FGT's submittal letter within 90 days. The Director, PHMSA Southwest Region, may provide a decision, request for additional information, or notify FGT of PHMSA's need for additional time to provide a decision.

[42] FGT must send a copy of the actions taken to clear the shorted casing to the Director, PHMSA Engineering and Research Division.

[43] The ***extended special permit segment*** is defined as the ***special permit segment*** and the five (5) contiguous miles past each endpoint.

Seam Evaluation," by Michael Baker Jr. and Kiefner and Associates, et. al. under PHMSA Contract DTRS56-02-D-70036.

ii) If the engineering integrity analysis identifies pipe seam issues in the ***extended special permit segment*** that are a threat to the integrity of the pipeline, FGT must confirm there are no systemic issues with the weld seam or pipe. Within 12 months of analysis completion, FGT must complete a hydrostatic test to a minimum of 1.39 times the MAOP for any identified ***special permit segment***.

b) **Seam Leak or Failure**:

i) If the pipeline experienced a seam leak or failure in the last five (5) years and FGT did not perform a hydrostatic test meeting **Condition 1(b)** after the seam leak or failure in the ***special permit segment*** of the same weld seam and manufacturer, then FGT must complete a hydrostatic test to a minimum of 1.39 times the MAOP within 18 months after the grant of this special permit in the ***special permit segment***.

ii) FGT must determine from the hydrostatic test whether there are systemic issues with the weld seam or pipe. FGT must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. FGT must provide the written results of this root cause analysis to the Director, PHMSA Southwest Region, within 90 days of the failure.[44]

c) **Pipe Replacement**: The ***special permit segment*** must be replaced if any of the following conditions exist or are discovered after the grant of this special permit:

i) The ***special permit segment*** has any direct current-electric resistance welded (DC-ERW) seam or pipe with a longitudinal joint factor below 1.0 as defined in 49 CFR 192.113;

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[44] FGT must send a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

ii) The ***special permit segment*** pipe has any LF-ERW or EFW seam pipe joints that had pipe seam leaks or ruptures and the pipe has not been replaced with new pipe;[45]

iii) Pipe in the ***extended special permit segment*** was constructed or manufactured prior to 1954 and had pipe seam leaks or ruptures;[46]

iv) The ***special permit segment*** pipe has unknown manufacturing processes (i.e., unknown seam type, yield strength, or wall thickness); or

v) The ***special permit segment*** pipe has known manufacturing or construction issues that are unresolved, such as concentrated hard spots, hard heat-affected weld zones, selective seam corrosion, pipe movement that has led to buckling, past leak and rupture issues, or any other systemic issues.

d) **Girth Weld or Seam Weld Repairs**: Within a ***special permit segment***, FGT must remove and replace, in accordance with 49 CFR Part 192 requirements, all weld seam or girth weld repairs that have been made by the usage of fittings such as weldolets, threadolets, repair clamps, and pipe sleeves (steel or composite). This remediation must be completed within six (6) months of the grant of this special permit or within six (6) months of the identification.

e) **Remediation Plan**: FGT must remediate all weld seam leaks, failures, or ruptures[47] discovered in the ***special permit segment***. FGT must submit a seam remediation plan for the ***special permit segment*** to the Director, PHMSA Southwest Region, no later than 30 days after finding a seam leak, seam failure, or seam rupture in the ***special permit segment*** containing one (1) of the following:

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45 As of the date of the grant of this special permit, FGT reported no LF-ERW or EFW seam pipe in a ***special permit segment***.

46 As of the date of the grant of this special permit, FGT reported no pipe manufactured prior to 1954 with seam integrity issues in a ***special permit segment***.

47 For all in-service and pressure test failures, FGT must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. FGT must provide the written results of this root cause analysis to the Director, PHMSA Southwest Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

i) A longitudinal weld seam remediation/repair plan that meets **Condition 10** and includes replacement, hydrostatic testing, or ILI, with completion of the remediation/repair plan within six (6) months of discovery, or

ii) A technical justification that shows that the ***special permit segment*** is not at risk for future longitudinal seam leaks or failures.

11) **<u>Condition 11 - Control of Interference Currents</u>**

FGT must address induced alternating current (AC) from parallel electric transmission lines and other interference issues, such as direct current (DC), that may affect the pipeline in a ***special permit segment***. FGT must have an induced AC or DC program and remediation plan to protect the pipeline from corrosion caused by stray currents within 12 months of the grant of this special permit.

a) **<u>Surveys</u>**: FGT must perform periodic interference surveys to detect the presence and level of any electrical stray current, including when there are current flow increases over the ***special permit segment*** grounding design from any co-located pipelines, structures, or high voltage alternating current (HVAC) powerlines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures.

b) **<u>Analysis of Results</u>**: FGT must analyze the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion (defined as 100 amps per meter squared for AC-induced corrosion), or if the interference impedes the safe operation of the pipeline, or that may cause a condition that would adversely impact the environment or the public.

c) **<u>Remediation</u>**: Remedial action is required when the interference in the ***special permit segment*** is at a level that could cause significant corrosion (defined as 100 amps per meter squared for AC-induced corrosion), or if it impedes the safe operation of a pipeline, or may cause a condition that would adversely impact the environment or the public. Within six (6) months after completing the interference survey, FGT must develop a remediation procedure and apply for any necessary permits to conduct remediation. FGT must complete all remediation within six (6) months, or as soon as practicable, after obtaining the necessary permits for the remediation.

d) **<u>Completion Schedules</u>**: If environmental permitting or right-of-way factors beyond FGT's control prevent the completion of any remediation within six (6) months of completing the interference engineering analysis of the survey results, FGT must complete remediation as soon as practicable and submit a letter justifying the delay and providing the anticipated date of completion to the Director, PHMSA Southwest Region, no later than one (1) month prior to the end of the six (6) month completion date. Any extended evaluation and remediation schedules submitted to PHMSA from FGT must receive a "no objection" letter from the Director, PHMSA Southwest Region.

12) **<u>Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures</u>**

FGT must automate mainline valves[48] for closure or demonstrate capability to manually close mainline valves in accordance with the requirements of this **Condition 12**. A ***special permit segment*** must have upstream and downstream automated shutdown valves (ASVs) or remote-controlled valves (RCVs) so that the distance between the valves is no greater than 20 miles.[49] FGT must automate mainline valves to close in accordance with the requirements in **Condition 12** within 12 months of the grant of this special permit. The ***special permit segment*** must have procedures for rupture isolation as follows:

a) **<u>Valve Locations</u>**: ASVs or RCVs must be installed as shown in **Table 4 - Valves and Lateral Locations with Isolations Methods**. Each ***special permit segment*** must have telemetry connections to the FGT supervisory control and data acquisition (SCADA) system installed.

b) **<u>Automatic Shutoff Valve Requirements</u>**:

i) If an ASV is used, FGT must confirm the 30-minute ASV shut-in pressure for a ***special permit segment*** after "notification of potential rupture" by flow modeling of the ***special permit inspection area*** and any looped pipelines or gas receipt tie-ins

[48] A mainline valve is a sectionalizing valve used to isolate or stop gas flow upstream or downstream along the pipeline.

[49] If the distance between mainline isolation valves exceed 20 miles, additional mainline valve(s) must be added.

between the ASVs or RCVs. Flow modeling must include anticipated maximum, normal, or any other flow volumes, pressures, or any other operating conditions that may be encountered during the calendar year. The flow model detection for a rupture must be based upon 0.500 times the pipe diameter area or smaller pipe area (partial pipe opening) for rupture sizing to account for pressure drop. If operating conditions change that could affect the ASV set pressures and the 30-minute isolation time after "notification of potential rupture," a new flow model must be conducted and ASV set pressures must be reset prior to the next review for ASV set pressures. If the ***special permit segment*** cannot be isolated within 30 minutes of a "notification of potential rupture" by usage of ASVs, then RCVs must be installed. **Table 4 - Valves and Lateral Locations with Isolations Methods** has the ASV shutoff pressures and shutoff times for isolation of the ***special permit segment*** after "notification of potential rupture."

ii) ASVs must be equipped with rupture sensing equipment to detect the s***pecial permit segment*** "rate of pressure drop" with a set-point of 20 psig/minute or less unless FGT submits a request for a "rate of pressure drop" set-point change and receives a "no objection" letter from the Director, PHMSA Southwest Region, for any revised shut-in pressures prior to their implementation.

iii) ASV shut-in pressures must be confirmed and reset on a calendar year basis not to exceed 15 months. FGT must submit initial and annual ASV shut-in pressures to the Director, PHMSA Southwest Region, as detailed in **Condition 15 – Annual Report**, and receive a "no objection" letter from the Director, PHMSA Southwest Region, for any revised shut-in pressures prior to their implementation. The Director, PHMSA Southwest Region, must respond to FGT's submittal letter within 90 days with a decision letter, or either give FGT a request for additional information or additional time for PHMSA to review the request.

iv) If the pipeline is impacted by extreme weather or other emergency conditions that reduce pipeline operating pressures in the ***special permit segment*** to operating pressures where the ASV shut-in pressures require emergency resetting, FGT may reset ASV shut-in pressures below the operating pressure requirements for a maximum period of seven (7) days, but must notify the Director, PHMSA Southwest Region, within two (2) days of the pressure reset.

c) **Remote Monitoring and Control**: Each ***special permit segment*** must be controlled by a SCADA system and must be equipped for remote monitoring and control, or remote monitoring and automatic control, in accordance with 49 CFR 192.620(d)(3)(iii) and the below requirements in this **Condition 12**.

d) **Crossover or Lateral Pipe Connection Isolation**: If any crossover or lateral pipe[50] connects to the isolated segment between the upstream and downstream mainline valves, the nearest valve on the crossover connection(s) or lateral(s) must be isolated such that, when all valves are closed, there is no flow path for gas to flow to the leak or rupture site (except for residual gas already in the shut-off segment). If the nearest valve for a gas receipt or delivery line to the ***special permit inspection area*** is not isolated, isolation valves must be installed within 12 months of the grant of this special permit.[51] Valves that are in the FGT O&M procedures as locked closed and that are only opened when manned by FGT operating personnel do not require RCVs or ASVs for closure.

e) **Remote-Control and Automatic-Shutoff Valve Status**:

   i) RCVs must be constantly monitored for valve status (open, closed, or partial closed/open), upstream pressure, and downstream pressure.

   ii) A ***special permit segment*** with ASVs must have a minimum of one (1) pressure monitoring point within the segment when the mainline valve locations do not have pressure monitoring. If an ASV is used, FGT must determine the set pressure used in **Condition 12(b)** on a calendar year basis not to exceed 15 months and must report the set pressure to PHMSA each year in the **Condition 15 - Annual Report**. ASV

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[50] **Table 4 - Valves and Lateral Locations with Isolations Methods** has a listing of all lateral valves. FGT must update **Table 4** if a lateral or crossover valve was not identified or is added after the grant of the special permit and submit this update in accordance with **Condition 15 – Annual Report**.

[51] Gas delivery or receipt pipelines must have a shutoff valve (gate or ball valve) either at the connection between the isolation valves for a ***special permit segment*** or at the delivery or receipt meter station. Any gas delivery or receipt station over 5-miles in length that is connected between the isolation valves for a ***special permit segment*** must have a RCV or ASV within 5-miles of the pipeline tie-in. For gas delivery or receipt pipelines manual shutoff valves can be used for isolation but must be closed within 30-minutes of the pipeline leak or rupture confirmation. Check valves cannot be used for pipelines over 8-inch diameter.

pressure settings must be determined by flow modeling of the ***special permit segment***, ***special permit inspection area***, and all looped, delivery, or receipt pipelines tied into the ***special permit inspection area*** that could affect pressures in the ***special permit segment***. If the ASV pressure settings cannot be accurately determined, RCVs must be installed for the ***special permit segment***. The shutdown time for ASVs must be within 30 minutes of the "notification of potential rupture."

f) **Mainline Valve Closure**: Closure of the appropriate valves following a pipeline leak or rupture must occur "as soon as practicable" and must not exceed 30 minutes from the "notification of potential rupture" as defined below:[52]

i) "Notification of Potential Rupture" means any of the following events that involve an unintentional or uncontrolled release of a large volume of gas from a transmission pipeline:

(1) A release of gas observed by or reported to FGT (e.g., by its controller(s) in a control room, field operations personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) that may be representative of an unintentional or uncontrolled release event meeting **paragraphs (2)** or **(3)** of this definition;

(2) FGT observes an unanticipated or unplanned pressure loss outside of the pipeline's normal operating pressures, as defined in FGT's written procedures. If FGT establishes an unanticipated or unplanned pressure loss threshold that is greater than a 10% pressure loss, occurring within a time interval of 15 minutes or less, FGT must document in its written procedures the need for a greater pressure-change threshold due to pipeline flow dynamics (including the pipeline operating pressure, gas flow rate or volume), that are caused by fluctuations in gas demand, gas receipts, or gas deliveries; or

[52] The pipeline valve section location to be closed and isolated (if there should be a rupture) must be confirmed by FGT through Gas Control or other field operations personnel monitoring of the appropriate pipeline pressures, pressure changes, or flow rate changes through a compressor discharge section or by location confirmation from responsible persons.

(3) FGT observes an unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication that may be representative of an event meeting **paragraph (2)** of this definition.

Note: Notification of potential rupture occurs when an event, as defined in this **section/paragraphs (2)** or **(3)** above, is first observed by or reported to FGT.

ii) FGT must evaluate and identify a rupture,[53] as defined above, as being either an actual leak event, rupture event, or non-rupture event in accordance with operating procedures and 49 CFR 192.615.

g) **Gas Control Center Monitoring**: The FGT Gas Control Center must monitor the ***special permit inspection area*** 24 hours a day, seven (7) days a week, and must confirm the existence of a leak or rupture as soon as practicable in accordance with FGT pipeline operating procedures.

h) **Remote Monitoring**: FGT must maintain remote monitoring and automatic control equipment, mainline valves, mainline valve operators, and pressure sensors in accordance with 49 CFR 192.631 and 192.745. All remote monitoring and automatic control equipment, including pressure sensors, must have backup power to maintain communications and control to the FGT Gas Control Center during power outages.

i) **Point-to-Point Verification**: FGT must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with 49 CFR 192.631(c) and (e).

j) **Valve Maintenance**: FGT must maintain all valves used to isolate a leak or rupture in accordance with this special permit and 49 CFR 192.745.

[53] For all in-service and pressure test failures, FGT must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. FGT must provide the written results of this root cause analysis to the Director, PHMSA Southwest Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

k) **<u>Inoperable Valves</u>**: FGT must take remedial measures to correct any valve used to isolate a leak or rupture that is found to be inoperable or unable to maintain shutoff, as follows:

   i) Repair or replace the valve as soon as practicable but no later than six (6) months after the finding;

   ii) Designate an alternative valve within 14 calendar days of the finding while repairs are being made. Repairs must be completed within six (6) months; and

   iii) If valve repair or replacement cannot be met due to circumstances beyond FGT's control, FGT must notify, in writing, the Director, PHMSA Southwest Region, of the reasons the schedule cannot be met and obtain a letter of "no objection" from PHMSA prior to implementing the schedule change.

l) **<u>Emergency Communications</u>**:

   i) FGT must establish and maintain adequate means of communication with the appropriate public safety access point (9-1-1 emergency call center) or emergency management coordinating agency and must notify them, as well other emergency responders, if there is a leak or rupture, as required in 49 CFR 192.615;

   ii) FGT must immediately and directly notify the appropriate public safety access point (9-1-1 emergency call center) or other emergency management coordinating agency for the communities and jurisdictions in which the pipeline is located when a release is indicated;[54] and

   iii) In accordance with these special permit conditions and as required in 49 CFR 192.615 and 192.631, FGT must establish actions required to be taken by a pipeline controller or the appropriate emergency response coordinator when an emergency occurs in the ***special permit inspection area***.

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[54] FGT must designate the pipeline controller or the appropriate operator emergency response coordinator in its operating procedures and train the designated individual for coordinating with emergency responders.

13) **<u>Condition 13 - Special Permit Specific Conditions</u>**

FGT must comply with the following requirements:

a) **<u>Line-of-Sight Markers</u>**: FGT must install and maintain line-of-sight markings on the pipeline in each ***special permit segment***, except in agricultural areas or large water crossings, such as lakes, where line-of-sight signage is not practical. Line-of-sight markers must be installed within six (6) months of the grant of this special permit and replaced as necessary by FGT within 30 days after identification of line-of-sight marker removal.

b) **<u>Depth of Cover Survey</u>**:

i) FGT must complete, within six (6) months of the grant of this special permit, a depth of cover survey for each ***special permit segment***.

ii) FGT must implement additional safety measures for any pipe in a ***special permit segment*** that does not meet 49 CFR 192.327(a) for a Class 1 location where there is a reduced depth of cover. A ***special permit segment*** with depth of cover less than 24-inches must be either lowered, have additional soil cover added, or have a concrete pad installed unless it is in consolidated rock.

iii) For FGT to use other remedial measures for depth of cover requirements that are based upon the threat, such as increased pipeline patrols or additional line markers, FGT must submit these procedures to the Director, PHMSA Southwest Region, for a "no objection" letter prior to usage. The Director, PHMSA Southwest Region, must respond to FGT's submittal letter within 90 days. The Director, PHMSA Southwest Region, may provide a decision, request for additional information, or notify FGT of PHMSA's need for additional time to provide a decision.

c) **<u>Data Integration</u>**: FGT must develop and maintain data integration[55] in accordance with 49 CFR 192.917, of all special permit condition findings and remediation in a ***special***

[55] Data integration is defined as the gathering of relevant pipeline attributes, operational, maintenance, environmental, and integrity information and integrating this information together to assess threats to the pipeline and to use this information to conduct assessments and remediation for those threats.

permit segment and ***special permit inspection area***. Data integration must be completed at least once each calendar year, with intervals not to exceed 15 months.

i) Data integration must include the following information: (1) Pipe diameter, wall thickness, grade, and seam type; (2) pipe coating; (3) MAOP; (4) class location, including boundaries on aerial photography; (5) HCAs, including boundaries on aerial photography; (6) hydrostatic test pressure, including any known test failures; (7) casings; (8) any in-service ruptures or leaks; (9) ILI survey results, including HR-MFL, HR-geometry/caliper, or deformation tools; (10) the most recent CIS results; (11) depth-of-cover surveys; (12) rectifier readings for the past five (5) years; (13) CP test point survey readings for the past five (5) years; (14) AC/DC interference surveys; (15) pipe coating surveys; (16) pipe coating and anomaly evaluations from pipe excavations; (17) SCC excavations and findings; and (18) pipe exposures from encroachments.[56] Structures must be validated each calendar year by obtaining new aerial imagery or by ground patrol in accordance with **Condition 13(h)**.

ii) If requested by PHMSA, FGT must complete and submit data integration documentation and drawings, with four (4) years of prior data, beginning with the 2nd annual report of this modified special permit.

iii) FGT must maintain data integration as a composite of all applicable data elements in a comparable data viewer.

d) **Pipe Properties Testing**: If the pipe does not meet **Condition 16(b)**, FGT must test the pipe in a ***special permit segment*** as follows: [57]

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for any ***special permit segment***, without TVC[58,]

[56] Hydrostatic test failures, in-service ruptures, rectifier readings, CP test point survey readings, AC/DC interference surveys, pipe coating surveys, pipe coating and anomaly evaluations from pipe excavations, SCC excavations and findings, and pipe exposures from encroachments must be maintained for data integration into a comparable data viewer. These data elements may not be on a drawing.

[57] FGT has furnished TVC material records to PHMSA for the ***special permit segment*** that meet **Condition 16(b)**.

[58] TVC procedures and records must follow the following: 1) "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments";

[59] pipe material properties records, in accordance with this condition and either 49 CFR 192.607 or 192.105 for determining MAOP. Non-destructive or destructive tests, examinations, and assessments must be completed within 18 months of the grant of this special permit.

ii) FGT must test pipe in each ***special permit segment*** without TVC material properties and of different vintages as defined in **Condition 13(d)(iv**). Material tests must be conducted at two (2) excavation sites per mile with excavations spaced between 1,320 to 3,960 feet in each mile segment. If the ***special permit segment*** is less than ½ mile, only one (1) excavation site is required.

iii) FGT must perform a minimum of two (2) destructive or NDT methods at an excavation site. FGT must conduct NDT assessments using test procedures, calibration pipe of similar confirmed properties for equipment testing, and ball indention methodology, or an equivalent method.[60] If NDT of pipe material properties show that the pipe wall thickness is not within API 5L specification tolerances, and the pipe grade is under the strength requirements of API 5L by 1,000 pounds per square inch (psi) or more, then FGT will confirm the yield strength of that individual pipe using destructive test methods or remove the ***special permit segment*** pipe. If ILI tools are used to verify the pipeline materials, FGT must submit an assessment procedure to the Director, PHMSA Southwest Region, for a "no objection" letter prior to its usage.[61] The Director, PHMSA Southwest Region, must respond to FGT's submittal letter within 90 days. The Director, PHMSA Southwest

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84 FR 52218 to 52219; October 1, 2019; and 2) PHMSA Advisory Bulletin: Pipeline Safety: Verification of Records; 77 FR 26822; May 7, 2012; https://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf.

[59] Material records must cover the entire length of the ***special permit segment***, regardless of when the pipeline, single or multiple pipe joints, or other pipeline components were installed. Affidavits for a material record are not acceptable TVC material records.

[60] FGT must submit the non-destructive assessment method and procedures to the Director, PHMSA Southwest Region, and the Director, PHMSA Engineering and Research Division. The Director, PHMSA Southwest Region, must respond to FGT's submittal letter within 90 days. The Director, PHMSA Southwest Region, may provide a decision, request for additional information, or notify FGT of PHMSA's need for additional time to provide a decision.

[61] FGT must send a copy of the assessment procedure to the Director, PHMSA Engineering and Research Division.

Region, may provide a decision, request for additional information, or notify FGT of PHMSA's need for additional time to provide a decision.

iv) FGT must assess pipe in a ***special permit segment*** with missing mill test reports (MTRs) or missing mill inspection reports (i.e. Moody Engineering Reports) for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a 2-year interval), and construction dates (within a 2-year interval).

v) FGT cannot use the material properties determined from either destructive or NDT required by this condition to raise the original grade or specification of the pipeline material. FGT must use the applicable standard referenced in 49 CFR 192.7.

vi) For a future ***special permit segment*** with missing mill inspection reports for mechanical and chemical properties, FGT must use the above methodology, or FGT may elect to remove pipe joints for destructive testing.[62]

e) **<u>Pipeline System Flow Reversals</u>**: For pipeline system flow reversals lasting longer than 90 days and where the MAOP for class location changes are exceeded under either 49 CFR 192.619(a)(1) or 192.611[63] in a ***special permit segment***, FGT must prepare a written plan that corresponds to the applicable criteria identified in the PHMSA Advisory Bulletin, ADB-2014-04, "Guidance for Pipeline Flow Reversals, Product Changes and Conversion of Service" (79 FR 56121; Sept. 18, 2014). FGT must submit the written flow reversal procedure to the Director, PHMSA Southwest Region, and submit a copy of the plan to the Federal Docket for this special permit at

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[62] FGT must prepare a procedure in accordance with **Condition 13(d) – Pipe Properties Testing**, for material documentation and submit to the Director, PHMSA Southwest Region, and receive a "no objection" letter prior to usage of the procedure. The Director, PHMSA Southwest Region, must respond to FGT's submittal letter within 90 days. The Director, PHMSA Southwest Region, may provide a decision, request for additional information, or notify FGT of PHMSA's need for additional time to provide a decision. A copy of the procedure must be sent to the Director, PHMSA Engineering and Research Division.

[63] An example of exceedance of 49 CFR 192.619(a)(1) is a Grandfathered MAOP which has a design factor above 0.72. An example of exceedance of 49 CFR 192.611 is a Class 1 to 3 location change.

www.regulations.gov.[64] FGT must receive a “no objection” letter from the Director, PHMSA Southwest Region, prior to implementing the pipeline system flow reversal through a ***special permit segment***.

f) **Environmental Assessments and Permits**: FGT must evaluate the potential environmental consequences and affected resources of any land disturbances and water body crossings, and pipeline natural gas emissions from implementation of the special permit conditions for a ***special permit segment*** or ***special permit inspection area*** prior to the disturbance or activity. If a land disturbance, water body crossing, or pipeline natural gas emission is required, FGT must obtain and adhere to all applicable federal, state, and local environmental permit requirements when conducting the special permit conditions activity.

g) **Gas Quality**: FGT must transport gas through the ***special permit segment*** whose composition quality is suitable for sale to gas distribution customers, including no free-flow water or hydrocarbons, no water vapor content that exceeds acceptable limits for gas distribution customer delivery, hydrogen sulfide (H_2S) not to exceed one (1) grain per 100 cubic feet, or carbon dioxide (CO_2) not to exceed three (3) percent by volume.

h) **Annual Class Location Study**: FGT must conduct a class location study on the ***special permit inspection area*** at least once each calendar year, with intervals not to exceed 15 months, in accordance with 49 CFR 192.609.

i) **Notifications**: For any special permit condition that requires FGT to provide a notice for a “no objection” response from PHMSA, other notice, annual report, or documentation to the Director, PHMSA Southwest Region, FGT must also send a copy to the State Agency that has interstate agent agreements with PHMSA and to the Director, PHMSA State Programs.

j) **Pipe and Soil Movement**: Girth weld strain from soil movement exerted onto the pipeline in the ***special permit segment*** must not exceed 0.5 percent and must account for girth weld misalignment. FGT must develop procedures on how to evaluate and

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[64] FGT must send a copy of the flow reversal procedure to the Director, PHMSA Engineering and Research Division.

remediate soil stresses and strains on the pipeline including IMU intervals. FGT must submit soil stress and strain evaluation and remediation procedures to the Director, PHMSA Southwest Region, within three (3) months of identification and must receive a "no objection" letter prior to implementation.

k) **Gas Leakage Surveys and Remediation**:

i) FGT must conduct gas leakage surveys using instrumented gas leakage detection equipment along each ***special permit segment*** and at all valves, flanges, pipeline tie-ins, ILI launcher and ILI receiver facilities in each ***special permit inspection area*** at least twice each calendar year, not to exceed 7½ months. FGT must document the type of equipment used, survey findings, and remediation of all instrumented gas leakage surveys.

ii) A gas transmission pipeline leak is a gas leak that can be seen, heard, felt, or detected by instrumented gas leakage detection equipment, or is an existing, probable, or future hazard to the public, operating personnel, property, or the environment. FGT must grade and remediate all gas transmission pipeline leaks in the ***special permit segment*** and at all valves, flanges, pipeline tie-ins, ILI launcher, and ILI receiver facilities in each ***special permit inspection area***, as follows:

(1) A Grade 1 leak requires immediate and/or continuous remediation efforts to stop the leak. A Grade 1 leak is defined as any of the following:

(a) Any leak which, in the judgment of the operating personnel at the scene, is regarded as an immediate hazard;

(b) Escaping gas that has ignited;

(c) Any indication of gas which has migrated into or under a building, or into a tunnel.

(d) Any reading at the outside wall of a building, or any reading where gas would likely migrate to an outside wall of a building;

(e) Any reading of 80% lower explosive limit (LEL), or greater, in a confined space;

(f) Any reading of 80% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building; or

(g) Any leak that can be seen, heard, or felt, and which is in a location that may endanger the public, property, or environment.

(2) A Grade 2 leak requires remediation activity to be completed within 30 days or must have continuous remediation efforts to stop the leak. A Grade 2 leak is defined as any of the following:

(a) Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building;

(b) Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak;

(c) Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak;

(d) Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard;

(e) Any reading between 20% LEL and 80% LEL in a confined space;

(f) Any reading on a pipeline operating at 30% SMYS or greater, in a Class 3 or 4 location, which does not qualify as a Grade 1 leak;

(g) Any reading of 80% LEL, or greater, in gas associated substructures; or

(h) Any leak which, in the judgement of operating personnel at the scene, is of sufficient magnitude to justify schedule repair.

(3) A Grade 3 leak must be reevaluated at the next scheduled survey, or within 7½ months of the date discovered, whichever occurs first, until the leak is cleared, re-graded, or remediated. Remediation of Grade 3 leaks must be completed within 24 months of discovery of the leak. A Grade 3 leak is defined as any of the following:

(a) Any reading of less than 80% LEL in small gas associated structures;

(b) Any reading in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building; or

(c) Any reading of less than 20% LEL in a confined space.

iii) When a pressure limiting device or relief valve allows a gas release to the atmosphere that is located along the ***special permit inspection area***, FGT must conduct an O&M procedure assessment of the pilot, springs, pressure gauges, and other pressure limiting equipment to ensure these items are properly functioning, sensing, and retaining set pressures. If a pressure limiting device or relief valve deficiency cannot be remediated, the pressure limiting device or relief valve must be replaced or continuously monitored until remediated. FGT cannot extend or change any remediation timing or continuous monitoring requirements in this paragraph without a "no objection" letter received by FGT from the Director, PHMSA Southwest Region.

iv) FGT may request an extension of the remediation time interval requirements by sending a request to the Director, PHMSA Southwest Region, but must receive a "no objection" letter from the Director, PHMSA Southwest Region, prior to extending the leak remediation timing or continuous monitoring requirements in **Condition 13(k)**.[65]

l) **Right-of-Way Patrols**: In addition to the requirements of 49 CFR 192.705, FGT must perform right-of-way patrols as follows:

i) Aerial flyover patrols or ground patrols by walking or driving of a ***special permit segment*** right-of-way once each month, not to exceed 45 days, contingent on weather conditions. Should mechanical availability of the patrol aircraft or weather conditions become an extended issue, the ***special permit segment pipeline*** aerial

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[65] Any FGT request for a time interval extension for a 24-month remediation interval must be 90 days prior to the end of the 24-month remediation interval.

flyover patrol must be completed within 60 days of the last patrol by other methods such as walking or driving the pipeline route, as feasible.

ii) If the schedule for either ground patrols or aerial flyover patrols cannot be met due to circumstances beyond FGT's control, FGT must notify the Director, PHMSA Southwest Region, in writing of the reasons the schedule cannot be met and obtain a letter of "No Objection" within three (3) business days of the exceedance.

m) **Minimization of Gas Released to the Environment**:

i) FGT must reduce the release of gas to the environment when replacing any pipe between the mainline isolating valves for a ***special permit segment***. FGT must use one (1) or more of following methods that will reduce the environmental effects of methane (gas) being released. FGT must calculate the volume of natural gas that will be released by each method or combination of methods and select an option(s) that minimizes the release of gas to the environment and is consistent with pipeline safety.[66]

1) Isolate a smaller pipeline segment length by use of valves and/or the installation of control fittings near the pipe being replaced;

2) Flaring the gas released from the pipeline from the nearest isolation valves or control fittings from the pipe being replaced;

3) Pressure reduction in the pipeline segment by use of inline compression;

4) Pressure reduction by use of mobile compression from the nearest isolation valves from the pipe being replaced;

5) Transfer the gas to a lower pressure pipeline system or segment from the nearest isolation valves nearest to the pipe being replaced such as through a lateral delivering gas to another pipeline facility; or

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[66] **Condition 13(m)** would not be required for a blowdown due to an immediate repair, as detailed in **Condition 8 - Anomaly Evaluation and Remediation**, or where immediate action is required to ensure public safety.

6) An alternative method demonstrated to minimize the release of gas to the environment similar to the other methods listed in the methods (1) through (5) above.

ii) FGT must document the determination and justification for the reduction method(s) implemented and how the method(s) used minimized the release of natural gas to the environment and was consistent with pipeline safety. FGT must also document and justify, any substantial difference (over 10 percent additional release) between the actual amount of natural gas released and the estimated volume calculated before the replacement.

iii) FGT must report all mainline blowdowns between the mainline isolating valves for a ***special permit segment*** due to pipe replacement as detailed in the **Condition 15(i) - Annual Report**.

14) **Condition 14 - Field Activity Notices to PHMSA**

FGT must give a minimum 14-day notice to the Director, PHMSA Southwest Region, to enable PHMSA to observe the excavations relating to **Condition 8 – Anomaly Evaluation and Remediation** and **Condition 13(d) – Pipe Properties Testing** of field activities in the ***special permit inspection area***. Immediate response conditions do not require 14-day notice, but FGT should notify the Director, PHMSA Southwest Region, no later than two (2) business days after the immediate condition is discovered. The Director, PHMSA Southwest Region, may elect not to require a notification for some activities.

15) **Condition 15 - Annual Report**

Annually[67] after the grant of this special permit, FGT must report the following to the Director, PHMSA Southwest Region, with copies to the Director, PHMSA Engineering and Research Division:[68]

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[67] PHMSA must receive the annual report by the last day of the month in which the special permit is dated. For example, the annual report for a special permit dated January 21, 2020, must be received by PHMSA no later than January 31, each year beginning in 2021.

[68] FGT must post the annual report to the special permit docket PHMSA-2021-0118 at www.regulations.gov.

a) The number of new residences, other structures intended for human occupancy, and public gathering areas built within each ***special permit segment*** during the previous year. FGT must include a summary of the results of the study conducted to meet **Condition 13(h) - Annual Class Location Study** in the annual report.

b) Any new integrity threats identified during the previous year and the results of any ILI or direct assessments performed (including any un-remediated anomalies over 30% wall loss; cracking found in the pipe body, weld seam, or girth welds; and dents with metal loss, cracking, or stress riser) and any soil movement (lateral or subsidence) that affects pipeline integrity[69] during the previous year in the ***special permit inspection area***, including their survey station, predicted failure pressure, anomaly depth and length, class location, and whether these threats are in an HCA.

c) In the 1st, 2nd, and 3rd annual reports FGT must report any ***special permit segment*** that does not have the following complaint TVC records:

   i) A pressure test that meets **Condition 1(b)**. FGT must report the planned or actual completion dates for the ***special permit segment*** pressure test including test pressure.

   ii) Material pipe properties tests that meet **Condition 13(d) – Pipe Properties Testing**. FGT must report the planned or actual completion dates for the ***special permit segment*** material pipe property tests.

d) Any reportable incident, any leak normally indicated on the DOT Annual Report, and all repairs on the pipeline that occurred during the previous year in a ***special permit inspection area***. FGT must include the location by mile post, County/Parish and State, the date of discovery, date of repair, and estimated gas loss (cubic feet) per day and in total for any Grade 1, 2, or 3 gas leak as described in **Condition 13(k) - Gas Leakage Surveys and Remediation**.

e) Any ongoing DP initiatives affecting a ***special permit inspection area*** and a discussion of the success of the initiatives, including findings and remediation actions.

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[69] FGT must develop and implement an O&M procedure to review soil movements that could damage the ***special permit segment*** on a periodic interval so the lateral stresses will not exceed 100% of SMYS (0.5% strain) on girth welds.

f) FGT must submit annual data integration information, as required in **Condition 13(c) - Data Integration,** beginning with the 2nd annual report, which must include an annual overview of any new threats. If requested by PHMSA, FGT must submit a full information package of the requested pipeline attribute and integrity items outlined in the condition.

g) If FGT uses ASVs for **Condition 12 – Mainline Valve**, FGT must report the set pressure and how it was determined for each year to meet "as soon as practicable but 30 minutes or less."

h) FGT must report the diameter and location of the lateral, if any lateral or crossover piping is not included in **Table 4 – Valves and Lateral Locations with Isolation Methods** or installed between isolation valves for a ***special permit segment***.

i) FGT must report all mainline blowdowns between the mainline isolating valves for a ***special permit segment*** due to pipe replacement which includes the date of blowdown, location (milepost/stationing), and the amount of gas released to comply with **Condition 13(m) – Minimization of Gas Released to the Environment**.

j) Any mergers, acquisitions, transfer of assets, or other events affecting the regulatory responsibility of the company operating the pipeline.

k) A senior executive officer, vice president, or higher executive of FGT must review for correctness, date, and sign the annual report prior to posting it to the Federal Docket (PHMSA-2021-0118) at www.regulations.gov and submitting a copy to the Director, PHMSA Southwest Region, and the Director, PHMSA Engineering and Research Division.

l) FGT must schedule a review meeting regarding **Condition 15 - Annual Report** with the Director, PHMSA Southwest Region, prior to or within one (1) month of the filing of each year.[70] During the annual review meeting, FGT must review the status of implementing the special permit conditions with the Director, PHMSA Southwest Region.

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[70] The Director, PHMSA Southwest Region, has the authority to waive this meeting.

16) **<u>Condition 16 – Documentation</u>**

FGT must maintain the following records for a ***special permit segment*** as follows:

a) FGT must keep documentation of compliance with all conditions of this special permit for the life of the pipe.

b) Documentation of the mechanical and chemical properties (e.g., mill test reports) that show the pipe in a ***special permit segment*** meets the wall thickness, yield strength, tensile strength, and chemical composition requirements of API Standard 5L, 5LX or 5LS, "Specification for Line Pipe" (API 5L) incorporated by reference into the 49 CFR Part 192 code at the time of manufacturing, or, if the pipe was manufactured and placed in-service prior to the inception of 49 CFR Part 192, the API 5L standard in use at that time. Any pipe in a ***special permit segment*** that does not have TVC mill test reports or does not meet **Condition 13(d) – Pipe Properties Testing** and 49 CFR 192.607 cannot be authorized per this special permit.

17) **<u>Condition 17 - Extension of the Special Permit Segment</u>**

PHMSA may extend a ***special permit segment*** to include contiguous segments up to the limits of the ***special permit inspection area*** pursuant to FGT implementing the following conditions:

a) Within six (6) months after the Class 1 to Class 3 location change, FGT must provide notice to the Director, PHMSA Southwest Region, and Director, PHMSA Engineering and Research Division, of the request for a ***special permit segment <u>extension</u>***.

   i) The notice must include the ***special permit segment extension*** survey stations, mile posts, additional pipeline footage, pipe attributes (wall thickness, grade, seam type, external coating, and latest pressure test), predicted failure pressure of any anomalies over 30% wall loss, schedule of inspections, and of any anticipated remedial actions.

   ii) FGT must update the Final Environmental Assessment (FEA) to reflect the ***special permit segment*** extension and Section IX of the FEA, "Affected Resources and Environmental Consequences" as necessary. FGT must submit the updated FEA with its request for an extension to PHMSA for review and consideration.

iii) Any request for a ***special permit segment*** extension does not become effective until FGT receives a "no objection" response from the Director, PHMSA Engineering and Research Division.

b) Any proposed ***special permit segment extension*** must meet the following requirements prior to the class location change or within 12 months of the class location change:

i) FGT must remediate all anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**;

ii) FGT must have hydrostatically tested[71] a ***special permit segment*** and ***extension*** in accordance with **Condition 1 – Maximum Allowable Operating Pressure**, as applicable; and

iii) FGT must complete all required special permit conditions, except **Condition 17(b)** above, for each ***special permit segment extension*** within two (2) years of the Class 1 to Class 3 location change, unless specified otherwise.

c) FGT must apply all the special permit conditions and limitations included herein to all future ***special permit segment extensions***.

18) **<u>Condition 18 – Certification</u>**

FGT must meet the following conditions for certification:

a) A senior executive officer, vice president, or higher executive of FGT must certify in writing the following:

i) Each ***special permit inspection area*** and ***special permit segment*** meet the conditions described in this special permit;

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[71] For all in-service and pressure test failures, FGT must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. FGT must provide the written results of this root cause analysis to the Director, PHMSA Southwest Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

ii) FGT has updated its O&M, IM program, and DP procedures required by **Condition 2 – Procedure Updates** to require the implementation of the special permit conditions for each ***special permit segment*** and ***special permit inspection area***;

iii) FGT has prepared an uprating plan in accordance with **Condition 1(c)**, if applicable; and

iv) FGT has implemented all conditions as required by this special permit.

b) FGT must send the certifications required in **Condition 18(a)**, with special permit condition status, completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Southwest Region; the Director, PHMSA Engineering and Research Division; and the Federal Register Docket (PHMSA-2021-0118) at www.regulations.gov within one (1) year of the issuance date of this special permit.

Limitations

This special permit is subject to the limitations set forth in 49 CFR 190.341, as well as the following limitations:

1) PHMSA has the sole authority to make all determinations on whether FGT has complied with the specified conditions of this special permit. Failure to comply with any condition of this special permit may result in revocation of the permit.

2) Any work plans and associated schedules for a ***special permit segment*** and ***special permit inspection area*** are automatically incorporated into this special permit and are enforceable in the same manner.

3) Failure by FGT to submit the certifications required by **Condition 18 - Certification** within the time frames specified may result in revocation of this special permit.

4) As provided in 49 CFR 190.341, PHMSA may issue an enforcement action for failure to comply with this special permit. The terms and conditions of any corrective action order, compliance order, or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit.

5) If FGT sells, merges, transfers, or otherwise disposes of all or part of the assets known as a ***special permit segment*** or ***special permit inspection area***, FGT must provide PHMSA with written notice of the change within 30 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the special permit if the transfer constitutes a material change in conditions or circumstances underlying the permit.
6) PHMSA grants this special permit to limit it to a term of no more than 10 years from the date of issuance. If FGT elects to seek renewal of this special permit, FGT must submit its renewal request at least 180 days prior to expiration of the 10-year period to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Southwest Region, and to the Director, PHMSA Engineering and Research Division. All requests for a renewal must include a summary report in accordance with the requirements in **Condition 15 - Annual Report** above and must demonstrate that the special permit is still consistent with pipeline safety. PHMSA may seek additional information from FGT prior to granting any request for special permit renewal.

AUTHORITY: 49 U.S.C. 60118 (c)(1) and 49 CFR 1.97.

Issued in Washington, DC on April 4, 2022.

Signed copy of the special permit with tables, figures, and attachments is available as noted below. Attachment A is in the special permit.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety

The granted special permit with conditions granted to FGT for Docket No. PHMSA-2021-0118 can be found the Federal Dockets Management System located on the internet at www.regulations.gov or on the PHMSA website for special permits issued at https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-issued.

Last Page of the FEA and FONSI