U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
SPECIAL PERMIT - Class 1 or Class 2 to Class 3 Location

Special Permit Information:

Docket Number:	PHMSA-2020-0044
Requested By:	Florida Gas Transmission Company, LLC
Operator ID#:	5304
Original Date Requested:	February 21, 2020
Original Issuance Date:	March 30, 2022
Segment Extensions Request:[1]	March 24, 2023
Effective Dates:[2]	March 30, 2022, to March 30, 2032
Code Section(s):	49 CFR 192.611(a)(3)(iii)

Grant of Special Permit:

By this order, subject to the terms and conditions set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS)[3] grants this special permit modification to Florida Gas Transmission Company, LLC (FGT)[4] for 7,130 feet of 18-inch diameter, 8,551 feet of 30-inch diameter, and 1,956 feet of 36-inch diameter gas transmission pipelines located in Citrus, Hernando, Hillsborough, and Pasco Counties, Florida.[5]

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[1] This special permit has been updated to account for the extensions (ext.) of ***five (5) special permit segments 166347 ext., 166349 ext., 166250 ext., 166256 ext., and 166129 ext.*** as shown in **Table 1 – Special Permit Segments**.

[2] The effective date for the extension of ***five (5) special permit segments 166347 ext., 166349 ext., 166250 ext., 166256 ext., and 166129 ext.*** as shown in **Table 1 – Special Permit Segments** is **the grant date of this special permit for the five (5) special permit segment extensions**.

[3] 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.

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

[5] Total pipeline footage under this special permit on the March 30, 2022, original issuance date was 7,418 feet (1.405 miles) of either 18-inch diameter, 30-inch diameter, or 36-inch diameter pipelines.

Within this special permit PHMSA waives compliance from 49 Code of Federal Regulations (CFR) 192.611(a)(3)(iii) for the ***three (3) special permit segments*** that have undergone a class change from Class 1 to Class 3 and ***fifteen (15) special permit segments*** that have changed from Class 2 to Class 3 locations. The Federal pipeline safety regulations in 49 CFR 192.611(a)(3)(iii) require natural gas pipeline operators to confirm or revise the maximum allowable operating pressure (MAOP) of a pipeline segment after a change in class location. [6]

A request for a special permit modification was submitted by FGT on March 24, 2023, for issuance of a special permit for ***five (5) special permit segment extensions*** pursuant to **Condition 17** of the special permit. The ***five (5) special permit segment extensions*** include a combined 10,219 feet (approximately 1.935 miles) from the 18-inch diameter St. Petersburg Sarasota Connector pipeline (***special permit segments 166347 extension (ext.) and 166349 ext.***), 30-inch diameter West Leg Station 26-27 (***special permit segments 166250 ext. and 166256 ext.***), and 36-inch diameter West Leg Loop (***special permit segment 166129 ext.***) where a class location has changed from Class 2 to Class 3 located in Hillsborough, Hernando, and Pasco County, Florida.

I. Purpose and Need:

FGT sought this special permit modification for Class 1 to Class 3 location or Class 2 to Class 3 location changes occurring on the 18-inch diameter St. Petersburg Sarasota Connector, 30-inch diameter West Leg Station 26-27, and 36-inch diameter West Leg Loop Pipelines (Pipelines). On the condition that FGT complies with the terms and conditions set forth below, this special permit waives compliance from 49 CFR 192.611 (a)(3)(iii) for 17,637 feet (approximately 3.340 miles) of natural gas transmission pipelines, where the class location of the lines changed from Class 1 or Class 2 to a Class 3 location in Citrus, Hernando, Hillsborough, and Pasco Counties, Florida. This special permit modification allows FGT to maintain the current MAOP of either 1,322 pounds per square inch gauge (psig) or 1,333 psig on the Pipelines, where the ***special permit segment*** pressure test does not meet the 1.5 times MAOP requirements in 49 CFR 192.611(a)(3)(iii) for a change to a Class 3 location. The

[6] The Class 1 to 3 or Class 2 to 3 location changes on the FGT pipelines have pipe with design factors in accordance with 49 CFR 192.620(a)(1) for Alternative MAOP. The ***special permit segments*** utilize alternate design factors from 49 CFR 192.620 per existing special permit PHMSA-2008-0077.

special permit segments were pressure tested between 1.42 to 1.46 times MAOP as shown in **Table 1 - Special Permit Segments.**

II. Special Permit Segments and Special Permit Inspection Areas:

This special permit modification pertains to the specified ***special permit segments*** and corresponding ***special permit inspection areas*** defined in this section.

Special Permit Segments:

This special permit applies to the ***special permit segments*** identified in **Table 1 – Special Permit Segments** and are identified using the FGT survey station (SS) references. A total of 1,603 feet (approximately 0.304 miles) of pipeline along the FGT system have undergone a class change from Class 1 to Class 3. A total of 16,034 feet (approximately 3.037 miles) of pipeline along the FGT system have undergone a class change from Class 2 to Class 3.

- The ***special permit segments*** utilize alternate design factors from 49 CFR 192.620 per existing special permit PHMSA-2008-0077.

Table 1 – Special Permit Segments											
Special Permit Segment Number	**Outside Diameter (inches)**	**Line Name/ (Diameter, wall thickness, Grade)**	**Length (feet)**	**Start Survey Station (SS)**	**End Survey Station (SS)**	**County, State**	**Class Summary**	**Year Installed**	**Seam and Coating Type**	**MAOP (psig)**	**Design/ Pressure Test Factor**
166334	18	St. Petersburg Sarasota Connector/ (18", 0.258", X70)	1,156	54+60	66+16	Hillsborough, FL	1 to 3	1992	HF-ERW/ FBE	1,333	0.67 / 1.42
166338	18	St. Petersburg Sarasota Connector/ (18", 0.309", X70)	315	206+51	209+66	Hillsborough, FL	1 to 3	1992	HF-ERW/ FBE	1,333	0.56 / 1.42
166340	18	St. Petersburg Sarasota Connector/ (18", 0.309", X70)	132	406+43	407+75	Hillsborough, FL	1 to 3	1992	HF-ERW/ FBE	1,333	0.56 / 1.42
166347 ext.	18	St. Petersburg Sarasota Connector (18", 0.258", X70)	269	901+98	904+67	Hillsborough, FL	2 to 3	1992	HF-ERW/ FBE	1,333	0.67 / 1.42
166347	18	St. Petersburg Sarasota Connector (18", 0.258", X70)	532	904+67	909+99	Hillsborough, FL	2 to 3	1992	HF-ERW/ FBE	1,333	0.67 / 1.42
166349	18	St. Petersburg Sarasota Connector (18", 0.309", X70)	456	1014+01	1018+57	Hillsborough, FL	2 to 3	1992	HF-ERW/ FBE	1,333	0.56 / 1.42
166349 ext.	18	St. Petersburg Sarasota Connector (18", 0.309", X70)	3,537	1018+57	1053+94	Hillsborough, FL	2 to 3	1992	HF-ERW/ FBE	1,333	0.56 / 1.42
166350	18	St. Petersburg Sarasota Connector (18", 0.309", X70)	474	1079+72	1084+46	Hillsborough, FL	2 to 3	1992	HF-ERW/ FBE	1,333	0.56 / 1.42
166352	18	St. Petersburg Sarasota Connector (18", 0.309", X70)	259	1212+12	1214+71	Hillsborough, FL	2 to 3	1992	HF-ERW/ FBE	1,333	0.56 / 1.42
166250 ext.	30	West Leg Station 26-27 MP 160.2 (30", 0.430", X70)	5,799	992+75	1050+74	Hernando, FL	2 to 3	1994	DSAW/ FBE	1,322	0.67 / 1.45
166250	30	West Leg Station 26-27 MP 160.2 (30", 0.430", X70)	1,004	1050+74	1060+78	Hernando, FL	2 to 3	1994	DSAW/ FBE	1,322	0.67 / 1.45
166256 ext.	30	West Leg Station 26-27 MP 160.2 (30", 0.430", X70)	404	1863+70	1867+74	Pasco, FL	2 to 3	1994	DSAW/ FBE	1,322	0.67 / 1.45
166256	30	West Leg Station 26-27 MP 160.2 (30", 0.430", X70)	318	1867+74	1870+92	Pasco, FL	2 to 3	1994	DSAW/ FBE	1,322	0.67 / 1.45
166257	30	West Leg Station 26-27 MP 160.2 (30", 0.430", X70)	165	1870+92	1872+57	Pasco, FL	2 to 3	1994	DSAW/ FBE	1,322	0.67 / 1.45
166267	30	West Leg Station 26-27 MP 160.2 (30", 0.515", X70)	861	3488+40	3497+01	Hillsborough, FL	2 to 3	1994	SAW/ FBE	1,322	0.56 / 1.44
166114	36	West Leg Loop (36", 0.515", X70)	1,252	104+57	117+09	Citrus, FL	2 to 3	2003	DSAW/ FBE	1,322	0.67 / 1.42
166129 ext.	36	West Leg Loop (36", 0.515", X70)	210	991+72	993+82	Hernando, FL	2 to 3	2007	DSAW/ FBE	1,322	0.67 / 1.46
166129	36	West Leg Loop (36", 0.515", X70)	494	993+82	998+76	Hernando, FL	2 to 3	2007	DSAW/ FBE	1,322	0.67 / 1.46

Notes:

1) **HF-ERW** is high frequency electric resistance welded seam type pipe.
2) **DSAW** is double submerged arc welded seam type pipe.
3) **SAW** is submerged arc welded seam type pipe.
4) **FBE** is fusion bonded epoxy external pipe coating.

Special Permit Inspection Areas:

Special permit inspection area is defined to mean the area that extends 220 yards on each side of the centerline. The ***eighteen (18) special permit segments*** are in a total of ***three (3) special permit inspection areas*** totaling 169.5 miles. A summary of ***special permit inspection areas*** is included in **Table 2 – Special Permit Inspection Areas**.

Table 2 – Special Permit Inspection Areas

Special Permit Inspection Area Name	Special Permit Segment Number(s)	Outside Diameter (inches)	Line Name	Start Survey Station (Mile Post)	End Survey Station (Mile Post)	Length[7] (miles)
FLMEF-26	166114, 166129, 166129 ext.	36	West Leg Loop	90.6	153.8	63.2
FLMEE-26-27	166250, 166250 ext., 166267, 166256, 166256 ext., 166257	30	West Leg Station 26-27 MP 160.2	90.6	160.2	69.6
FLBVW	166334, 166338, 166340, 166347, 166347 ext., 166349, 166349 ext., 166350, 166352	18	St. Petersburg/ Sarasota Connector	0.2	36.9	36.7

Note: The ***special permit inspection areas*** are in Citrus, Hernando, Hillsborough, and Pasco Counties, Florida.[8]

Extended special permit segment: The ***extended special permit segment*** is defined as the ***special permit segment*** and the five (5) contiguous miles past each endpoint. **Attachments B-1 through B-3** are route maps showing the ***special permit segments, special permit inspection areas***, and class locations.

PHMSA is granting this special permit modification based on the findings set forth in the "Special Permit Analysis and Findings" document, which can be read in its entirety in Docket No. PHMSA-2020-0044 in the Federal Docket Management System (FDMS) located on the internet at www.regulations.gov.

III. Conditions:

PHMSA grants this special permit modification subject to FGT implementing the following conditions on the ***special permit segments*** and ***special permit inspection areas***. FGT must

[7] If the ***special permit inspection area*** footage does not extent from launcher to receiver then the ***special permit inspection area*** would need to be extended.

[8] The ***special permit inspection areas*** include the ***special permit segments***.

continue to implement all applicable conditions of **Special Permit – PHMSA-2008-0077** unless the condition is less stringent than **Special Permit – PHMSA-2020-0044**. The lower pressure test factors shown in **Table 1 – Special Permit Segments** are allowed by Special Permit 2020-0044.

- PHMSA emphasizes that the required conditions specified for the ***eighteen (18) special permit segments*** and ***three (3) special permit inspection areas*** addressed here will control, superseding any inconsistent requirements applicable to the ***eighteen (18) special permit segments*** and ***three (3) special permit inspection areas*** in special permit PHMSA-2008-0077.

Each condition detailed in this section is applicable to the ***special permit inspection areas*** and the corresponding ***special permit segments*** unless otherwise noted in the condition:

1) **Condition 1 - Maximum Allowable Operating Pressure**

   a) **Maximum Allowable Operating Pressure**: FGT must continue to operate the ***special permit segments*** and ***special permit inspection areas*** at or below the existing MAOP as follows:

   - ***Special permit segment 166334*** – 1,333 psig;
   - ***Special permit segment 166338*** – 1,333 psig;
   - ***Special permit segment 166340*** – 1,333 psig;
   - ***Special permit segment 166347*** – 1,333 psig;
   - ***Special permit segment 166347 ext.*** – 1,333 psig;
   - ***Special permit segment 166349*** – 1,333 psig;
   - ***Special permit segment 166349 ext.*** – 1,333 psig;
   - ***Special permit segment 166350*** – 1,333 psig;
   - ***Special permit segment 166352*** – 1,333 psig;
   - ***Special permit segment 166250*** – 1,322 psig;
   - ***Special permit segment 166250 ext.*** – 1,322 psig;
   - ***Special permit segment 166256*** – 1,322 psig;
   - ***Special permit segment 166256 ext.*** – 1,322 psig;
   - ***Special permit segment 166257*** – 1,322 psig;
   - ***Special permit segment 166267*** – 1,322 psig;
   - ***Special permit segment 166114*** – 1,322 psig; and

- ***Special permit segment 166129*** – 1,322 psig.
- ***Special permit segment 166129 ext.*** – 1,322 psig.

b) **Pressure Test**: 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)[9] 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)**.[10] 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)**.[11]

ii) If FGT does not have a TVC record of 1.25 times the MAOP hydrotest in accordance with Subpart J, or the ***special permit segment*** requires an updated pressure test, the ***special permit segment*** must be hydrostatically tested[12] 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.[13]

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[9] 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; https://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf.

[10] 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.

[11] FGT has furnished TVC pressure test records to PHMSA for the ***special permit segments*** that meet **Condition 1(b)**.

[12] 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.

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

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.[14] 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.

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

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

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)[15] 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 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

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

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) **Condition 4 – Close Interval Surveys**

a) **Survey Methodology and Boundaries**:

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***.[16]

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) **Survey Intervals**: FGT must perform the CIS assessments 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 assessment may be conducted at the next reassessment interval.[17]

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[16] 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.

[17] 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.

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

c) **Survey Remediation and Remedial Action Plans**:

i) If a ***special permit segment*** requires the use of 100 millivolt shift criteria[18] 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 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.[19]

5) **Condition 5 – Inline Inspection**

a) **Threat Identification**: 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

[18] 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."

[19] 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.

the ***extended special permit segment***,[20] must be conducted using the current incorporated by reference (IBR) edition of the American Society of Mechanical Engineers Standard B31.8S, "Managing System Integrity of Gas Pipelines" (ASME B31.8S) Appendix A3 and NACE SP 0204-2008, "Stress Corrosion Cracking Direct Assessment Methodology," Sections 1.2.1.1 and 1.2.2.

b) **Inline Inspection Methodology**: 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[21] that will identify tight cracks.[22]

   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) **Inline Inspection Assessment Intervals**: 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:

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

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

[22] 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.

(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 a special permit grant date.

(3) All other identified threats must be assessed within two (2) years of 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 inspected, 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;[23] and

[23] 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.

iii) Excavate,[24] visually inspect, and perform NDT on at least two (2) girth welds on each ***special permit segment*** in accordance using 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.[25] FGT must remediate girth welds in the ***special permit segment*** in accordance with the inspection and remediation plan within 90 days of the "no-objection" letter receipt.[26]

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

FGT must evaluate the entire length of each ***special permit inspection area***[27] for SCC as follows:

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

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[24] 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***.

[25] 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.

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

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

b) **SCC Integrity Assessment**: If the threat assessment required under **Condition 7(a)** indicates the ***extended special permit segment***[28] 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.[29]

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 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 (PAUT), inverse wavefield extrapolation (IWEX), or magnetic particle inspection (MPI),[30] 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

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

[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.

[30] 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.

records[31] at all excavation locations in the ***special permit inspection area*** to demonstrate the coating condition.

e) **Discovery of SCC**: If FGT discovers SCC[32] 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,[33] 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[34] based upon the evaluated growth of the SCC, using one (1) of the following methods:

i) **Spike Hydrostatic Test Program**:[35]

(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;

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

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

[33] 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.

[34] 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 a 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.

[35] 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.

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 Southwest Region, and send a copy to the Director, PHMSA Engineering and Research Division, no later than 90 days after the finding of SCC.[36] 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

[36] 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.

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 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.[37]

(2) **EMAT ILI Tool Calibration**:

(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.

[37] 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.

(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 - 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"[38] interaction criteria for determining anomaly failure pressures and response timing.

iv) **Discovery Date**: The discovery date[39] 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***[40] 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***:

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[38] "6t" means pipe wall thickness times six (6).

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

[40] 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.

(1) Metal loss greater than 60% of pipe wall thickness, regardless of dimensions.

(2) 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) that meets any of the following:[41]

(a) Pipe operating up to 80% SMYS (Class 1 pipe) where the predicted failure pressure is less than or equal to 1.10 times the MAOP;

(b) Pipe operating up to 67% SMYS (Class 2 pipe) where the predicted failure pressure is less than or equal to 1.25 times the MAOP; or

(c) Pipe operating up to 56% SMYS (Class 3 pipe) where the predicted failure pressure is less than or equal to 1.40 times the MAOP.

(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 for pipe operating above 56% SMYS (Class 1 and 2 pipe) and that is less than 1.40 times MAOP for pipe operating up through 56% SMYS (Class 3 pipe) or the metal loss is greater than 50% of pipe wall thickness.[42]

(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

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[41] Special permit PHMSA-2008-0077 allows the ***special permit inspection area*** defined in this special permit (PHMSA-2020-0044) to be operated at the following MAOP stress levels: Class 1 pipe can operate up to 80% SMYS, Class 2 pipe up to 67% SMYS, and Class 3 up to 56% SMYS.

[42] 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).

MAOP for pipe operating above 56% SMYS (Class 1 and 2) and that is less than 1.40 times MAOP for pipe operating up through 56% SMYS (Class 3).

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

ii) **One-year conditions – Hard Spots for a "*special permit inspection area*"**: 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 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) **One-year conditions – dents, metal loss, and cracks for a "*special permit inspection area*"**: 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 anomaly 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 1.25 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe operating up to 80% SMYS, less than 1.50 times the MAOP for all other Class 2 locations or where Class 3 locations contain Class 2 pipe operating up to 67% SMYS, and less than 1.80 times the MAOP for Class 3 locations operating up to 56% SMYS.

(5) Metal loss anomaly 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 1.25 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe operating up to 80% SMYS, less than 1.50 times the MAOP for all other Class 2 locations or where Class 3 locations contain Class 2 pipe operating up to 67% SMYS, and less than 1.80 times the MAOP for Class 3 locations operating up to 56% SMYS.

(6) Metal loss anomaly 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 1.25 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe operating up to 80% SMYS, less than 1.50 times the MAOP for all other Class 2 locations or where Class 3 locations contain Class 2 pipe operating up to 67% SMYS, and less than 1.80 times the MAOP for Class 3 locations operating up to 56% SMYS.[43]

(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 1.25 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe operating up to

[43] 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).

80% SMYS, is less than 1.50 times the MAOP for all other Class 2 locations or where Class 3 locations contain Class 2 pipe operating up to 67% SMYS, and is less than 1.80 times the MAOP for Class 3 locations operating up to 56% SMYS.

iv) **Two-year condition for crack repairs for a "*special permit inspection area*"**: 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 outside of the ***special permit segment***.

(v) **Monitored conditions for a "*special permit inspection area*"**: 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 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: 1.25 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe operating up to 80% SMYS, 1.50 times the MAOP for all other Class 2 locations or where Class 3 locations contain Class 2 pipe operating up to 67% SMYS and 1.80 times the MAOP for Class 3 locations operating up to 56% SMYS.[44]

(6) A crack or crack-like anomaly where the crack depth is less than 40% of the pipe wall thickness and the predicted failure pressure, determined in accordance with 49 CFR 192.712(d), is greater than or equal to: 1.25 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe operating up to 80% SMYS, 1.50 times the MAOP for all other Class 2 locations or where Class 3 locations contain Class 2 pipe operating up to 67% SMYS and 1.80 times the MAOP for Class 3 locations operating up to 56% SMYS.[45]

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:[46]

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[44] 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).

[45] 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.

[46] 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.

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.[47]

(3) **Class 1 pipe**: Any anomaly with a predicted failure pressure less than 1.39 times the MAOP. **Note:** This special permit does not allow pipe to operate above 72% of SMYS in the ***special permit segment***.

(4) **Class 2 pipe**: Any anomaly with a predicted failure pressure less than 1.50 times the MAOP.

(5) **Class 3 pipe**: Any anomaly with a predicted failure pressure less than 1.8 times the MAOP.

ii) **One-year crack repair conditions for a "*special permit segment*"**: 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) **Un-cleared shorted casing for a "*special permit segment*"**: 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) **Monitored conditions for a "*special permit segment*"**: 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) **Class 1 pipe**: 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.

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[47] 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).

(2) **Class 2 pipe**: Any anomaly with a predicted failure pressure greater than or equal to 1.50 times the MAOP and an anomaly depth less than or equal to 40% wall thickness loss.

(3) **Class 3 pipe**: Any anomaly with a predicted failure pressure greater than or equal to 1.8 times the MAOP and an anomaly depth less than or equal to 40% of pipe wall thickness.

9) **Condition 9 - Pipe Casings**

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.[48]

a) **Clear Shorted Casings**: 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) **Metallic Shorts**: 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) **Electrolytic Shorts**: 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) **All Shorted Casings**: 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.

[48] As of the date of the grant (issuance date) of this special permit, FGT reported they identified zero (0) shorted casings within a ***special permit segment***.

b) **Remediation of Un-cleared Casing Shorts**: 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.[49, 50] 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 (a minimum of HR-MFL and HR-Deformation ILI and with EMAT ILI when a ***special permit segment*** is susceptible to SCC) 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) **Condition 10 - Pipe - Seam Evaluations**

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) **Identify and Test Pipe Seam Issues**:

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***.[51] 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

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[49] 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.

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

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

(2) Figure 4.2, "Framework for Evaluation with Path for the Segment Analyzed Highlighted" from TTO-5, "Low Frequency ERW and Lap Welded Longitudinal 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.[52]

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;

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;[53]

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

[53] 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***.

iii) Pipe in the ***extended special permit segment*** was constructed or manufactured prior to 1954 and had pipe seam leaks or ruptures;[54]

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[55] 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:

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.

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[54] 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***.

[55] 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.

11) **Condition 11 - Control of Interference Currents**

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) **Surveys**: 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) **Analysis of Results**: 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) **Remediation**: 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) **Completion Schedules**: 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) **Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures**

FGT must automate mainline valves[56] 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.[57] 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) **Valve Locations**: ASVs or RCVs must be installed as shown in **Table 4 – Valves and Lateral Locations with Isolations Methods.** All ***special permit segments*** must have telemetry connections to the FGT supervisory control and data acquisition (SCADA) system installed.

b) **Automatic Shutoff Valve Requirements**:

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 between the ASV or RCV valves. 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

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

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

be installed. **Table 4 – Valves and Lateral Locations with Isolation Methods** has the ASV shutoff pressures and shut-off 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 ***special 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[58] connects to the isolated segment between the upstream and downstream mainline valves,

[58] **Table 4 – Valves and Lateral Locations with Isolation Methods** has a listing of all lateral valves. FGT must update **Table 4 – Valves and Lateral Locations with Isolation Methods** 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**.

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.[59] Crossover 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 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."

[59] 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.

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:[60]

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

(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.

[60] 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.

ii) FGT must evaluate and identify a rupture,[61] 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.

k) **Inoperable Valves**: 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

[61] 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.

reasons the schedule cannot be met and obtain a letter of "no objection" from PHMSA prior to implementing the schedule change.

l) **Emergency Communications:**

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;[62] 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***.

13) **Condition 13 - Special Permit Specific Conditions**

FGT must comply with the following requirements:

a) **Line-of-Sight Markers**: 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) **Depth of Cover Survey**:

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-

[62] 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.

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) **Data Integration**: FGT must develop and maintain data integration[63] in accordance with 49 CFR 192.917, of all special permit condition findings and remediation in a ***special 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.[64] Structures must be validated each calendar year by obtaining new aerial imagery or by ground patrol in accordance with **Condition 13(h)**.

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[63] 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.

[64] 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.

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:[65]

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for any ***special permit segment***, without TVC[66, 67] 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.[68] If NDT of pipe material

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

[66] 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; https://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf.

[67] 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.

[68] 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.

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.[69] 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.

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% 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.[70]

e) **Pipeline System Flow Reversals**: For pipeline system flow reversals lasting longer than 90 days and where the MAOP for class location changes are exceeded under either 49

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

[70] FGT must prepare a procedure in accordance with **Condition 13(d) – Pipe Property 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.

CFR 192.619(a)(1) or 192.611[71] 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 www.regulations.gov.[72] 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

[71] 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.

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

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 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

(f) 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 writing 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)**.[73]

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 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

[73] 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.

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.[74]

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 facilit***y***; or
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.

[74] **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.

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[75] 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:[76]

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[77] during the previous year in the ***special permit inspection area***,

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[75] 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.

[76] FGT must post the annual report to the special permit docket PHMSA-2020-0044 at www.regulations.gov.

[77] 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.

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 all ***special permit segments*** that do 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.

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-2020-0044) 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.[78] During the annual review meeting, FGT must review the status of implementing the special permit conditions with the Director, PHMSA Southwest Region.

16) **Condition 16 – Documentation**

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 for the pipe cannot be authorized per this special permit.

17) **Condition 17 - Extension of the *Special Permit Segment***

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:

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

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 extension***.
   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**, and
   ii) FGT must have hydrostatically tested[79] a ***special permit segment*** and ***extension*** in accordance with **Condition 1 – Maximum Allowable Operating Pressure**, as applicable.
   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***.

[79] 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.

18) **Condition 18 – Certification**

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;

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 with copies to the Director, PHMSA Southwest Region; the Director, PHMSA Engineering and Research Division; and the Federal Register Docket (PHMSA-2020-0044) at www.regulations.gov within one (1) year of the issuance date of this special permit.

IV. 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 ten (10) years from March 30, 2022. 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, March 30, 2032, 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 July 28, 2023.

ALAN KRAMER MAYBERRY

Digitally signed by ALAN KRAMER MAYBERRY
Date: 2023.07.28 16:18:45 -04'00'

Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

Attachment A - Dent Anomalies – Engineering Critical Assessment

To evaluate dents and other mechanical damage anomalies that conform to the conditions described in **Table 3 – Dent Criteria** below, FGT must perform an engineering critical assessment (ECA) as follows:

1) Identify and assess all threats for the pipe segment such as ground movement, other external loading, cracking, and corrosion that may be impacting the dent and mechanical damage.
2) Review all available high-resolution magnetic flux leakage (HR-MFL), high-resolution deformation, inertial mapping tool, and crack detection ILI data for damage in the dent area and any associated weld region.
3) If multiple ILI runs over time are available, the dent profile between the most recent and previous inline inspections should be compared to identify changes or significant changes in dent depth and shape and its possible impact to the integrity of the pipeline.
4) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.
5) Identify and quantify all significant loads acting on the dent.
6) FGT must use finite element analysis to quantify the dent strain, and then estimate the damage using either Strain Limit Damage (SLD) or Ductile Failure Damage Indicator (DFDI) at the dent. Finite element analysis modeling of the dent must include all associated anomalies, defects, and welds. Other methodologies and approaches that are supported by peer reviewed publications will also be considered as part of the ECA but will require a "no objection" letter from the Director, PHMSA Southwest Region.
7) The analyses performed must account for material property uncertainties and model inaccuracies and ILI tool sizing tolerances.
8) Using operational pressure data, appropriate fatigue models, and assuming the appropriate safety factor, FGT must estimate the fatigue life of the dent in accordance with API 1156 (1997 Edition), API RP 1183 (1st Edition, 2020, or IBR Edition) or other published literature that is technically appropriate for dent assessment. Multiple dent or other fatigue models must be evaluated as part of the ECA.
9) If the dent is suspected to have cracks, then a crack growth rate assessment is required (or the dent needs to be remediated) to ensure adequate life for the dent with crack(s) and the

crack(s) in the dent must be evaluated and remediated in accordance with the criteria in **Condition 8 – Anomaly Evaluation and Remediation**.

10) If FGT uses other technologies or techniques to comply with failure pressure determinations, FGT must submit advance notification to Director, PHMSA Southwest Region, and must receive a "no objection" letter from the Director, PHMSA Southwest Region, prior to usage.
11) The ECA process must be repeated following each assessment to ensure conformance to the original ECA conclusions.
12) To use ECA for dents with a depth greater than 6% up to 10% of the outside diameter (OD) requires a "no-objection" letter from the Director, PHMSA Southwest Region.
13) FGT must remediate dents and mechanical damage that do not pass the criteria defined in **Table 1 – Dent Criteria**, or FGT must conduct an acceptable ECA as described in this **Attachment A, Items 1 through 12**.
14) FGT must submit the dent ECA procedure to the Director, PHMSA Southwest Region, for a "no objection" letter prior to conducting the anomaly evaluation.[80] 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.

[80] A copy of the dent ECA procedure must be sent to the Director, PHMSA Engineering and Research Division.

Table 3 – Dent Criteria		
Dent type	**Critical Dents that Require Action**	**ECA an Option**
Plain Dent	Dent of depth > 6% Outside Diameter (OD) or dent strain level exceeding: i. Dent with strain > 6% limit (ASME B31.8, 2018 Edition) **or** ii. Strain Limit Damage (SLD) or Ductile Failure Damage Indicator (DFDI) > 0.6 (per API RP 1183, IBR Edition or 1st Edition, 2020, if not IBR)	YES
Dent Associated with Corrosion**	i. Dent depth of > 6% OD with corrosion of any depth** **or** ii. Dent of depth ≤ 6% OD with corrosion depth that is more than 15% of the pipe wall thickness. **	YES
Dent Associated with Metal Loss other than Corrosion	Dent associated with metal loss other than corrosion: gouge, axial or circumferential groove, SCC, fatigue cracks, and/ or other cracks.**	YES
Dent Affecting Weld (Girth Weld, Longitudinal Seam Weld or Spiral Seam Weld)	Dent of any depth affecting pipe with: Low Frequency Electric Resistance Welded (LF-ERW), Electric Flash Welded (EFW), Lap Welded, or Longitudinal Joint Factor < 1.0.*	YES*
	Dent of depth > 2% OD affecting other types of weld seams, see above, or girth welds with strain level exceeding 4% (ASME B31.8, 2018 Edition).	YES
Skewed and/or Multiple Dent Peaks	Any complex dent geometry identified by FGT or ILI vendor such as skewed dent, two or multi-peak deformations.	YES

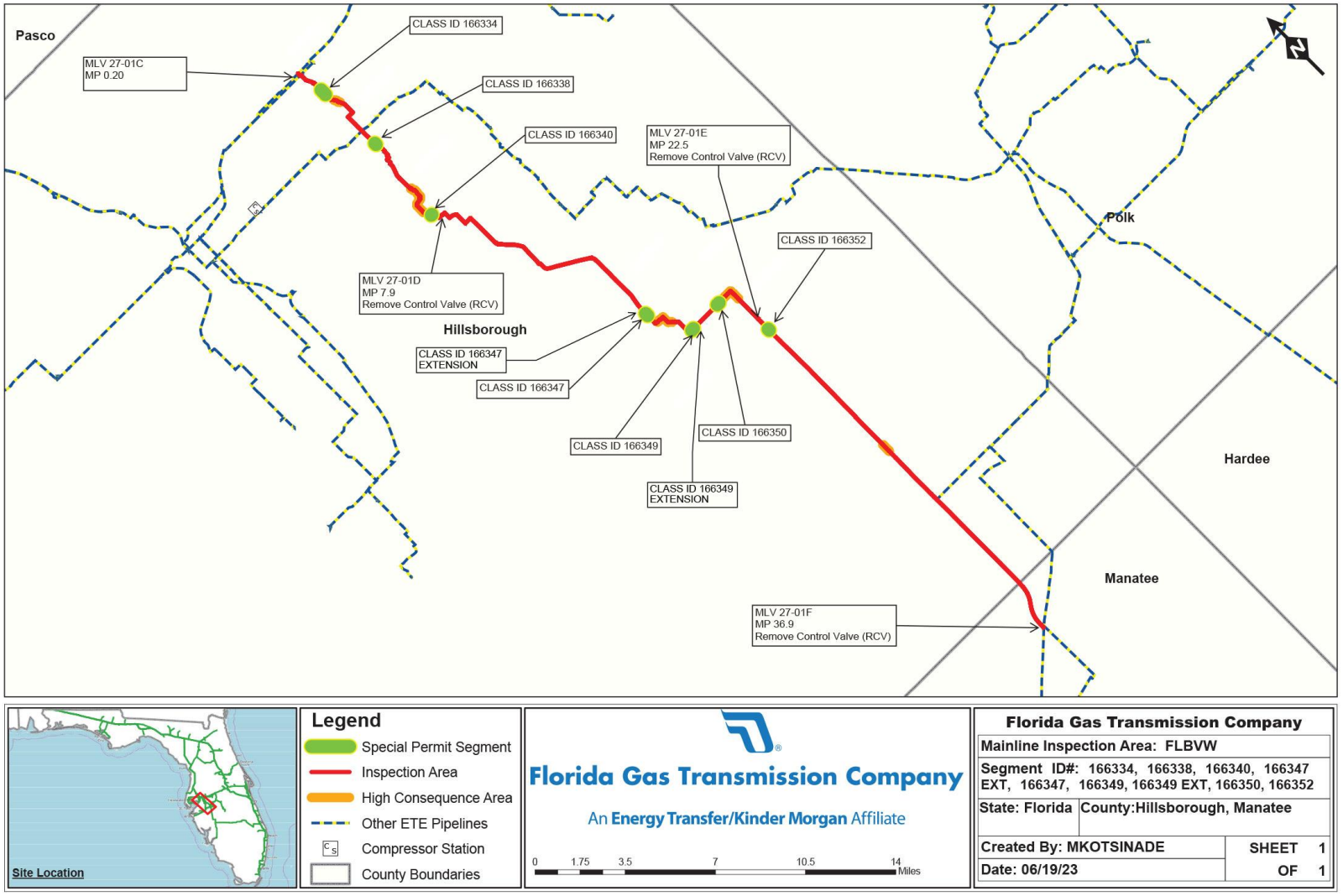
* Lack of ductility must be integrated into the ECA.

** Corrosion failure pressure with safety factor must meet the MAOP requirements in **Condition 8 - Anomaly Evaluation and Remediation**.

Note: FGT may use 49 CFR Part 192 compliant dent remediation procedures, for the evaluation and remediation of a dent ≤ 6% OD, with a corrosion depth < 15% of the pipe wall, and corrosion failure pressure with safety factor that meets the MAOP requirements in **Condition 8 - Anomaly Evaluation and Remediation.**

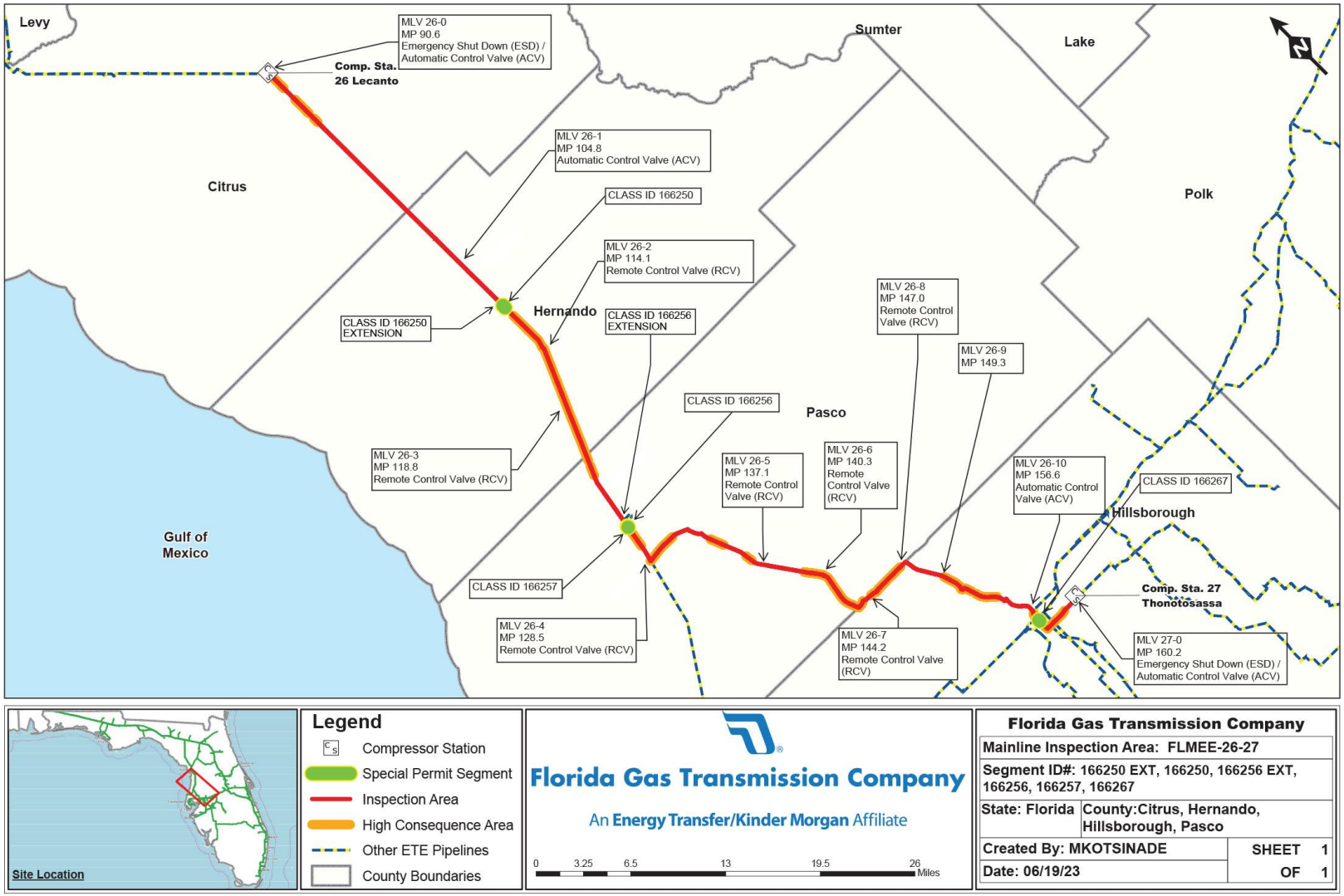
Attachment B-1 - St. Petersburg Sarasota Connector Pipeline Route Map

Special Permit Segments and Inspection Area Route Maps



Attachment B-2 – West Leg Station 26-27 Pipeline Route Map

Special Permit Segments and Inspection Area Route Maps



Attachment B-3 – West Leg Loop Station 26-27 Pipeline Route Map

Special Permit Segments and Inspection Area Route Maps

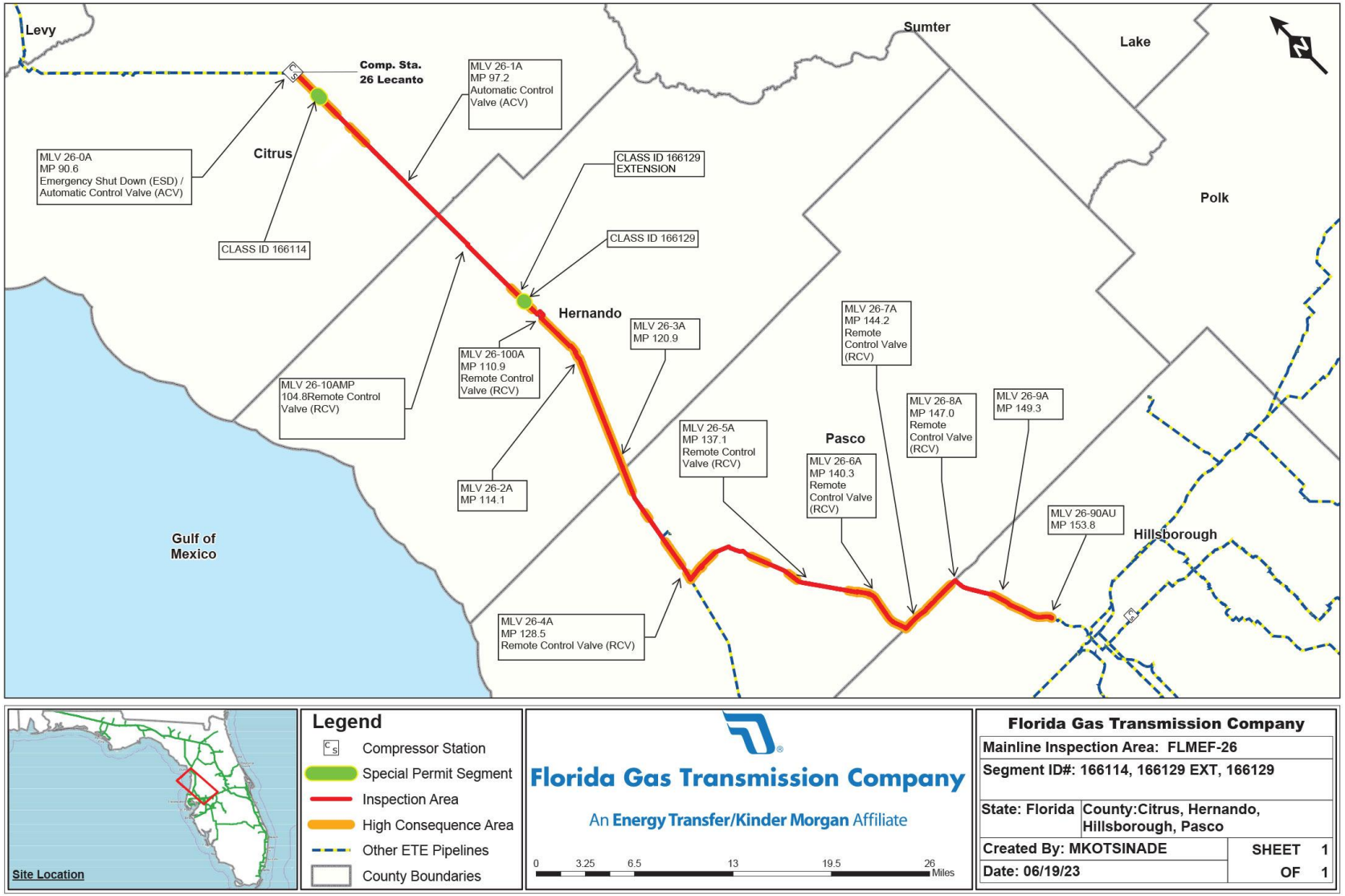


Table 4 – Valves and Lateral Locations with Isolations Methods									
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name	Nominal Diameter (inches)	Valve Automation Methodology[81]	For ASVs – Complete this Section			
						ASV Low Pressure Set-point (psig)	Rate of Pressure Drop Set-point (psig/minute)	Rate of Change Timing (minutes)	Low Pressure Timing (minutes)
166334 166338 166340	0.20	Upstream Isolation Valve	27-01C	18	Closed	N/A	N/A	N/A	N/A
	0.20	Crossover	27-01CD	16	RCV	N/A	N/A	N/A	N/A
	0.20	Crossover	27-01CL	18	Closed	N/A	N/A	N/A	N/A
	3.3	Crossover	27-01B	20	RCV	N/A	N/A	N/A	N/A
	3.3	Crossover	27-11B	16	Closed	N/A	N/A	N/A	N/A
	7.9	Downstream Isolation Valve	27-01D	18	RCV	N/A	N/A	N/A	N/A
166347 extension 166347 166349 166349 extension 166350	7.9	Upstream Isolation Valve	27-01D	18	RCV	N/A	N/A	N/A	N/A
	19.1	Lateral	27-02B	4	Check Valve	N/A	N/A	N/A	N/A
	22.5	Downstream Isolation Valve	27-01E	18	RCV	N/A	N/A	N/A	N/A
166352	22.5	Upstream Isolation Valve	27-01E	18	RCV	N/A	N/A	N/A	N/A
	31.0	Crossover	27-03C	16	RCV	N/A	N/A	N/A	N/A
	36.9	Crossover	27-01FR	18	Closed	N/A	N/A	N/A	N/A
	36.9	Lateral	27-04B	18	RCV	N/A	N/A	N/A	N/A
	36.9	Downstream Isolation Valve	27-01F	18	RCV	N/A	N/A	N/A	N/A
166114	90.6	Upstream Isolation Valve	26-0ALB	36	RCV	N/A	N/A	N/A	N/A
	90.6	Crossover	26-0AL	36	Closed	N/A	N/A	N/A	N/A
	97.2	Downstream Isolation Valve	26-1A	36	ASV and Line Break	485	-20	1	N/A
166129 extension 166129	104.8	Upstream Isolation Valve	26-10A	36	RCV	N/A	N/A	N/A	N/A
	104.8	Crossover	26-10A DSB	12	Closed	N/A	N/A	N/A	N/A
	104.8	Crossover	26-1D	20	Closed	N/A	N/A	N/A	N/A
	110.9	Crossover	26-1X1	16	Closed	N/A	N/A	N/A	N/A
	110.9	Downstream Isolation Valve	26-100A	36	RCV	N/A	N/A	N/A	N/A
166250 extension 166250	97.2	Upstream Isolation Valve	26-1	30	ASV and Line Break	485	-20	1	N/A
	97.2	Crossover	26-1D	20	Closed	N/A	N/A	N/A	N/A
	97.2	Crossover	26-1 DSB	10	Closed	N/A	N/A	N/A	N/A
	110.9	Crossover	26-1X1	16	Closed	N/A	N/A	N/A	N/A
	110.9	Crossover	26-1X2	16	Closed	N/A	N/A	N/A	N/A
	114.1	Downstream Isolation Valve	26-2	30	RCV	N/A	N/A	N/A	N/A
166256 extension 166256 166257	118.8	Upstream Isolation Valve	26-3	30	RCV	N/A	N/A	N/A	N/A
	118.8	Crossover	26-3D	16	Closed	N/A	N/A	N/A	N/A
	128.5	Crossover	26-4U	16	RCV	N/A	N/A	N/A	N/A
	125.4	Lateral	26-32B	12	Closed	N/A	N/A	N/A	N/A
	126.3	Lateral	26-31B	12	Closed	N/A	N/A	N/A	N/A
	128.5	Downstream Isolation Valve	26-4	30	RCV	N/A	N/A	N/A	N/A
166267	156.6	Upstream Isolation Valve	26-10	30	ASV and Line Break	485	-20	1	N/A
	160.2	Crossover	27-0RB	30	RCV	N/A	N/A	N/A	N/A
	160.2	Crossover	27-0R	30	Closed	N/A	N/A	N/A	N/A
	157.8	Lateral	26-101B	24	RCV	N/A	N/A	N/A	N/A
	160.2	Downstream Isolation Valve	27-0	30	RCV	N/A	N/A	N/A	N/A

Software Package – Greg Engineering Winflow and Wintran Pipeline Simulation
Florida Gas utilizes a copyrighted program (Gregg Engineering) and has prepared the pressure graphs included in the Special Permit Conditions. This computer program simulates the operation of the FGT system. It models a pipe segment by the simultaneous solution of the mass, momentum, and energy balance equations. FGT uses the Colebrook-White and API 520 equations. FGT believes the Colebrook-White equation fairly typifies the steady state and transient conditions regularly experienced on the FGT pipeline system. As part of developing the Special Permit Conditions, FGT believes the API 520 equation is sufficient to estimate the rupture pattern and thereby accurately computes the reaction times simulated for these pipeline ruptures on the FGT pipeline system.

[81] Any isolation valve that is not an RCV, ASV, or check must be blinded or closed. Isolation valve(s) shown as CLOSED, when opened, must be manned by FGT personnel. **Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures** is applicable to all crossover valves, valve spacing, and lateral tie-ins.

Last Page of the Special Permit