MAY 15 2015

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)
SPECIAL PERMIT

Docket Number:	RSPA-2000-8453; (renamed PHMSA–RSPA-2000-8453)
Requested By:	Tennessee Gas Pipeline Company
Original Issuance Date:	March 16, 2001
Renewal Effective Dates:	May 15, 2015 to May 15, 2020
Code Section(s):	49 CFR § 192.611(a)

MAY 15 2015

Grant of Special Permit:

By this order, subject to the terms and conditions set forth below the Pipeline and Hazardous Materials Safety Administration (PHMSA) grants a modified special permit RSPA-2000-8453 (renamed PHMSA-RSPA-2000-8453) to Tennessee Gas Pipeline Company (TGP) waiving compliance from 49 CFR § 192.611(a) for four (4) natural gas transmission pipeline segments in Hickman and Dickson Counties, Tennessee, as described below.

On March 16, 2001, pursuant to its authority under 49 U.S.C. § 60118(c), PHMSA[1] issued a waiver[2] to Tennessee Gas Pipeline Company, (TGP or Respondent).[3] The waiver, referred to as RSPA 2000-8453 ("special permit") waived TGP's obligation to comply with the requirement in 49 C.F.R. § 192.611 to confirm or revise maximum allowable operating pressure (MAOP) following a change in class location for four (4) pipeline segments located on the parallel Lines

[1] Effective February 20, 2005, the Pipeline and Hazardous Materials Safety Administration (PHMSA) succeeded Research and Special Programs Administration as the agency responsible for regulating safety in pipeline transportation and hazardous materials transportation. See, section 108 of the Norman Y. Mineta Research and Special Programs Improvement Act (Public Law 108-426, 118 Stat. 2423-2429 (November 30, 2004)). See also, 70 Fed. Reg. 8299 (February 18, 2005) redelegating the pipeline safety authorities and functions to the PHMSA Administrator.

[2] *"Tennessee Gas Pipeline Company"*, Docket No. RSPA-2000-8453, 66 Fed. Reg. 15321 (March 16, 2001).

[3] The original waiver was issued to Tennessee Gas Pipeline Company, since 2012 TGP is owned by Kinder Morgan Energy Partners, L.P. (Kinder Morgan, Inc. or KMI Pipeline).

800-1, 500–1, 500–2, and 500–3, approximately 11.2 miles downstream of Compressor Station 860, in Hickman and Dickson Counties, Tennessee (the "special permit segments").[4] The original special permit segments included a total of 15,006 feet of pipeline. This revised special permit includes a total of 37,531 feet of pipeline. The original special permit was part of the Risk Management Demonstration Program (RMDP) in which PHMSA consulted with operators to determine how risk management might be used to complement and improve the existing Federal pipeline safety regulatory process.

Based on the determination in the Special Permit Analysis and Findings (available in the docket) that this special permit, as modified, is not inconsistent with pipeline safety, PHMSA hereby modifies special permit RSPA-2000-8453 (renamed PHMSA-RSPA-2000-8453) by modifying the special permit segment definitions (section I), including additional special permit conditions (section II), and including special permit limitations (section III) as follows:

I. Special Permit Segment and Special Permit Inspection Area:

Hickman and Dickson Counties, Tennessee

On the condition that TGP complies with the terms and conditions set forth below, this special permit, as modified, allows TGP to continue to operate each ***special permit segment*** at its current maximum allowable operating pressure (MAOP) for the Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines.

This special permit applies to the ***special permit segment(s)*** defined as follows using the TGP mile post (M.P.) or survey station (Sta.) references:

- ***Special permit segment 1*** – 30-inch Line 800-1, MLV 860-1 from Sta. 546+06 to Sta. 657+73, 11,167 feet, located between approximate M.P. 10.34 to M.P. 12.46 in Dickson and Hickman Counties, Tennessee, as shown on Drawing No. TO-T5-800-1-176, dated 01/06/2014;

4 At the time the waiver proceeding commenced on December 11, 2000, it was designated by PHMSA's predecessor agency, the Research and Special Programs Administration (RSPA), as RSPA-2000-8453 (65 Fed. Reg. 77422). On March 16, 2001, RSPA granted the waiver (66 Fed. Reg. 15321).

- ***Special permit segment 2*** – 30-inch Line 500–1, MLV 559-1 from Sta. 546+64 to Sta. 657+65, 11,101 feet, located between approximate M.P. 10.35 to M.P. 12.46 in Dickson and Hickman Counties, Tennessee, as shown on Drawing No. TO-T5-500-1-162, dated 01/07/2014;
- ***Special permit segment 3*** – 36-inch Line 500–2, MLV 559-2 from Sta. 544+95 to Sta. 656+10, 11,115 feet, located between approximate M.P. 10.32 to M.P. 12.43 in Dickson and Hickman Counties, Tennessee, as shown on Drawing No. TO-T5-500-2-162, dated 01/07/2014; and
- ***Special permit segment 4*** – 36-inch Line 500–3: MLV 559-3 from Sta. 599+20 to Sta. 640+68, 4148 feet, located between approximate M.P. 11.35 to M.P. 12.14 in Dickson and Hickman Counties, Tennessee, as shown on Drawing No. TO-T5-500-3-162, dated 01/06/2014.

This special permit applies to the ***special permit inspection area*** defined as follows using Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines stationing as a reference.

Special permit inspection areas[5] – are defined as the area that extends 220 yards on each side of the centerline along the entire length of Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines from:

- ***Special permit inspection area 1*** – 30-inch Line 800–1
  - Includes ***special permit segment 1*** in Hickman and Dickson Counties, Tennessee;
  - Starts downstream of the Compressor Station 860 at MLV 860-1+00 in Centerville, Tennessee.
  - Ends at MLV 864-1 Sta. 0+00 (138,718 feet) upstream of Compressor Station 87 in Portland, Tennessee, a distance of approximately 50 miles on 30-inch Line 800-1.
- ***Special permit inspection area 2*** – 30-inch Line 500–1
  - Includes ***special permit segment 2*** in Hickman and Dickson Counties, Tennessee;
  - Starts downstream of the Compressor Station 860 at MLV 559-1+00 in Centerville, Tennessee.

[5] ***Special permit inspection areas*** in these conditions include ***special permit segments*** unless specifically defined as not applicable or if the special permit segment has more stringent conditions.

- Ends at MLV 563-1 Sta. 0+00 (139,030 feet) upstream of Compressor Station 87 in Portland, Tennessee, a distance of approximately 50 miles on 30-inch Line 500-1.

- ***Special permit inspection area 3*** – 36-inch Line 500–2
  - Includes ***special permit segment 3*** in Hickman and Dickson Counties, Tennessee;
  - Starts downstream of the Compressor Station 860 at MLV 559-2+00 in Centerville, Tennessee.
  - Ends at MLV 563-2 Sta. 0+00 (139,586 feet) upstream of Compressor Station 87 in Portland, Tennessee, a distance of approximately 50 miles on 36-inch Line 500-2.
- ***Special permit inspection area 4*** – 36-inch Line 500–3
  - Includes ***special permit segment 4*** in Hickman and Dickson Counties, Tennessee;
  - Starts downstream of the Compressor Station 860 at MLV 559-3+00 in Centerville, Tennessee.
  - Ends at approximately 18.22 miles downstream of Compressor Station 860 at Mainline Valve (MLV) 560-3.

II. Conditions:

1) **Maximum Allowable Operating Pressure (MAOP)**:
   a) TGP must continue to operate the ***special permit segments*** at or below their existing MAOP of 936 pounds per square inch (psi).
   b) TGP must operate all pipeline ***special permit segments*** and ***special permit inspection areas*** with flow reversals conducted prior to January 1, 2014, between Compressor Station 860 (Centerville, TN) and Compressor Station 87 (Portland, TN) to a maximum operating pressure of 883 psig until Condition 24(h) have been met. After Condition 24 (h) has been implemented, TGP must operate the pipeline ***special permit segments*** and ***special permit inspection areas*** with flow reversals at a maximum MAOP of 936 psig.

2) **Integrity Management Program**: TGP must incorporate the ***special permit segments*** into its written integrity management program (IMP) as a *"covered segment"* in a *"high*

consequence area (HCA)" in accordance with 49 Code of Federal Regulations (CFR) § 192.903, except for the reporting requirements contained in 49 CFR § 192.945. TGP need not include the ***special permit segments*** described in this special permit in its IMP baseline assessment plan unless those areas meet the conditions of an HCA in accordance with 49 CFR § 192.905.

3) **Close Interval Surveys**: TGP must perform a close interval survey (CIS) of Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines along the entire length of all ***special permit inspection areas***[6] and remediate any areas of inadequate cathodic protection no later than one (1) year after the modification of this special permit. However, a CIS need not be performed, if TGP has performed a CIS and completed remediation[7] including damaged coating repair on Line 800-1, Line 500-1, Line 500-2, and Line 500-3 along the entire length of all ***special permit inspection areas*** less than seven (7) years[8] prior to the modification of this special permit. If factors beyond TGP control prevent the completion of the CIS and remediation activities within the one (1) year from the modification of this special permit, a CIS and subsequent remediation including coating repair must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the end of one (1) year after the modification of this special permit. Any extended evaluation and remediation schedules submitted to PHMSA from TGP must receive a "no objection" from the Director, PHMSA Southern Region.

4) **Close Interval Surveys – Reassessment Interval**: TGP must perform a periodic close interval survey (CIS) of the ***special permit segments*** at the applicable reassessment interval(s) for a "covered segments" in accordance with 49 CFR 192 Subpart O reassessment

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[6] Each condition that requires TGP to perform an action with respect to the ***special permit inspection areas*** shall also require TGP to perform that action on all ***special permit segments*** within such areas.

[7] The terms "remediate" or "remediation" of pipe coating shall include repair of damaged external pipe coating, where required to maintain cathodic protection of the pipeline in accordance with 49 CFR § 192.463.

[8] If § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, TGP may use that reassessment interval instead of seven (7) years.

intervals as contained in 49 CFR §§ 192.937(a) and (b) and 192.939, not to exceed a seven (7) year reassessment interval[9] and CIS data integrated with in-line inspection (ILI). Condition 24 (d) – Data Integration – gives a complete description of data integration information that an operator must maintain for a special permit in the ***special permit segments*** and ***special permit inspection areas*** which includes CIS and ILI data. CIS assessments within the reassessment interval are not required to be performed in the same year as ILI reassessments.

5) **Cathodic Protection Reliability Improvement Plan**: TGP will implement a plan to improve cathodic protection reliability and perform inspections for SCC.

   a) Cathodic Protection Reliability Improvement Plan

      i) TGP must perform a periodic CIS of the ***special permit segments*** as part of Condition 4 Close Interval Surveys – Reassessment Interval at an increased frequency, not to exceed a seven (7) year reassessment interval with CIS data integrated with the most-recent in-line inspection data[10].

      ii) TGP must perform magnetic particle inspection on any pipe (with the exception of pipe coated with fusion-bonded or liquid-applied epoxy coatings, which are not at risk for SCC) excavated in the ***special permit segments*** and ***special permit inspection areas*** to evaluate the pipe for SCC where sufficient disbonded coating is removed in order to perform the inspection."

      iii) TGP must integrate the most current CIS data with in-line inspection results in the ***special permit segments***;

      iv) Within one (1) year of the modifications of this special permit, TGP must install cathodic protection remote monitoring units (RMUs) at all impressed current sources directly influencing the ***special permit segments***;

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9 If § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, TGP may use that reassessment interval instead of seven (7) years.

10 If § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, TGP may use that reassessment interval instead of seven (7) years.

v) TGP must configure the RMUs in the ***special permit segments*** with alarms to notify TGP immediately in the event of any interruption in cathodic protection current output;

vi) TGP must respond and correct any interruption in cathodic protection current output immediately (within two (2) days). If a systemic issue is present, then TGP must investigate and remediate the problem within one (1) month or less or TGP must receive a "no objection" from the Director, PHSMA Southern Region for issues that require longer to remediate;

vii) TGP must amend applicable sections of its operations and maintenance (O&M) manual(s) to prohibit future use of coating that is known to shield cathodic protection along the entire length of the ***special permit inspection areas***; and

viii) TGP must perform a run comparison analysis on all in-line inspection results subsequent to the baseline inspection in the ***special permit inspection areas*** to identify areas of external corrosion growth. Areas with corrosion growth over 30% in depth must be remediated or DCVG run to locate problem coating areas.

ix) If factors beyond TGP control prevent the completion of any of the elements of the cathodic protection reliability improvement plan within one (1) year, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than the end of the one (1) year completion date. Any extended evaluation and remediation schedules submitted to PHMSA from TGP must receive a "no objection" from the Director, PHSMA Southern Region.

b) Stress Corrosion Cracking Inspections

i) TGP must review historical records to determine if SCC inspections have been performed in the ***special permit segments*** to evaluate the threat of stress-corrosion cracking.

ii) TGP must implement Kinder Morgan O&M Procedure 917 (Stress Corrosion Cracking) dated 2014-05-01 on all excavations in the ***special permit segments*** and ***special permit inspection areas*** to evaluate all pipeline excavations for SCC.

iii) If no documentation of previous SCC inspections exists, then as part of Condition 6 (a) TGP will perform a minimum of two (2) excavations and direct examinations in each of the ***special permit segments***.

6) **Stress Corrosion Cracking Direct Assessment**: TGP must evaluate Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines for stress corrosion cracking (SCC) as follows:

a) TGP must perform a stress corrosion cracking direct assessment (SCCDA) or other appropriate assessment method for SCC [such as pressure test or in-line inspection (ILI) with a crack detection tool] of Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines along the entire length of all ***special permit inspection areas*** according to the requirements of 49 CFR § 192.929 and/or NACE SP 0204-2008 no later than one (1) year for the ***special permit segment*** and two (2) years for the remaining ***special permit inspection area*** after of the modification of this special permit. The SCCDA or other approved method must address both high pH SCC and near neutral pH SCC. The SCCDA Pre-Assessment Step will include the results of all close-interval surveys and coating surveys required in Conditions 3, 4, and 5, and coating remediation required in Condition 19.

i) If factors beyond TGP control prevent the completion of the SCCDA survey and remediation within one (1) year for the ***special permit segment*** and two (2) years for the remaining ***special permit inspection area*** from the modification of this special permit, a SCCDA and remediation must be performed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than two (2) years after the modification of this special permit.

ii) TGP may eliminate this Condition 6 (a), provided TGP provides an engineering assessment showing that the pipeline does not meet the criteria for either near neutral or high pH SCC in accordance with the applicable edition of the American Society of Mechanical Engineers Standard B31.8S, *"Managing System Integrity of Gas Pipelines"* (ASME B31.8S), Appendix A3, or NACE SP 0204-2008, "*Stress Corrosion Cracking (SCC) Direct Assessment Methodology*", Section 1.2.1.1 and 1.2.2.

iii) A SCCDA need not be performed if TGP has performed a SCCDA of Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines along the entire length of the ***special permit inspection areas*** within the timeframe for SCCDA re-assessments specified in 49 CFR Part 192, Subpart O, not to exceed seven (7) years[11] prior to the modification of this special permit.

b) If the threat of SCC exists as determined in Condition 6 (a) and when the TGP's Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines are exposed for any reason, including damage prevention activities, in the ***special permit inspection areas*** and the coating has been identified as poor during the pipeline examination, then TGP must directly examine the pipe for SCC using an accepted industry detection practice such as dry or wet magnetic particle tests. Poor coating is coating losing adhesion to the pipe which is shown by falling off the pipe, and/or shields the cathodic protection. TGP must keep coating records[12] of all excavation locations for the ***special permit inspection areas*** to demonstrate the coating condition.

c) If SCC[13] activity is discovered by any means within the ***special permit inspection area*** in similar pipe and pipe coating vintage [in accordance with 49 CFR § 192.917(e)], or has had an in service or hydrostatic test SCC failure or leak; the ***special permit segment*** must be further assessed and mitigated, using one of the following methods, within one (1) year of finding SCC:

i) Hydrostatic test program

A. The SCC hydrostatic test program must be performed at an interval no

[11] If § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, TGP may use that reassessment interval instead of seven (7) years.

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

[13] "SCC" activity shall be defined as over both 10 percent wall thickness depth and 2-inches in length.

8) **<u>O&M Manual – In-Line Inspection and Reassessment Intervals</u>**: TGP must amend applicable sections of its operations and maintenance (O&M) manual(s) to incorporate the inspection and reassessment intervals by in-line inspection (ILI) including both metal loss and geometry tools of Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines along the entire length of the ***special permit inspection areas*** at a frequency consistent with 49 CFR Part 192, Subpart O, but not to exceed a seven (7) year reassessment interval[15]. [Deformation tools with up to +/- 1% accuracy may be considered as a replacement for geometry tools.]

9) **<u>O&M Manual - CIS Inspection and Reassessment Intervals</u>**: TGP must amend applicable sections of its O&M manual(s) to require the CIS inspection and reassessment intervals of Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines ***special permit segments*** at a frequency consistent with 49 CFR Part 192, Subpart O, but not to exceed a seven (7) year reassessment interval[16].

10) **<u>In-Line Inspection Initial Assessment</u>**: TGP must perform ILI assessment along the entire length of the ***special permit inspection area*** using ILI Tools (both high resolution magnetic flux leakage (HR-MFL) and either HR-geometry or HR-deformation tools) and must remediate discovered conditions in accordance with Condition 20 of this permit. If ILI assessments have not been run based upon either the previous special permit assessment/re-assessment intervals or within seven (7) years of the modification of this special permit using both HR-MFL and either HR-geometry or HR-deformation tools, TGP must complete initial ILI Tool inspections on Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines within one (1) year of the modification of this special permit. Subsequent ILI assessments of Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines along the entire length of the ***special permit inspection areas*** using ILI must conform to the required maximum reassessment intervals specified in 49 CFR § 192.939, but may not to exceed a seven (7) year

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[15] If § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, TGP may use that reassessment interval instead of seven (7) years.

[16] If § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, TGP may use that reassessment interval instead of seven (7) years.

greater than seven (7) calendar years (but may be at a lesser interval in accordance with the results of an engineering critical assessment) in the ***special permit segment***.

B. If pipe in the ***special permit segment*** leaks or ruptures during a hydrostatic test due to SCC, all pipe in the ***special permit segment*** must be replaced with new pipe.

ii) Crack detection tool assessment

A. SCC detection tool must be run in the ***special permit inspection area***,

B. All SCC[14] cracking found in the ***special permit segment*** must be replaced with new pipe,

iii) Operating pressure lowered to 60% specified minimum yield strength (SMYS),

iv) Replace all affected pipe to meet 49 CFR § 192.611 in the ***special permit segment***.

d) If any SCC activity is discovered in the ***special permit inspection area***, TGP must submit a SCC remediation plan to the Director, PHMSA Southern Region with a copy to the Director, PHMSA Engineering and Research Division no later than 60 days after the finding of SCC:

i) That meets Condition 6 (c), including a SCC remediation/repair plan with SCC characterization and timing, or

ii) Technical justification that shows that the ***special permit segment*** is not at risk for SCC.

7) **Reporting of Pipe and Coating Remediation**: TGP must submit the CIS, and SCCDA [or other PHMSA approved methods of determining SCC] findings including remediation actions in a written report to the Director, PHMSA Southern Region with a copy to the Director, PHMSA Engineering and Research Division, no later than the latest of one (1) year or the 2nd annual report (Condition 15) after the modification of this special permit.

[14] "SCC" activity shall be defined as over both 10 percent wall thickness depth and 2-inches in length.

reassessment interval[17].

11) **In-Line Inspection Reassessment Intervals**: TGP must schedule ILI reassessment dates for Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines along the entire length of the ***special permit inspection areas*** according to 49 CFR § 192.939 by adding the required time interval to the previous assessment date, but may not to exceed a seven (7) year reassessment interval[18].

12) **Damage Prevention Best Practices**: TGP must incorporate the applicable best practices of the Common Ground Alliance (CGA) into its damage prevention program within the ***special permit inspection areas***.

13) **Field Activity Advance Notice to PHMSA**: TGP must give a minimum of 14 days advance notice[19] to the Director, PHMSA Southern Region to enable PHMSA to observe the excavations relating to Conditions 5, 6 (b), 19, 20, 21, 22, 23, 24(f), and 24(g) of field activities in the ***special permit inspection areas***. Immediate response conditions do not require a 14-day advance notice, but the Director, PHMSA Southern Region should be notified by TGP no later than two (2) business days after the immediate condition is discovered. The Director, PHMSA Southern Region may elect to not require a notification for some activities.

14) **High Consequence Area Assessments**: TGP must not let this special permit be a basis for deferring any of its assessments for HCAs in accordance with 49 CFR Part 192, Subpart O.

15) **Annual Reports to PHMSA**: Within three (3) months following the modification of this

[17] If § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, TGP may use that reassessment interval instead of seven (7) years.

[18] If § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, TGP may use that reassessment interval instead of seven (7) years.

[19] TGP must give notice in 1st quarter of each year any planned field activities under this special permit to the Director, PHMSA Southern Region. PHMSA Director may elect to not witness and be noticed on some field activities.

special permit and annually[20] thereafter, TGP must report the following to the Director, PHMSA Southern Region with copies to the Deputy Associate Administrator, PHMSA Field Operations; Director, PHMSA Engineering and Research Division; and Director, PHMSA Standards and Rulemaking Division:

a) In the first annual report, TGP must describe the economic benefits of the special permit including both the costs avoided from not replacing the pipe and the added costs of the inspection program. Subsequent annual reports should address any changes to these economic benefits.

b) In the first annual report, fully describe how the public benefits from energy availability. This should address the benefits of avoided disruptions as a consequence of pipe replacement and the benefits of maintaining system capacity. Subsequent reports must indicate any changes to this initial assessment.

c) The number of new residences, other structures intended for human occupancy and public gathering areas built within one (1) mile on either end of the ***special permit segment***.

d) 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) during the previous year in the ***special permit inspection areas***.

e) Any reportable incident or any leak normally indicated on the DOT Annual Report, and all repairs on the pipeline that occurred during the previous year in the ***special permit inspection areas***. Data must include a summary of anomaly remediation findings (location, failure pressure ratio, dent size, and remediation measure) to meet Condition 20 and any findings in Conditions 6 and 23.

f) Any on-going damage prevention initiatives affecting the ***special permit inspection areas*** and a discussion of the success of the initiatives.

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[20] Annual reports must be received by PHMSA by the last day of the month in which the Special Permit is dated. For example, the annual report for a modified Special Permit dated November, 2012, must be received by PHMSA no later than November 30, each year beginning in 2013. For past special permit segments where there is an existing annual report schedule such as November of each year, then TGP may keep this reporting month for annual report submittals.

g) Annual data integration information, as required in Condition 24 (d) - Data Integration must be submitted beginning with the 2nd annual report that includes an annual overview of any new threats, or if requested by PHMSA a full information package.
h) Any mergers, acquisitions, transfer of assets, or other events affecting the regulatory responsibility of the company operating the pipeline.

16) **Cathodic Protection Test Station – Location**: At least one (1) cathodic protection (CP) pipe-to-soil test station must be located within each HCA with a maximum spacing between test stations of one-half mile within an HCA. In cases where obstructions or restricted areas prevent test station placement, the test station must be placed in the closest practical location. This requirement applies to any HCA within the ***special permit inspection areas***. TGP must install CP test stations as required within one (1) year of this special permit modification. If factors "beyond TGP's control" prevent the completion of the installation of CP test stations within one (1) year after modification of this special permit, TGP must complete installation of CP test stations as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the required installation date. Any extended installation schedules submitted to PHMSA from TGP must receive a "no objection" from the Director, PHMSA Southern Region.

17) **Cathodic Protection Test Station - Remediation**: If any annual CP test station readings on Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines within the ***special permit inspection areas*** fall below 49 CFR Part 192, Subpart I requirements, remediation must occur within six (6) months of the test station reading and include a CIS on each side of the affected test station to the next test station and any identified corrosion system modifications to ensure corrosion control. If factors "beyond TGP control"[21] prevent the completion of

[21] Examples of "beyond TGP control" would include extreme weather conditions, environmental permits, or landowner issues that might limit TGP location access to remediate the condition. TGP's budget cycle and manpower and contractor schedules are examples of factors that are within TGP's control and cannot be used for an extension of remediation time interval.

remediation including coating repairs within six (6) months, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the end of the six (6) months completion date. Any extended evaluation and remediation schedules submitted to PHMSA from TGP must receive a "no objection" from the Director, PHMSA Southern Region.

18) **Interference Currents Control**: TGP must address induced alternating current (AC) from parallel electric transmission lines and other interference issues such as direct current (DC) in the ***special permit inspection areas*** that may affect the pipeline. An induced AC or DC program and remediation plan to protect the pipeline from corrosion caused by stray currents must be in place within one (1) year of the date of this special permit.

a) At least once every seven (7) years not exceeding 90 months, TGP must perform an engineering analysis on the effectiveness of the AC and DC mitigation measures and must evaluate any AC interference between 20 and 50 Amps per meter squared. In evaluating such interference, TGP must integrate AC interference data with the most recent ILI results to determine remediation measures. If TGP does not remediate AC interference between 20 and 50 Amps per meter squared, TGP must provide an engineering justification for not remediating such interference to the Director, PHMSA Southern Region, who may accept or reject the justification and require remediation.

b) TGP must take interference readings (continuous 24 hour recordings) during the calendar quarter of the known or anticipated highest voltage reading. If there are any significant increases to the amount of electricity/current flowing in any co-located high voltage alternating current (HVAC) power lines, such as from additional generation, a voltage up rating, additional lines, or new or enlarged substations, TGP must perform an AC mitigation survey along the entire co-located pipeline ***special permit inspection areas*** right of way within six (6) months of any such change.

c) Within six (6) months of the engineering analysis, TGP must remediate any AC interference greater than 50 Amps per meter squared. Remediation means the implementation of performance measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any DC interference that results in CP levels that do not meet the requirements of 49 CFR Part 192, Subpart I, must be remediated within six (6) months of this evaluation.

d) If factors "beyond TGP control" prevent the completion of remediation within six (6) months of the interference evaluation and remediation, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the end of the six (6) months completion date. Any extended evaluation and remediation schedules submitted to PHMSA from TGP must receive a "no objection" from the Director, PHMSA Southern Region.

19) **Field Coating**: The coatings used on the pipeline and girth weld joints in the ***special permit segments*** must be non-shielding to CP. In the event that the coating type is unknown or is known to shield CP for girth weld joints then TGP must take special care to:

a) Provide a plan to the Director, PHMSA Southern Region for removing all shielding coatings such as shrink sleeves and tape coatings and replace them with a non-shielding coating in the ***special permit segment*** within six (6) months of receipt of this permit.

b) Analyze ILI logs in the areas of girth welds in the ***special permit segment*** for potential corrosion indications.

c) Any ILI corrosion indications above 30% wall loss at girth welds in the ***special permit segment*** where the coating type is unknown, the girth weld joints must be exposed and evaluated each time the ILI is run or until the unknown girth weld coating is replaced.

d) If any SCC[22] activity is found on girth welds or pipe in the ***special permit segment***, the pipe and girth welds in the ***special permit segment*** must be remediated in accordance with Condition 6 within six (6) months of finding the SCC.

e) If factors "beyond TGP's control" prevent completion of the coating shielding evaluation and remediation within six (6) of permit receipt, remediation must be

[22] "SCC" activity shall be defined as over both a 10 percent wall thickness depth and 2-inches in length.

completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the end of the six (6) months completion date. Any extended evaluation and remediation schedules submitted to PHMSA from TGP must receive a "no objection" from the Director, PHMSA Southern Region.

20) **Anomaly Evaluation and Repair**:

a) **General**: TGP must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs and document and justify the values used. TGP must demonstrate ILI Tool tolerance accuracy for each ILI Tool run by usage of 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). The unity plots must show: a) actual anomaly depth versus predicted depth and b) actual failure pressure/MAOP versus predicted failure pressure/MAOP. Discovery date must be within 120 days of an ILI Tool run for each type ILI Tool (HR-geometry, HR-deformation or high resolution HR-MFL).

i) ILI tool evaluations for metal loss must use "6t x 6t" interaction criteria (or more conservative criteria) for determining anomaly failure pressures and remediation response timing with *"6t" being pipe wall thickness times six.*

b) **Dents**: TGP must repair dents to Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines in the ***special permit segment*** and ***special permit inspection area*** in accordance with 49 CFR § 192.933 repair criteria. S***pecial permit segment*** and ***special permit inspection area*** must have a geometry or deformation tool inspection as part of the initial ILI, if no geometry or deformation tool has been completed it must be completed and all dent repairs made in accordance with 49 CFR § 192.933 repair criteria. The geometry tool can be from past ILI inspections. The timing for these dent repairs should follow TGP O&M Manual but must not be longer than one (1) year after discovery.

c) **Investigation and Repair Criteria**: Investigation, evaluation, and repair criteria applies to all anomalies located on Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines within the ***special permit segments*** and ***special permit inspection area*** when they have been excavated, investigated, and remediated in accordance with 49 CFR §§ 192.485 and 192.933 incorporating appropriate class location design factors in the anomaly repair criteria, including HCAs[23] as follows:

- ***<u>Special permit segments</u>***: Repair any anomaly within a ***special permit segment*** that meets either: (1) a failure pressure ratio[24] (FPR) less than 1.39 for original Class 1 location pipe in a Class 3 location operating up to 72% of the specified minimum yield strength (SMYS); or (2) an anomaly depth greater than 40% of pipe wall thickness.
- ***<u>Special permit inspection areas</u>***: Repair any anomaly within a ***special permit inspection area*** that meets either: (1) an FPR less than design factor – for Class 1 location – FPR less than 1.39; for Class 2 location – FPR less than 1.67; and for Class 3 location – FPR less than 2.0; or (2) an anomaly depth greater than 60% wall thickness loss.
  - Repair anomalies in original Class 1 location pipe that are now in a Class 2 location in accordance with 49 CFR §§ 192.5 and 192.611 that meets either: (1) is less than the Class 1 location FPR of 1.39; or (2) an anomaly depth greater than 50% wall thickness loss for anomaly repairs.
  - Repair anomalies in original Class 2 location pipe that is now in a Class 3 location in accordance with § 192.611 that meets either: (1) is less than the Class 2 location FPR of 1.67; or (2) an anomaly depth greater than 50% wall thickness loss for anomaly repairs.

d) **<u>Response Time for ILI Results</u>**: The following section provides the required timing for excavation, investigation, and remediation of anomalies based on ILI data results in accordance with 49 CFR §§ 192.485 and 192.933, and must incorporate appropriate class location design factors in the anomaly repair criteria for ***special permit segments*** and ***special permit inspection areas*** including all HCAs.

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[23] HCAs in the ***special permit inspection area*** and ***special permit segment*** must have anomalies evaluated and repaired based upon the most stringent requirements of either: this special permit, 49 CFR Part 192, Subpart O, or TGP Integrity Management Plan.

[24] Failure pressure ratio (FPR) is based upon the class location where the ***special permit segment*** or ***special permit inspection area*** pipe is located in accordance with 49 CFR § 192.5 and is the reciprocal of the class location design factor in 49 CFR § 192.111(a).

Reassessment by ILI will reset the timing for anomalies not already investigated and/or repaired. TGP must evaluate ILI data by using either the ASME Standard B31G, "*Manual for Determining the Remaining Strength of Corroded Pipelines*" (ASME B31G), the modified B31G (0.85dL) or R-STRENG for calculating the predicted FPR to determine anomaly responses.

- ***Special permit segments***:
  - Immediate response: Any anomaly within a ***special permit segment*** operating up to 72% SMYS that meets either: (1) an FPR equal to or less than 1.1; or (2) an anomaly depth equal to or greater than 80% wall thickness loss.
  - One-year response: Any anomaly within a ***special permit segment*** with original Class 1 location pipe in a Class 3 location operating up to 72% SMYS that meets either: (1) an FPR less than 1.39; or (2) an anomaly depth greater than 40% wall thickness loss.
  - Monitored response: Any anomaly within a ***special permit segment*** with original Class 1 location pipe in a Class 3 location operating up to 72% SMYS that meets both: (1) an FPR equal to or greater than 1.39; or (2) an anomaly depth less than or equal to 40% wall thickness loss. The schedule for the response must take tool tolerance and corrosion growth rates into account.
- ***Special permit inspection area***:
  - Immediate response: Any anomaly within a ***special permit inspection area*** operating up to 72% SMYS that meets either: (1) an FPR equal to or less than 1.1; (2) an anomaly depth equal to or greater than 80% wall thickness loss.
  - One-year response: Any anomaly within a ***special permit inspection area*** that meets either: (1) an FPR less than design factor – for Class 1 location- FPR less than 1.39; Class 2 location – FPR less than 1.67; and for Class 3 location – FPR less than 2.0; or (2) an anomaly depth greater than 60% wall thickness loss.

    Any anomaly for Class location changes from original Class 1 to 2 location or original Class 2 to 3 location in accordance with 49 CFR §§ 192.5 and 192.611 that meets either: (1) an anomaly FPR less than the FPR of the original Class location; or (2) an anomaly depth greater than 50% wall thickness loss.

- Monitored response: Any anomaly within a ***special permit inspection area*** that meets both: (1) an FPR less than design factor – for Class 1 location – FPR equal to or greater than 1.39; Class 2 location – FPR equal to or greater than 1.67; and for Class 3 location – FPR equal to or greater than 2.0; or (2) an anomaly depth less than or equal to 60% wall thickness loss.

  Any anomaly repairs for Class location changes from original Class 1 to 2 location or original Class 2 to 3 location in accordance with 49 CFR §§ 192.5 and 192.611 that meets both: (1) an anomaly FPR equal to or greater than the FPR of the original Class location; or (2) an anomaly depth equal to or less than 50% wall thickness loss.
- The schedule for the response must take tool tolerance and corrosion growth rates into account.

e) ***Special permit segments*** and ***special permit inspection area:*** Upon modification of this special permit, TGP must implement the repair and remediation of any pipe anomalies or dents that are not in compliance with Condition 20 based upon existing ILI assessments results from the high resolution MFL and geometry/deformation tools used to previously assess Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines in the ***special permit segments*** and ***special permit inspection areas***. Remediation of anomalies and dents must be completed in accordance with Condition 20 timing requirements and completed within 12 months from modification of this special permit.

21) **Girth Welds**: TGP must provide records to PHMSA to demonstrate the girth welds on Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines were nondestructively tested at the time of construction in accordance with:

a) The Federal pipeline safety regulations at the time the pipelines were constructed. If not, show that at least 10% of the girth welds in each ***special permit segment*** or ***special permit inspection area*** were non-destructively tested (NDT) after construction but prior to the application for this special permit provided at least two

(2) girth welds in each ***special permit segment*** were excavated and NDT inspected.

b) If TGP cannot provide girth weld records to PHMSA to demonstrate either of the above in Condition 21 (a), TGP must accomplish either (i); or (ii) and (iii) of the following:

   i) Certify to PHMSA in writing that there have been no in-service leaks or breaks in the girth welds on Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines within the entire ***special permit inspection areas*** for the entire life of the pipelines, or

   ii) Evaluate the terrain along each ***special permit segment*** for threats to girth weld integrity from soil types, soil settlement, soil movement, terrain, or heavy loads across the pipeline; and

   iii) Excavate,[25] visually inspect, and nondestructively test at least two (2) girth welds on Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines in each ***special permit segment*** in accordance with the American Petroleum Institute Standard 1104, *"Welding of Pipelines and Related Facilities"* (API 1104) as follows:

      A. Use the edition of API 1104 current at the time the pipelines were constructed; or

      B. Use the edition of API 1104 recognized in the Federal pipeline safety regulations at the time the pipelines were constructed; or

      C. Use the edition of API 1104 currently recognized in the Federal pipeline safety regulations.

c) If any girth weld in any of the ***special permit segments*** is found unacceptable in accordance with API 1104, TGP must repair the girth weld immediately and then prepare an inspection and remediation plan for all remaining girth welds in the ***special permit segments*** based upon the repair findings and the threat to the ***special permit segments***. TGP must submit the inspection and remediation plan for these remaining girth welds to the Director, PHMSA Southern Region and remediate girth welds in the ***special permit segments*** in accordance with the inspection and

[25] TGP must evaluate for SCC any time Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines are uncovered in accordance with Condition 6 (b) of this special permit.

remediation plan within 60 days of finding girth welds that do not meet this Condition 21 (c).

d) Additionally, all oxy-acetylene girth welds, mechanical couplings and wrinkle bends in any ***special permit segment*** must be removed.

e) TGP must complete the girth weld testing, and the girth weld inspection and remediation plan, within one (1) year after the modification of this special permit. If factors beyond TGP control prevent the completion of these tasks within one (1) year, the tasks must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) year after the modification of this special permit.

22) **Casings**: TGP must identify all shorted casings (metallic or electrolytic) within each ***special permit segment*** no later than six (6) months after the modification 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, DCVG, ACVG or AC Attenuation.

a) **Metallic Shorts**: TGP must clear any metallic short on a casing in the ***special permit segments*** no later than six (6) months after the short is identified, where it can be safely and practically accomplished, or will follow the provisions of Condition 22 (c) below.

b) **Electrolytic Shorts**: TGP must remove the electrolyte from the casing/pipe annular space on any casing in the ***special permit segments*** that has an electrolytic short/contact[26] no later than six (6) months after the short is identified, unless TGP can demonstrate adequate levels of cathodic protection by in-line inspection data showing no external corrosion growth on the carrier pipe, or will follow the provisions of Condition 22 (c) below.

c) **All Shorted Casings**: If not already installed, TGP must install external corrosion

[26] NACE SP0200-2008 Steel-cased Pipeline Practices defines the terms "metallic short" and "electrolytic contact."

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 and may then choose to fill the casing/pipe annular space with a high dielectric casing filler or other material which provides a corrosion inhibiting environment provided an assessment and all repairs were completed.

d) **Evaluation Schedule**: If factors "beyond TGP's control" prevent the completion of remediation within six (6) months after the short identification, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than the end of the six (6) months completion date. Any extended evaluation and remediation schedules submitted to PHMSA from TGP must receive a "no objection" from the Director, PHMSA Southern Region.

If TGP identifies any shorted casings within the ***special permit segments,*** they must monitor[27] all casings within the ***special permit segments*** for shorts at least once each calendar quarter, but at intervals not to exceed 100 days, for four (4) consecutive calendar quarters after the modification of this special permit. The intent is to identify through monitoring the calendar quarter(s) when electrolytic casing shorts are most likely to be identified. Thereafter, TGP must then monitor all casings for shorts within the ***special permit segments*** at least once each calendar year during the calendar quarter(s) when electrolytic casing shorts are most likely to be identified. Any casing shorts found in the ***special permit segments*** at any time must be classified and cleared as explained above.

23) **Pipe Seam Evaluations**: TGP must identify any pipe in the ***special permit inspection area*** that may be susceptible to pipe seam issues because of the vintage of the pipe, the manufacturing process of the pipe, or other issues. Once TGP has identified such issues, TGP must complete Condition 23 (a). If the engineering analysis required in Condition 23(a) reveals that there is a threat to the pipeline, then TGP must complete all of the applicable condition requirements in Condition 23 (b), (c), (d), (e), (f), and (g):

[27] Monitoring of casings in this situation means an acceptable test method in accordance with 49 CFR Part 192 to determine if the casing and carrier pipe have either a metallic or electrolytic short (connection or contact).

a) TGP must perform an engineering analysis to determine if there are any pipe seam threats on Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines located in the ***special permit inspection area***. This analysis must include the documentation that the processes in '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-C0SP02120 and 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 were utilized along with other relevant materials. If the engineering analysis shows that the pipe seam issues on Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines located in the ***special permit inspection area*** are not a threat to the integrity of the pipeline, TGP does not have to complete Conditions 23 (b) through 23 (e). Condition 23 (f) and (g) must be completed.

b) If a 49 CFR Part 192, Subpart J hydrostatic test has not been performed, the ***special permit segments*** must be hydrostatically tested to a minimum pressure of 100 percent SMYS, in accordance with 49 CFR Part 192, Subpart J requirements for eight (8) continuous hours, within one (1) year of issuance of this special permit. The hydrostatic test must confirm no systemic issues with the weld seam or pipe. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic issue. The results of this root cause analysis must be reported to the Director, PHMSA Southern Region with a copy to the Director, PHMSA Engineering and Research Division, within 60 days of the failure; or

c) If the pipeline in the ***special permit inspection area*** has experienced a seam leak or failure in the last five (5) years and no hydrostatic test meeting the conditions of 49 CFR Part 192, Subpart J was performed after the seam leak or failure, then a hydrostatic test must be performed within one (1) year after the modification of this special permit on the ***special permit segment*** pipeline; or

d) If the pipeline in any ***special permit segment*** has pipe seam conditions as noted below in (i), (ii), (iii), or (iv), such ***special permit segment*** pipeline shall not be eligible for this special permit:

i) has had any pipe seam leaks or ruptures in the ***special permit inspection area*** and a subsequent 49 CFR Part 192, Subpart J hydrostatic test has not been conducted (an exception to this provision are those segments meeting Condition 23) c) above), or

ii) has unknown manufacturing processes without the greater of a 49 CFR Part 192, Subpart J hydrostatic test or a 1.25 times MAOP pressure test, or

iii) has low fracture toughness pipe that will not ensure ductile fracture and arrest, or

iv) 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, have had past leak and rupture issues, or any other systemic issues].

e) If the pipeline in any ***special permit segment*** has a reduced longitudinal joint seam factor, below 1.0, as defined in 49 CFR § 192.113 the ***special permit segment*** pipeline must be replaced.

f) Pipe in the ***special permit segments*** must have 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 removed and replaced with pipe in accordance with 49 CFR Part 192 requirements.

g) TGP must submit a seam remediation plan for the ***special permit segments*** to the Director, PHMSA Southern Region no later than 30 days after the finding a seam leak in the ***special permit segment***:

i) Longitudinal weld seam remediation/repair plan that meets Condition 23 (a) and includes either replacement, hydrostatic testing, or in-line inspection (ILI), and timing of the plan not to exceed six (6) months, or

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

24) ***Special Permit Segment*** **Specific Conditions**: TGP must comply with the following requirements.

a) **Depth of Cover Survey**: TGP must complete within one (1) year of the modification of this special permit a depth of cover survey of the ***special permit segments***. Any pipe in the ***special permit segments*** that does not meet 49 CFR § 192.327(a) must have additional safety measures implemented in areas with reduced depth of cover. TGP must submit to the Director, PHMSA Southern Region for PHMSA's "no objection" of remedial measures to implement based upon the threat, such as lowering the pipeline, increased pipeline patrols and/or additional line markers.

b) **Line-of-Sight Markers**: TGP must install and maintain line-of-sight markings on the pipeline in the ***special permit segments*** and ***special permit inspection areas*** except in agricultural areas or large water crossings such as lakes where line-of-sight signage is not practical.

c) **Right-of-Way Patrols**: TGP must perform ground or aerial right-of-way patrols, monthly not to exceed 45 days, in the ***special permit segments*** and ***special permit inspection areas***. Each calendar year not to exceed 15 months, one of these right-of-way patrols must be a ground patrol in the ***special permit segment***. All patrols must document compliance with Condition 12 and Conditions 24 (b).

d) **Data Integration**: TGP must maintain data integration of special permit condition findings and remediation in the ***special permit segments*** and 2 miles beyond both sides of each ***special permit segment***. Data integration must include the following information: Pipe diameter, wall thickness, grade, and seam type; pipe coating including girth weld coating; maximum allowable operating pressure (MAOP); class location (including boundaries on aerial photography); high consequence areas (HCAs) (including boundaries on aerial photography); hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; in-line inspection (ILI) survey results including HR-MFL, HR-geometry/caliper or deformation tools; close interval survey (CIS) surveys – most recent; depth of cover surveys; rectifier readings; test point survey readings; AC/DC interference surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; stress corrosion cracking (SCC) excavations and findings; and pipe exposures from encroachments. Data integration must be outlined on pipeline route drawings with parallel sections for each integrity category and recent aerial photography (recent photography, within three (3) years of initial filing and every three (3) years thereafter).

i) Data integration documentation and drawings to meet Condition 24(d) must be completed and must be submitted, if requested by PHMSA, beginning with the 2nd annual report of this revised special permit with four (4) years of prior data.

ii) Data integration must be updated on an annual basis and with at least an annual review of integrity issues to be remediated.

e) **Root Cause Analysis for Failure or Leak**: TGP must notify PHMSA's Southern Regional Director within five (5) days, if a leak or rupture (incident) occurs in any of the ***special permit inspection areas*** and ***special permit segments.*** A 'root cause analysis' must be performed to determine the cause of the failure and must be sent to PHMSA's Southern Regional Director and Director of Engineering and Research Division within 60-days of the incident. PHMSA will review the 'root cause analysis' report to determine if revocation, suspension, or modification of the special permit is warranted based upon incident findings.

f) **Pipe Properties Records**: TGP must mechanically and hydrostatically test pipe in each ***special permit segment*** that does not meet Condition 25 (b) as follows:

i) Test a minimum of 10% of pipe lengths/joints, or at least two (2) pipe lengths/joints when percentage is less than two (2) pipe lengths/joints, must be tested in accordance with 49 CFR §§ 192.109 and 192.107(b).

ii) ***Special permit segments*** pipe must meet the requirements of 49 CFR § 192.107 (b).

iii) ***Special permit segments*** pipe must be tested for mechanical and chemical properties (properties) as required in 49 CFR Part 192, Appendix B, Section III (B) and (C).

iv) Pipe that is tested for properties in accordance with Condition 24 (f) (i),(f) (ii) and (f) (iii), must meet the hydrostatic test requirements of 49 CFR Part 192, Appendix B, Section III (C)(2). Original Class 1 location pipe that is approved for Class 3 locations per this special permit must be tested to a minimum of 100% SMYS for eight (8) continuous hours in accordance with

49 CFR Part 192, Subpart J.

v) The requirements in Condition 24 (f) must be completed within one (1) year of issuance of this special permit and must meet pipe properties requirements for the pipe designed class location factor in accordance with 49 CFR §§ 192.103. 192.105, 192.107, 192.109, 192.111 and 192.113.

g) **Pipe Hard Spots:** If TGP has pipe that is susceptible to hard spots based upon the manufacturing vintage[28] or has had a leak or failure due to a pipe hard spot in the ***special inspection area***, TGP must perform in-line inspection (ILI), evaluation, and remediation in the ***special permit inspection area*** of the pipelines (Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines) susceptible to hard spots as soon as practicable but not later than during the next scheduled ILI run not to exceed seven (7) years after the grant of this special permit[29]. The results of the hard spot ILI tool must be assessed using the following criteria:

i) Brinnel hardness equal to or greater than 300 HB: Check for cracks by excavation, nondestructive examination (NDE), repair by an acceptable repair technique, and recoat.

ii) Brinnel hardness equal to or greater than 300 HB with the presence of cracking: Check for cracks by NDE, repair with Type B sleeve or replace pipe, and re-coat.

iii) Brinnel hardness equal to or greater than 300 HB with mill or mechanical deformation: Check for cracks by NDE, repair by an acceptable repair technique or replace and recoat.

iv) Brinnel hardness equal to or greater than 300 HB: Establish a monitoring program with an inspection frequency in accordance with 49 CFR § 192.465(b) to maintain CP voltage levels below minus 1.2 volts DC across the structure-electrolyte boundary with reference to a saturated copper-copper sulfate half-cell on the ***special permit inspection area***.

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[28] Pipe manufacturing vintage is defined as the manufacturers and decades shown on Table 5 – Hard spot incident summary, page 21 of the "Integrity Characteristics of Vintage Pipelines" prepared on October, 2004, by E. B. Clark and B. N. Leis of Battelle Memorial Institute and R. J. Eiber of R .J. Eiber Consultants Inc. for the INGAA Foundation, Inc. in conjunction with American Gas Foundation.

[29] If § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, TGP may use that reassessment interval instead of seven (7) years.

v) Brinnel hardness equal to or greater than 400 HB: Repair with Type B sleeve or replace pipe and recoat.

vi) TGP must amend applicable sections of its O&M manual(s) to incorporate the monitoring required to maintain CP voltage levels below minus 1.2 volts DC on the special permit inspection areas with any pipe areas with a Brinnel Hardness equal to or greater than 300 HB.

vii) TGP must inspect, evaluate, remediate, recoat and monitor the ***special permit inspection area*** for hard spots. TGP must submit a hard spot remediation plan for the ***special permit inspection area*** to the Director, PHMSA Southern Region with a copy to the Director, PHMSA Engineering and Research Division no later than 30 days prior to the inspection, evaluation or remediation:

A) Hard spot ILI inspection, evaluation, remediation, recoating, and monitoring plans and procedures that meets Condition 24 (g) – Pipe Hard Spots, or

B) Technical justification that shows that the ***special permit segment*** and ***special permit inspection area*** are not at risk for future hard spot leaks or failures.

h) **<u>Pipeline System Flow Reversals</u>**:

i) For long term pipeline system flow reversals exceeding 90 days where either 49 CFR § 192.619(a)(1) or § 192.611 MAOPs for class location changes are exceeded[30] for a ***special permit segment***, TGP must document the flow reversal operational, integrity, and safety processes for the ***special permit segment*** and ***special permit inspection area*** as follows:

A) For flow reversals implemented prior to January 1, 2015, TGP shall review the pressure tests, material, mechanical and chemical properties as required in Condition 25 (a) and (b) for the special permit segments. TGP shall determine the maximum suction pressure of the downstream compressor station (Compressor Station 87 near Portland, Tennessee), based upon the historical flow direction, for the period of November 1,

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[30] 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.

2011 to October 31, 2012 (maximum suction pressure was 883 psig during this time interval); and limit the pipeline operating pressures for the ***special permit segments*** and ***special permit inspection areas*** to the maximum suction pressure determined above (883 psig) until pressure tests, pipeline replacements, and anomaly remediation required to satisfy the MAOP criteria of either § 192.619(a)(1) or § 192.611 are completed for pipe outside the ***special permit segments*** but within the ***special permit inspection areas***. In addition:

1. TGP shall limit the pipeline operating pressures to a maximum of 883 psig for the special permit segments until all pipeline segments from Station 87 discharge up to the operating null point (which is approximately midstream between Compressor Stations 87 and 860) have been pressure tested or pipe segments replaced in accordance with 192.619(a)(1) and (a)(2) or 192.611 and all anomalies found by ILI or otherwise have been remediated in accordance with Condition 20. These pressure test/pipe replacement projects are listed in the following table:

TGP Projects Related to Flow Reversal – Station 860 to 87			
Project Location	**Project Description**	**Length, feet**	**Activity**
MLV 559-1, (Station 860 piping)	Station 0+00 to 6+04	604 feet	Pressure Test
MLV 564-1	Station 700+62 to 702+45	183 feet	Pressure Test
MLV 565-1S, (Station 87 piping)	Station 0+00 to 0+36	36 feet	Pressure Test
MLV 565-1B, (Station 87 piping)	Station 0+00 to 7+52	752 feet	Pressure Test
MLV 565-1D, (Station 87 piping)	Station 7+52 to 7+54	2 feet	Pressure Test

TGP must document completion of the above pressure test projects in accordance with Condition 24(h)(ii);

2. TGP must implement any pressure control changes including applicable pressure relief, pressure monitor, or pressure limiting devices commensurate with the temporary pressure limit of 883 psig or less, as determined above in Condition 24 (h)(i)(A), until the required pressure tests, pipeline replacements, or anomaly remediation have been completed for pipe outside the ***special permit segments*** but within the ***special permit inspection areas***;

3. TGP shall incorporate information related to the pipeline flow reversal in their emergency responder and public awareness programs/procedures, as determined to be applicable, and

4. TGP shall confirm through ILI inspections and/or direct examinations that the repair of any leaks, failures, incidents, or remediation have been conducted in conformance of the lowest failure pressure ratio (to MAOP) in accordance with Condition 20. This review includes the most severe dent and largest wall loss anomalies that may be remaining in the ***special permit segments*** and ***special permit inspection areas***; and

5. TGP must submit to this Docket those measures already implemented prior to the reversal of flow of this pipeline segment that correspond to those criteria identified in PHMSA Advisory Bulletin (ADB-2014-04), "Guidance for Pipeline Flow Reversals, Product Changes and Conversion of Service" issued on September 18, 2014 (79 FR 56121, Docket PHMSA-2014-0400).

ii) TGP must submit the documents, not already submitted, as required to meet Condition 24(h)(i) above to the PHMSA Director, PHMSA Southern Region; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA

Engineering and Research Division within 60-days prior to operating at pressures above 883 psig for a ***special permit segment*** or ***special permit inspection area*** that would exceed either 49 CFR § 192.619(a)(1) or § 192.611 allowed MAOPs.

iii) Based upon PHMSA's review of TGP's flow reversal process for the ***special permit segment*** or ***special permit inspection area***, TGP may be given a "no objection" to the pipeline flow reversal by PHMSA or will be informed by PHMSA that re-applying for a new special permit may be necessary.

25) **Documentation**: TGP must maintain the following records for each ***special permit segment***:

a) Documentation showing that each ***special permit segment*** has received a 49 CFR § 192.505, Subpart J, hydrostatic test for eight (8) continuous hours and at a minimum pressure of 1.25 times MAOP (1.25 x MAOP). If TGP does not have hydrostatic test documentation, then the ***special permit segment*** must be hydrostatically tested to meet this requirement within one (1) year of the modification of this special permit.

b) Documentation of mechanical and chemical properties including pipe toughness (mill test reports) showing that the pipe in each ***special permit segments*** meets the wall thickness, yield strength, tensile strength and chemical composition of either the American Petroleum Institute Standard 5L, 5LX or 5LS, *"Specification for Line Pipe"* (API 5L) referenced in the 49 CFR Part 192 code at the time of manufacturing or if pipe was manufactured and placed in-service prior to the inception of 49 CFR Part 192 then the pipe meets the API 5L standard in usage at that time. Any ***special permit segment*** that TGP does not have mill test reports for the pipe cannot be authorized per this special permit.

c) Documentation of compliance with all the conditions of this special permit must be kept for the applicable life of this special permit for the referenced ***special permit segments*** and ***special permit inspection areas.***

26) **Extension of Special Permit Segments**: PHMSA may extend the original ***special permit segments*** to include contiguous segments of Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines up to the limits of the ***special permit inspection areas*** pursuant to the

following conditions. TGP must:

a) Provide notice to the Director, PHMSA Southern Region; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division of a requested ***special permit segment or extension***[31] of Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipelines based on actual class location change and include a schedule of inspections, of any anticipated remedial actions and the location of the new request including survey stationing. All requests for a ***special permit segment or extension*** must be submitted in the first nine (9) months of the 49 CFR § 192.611(d) timing limits, and must include data integration (see Condition 24 (d)) and information on the potential environmental impacts of the extension to determine whether an environmental assessment is required for the ***special permit segment extension***.

b) Complete all inspections and remediation of the proposed ***special permit segments*** extension to the extent required of the original Line 800-1, Line 500-1, Line 500-2, and Line 500-3 pipeline ***special permit segments***.

c) Comply with all the special permit conditions and limitations included herein to all future ***special permit segments or extensions***.

d) Comply with all conditions of this special permit for the contiguous new ***special permit segments or extensions*** required for implementation and certification in accordance with 49 CFR § 192.611(d) timing limits, including submittal of documents to PHMSA required in Condition 27.

27) **Certification**: A senior executive officer, vice president or higher, of TGP must certify in writing the following:

a) TGP pipeline ***special permit inspection areas*** and ***special permit segments*** meet the conditions described in this special permit,

b) The written manual of O&M procedures (required by § 192.605) for the TGP pipeline has been updated to include all additional requirements of this special permit; and

c) TGP has implemented all conditions as required by this special permit.

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[31] For a new ***special permit segment or extension*** to be considered by PHMSA, TGP must notify PHMSA's Southern Region Director to determine the need for a draft environmental assessment.

TGP must send the certifications required in Condition 27 (a) through (c) with completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator with copies to the Deputy Associate Administrator, PHMSA Field Operations; Director, PHMSA Southern Region; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division within one (1) year of the modification date of this special permit.

III. Limitations:

PHMSA modifies this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether TGP has complied with the specified conditions of this special permit.
2) Failure to submit the certifications required by Condition 27 within the time frames specified may result in revocation of this special permit.
3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1) and require TGP to comply with the regulatory requirements in 49 CFR § 192.611. As provided in 49 U.S.C. Chapter 601 and 49 CFR Part 190, PHMSA may also issue an enforcement action for failure to comply with this Order. Any work plans and associated schedules shall be automatically incorporated into this order and are enforceable in the same manner.
4) Should PHMSA revoke, suspend, or modify a special permit under 49 CFR § 190.341(h)(1), PHMSA will notify TGP in writing of the proposed action and provide TGP an opportunity to show cause why the action should not be taken. In accordance with 49 CFR § 190.341(h)(3), if necessary to avoid the risk of significant harm to persons, property, or the environment, PHMSA will not give advance notice and will declare the proposed action (revocation, suspension, or modification) immediately effective.
5) 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 in accordance with 49 CFR § 190.341(h)(4). To the extent a term, conditions, or limitations in the original special permit and this order are in conflict, the

term, conditions, and limitations in this order are controlling.

6) If TGP sells, merges, transfers, or otherwise disposes of the assets known as the ***special permit segments*** or the ***special permit segment extension***, TGP must provide PHMSA with written notice of the transfer within 30 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the permit if the transfer constitutes a material change in conditions or circumstances pursuant to 49 CFR § 190.341(h)(1)(ii) or any other circumstances listed under 49 CFR § 190.341(h)(1).

7) PHMSA modifies this special permit to limit it to a term of no more than five (5) years from the modification date. If TGP elects to seek renewal of this special permit, as modified, TGP must submit its renewal request at least 180 days prior to expiration of the five (5) year period to the PHMSA Associate Administrator with copies to the Deputy Associate Administrator, PHMSA Field Operations; Director, PHMSA Southern Region; Deputy Associate Administrator, PHMSA Policy and Programs; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division. PHMSA will consider requests for a special permit renewal for up to an additional five (5) year period. All requests for a special permit renewal must include a summary report in accordance with the requirements in Condition 15 above and must demonstrate that the special permit is still consistent with pipeline safety. PHMSA may seek additional information from TGP prior to granting any request for special permit renewal.

AUTHORITY: 49 U.S.C. 60118 (c)(1) and 49 CFR § 1.53.

Issued in Washington, DC on MAY 15 2015.

for: Jeffrey D. Wiese,
Associate Administrator for Pipeline Safety