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

Special Permit Information:

Docket Number:	PHMSA-2016-0004
Requested By:	Tennessee Gas Pipeline Company, LLC
Operator ID#:	19160
Original Issuance Date:	September 1, 2016
1st Renewal Issuance Date:	March 17, 2023
Effective Dates:	March 17, 2023, to March 17, 2028
Code Section(s):	49 CFR 192.611(a) and (d), 192.619(a), and 192.5

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)[1] grants this special permit renewal to Tennessee Gas Pipeline Company, LLC (TGP)[2] for 162 ***special permit segments*** consisting of approximately 1.025 miles of 20-inch diameter gas transmission pipelines, 9.113 miles of 24-inch diameter gas transmission pipelines, 5.168 miles of 26-inch diameter gas transmission pipelines, 14.949 miles of 30-inch diameter gas transmission pipelines, 0.212 miles of 31-inch diameter gas transmission pipeline, and 6.433 miles of 36-inch gas transmission pipelines located in Kentucky, Louisiana, Mississippi, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia. This special permit waives compliance from 49 Code of Federal Regulations (CFR) 192.611 the 162 ***special permit segments*** that have undergone changes from Class 1 to Class 3. The Federal pipeline safety regulations in 49 CFR 192.611(a) require natural gas pipeline operators to confirm or revise the

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

2 Tennessee Gas Pipeline Company, LLC is owned by Kinder Morgan, Inc.

maximum allowable operating pressure (MAOP) of a pipeline segment after a change in class location.

I. Purpose and Need

TGP sought this special permit for Class 1 to Class 3 location changes occurring on 16 pipelines. On the condition that TGP complies with the terms and conditions set forth below, the special permit waives compliance from 49 CFR 192.611[3] for approximately 36.901 miles (194,837.38 feet) of natural gas transmission pipeline. This special permit renewal allows TGP to maintain the current MAOP as shown in **Table 1 – Type A Special Permit Segments and Inspection Areas** and **Table 2 – Type B Special Permit Segments and Inspection Areas**.

II. Special Permit Segment and Special Permit Inspection Area

This special permit 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*** in this section and are identified using the TGP mile post (MP) and survey station (SS) references. ***Special permit segments*** are divided into two (2) categories: ***Type A special permit segments*** and ***Type B special permit segments***.

1) ***Type A special permit segments*** include those ***special permit segments*** as described in **Table 1 – Type A Special Permit Segments and Inspection Areas**. These ***special permit segments*** are where there is a cluster, as described in 49 CFR 192.5(c), of more than 10 buildings intended for human occupancy in a "class location unit" and the MAOP has not been confirmed in accordance with 49 CFR 192.611(a) or where the pipe installed has been identified to have a seam type or manufacturer type that is problematic for maintaining pipeline integrity. ***Type A special permit segments*** total approximately 10.553 miles (55,722.38 feet) of pipe. ***Type A special permit segments*** must meet **Condition 1(d)** and **Conditions 8(b)(i)** and **(c)**.

[3] PHMSA is granting this special permit for Class 1 to Class 3 location changes where the pipeline has been pressure tested to 1.25 times MAOP or greater for eight (8) hours to meet 49 CFR 192.619(a)(2), 192.611(a), 192.517, and **Condition 1(b)**. Each ***special permit segment*** must meet the documentation requirements in **Condition 16 - Documentation**.

2) ***Type B special permit segments*** include those ***special permit segments*** where there is a cluster, as described in 49 CFR 192.5(c), of 10 or fewer buildings intended for human occupancy in a "class location unit" and the MAOP has not been confirmed in accordance with 49 CFR 192.611. ***Type B special permit segments*** total approximately 26.348 miles (139,115.00 feet) of pipe as described in **Table 2 – Type B Special Permit Segments and Inspection Areas.**

Special Permit Inspection Area:

The ***special permit inspection area*** is defined as the one (1) mile continuous segment on both sides of the ***special permit segment*** plus the footage in the ***special permit segment***. **Attachment A** lists the boundaries for the ***special permit inspection area*** associated with each ***special permit segment***. The TGP ***special permit inspection areas*** totals 360.90 miles of pipe.

Extended Special Permit Segments:

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

PHMSA grants this special permit renewal based on the findings set forth in the "Special Permit Analysis and Findings" and "Final Environmental Assessment and Finding of No Significant Impact" documents, which can be read in their entirety in Docket No. PHMSA-2016-0004 in the Federal Docket Management System located on the internet at www.regulations.gov.

III. Conditions

PHMSA grants this special permit renewal subject to TGP implementing the following conditions on the ***special permit segments*** and ***special permit inspection areas***. Each condition detailed in this section applies 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**: TGP must continue to operate each ***special permit segment*** and ***special permit inspection area*** at or below the existing MAOP as shown in **Table 1 – Type A Special Permit Segments and Inspection Areas** and **Table 2 – Type B Special Permit Segments and Inspection Areas**.

b) **<u>Pressure Test</u>**: TGP must identify previous pressure tests for each ***Type B special permit segment***. Pressure test records for each ***Type B special permit segment*** must meet 49 CFR 192.517(a) and be traceable, verifiable, and complete (TVC)[4] as required in 49 CFR 192.624(a)(1). ***Type A special permit segments*** must meet **Condition 1(d)**.[5]

i) TGP must furnish TVC pressure test records to the Director, PHMSA Engineering and Research Division, and to the Director, PHMSA Southern Region, within 60 days of the grant of the special permit. The pressure test records must be compliant with **Condition 1(b)**.[6] TGP must receive a "no objection" letter from the Director, PHMSA Southern 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 TGP must pressure test each ***Type B special permit segment*** in accordance with **Condition 1(b)(ii)**.

ii) If TGP does not have a TVC record of a 1.25 times the MAOP hydrotest in accordance with Subpart J, or the ***special permit segment*** requires an updated pressure test, the ***special permit segment*** must be hydrostatically tested[7] 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.[8]

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

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4 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.

5 TGP must complete **Condition 1(b)** for each ***special permit segment*** flagged as required ("Yes") in **Table 2 – Special Permit Segments and Inspection Areas**.

6 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.

7 For all in-service and pressure test failures, TGP 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. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern 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.

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

d) **Code Compliance by Lowering of MAOP or Pipe Replacement**: TGP must meet 49 CFR 192.611(a) for each ***special permit segment*** listed in **Table 1 – Type A Special Permit Segments and Inspection Areas** or for a **Table 2 – Type B Special Permit Segments and Inspection Areas** where the cluster has grown to over 10 buildings, by completing either of the following:

i) Lower the MAOP within 60 days of the special permit renewal grant; or

ii) Continue to operate at the current MAOP and complete the following:

a) Evaluate and remediate any anomaly in each ***special permit segment*** that meets the criteria detailed in **Condition 8(b)(i) and (c)**; and

b) TGP must replace 20 of the ***Type A special permit segments*** by May 31, 2026, and the remaining 31 ***Type A special permit segments*** by May 31, 2027, or within 24 months of the class location determination that identified the cluster has grown to over 10 buildings for a ***Type B special permit segment***.

2) **Condition 2 - Procedure Updates**

Within 90 days of the grant of the special permit, TGP 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**: TGP 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) TGP must incorporate each ***special permit segment*** into its written integrity management program (IMP) 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.[9] A ***special permit inspection area*** outside of a ***special permit segment*** is not required to be included as a "covered segment" in accordance with 49 CFR 192.903.

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

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

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

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

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

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

c) **Damage Prevention Program**: TGP must incorporate within a ***special permit inspection area*** the applicable best practices of the Common Ground Alliance (CGA)[10] in its damage prevention (DP) program.

3) **Condition 3 – Corrosion Control**

TGP 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.

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

b) **<u>Annual Monitoring of Test Station Potential Measurements</u>**: At least once every calendar year, not to exceed 15 months, TGP 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) **<u>Inadequate Cathodic Protection Level Determination</u>**:

i) In instances where inadequate potentials are a result of an electrical short to an adjacent foreign structure, a rectifier malfunction, an interruption of power source, or an interruption of CP current due to other non-systemic or location-specific causes, TGP 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) **<u>Remedial Action Plans</u>**:

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

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

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

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

i) TGP must perform an "on and off" current CIS at a maximum 5-foot spacing along the entire length of each ***special permit segment***.[11]

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

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

iii) For inadequate CP level determination described in **Condition 3(c)(ii)**, TGP 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**: TGP must perform the CIS within the following timeframes:

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

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[13] 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. TGP 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, TGP 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, TGP must apply for any necessary environmental permits (Federal or state).

iii) TGP must complete remediation of each ***special permit segment*** and confirm restoration of adequate CP over the entire area where inadequate CP levels were

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12 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.

13 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."

detected within 12 months of the survey or as soon as practicable after obtaining the necessary permits.[14]

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

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

b) **<u>Inline Inspection Methodology</u>**: TGP 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, TGP 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), TGP must use an ILI tool[16] that will identify tight cracks.[17]

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.

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

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

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

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

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, TGP 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**: TGP must conduct initial assessments and reassessments for the ***special permit inspection area*** in accordance with the following:

i) Initial ILI assessments must be conducted as follows:

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

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

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

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

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

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

(1) 49 CFR 192.939(a);

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

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

(b) hard spots,

(c) shorted carrier pipe to the casing,

(d) susceptible to SCC, or

(e) pipe or soil movement; or

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

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

iv) If factors beyond TGP's control prevent the completion of an assessment within the required timeframe or reassessment interval, TGP must perform the assessment as soon as practicable, and TGP must submit a letter justifying the delay and provide the anticipated date of completion to the Director, PHMSA Southern Region, no later than two (2) months prior to the end the timeframe or interval. TGP must receive a "no objection" letter from the Director, PHMSA Southern 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**: TGP 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. TGP must demonstrate these welds were excavated, NDT, and repaired, if the welds do not meet Federal pipeline safety regulations at the time the pipelines were constructed.

b) **Missing Records**: If TGP cannot provide girth weld records to PHMSA to demonstrate compliance with **Condition 6(a)**, TGP 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;[18] and

iii) Excavate,[19] visually inspect, and perform NDT on at least two (2) girth welds on each ***special permit segment*** in accordance with the applicable American Petroleum Institute Standard 1104, "*Welding of Pipelines and Related Facilities*" (API 1104) as follows:

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

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

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

c) **Defective Girth Welds**: If any girth weld in a ***special permit segment*** is found unacceptable in accordance with the API 1104 IBR Edition at the time of pipeline construction, TGP 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***. TGP must submit the inspection and remediation plan for girth welds to the Director, PHMSA Southern Region, and must receive a "no objection" letter for the girth weld remediation plan prior to its implementation.[20] TGP must remediate girth welds in the ***special permit segment***

[18] 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.

[19] TGP 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***.

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

in accordance with the inspection and remediation plan within 90 days of the "no-objection" letter receipt.[21]

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

TGP must evaluate the entire length of each ***special permit inspection area*** for SCC as follows:

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

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

c) **Examination of Pipe**: If the threat of SCC exists in the ***extended special permit segment*** as determined in **Condition 7(a)**, TGP 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 integrity management 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), TGP 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. TGP must use appropriate methods for crack detection, such as phased array ultrasonic testing (PAUT), inverse wavefield extrapolation (IWEX), or

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[21] TGP must include any plan requirements or comments received from the Director, PHMSA Southern Region, into the remediation plan.

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

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

magnetic particle inspection (MPI),[24] when an ***extended special permit segment*** is uncovered, and the coating has been identified as poor during the pipeline examination. Visual inspection is not sufficient to determine "poor coating." TGP 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. TGP must keep coating records[25] at all excavation locations in the ***special permit inspection area*** to demonstrate the coating condition.

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

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

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

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

[27] For all in-service and pressure test failures, TGP 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. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

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

i) <u>**Spike Hydrostatic Test Program**</u>:[29]

(1) TGP 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, TGP must replace the pipe joint that does not meet 49 CFR 192.611 in the ***extended special permit segment*** with new pipe. TGP must complete a successful SCC hydrostatic test prior to returning the ***extended special permit segment*** to operational service;

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

iii) <u>**MAOP Lowered**</u>: TGP must lower the MAOP of the ***special permit segment*** to 60% specified minimum yield strength (SMYS);

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

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

f) <u>**SCC Remediation Plan**</u>: If TGP discovers any SCC activity in the ***extended special permit segment***, TGP must submit an SCC remediation plan to the Director, PHMSA Southern Region, and send a copy to the Director, PHMSA Engineering and Research Division, no later than 90 days after the finding of SCC.[30] The plan must:

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

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

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

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

8) **<u>Condition 8 - Anomaly Evaluation and Remediation</u>**

a) **<u>General</u>**: TGP must use the procedures specified in the special permit conditions, 49 CFR 192.712, and **Attachment A** when evaluating anomalies. TGP 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) **<u>ILI Tool Accuracy</u>**: TGP 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). TGP must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool and includes that tolerance in determining the size of each anomaly feature reported to TGP. TGP 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) **<u>General ILI Tool Calibration</u>**: 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.[31]

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

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

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

(1) EMAT ILI service provider report with any TGP 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.

[31] Other known and documented pipeline features that are appropriate for the type of ILI tool used may be used as calibration excavations for ILI tool calibration with technical documentation of their validity. To use other known and documented pipeline features as calibration excavations for ILI tool calibration, TGP must complete the following: (1) submit a plan for using known and documented pipeline features such as calibration excavation data, to the Director, PHMSA Southern 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 Southern Region, prior to performing the ILI tool calibration using pipeline features; (3) submit a report to the Director, PHMSA Southern 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[36]

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

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

(v) **<u>Monitored conditions for a "special permit inspection area"</u>**: TGP 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

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

Attachment A demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

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

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

(5) Metal loss preferentially affecting a detected pipe weld seam and where the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[37]

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

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

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

c) **<u>Remediation schedule for a “special permit segment”</u>**: In addition to the requirements in paragraphs (a) and (b) of **Condition 8** for a ***special permit inspection area***, TGP must remediate conditions in a ***special permit segment*** as follows:[39]

   i) **<u>One-year conditions for a “special permit segment”</u>**: TGP must repair the following conditions within one (1) year of discovery in a ***special permit segment***:

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

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

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

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

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

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

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

   iv) **<u>Monitored conditions for a “special permit segment</u>**”: TGP 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

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

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

conditions are the least severe and will not require examination and evaluation until the next scheduled integrity assessment.

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

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

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

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

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

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

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

ii) **<u>Electrolytic Shorts</u>**: TGP 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 TGP identifies any shorts after uprating, they must be cleared no later than 12 months after identification.

iii) **<u>All Shorted Casings</u>**: TGP 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. TGP 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 TGP completed an assessment and all necessary repairs.

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

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

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

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

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

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

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

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

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

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

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

(2) Figure 4.2, “Framework for Evaluation with Path for the Segment Analyzed Highlighted” from TTO-5, “Low Frequency ERW and Lap Welded Longitudinal 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, TGP must confirm there are no systemic issues with the weld seam or pipe. Within 12 months of analysis completion, TGP 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 TGP 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 TGP 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) TGP must determine from the hydrostatic test whether there are systemic issues with the weld seam or pipe. TGP 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. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure.[44]

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

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

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

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

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

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***, TGP 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**: TGP must remediate all weld seam leaks, failures, or ruptures[45] discovered in the ***special permit segment***. TGP must submit a seam remediation plan for the ***special permit segment*** to the Director, PHMSA Southern 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.

[45] For all in-service and pressure test failures, TGP 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. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern 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**

TGP 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***. TGP 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**: TGP 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**: TGP 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, TGP must develop a remediation procedure and apply for any necessary permits to conduct remediation. TGP 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 TGP's control prevent the completion of any remediation within six (6) months of completing the interference engineering analysis of the survey results, TGP 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 Southern 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 TGP must receive a "no objection" letter from the Director, PHMSA Southern Region.

12) **Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures**

TGP must automate mainline valves[46] 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 remote-controlled valves (RCVs) so that the distance between the valves is no greater than 20 miles.[47] TGP must automate mainline valves to close in accordance with the requirements in **Condition 12** with 30% of the TGP ***special permit segment*** isolation valves completed/operational by May 31, 2025, and 100% of the TGP ***special permit segment*** isolation valves completed/operational by May 31, 2026. The ***special permit segment*** must have procedures for rupture isolation as follows:

a) **Valve Locations**: RCVs must be installed as shown in **Table 4 - Valves and Lateral Locations with Isolations Methods**. Each ***special permit segment*** must have telemetry connections to the TGP supervisory control and data acquisition (SCADA) system installed. If a mainline upstream or downstream isolation valve shown in **Table 4** requires a location change, TGP must notify the Director, PHMSA Southern Region, of the reasons the "mainline isolation valve" location changed and how it meets **Condition 12**. TGP must obtain a letter of "no objection" from PHMSA prior to implementing the change. TGP must update **Table 4** if a mainline, lateral, or crossover valve was mis-identified, added, or modified after the grant of the special permit and submit this update in accordance with **Condition 15 – Annual Report**.

b) **Automatic Shutoff Valve Requirements**: This special permit does not allow the use of automated shutdown valves (ASVs).

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**.

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

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

d) **<u>Crossover or Lateral Pipe Connection Isolation</u>**: If any crossover or lateral pipe[48] connects to the isolated segment between the upstream and downstream mainline valves, the nearest valve on the crossover connection(s) or lateral(s) must be isolated such that, when all valves are closed, there is no flow path for gas to flow to the leak or rupture site (except for residual gas already in the shut-off segment). If the nearest valve for a gas receipt or delivery line to the ***special permit inspection area*** is not isolated, isolation valves must be installed when the ***special permit segment*** isolation valves are required to be completed.[49] Valves that are in the TGP O&M procedures as locked closed and that are only opened when manned by TGP operating personnel do not require RCVs or ASVs for closure.

e) **<u>Remote-Control and Automatic-Shutoff Valve Status</u>**:

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

   ii) This special permit does not allow the use of ASVs.

f) **<u>Mainline Valve Closure</u>**: 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:[50]

   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 TGP (e.g., by its controller(s) in a control room, field operations personnel, nearby pipeline or utility personnel, the

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48 **Table 4 - Valves and Lateral Locations with Isolations Methods** has a listing of all lateral valves. TGP must update **Table 4** if a mainline, lateral, or crossover valve was mis-identified, added, or modified after the grant of the special permit and submit this update in accordance with **Condition 15 – Annual Report**.

49 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 nominal diameter.

50 The pipeline valve section location to be closed and isolated (if there should be a rupture) must be confirmed by TGP 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.

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) TGP observes an unanticipated or unplanned pressure loss outside of the pipeline's normal operating pressures, as defined in TGP's written procedures. If TGP 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, TGP 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) TGP 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 TGP.

ii) TGP must evaluate and identify a rupture,[51] 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 TGP 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 TGP pipeline operating procedures.

h) **Remote Monitoring**: TGP 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

[51] For all in-service and pressure test failures, TGP 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. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern 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.

equipment, including pressure sensors, must have backup power to maintain communications and control to the TGP Gas Control Center during power outages.

i) **Point-to-Point Verification**: TGP 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**: TGP 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**: TGP 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 TGP's control, TGP must notify, in writing, the Director, PHMSA Southern Region, of the reasons the schedule cannot be met and obtain a letter of "no objection" from PHMSA prior to implementing the schedule change.

l) **Emergency Communications**:

   i) TGP 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) TGP 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;[52] and

[52] TGP 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.

iii) In accordance with these special permit conditions and as required in 49 CFR 192.615 and 192.631, TGP 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**

TGP must comply with the following requirements:

a) **Line-of-Sight Markers**: TGP 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 TGP within 30 days after identification of line-of-sight marker removal.

b) **Depth of Cover Survey**:

i) TGP must complete, within two (2) years of the grant of this special permit, a depth of cover survey for each ***special permit segment***.

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

iii) For TGP 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, TGP must submit these procedures to the Director, PHMSA Southern Region, for a "no objection" letter prior to usage. The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify TGP of PHMSA's need for additional time to provide a decision.

c) **Data Integration**: TGP must develop and maintain data integration[53] 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.[54] Structures must be validated each calendar year by obtaining new aerial imagery or by ground patrol in accordance with **Condition 13(h)**.

ii) If requested by PHMSA, TGP 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) TGP 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)**, TGP must test the pipe in a ***special permit segment*** as follows: [55]

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53 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.

54 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.

55 **Table 2 – Type B Special Permit Segments and Inspection Areas** identifies the ***special permit segments*** where the material records supplied by TGP do not meet the requirements for TVC and the completion of **Condition 13(d) – Pipe Properties Testing** is required. If TGP identifies additional material records that are TVC records, TGP has the option to submit these material records to the Director, PHMSA Southern Region, and to the Director, PHMSA Engineering and Research Division, within 60 days of the grant of the special permit.

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for any ***special permit segment***, without TVC[56, 57] 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) TGP 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) TGP must perform a minimum of two (2) destructive or NDT methods at an excavation site. TGP must conduct NDT assessments using test procedures, calibration pipe of similar confirmed properties for equipment testing, and ball indention methodology, or an equivalent method.[58] If NDT of pipe material properties show that the pipe wall thickness is not within API 5L specification tolerances, and the pipe grade is under the strength requirements of API 5L by 1,000 pounds per square inch (psi) or more, then TGP 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, TGP must submit an assessment procedure to the Director, PHMSA Southern Region, for a "no objection" letter prior to its usage.[59] The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may

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[56] 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.

[57] 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.

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

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

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

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

v) TGP 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. TGP 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, TGP must use the above methodology, or TGP may elect to remove pipe joints for destructive testing.[60]

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 CFR 192.619(a)(1) or 192.611[61] in a ***special permit segment***, TGP 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). TGP must submit the written flow reversal procedure to the Director, PHMSA Southern Region, and submit a copy of the plan to the Federal Docket for this special permit at www.regulations.gov.[62] TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing the pipeline system flow reversal through a ***special permit segment***.

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[60] TGP must prepare a procedure in accordance with **Condition 13(d) – Pipe Properties Testing**, for material documentation and submit to the Director, PHMSA Southern Region, and receive a "no objection" letter prior to usage of the procedure. The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify TGP 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.

[61] 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.

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

f) **<u>Environmental Assessments and Permits</u>**: TGP 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, TGP must obtain and adhere to all applicable Federal, state, and local environmental permit requirements when conducting the special permit conditions activity.

g) **<u>Gas Quality</u>**: TGP 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) **<u>Annual Class Location Study</u>**: TGP 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) **<u>Notifications</u>**: For any special permit condition that requires TGP to provide a notice for a "no objection" response from PHMSA, other notice, annual report, or documentation to the Director, PHMSA Southern Region, TGP must also send a copy to the State Agency that has interstate agent agreements with PHMSA and to the Director, PHMSA State Programs.

j) **<u>Pipe and Soil Movement</u>**: 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. TGP must develop procedures on how to evaluate and remediate soil stresses and strains on the pipeline including IMU intervals. TGP must submit soil stress and strain evaluation and remediation procedures to the Director, PHMSA Southern Region, within three (3) months of identification and must receive a "no objection" letter prior to implementation.

k) **<u>Gas Leakage Surveys and Remediation</u>**:

   i) TGP 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. TGP 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. TGP must grade and remediate all gas transmission pipeline leaks in the ***special permit segment*** and at all valves, flanges, pipeline tie-ins, ILI launcher, and ILI receiver facilities in each ***special permit inspection area***, as follows:

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

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

(b) Escaping gas that has ignited;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

iii) When a pressure limiting device or relief valve allows a gas release to the atmosphere that is located along the ***special permit inspection area***, TGP 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. TGP cannot extend or change any remediation timing or continuous monitoring requirements in this paragraph without a "no objection" letter received by TGP from the Director, PHMSA Southern Region.

iv) TGP may request an extension of the remediation time interval requirements by sending a request to the Director, PHMSA Southern Region, but must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to extending the leak remediation timing or continuous monitoring requirements in **Condition 13(k)**.[63]

l) **Right-of-Way Patrols**: In addition to the requirements of 49 CFR 192.705, TGP 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 TGP's control, TGP must notify the Director, PHMSA Southern 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) TGP must reduce the release of gas to the environment when replacing any pipe between the mainline isolating valves for a ***special permit segment***. TGP must use one (1) or more of following methods that will reduce the environmental effects of methane (gas) being released. TGP 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.[64]

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

[63] Any TGP 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.

[64] **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.

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

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

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

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

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) TGP 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. TGP must also document and justify, any substantial difference (over 10 percent additional release) between the actual amount of natural gas released and the estimated volume calculated before the replacement.

iii) TGP 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**

TGP must give a minimum 14-day notice to the Director, PHMSA Southern 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 TGP should notify the Director, PHMSA Southern Region, no later than two (2) business days after the immediate condition is discovered. The Director, PHMSA Southern Region, may elect not to require a notification for some activities.

15) **<u>Condition 15 - Annual Report</u>**

Annually[65] after the grant of this special permit, TGP must report the following to the Director, PHMSA Southern Region, with copies to the Director, PHMSA Engineering and Research Division:[66]

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. TGP must identify where a ***Type B special permit segment*** has become a ***Type A special permit segment*** due to the structure count exceeding 10 building. TGP must also report the date when the ***Type A special permit segments*** meet Condition 1 on the annual report. TGP 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[67] during the previous year in the ***special permit inspection area***, including their survey station, predicted failure pressure, anomaly depth and length, class location, and whether these threats are in an HCA.

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

   i) A pressure test that meets **Condition 1(b)**. TGP 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**. TGP must report the planned or actual completion dates for the ***special permit segment*** material pipe property tests.

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65 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.

66 TGP must post the annual report to the special permit docket PHMSA-2016-0004 at <u>www.regulations.gov</u>.

67 TGP 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.

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***. TGP 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) TGP 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, TGP must submit a full information package of the requested pipeline attribute and integrity items outlined in the condition.

g) This special permit does not allow the use of ASVs, since TGP did not comply with **Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures** requirements for flow modeling to determine shutoff pressures of ASVs.

h) TGP 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) TGP 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 TGP must review for correctness, date, and sign the annual report prior to posting it to the Federal Docket (PHMSA-2016-0004) at www.regulations.gov and submitting a copy to the Director, PHMSA Southern Region, and the Director, PHMSA Engineering and Research Division.

l) TGP must schedule a review meeting regarding **Condition 15 - Annual Report** with the Director, PHMSA Southern Region, prior to or within one (1) month of the filing of each year.[68] During the annual review meeting, TGP must review the status of implementing the special permit conditions with the Director, PHMSA Southern Region.

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

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

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

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

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

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

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

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

[68] The Director, PHMSA Southern Region, has the authority to waive this meeting.

ii) TGP 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. TGP 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 TGP 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) TGP must remediate all anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**;

ii) TGP must have hydrostatically tested[69] a ***special permit segment*** and ***extension*** in accordance with **Condition 1 – Maximum Allowable Operating Pressure**, as applicable; and

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

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

TGP must meet the following conditions for certification:

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

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

[69] For all in-service and pressure test failures, TGP 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. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

ii) TGP has updated its O&M, IMP, 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) TGP has prepared an uprating plan in accordance with **Condition 1(c)**, if applicable; and

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

b) TGP must send the certifications required in **Condition 18(a)**, with special permit condition status, completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Southern Region; the Director, PHMSA Engineering and Research Division; and the Federal Register Docket (PHMSA-2016-0004) 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 TGP 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 TGP 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 TGP sells, merges, transfers, or otherwise disposes of all or part of the assets known as a ***special permit segment*** or ***special permit inspection area***, TGP 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 limited to a term of no more than 5 years from the date of issuance. If TGP elects to seek renewal of this special permit, TGP must submit its renewal request at least 180 days prior to expiration of the 5-year period to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Southern 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 TGP 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 March 17, 2023.

ALAN KRAMER MAYBERRY

Digitally signed by ALAN KRAMER MAYBERRY
Date: 2023.03.17 08:47:06 -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, TGP 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) TGP 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 Southern 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, TGP 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 TGP uses other technologies or techniques to comply with failure pressure determinations, TGP must submit advance notification to Director, PHMSA Southern Region, and must receive a "no objection" letter from the Director, PHMSA Southern 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 Southern Region.

13) TGP must remediate dents and mechanical damage that do not pass the criteria defined in **Table 3 – Dent Criteria**, or TGP must conduct an acceptable ECA as described in this **Attachment A, Items 1 through 12**.

14) TGP must submit the dent ECA procedure to the Director, PHMSA Southern Region, for a "no objection" letter prior to conducting the anomaly evaluation.[70] The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify TGP of PHMSA's need for additional time to provide a decision.

[70] 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 TGP 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**.

<u>Note:</u> TGP 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 A – Special Permit Segments and Special Permit Inspection Areas

Table 1 – Type A Special Permit Segments and Inspection Areas

Special Permit Segment Number	Outside Diameter (inches)	Line Name	Segment Length (feet)	Start Survey Station (Valve - SS)	End Survey Station (Valve - SS)	Inspection Area Start SS (Valve – SS)	Inspection Area End SS (Valve – SS)	Inspection Area Length (Miles)	County or Parish, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)
1 (KM 69)	24	100-1	526.27	102-1A - 68947	102-1A - 69473	102-1A - 63667	102-1A - 74753	2.10	Madison, KY	3	1971	FW	750
3 (KM 71)	24	100-1	168.34	102-1A - 77036	102-1A - 77204	102-1A - 71756	102-1A - 82484	2.03	Madison, KY	1	1971	FW	750
4 (KM 72)	26	100-2	606.6	108-2 - 33270	108-2 - 33876	108-2 - 27990	108-2 - 39156	2.11	Bath, KY	5	1948	FW	750
6 (KM 74)	26	100-2	1,515.3	108-2 - 40523	108-2 - 42039	108-2 - 35243	108-2 - 47319	2.29	Bath, KY	3	1948	FW	750
7 (KM 75)	26	100-2	344.2	108-2 - 44555	108-2 - 44899	108-2 - 39275	109-2 - 597	2.07	Bath, KY	6	1948	FW	750
8 (KM 76)	26	100-2	252.39	109-2 - 1131	109-2 - 1384	108-2 - 45434	109-2 - 6664	2.05	Rowan, KY	0	1948	FW	750
13 (KM 82)	26	100-3	1,054.07	108-3 - 52941	108-3 - 53995	108-3 - 47661	109-3 - 4870	2.20	Rowan, KY	6	1949	FW	750
14 (KM 83)	26	100-3	338.7	108-3 - 54035	108-3 - 54402	108-3 - 48755	109-3 - 5277	2.06	Rowan, KY	4	1949	FW	750
15 (KM 84)	26	100-3	912.96	109-3 - 472	109-3 - 1385	108-3 - 49597	109-3 - 6665	2.17	Rowan, KY	3	1949	FW	750
17 (KM 86)	26	100-3	655.37	112-3 - 47754	112-3 - 48425	112-3 - 42474	112-3A - 53705	2.12	Boyd, KY	0	1950	FW	790
18 (KM 87)	26	100-3	494.4	112-3A - 48525	112-3A - 49019	112-3 - 43245	112-3A - 54299	2.09	Boyd, KY	1	1950	FW	790
23 (KM 101)	24	100-1	598.4	36-1 - 47642	36-1 - 48240	36-1 - 42362	36-1 - 53520	2.11	Sabine, LA	3	1944	FW	750
24 (KM 102)	24	100-1	1,118.3	39-1 - 57784	39-1 - 58902	39-1 - 52504	39-1 - 64182	2.21	Natchitoches, LA	6	1944	FW	750
29 (KM 109)	26	100-2	920.8	47-2D - 10183	47-2D - 11104	47-2D - 4903	47-2D - 16384	2.17	Ouachita, LA	1	1947	FW	750
46 (KM 134)	26	100-2	112.4	53-2B - 95230	53-2B - 95230	53-2B - 89950	53-2B - 100623	2.02	Washington, MS	1	1948	FW	750
47 (KM 135)	26	100-2	2,073.94	53-2B - 95383	53-2B - 97457	53-2B - 90103	53-2B - 102737	2.39	Washington, MS	2	1948	FW	750
50 (KM 139)	30	500-1	1,471.05	530-1 - 71188	530-1 - 72659	530-1 - 65908	530-1 - 77939	2.28	Hancock, MS	2	1959	FW	936
51 (KM 140)	30	500-1	482.4	535-1 - 38349	535-1 - 38831	535-1 - 33069	535-1 - 44111	2.09	Forrest, MS	2	1959	FW	936
52 (KM 141)	30	500-1	1,370.49	535-1 - 38884	535-1 - 40254	535-1 - 33604	535-1 - 45534	2.26	Forrest, MS	2	1959	FW	936
60 (KM 152)	36	500-2	1,488.68	530-2 - 71038	530-2 - 72527	530-2 - 65758	530-2 - 77807	2.28	Hancock, MS	2	1965	FW	936
61 (KM 153)	36	500-2	1,909.29	535-2 – 38304	535-2 – 40214	535-2 – 33024	535-2 – 45494	2.36	Forrest, MS	2	1966	LF-ERW	936
75 (KM 178)	24	200-1	654.33	236-1 - 13357	236-1 - 14012	236-1 - 8077	236-1 - 19292	2.12	Ontario, NY	2	1951	FW	760
82 (KM 187)	26	200-1	2,658.16	213-1 - 35693	213-1 - 38351	213-1 - 30413	213-1 - 43631	2.50	Carroll, OH	5	1950	FW	790
83 (KM 188)	26	200-1	2,044.66	215-1 - 37377	215-1 - 39422	215-1 - 32097	215-1 - 44702	2.39	Columbiana, OH	8	1950	FW	790
84 (KM 189)	26	200-1	1,270.1	215-1 - 44383	215-1 - 45653	215-1 - 39103	215-1 - 50933	2.24	Columbiana, OH	2	1950	FW	790
85 (KM 190)	26	200-1	1,382.31	215-1 - 46382	215-1 - 47765	215-1 - 41102	215-1 - 53045	2.26	Columbiana, OH	1	1950	FW	790
86 (KM 191)	26	200-2	1,513.05	205-2 - 8795	205-2 - 10308	205-2 - 3515	205-2 - 15588	2.29	Athens, OH	3	1952	FW	790

Table 1 – Type A Special Permit Segments and Inspection Areas													
Special Permit Segment Number	Outside Diameter (inches)	Line Name	Segment Length (feet)	Start Survey Station (Valve - SS)	End Survey Station (Valve - SS)	Inspection Area Start SS (Valve – SS)	Inspection Area End SS (Valve – SS)	Inspection Area Length (Miles)	County or Parish, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)
88 (KM 193)	26	200-2	2,680.73	213-2 - 35739	213-2 - 38419	213-2 - 30459	213-2 - 43699	2.51	Carroll, OH	5	1952	FW	790
89 (KM 194)	26	200-2	1,296.36	216-2 - 15651	216-2 - 16947	216-2 - 10371	216-2 - 22227	2.25	Columbiana, OH	5	1954	FW	790
109 (KM 223)	26	100-2	554.05	82-2C - 49652	82-2C - 50206	82-2C - 44372	82-2C - 55486	2.10	Dickson, TN	1	1948	FW	750
110 (KM 224)	26	100-2	177.44	82-2C - 59530	82-2C - 59708	82-2C - 54250	83-2 - 2036	2.03	Dickson, TN	1	1948	FW	750
120 (KM 238)	30	500-1	9.9	562-1 - 1259	562-1 - 1269	560-1 - 97810	562-1 - 6549	2.00	Cheatham, TN	1	1959	FW	936
128 (KM 250)	36	500-2	1,318.68	560-2 – 37151	560-2 – 38470	560-2 – 31871	560-2 – 43750	2.25	Cheatham, TN	4	1968	LF-ERW	936
129 (KM 251)	36	500-2	381.21	560-2 – 43790	560-2 – 44171	560-2 – 38510	560-2 – 49451	2.07	Cheatham, TN	5	1968	LF-ERW	936
130 (KM 252)	36	500-2	420.56	560-2 – 99604	560-2 – 100024	560-2 – 94324	562-2 – 3915	2.08	Cheatham, TN	1	1968	LF-ERW	936
151 (KM 290)	24	100-1	1,677.99	19-1 - 21876	19-1 - 24570	19-1 - 16596	19-1 - 29850	2.32	Waller, TX	5	1944	FW	750
152 (KM 291)	24	100-1	753.7	20-1 - 36048	20-1 - 36801	20-1 - 30768	20-1 - 41976	2.14	Harris, TX	2	1944	FW	750
153 (KM 292)	24	100-1	675	36-1 - 13320	36-1 - 13995	36-1 - 8040	36-1 - 19275	2.13	Sabine, TX	1	1944	FW	750
160 (KM 300)	30	100-3	1,531.99	19-3 -20924	19-3 - 23684	19-3 - 15644	19-3 - 28964	2.29	Waller, TX	4	1952	EFW	750
161 (KM 301)	30	100-3	1,727.52	19-3 - 41139	19-3 - 42867	19-3 - 35859	19-3 - 48147	2.33	Waller, TX	3	1952	EFW	750
162 (KM 302)	30	100-3	1,024.5	19-3 - 48100	19-3 - 49125	19-3 - 42820	20-3 - 5225	2.19	Harris, TX	7	1952	EFW	750
169 (KM 312)	24	409A-100 DONNA LINE	1,237.01	409A-101.1 - 5411	409A-101.1 - 6648	409A-101.1 - 131	409A-101.1 - 11928	2.23	Hidalgo, TX	76	1950	FW	933
171 (KM 316)	24	409A-100 DONNA LINE	1,523.74	409A-102 - 10119	409A-102 - 11643	409A-102 - 4839	409A-102 - 16923	2.29	Hidalgo, TX	4	1950	FW	933
172 (KM 317)	24	409A-100 DONNA LINE	1,787.31	409A-102 - 35417	409A-102 - 37204	409A-102 - 30137	409A-102 - 42484	2.34	Hidalgo, TX	9	1950	FW	933
177 (KM 323)	24	100-2	2,657.51	115-2 - 18573	115-2 - 21231	115-2 - 13293	115-2 - 26511	2.50	Wayne, WV	3	1948	FW	973
178 (KM 326)	24	100-2	1,833.55	119-2 - 3970	119-2 - 5881	118-3 - 65930	119-2 - 11161	2.35	Putnam, WV	3	1948	FW	938
181 (KM 329)	26	100-3	438.1	117-3 - 37414	117-3 - 37852	117-3 - 32134	117-3 - 43132	2.08	Cabell, WV	2	1966	FW	910
185 (KM 335)	24	100-1	1,181.7	19-1 - 47777	19-1 - 48959	19-1 - 42497	20-1 - 5235	2.22	Harris, TX	8	1944	FW	750
186 (KM 336)	24	100-1	1,351.66	20-1 - 0034	20-1 - 1386	19-1 - 43757	20-1 - 6666	2.26	Harris, TX	8	1966	FW	750
187 (KM 340)	24	100-2	1,233.7	121-2 - 54382	121-2 - 55616	121-2 - 49102	121-2 - 60896	2.23	Kanawha, WV	1	1948	FW	910
191 (KM 348)	36	500-2	311.51	541-2 - 72	541-2 - 383	540-2 - 81127	541-2 - 5663	2.06	Lauderdale, MS	3	1963	FW	936

Note: **FW** is a flash welded pipe longitudinal seam.
EFW is electric flash welded pipe longitudinal seam.
LF-ERW is low frequency electric welded longitudinal seam pipe.

Table 2 – Type B Special Permit Segments and Inspection Areas															
Special Permit Segment Number	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (Valve - SS)	End Survey Station (Valve - SS)	Inspection Area Start SS (Valve – SS)	Inspection Area End SS (Valve – SS)	Inspection Area Length (Miles)	County or Parish, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)	Pressure Test – Condition 1(b) required	Material Records – Condition 13(d) required
2 (KM 70)	24	100-1	12.7	102-1A – 71157	102-1A – 71170	102-1A – 65877	102-1A – 76450	2.00	Madison, KY	1	1971	SAW	750		Yes – M1
10 (KM 78)	30	100-3	824.32	102-3 – 53270	102-3 – 54095	102-3 – 47990	103-3 – 5236	2.16	Madison, KY	4	1950	DSAW	750		
11 (KM 79)	30	100-3	536.3	103-3 – 1904	103-3 – 2440	102-3 – 50762	103-3 – 7720	2.10	Madison, KY	1	1950	DSAW	750		
12 (KM 80)	30	100-3	806.72	103-3 – 8570	103-3 – 9377	103-3 – 3290	103-3 – 14657	2.15	Madison, KY	1	1950	DSAW	750		
19 (KM 88)	30	100-4	521.39	103-4 – 15933	103-4 – 16455	103-4 – 10653	103-4 – 21735	2.10	Madison, KY	1	1951	DSAW	750		
20 (KM 89)	30	100-4	607.56	103-4 – 17254	103-4 – 17861	103-4 – 11974	103-4 – 23141	2.12	Madison, KY	2	1951	DSAW	750		
21 (KM 90)	36	800-2	1,690.82	874-2 – 69802	874-2 – 71493	874-2 – 64522	874-2 – 76773	2.32	Madison, KY	3	1969	DSAW	936		
27 (KM 106)	30	100-2	272.2	36-2 – 47634	36-2 – 47906	36-2 – 42354	36-2 – 53186	2.05	Sabine, LA	2	1949	DSAW	750	Yes – PT1	
28 (KM 108)	31	100-2	1,121.16	39-2 – 57758	39-2 – 58879	39-2 – 52478	39-2 – 64159	2.21	Natchitoches, LA	6	1948	DSAW	604		
31 (KM 111)	30	100-3	740.5	36-3 – 47480	36-3 – 48221	36-3 – 42200	36-3 – 53501	2.14	Sabine, LA	2	1951	DSAW	750	Yes – PT1	
32 (KM 113)	30	100-3	1,772.33	39-3 – 57098	39-3 – 58870	39-3 – 51818	39-3 – 64150	2.34	Natchitoches, LA	6	1951	DSAW	750	Yes – PT1	
33 (KM 115)	30	100-3	907.8	47-3D – 10212	47-3D – 11120	47-3D – 4932	47-3D – 16400	2.17	Ouachita, LA	1	1949	DSAW	750	Yes – PT1	
34 (KM 116)	30	100-4	1,414.14	47-4D – 9988	47-4D – 11056	47-4D – 4708	47-4D – 16337	2.27	Ouachita, LA	1	1951	DSAW	750	Yes – PT1	
36 (KM 118)	24	500-1	872.7	511-1 – 10843	511-1 – 11716	511-1 – 5572	511-1 – 16996	2.17	Vermillion, LA	8	1956	DSAW	973		
37 (KM 119)	24	500-1	3,005.66	511-1 – 15728	511-1 – 18734	511-1 – 10448	511-1 – 24014	2.57	Vermillion, LA	10	1956	DSAW	973		
38 (KM 120)	24	500-1	858.45	512-1 – 45271	512-1 – 46129	512-1 – 39991	512-1 – 51409	2.16	Iberia, LA	4	1956	DSAW	973		
41 (KM 124)	30	800-1	102.57	834-1 – 77999	834-1 - 78101	834-1 – 72719	834-1 – 83381	2.02	Franklin, LA	0	1954	DSAW	936		
42 (KM 125)	30	800-1	1,259.31	834-1 - 78142	834-1 - 79401	834-1 – 72862	834-1 – 84682	2.24	Franklin, LA	1	1954	DSAW	936		
43 (KM 126)	30	800-1	75.63	835-1 – 694	835-1 – 797	834-1 – 80806	835-1 – 6050	2.01	Franklin, LA	1	1954	DSAW	936		
44 (KM 131)	24	100-1	731.04	53-1B1 – 95339	53-1B1 – 96070	53-1B1 – 90059	53-1B1 – 101350	2.14	Washington, MS	1	1944	SMLS	750		
45 (KM 132)	24	100-1	964.23	53-1B1 – 101333	53-1B1 – 102270	53-1B1 – 96053	53-1B1 – 107550	2.18	Washington, MS	1	1944	SMLS	750		
48 (KM 136)	30	100-3	1,198.98	69-3 – 3436	69-3 – 4635	68-3 – 59355	69-3 – 9915	2.23	Benton, MS	2	1949	DSAW	750		
49 (KM 137)	30	100-4	1,234.46	69-4 – 3494	69-4 – 4728	68-4 – 59426	69-4 – 10008	2.23	Benton, MS	2	1952	DSAW	750		
53 (KM 142)	30	500-1	1,474.9	540-1 – 77758	540-1 – 79233	540-1 – 72478	540-1 – 84513	2.28	Lauderdale, MS	5	1959	SAW	936		Yes – M2
55 (KM 144)	30	500-1	257.2	541-1 - 00042	541-1 – 00313	540-1 – 81096	541-1 – 5593	2.05	Lauderdale, MS	4	1959	DSAW	936		Yes – M1
58 (KM 148)	30	500-1	959.21	546-1 – 26190	546-1 – 27149	546-1 – 20910	546-1 – 32429	2.18	Lowndes, MS	1	1959	DSAW	936		Yes – M2

PT1 – Elevation profile and corrected test pressure is required to verify pressure test was conducted to Subpart J requirements.
M1 – Confirm pipe is DSAW. Any A.O. Smith EFW pipe or LF-ERW pipe found or identified must be replaced as a ***Type A special permit segment***.
M2 – Confirm pipe in special permit segment was manufactured by Republic. Any A.O. Smith EFW pipe or LF-ERW pipe found or identified must be replaced as a ***Type A special permit segment***.

Special Permit Segment Number	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (Valve - SS)	End Survey Station (Valve - SS)	Inspection Area Start SS (Valve – SS)	Inspection Area End SS (Valve – SS)	Inspection Area Length (Miles)	County or Parish, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)	Pressure Test – Condition 1(b) required	Material Records – Condition 13(d) required
59 (KM 150)	30	500-1	1,581.69	546-1 – 34988	546-1 – 36570	546-1 – 29708	546-1 – 41850	2.30	Lowndes, MS	3	1959	DSAW	936		Yes – M2
62 (KM 154)	36	500-2	1,439.84	540-2 – 77710	540-2 – 79150	540-2 – 72430	540-2 – 84430	2.27	Lauderdale, MS	6	1966	DSAW	936		
64 (KM 157)	36	500-2	1,585.26	546-2 – 34989	546-2 – 36574	546-2 – 29709	546-2 – 41854	2.30	Lowndes, MS	3	1964	DSAW	936		
65 (KM 158)	36	500-3	1,347.37	530-3 – 70819	530-3 – 72167	530-3 – 65539	530-3 – 77447	2.26	Hancock, MS	2	1972	DSAW	936		
66 (KM 159)	24	300-1	2,953.04	324-1A - 55004	324-1A – 57957	324-1A – 49724	324-1A - 63237	2.56	Sussex, NJ	10	1955	SMLS	1,170		
67 (KM 160)	24	300-1	638.57	324-1A - 63558	324-1A – 64196	324-1A – 58278	324-1A - 69476	2.12	Sussex, NJ	1	1955	SMLS	1,170		
68 (KM 162)	24	300-1	471.55	325-1 – 16365	325-1 – 16837	325-1 – 11085	325-1A - 22117	2.09	Sussex, NJ	5	1955	SMLS	1,170		
69 (KM 163)	24	300-1	1,121.11	325-1 – 17148	325-1 – 18277	325-1 – 11868	325-1A - 23557	2.21	Sussex, NJ	8	1955	SMLS	1,170		
70 (KM 164)	24	300-1	811.71	325-1A – 38824	325-1A – 39635	325-1A – 33544	326-1 – 3519	2.15	Sussex, NJ	2	1955	SMLS	1,170		
71 (KM 166)	24	300-1	373.7	326-1 – 8209	326-1 – 8582	326-1 – 2929	326-1 – 13862	2.07	Sussex, NJ	2	1955	SMLS	1,170		
72 (KM 167)	24	300-1	1,729.51	326-1 – 11749	326-1 – 13479	326-1 – 6469	326-1 – 18759	2.33	Sussex, NJ	2	1955	SMLS	1,170		
77 (KM 180)	24	200-1	1,478.51	243-1 – 20348	243-1 – 21827	243-1 – 15068	243-1 – 27107	2.28	Madison, KY	3	1951	DSAW	760		
79 (KM 182)	24	200-1	1,153.88	251-1 – 18683	251-1 – 19837	251-1 – 13403	251-1 – 25117	2.22	Albany, NY	1	1951	DSAW	760		
80 (KM 183)	24	200-1	1,059.96	251-1 – 34314	251-1 – 35374	251-1 – 29034	252-1 – 2901	2.20	Albany, NY	1	1951	DSAW	760		
90 (KM 195)	26	200-3	1,081.17	213-3 – 26889	213-3 – 27970	213-3 – 21609	213-3 – 33250	2.20	Carroll, OH	4	1956	DSAW	790		Yes – M2
92 (KM 197)	26	200-3	974.2	213-3 – 35492	213-3 – 364478	213-3 – 30212	213-3 – 41746	2.18	Carroll, OH	5	1956	DSAW	790		Yes – M2
94 (KM 200)	36	200-4	2,648.75	213-4 – 35689	213-4 – 38338	213-4 – 30409	213-4 – 43618	2.50	Carroll, OH	5	1963	DSAW	790		
95 (KM 201)	36	200-4	1,950.62	215-4 – 37485	215-4 – 39436	215-4 – 32205	215-4 – 44716	2.37	Columbiana, OH	8	1963	DSAW	790	Yes – PT2	
96 (KM 202)	36	200-4	1,248.52	215-4 – 44504	215-4 – 45753	215-4 – 39224	215-4 – 51033	2.24	Columbiana, OH	2	1963	DSAW	790	Yes – PT2	
97 (KM 203)	36	200-4	1,358.28	215-4 – 46492	215-4 – 47844	215-4 – 41212	215-4 – 53124	2.26	Columbiana, OH	1	1963	DSAW	790	Yes – PT2	
98 (KM 205)	26	200-1	1,935.75	217-1 – 38468	217-1 – 40404	217-1 – 33188	217-1 – 45684	2.37	Lawrence, PA	5	1950	DSAW	790		Yes – M2
99 (KM 206)	24	300-1	839.87	219-2D – 22733	219-2D – 23573	219-2D – 17453	219-2D – 28853	2.16	Mercer, PA	2	1953	DSAW	877		
100 (KM 207)	24	300-1	491.7	219-2D – 28609	219-2D – 29100	219-2D – 23329	219-2D – 34380	2.09	Mercer, PA	1	1953	DSAW	877		
101 (KM 208)	30	300-2	875.56	219-3 – 22847	219-3 – 23723	219-3 – 17567	219-3 – 29003	2.17	Mercer, PA	2	1965	DSAW	877		
102 (KM 209)	30	300-2	573.79	219-3 – 28627	219-3 – 29201	219-3 – 23347	219-3 – 34507	2.11	Mercer, PA	1	1965	DSAW	877		
103 (KM 213)	24	100-1	533.33	82-1C – 18316	82-1C – 18849	82-1C – 13036	82-1C – 24129	2.10	Dickson, TN	2	1944	SMLS	750	Yes – PT2	

PT2 - The pressure test records supplied by TGP did not cover the location of the proposed segment. The correct TVC pressure test record must be supplied.
M2 – Confirm pipe in special permit segment was manufactured by Republic or National Tube. Any A.O. Smith EFW pipe or LF-ERW pipe found or identified must be replaced as a ***Type A special permit segment***.

Special Permit Segment Number	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (Valve - SS)	End Survey Station (Valve - SS)	Inspection Area Start SS (Valve – SS)	Inspection Area End SS (Valve – SS)	Inspection Area Length (Miles)	County or Parish, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)	Pressure Test – Condition 1(b) required	Material Records – Condition 13(d) required
104 (KM 215)	24	100-1	2,782.53	83-1A – 78304	83-1A – 81086	83-1A – 73024	83-1A – 86366	2.53	Cheatham, TN	10	1944	SMLS	750		
105 (KM 216)	24	100-1	1,490.6	83-1A – 97294	83-1A – 98785	83-1A – 92014	83-1A - 104065	2.28	Cheatham, TN	7	1944	SMLS	750		
106 (KM 217)	24	100-1	28.61	83-1A – 105135	83-1A – 105164	83-1A – 99855	83-1A - 110444	2.01	Cheatham, TN	1	1944	SMLS	750		
107 (KM 220)	24	100-1	668.38	84-1 – 49147	84-1 – 49815	84-1 – 438667	85-1 – 5224	2.13	Robertson, TN	5	1944	SMLS	750		
108 (KM 221)	24	100-1	1,953.93	85-1 – 150	85-1 – 2103	84-1 – 44741	85-1 – 7383	2.37	Robertson, TN	10	1944	SMLS	750		
111 (KM 226)	30	500-1	566.83	557-1 – 27037	557-1 – 27604	557-1 – 21757	557-1 – 32884	2.11	Lewis, TN	2	1959	SAW	936		Yes – M2
112 (KM 227)	30	500-1	686.45	557-1 – 32179	557-1 – 32866	557-1 – 26899	557-1 – 38146	2.13	Lewis, TN	1	1959	SAW	936		Yes – M2
113 (KM 228)	30	500-1	1,376.94	557-1 – 33305	557-1 – 34682	557-1 – 28025	557-1 – 39962	2.26	Lewis, TN	3	1959	SAW	936		Yes – M2
114 (KM 232)	30	500-1	732.13	560-1 – 37152	560-1 – 37885	560-1 – 31872	560-1 – 43165	2.14	Cheatham, TN	1	1959	DSAW	936		Yes – M2
115 (KM 233)	30	500-1	1006	560-1 – 42304	560-1 – 43310	560-1 – 37024	560-1 – 48590	2.19	Cheatham, TN	10	1959	DSAW	936		Yes – M2
116 (KM 234)	30	500-1	757.26	560-1 – 43428	560-1 – 44185	560-1 – 38148	560-1 – 49465	2.14	Cheatham, TN	7	1959	DSAW	936		Yes – M2
117 (KM 235)	30	500-1	1,332.21	560-1 - 98120	560-1 – 99452	560-1 – 92840	562-1 – 2902	2.25	Cheatham, TN	1	1959	DSAW	936		Yes – M2
118 (KM 236)	30	500-1	633.98	560-1 – 99846	560-1 – 100480	560-1 – 94566	562-1 – 3930	2.12	Cheatham, TN	2	1959	DSAW	936		Yes – M2
119 (KM 237)	30	500-1	994.45	562-1 – 66	562-1 – 1061	560-1 – 96617	562-1 – 6341	2.19	Cheatham, TN	5	1959	SAW	936		Yes – M2
121 (KM 239)	30	500-1	1,339.84	562-1 – 6239	562-1 – 7579	562-1 – 959	562-1 – 12859	2.25	Cheatham, TN	1	1959	SAW	936		Yes – M2
122 (KM 240)	30	500-1	2,474.52	563-1 – 29453	563-1 – 31925	563-1 – 24173	563-1 – 37205	2.47	Robertson, TN	6	1959	DSAW	936		Yes – M2
123 (KM 241)	30	500-1	4,358.19	563-1 – 42160	563-1 – 46519	563-1 – 36880	563-1 – 51799	2.83	Robertson, TN	10	1959	DSAW	936		Yes – M2
124 (KM 242)	30	500-1	1,929.95	564-1 – 14368	564-1 – 16298	564-1 – 9088	564-1 – 21578	2.37	Robertson, TN	4	1959	DSAW	936		Yes – M2
125 (KM 243)	30	500-1	3,262.84	564-1 – 20668	564-1 – 23931	564-1 – 15388	564-1 – 29211	2.62	Robertson, TN	10	1959	DSAW	936		Yes – M2
126 (KM 244)	36	500-2	469.38	557-2 – 27013	557-2 – 27483	557-2 – 21733	557-2 – 32763	2.09	Lewis, TN	2	1964	DSAW	936		
127 (KM 245)	36	500-2	738.42	557-2 – 32134	557-2 – 32872	557-2 – 26854	557-2 – 38152	2.14	Lewis, TN	1	1964	DSAW	936		
131 (KM 253)	36	500-2	502.7	562-2 – 551	562-2 – 1054	560-2 – 96661	562-2 – 6334	2.10	Cheatham, TN	6	1963	DSAW	936		Yes – M2
132 (KM 254)	36	500-2	16.9	562-2 – 1253	562-2 – 1270	560-2 – 97362	562-2 – 6550	2.00	Cheatham, TN	1	1963	DSAW	936		
133 (KM 255)	36	500-2	2,062.21	562-2 – 5535	562-2 – 7598	562-2 – 255	562-2 – 12878	2.39	Cheatham, TN	2	1963	DSAW	936		Yes – M2
134 (KM 256)	36	500-2	1,001.81	563-2 – 29422	563-2 – 30424	563-2 – 24142	563-2 – 35704	2.19	Robertson, TN	4	1965	DSAW	936		
135 (KM 257)	36	500-2	1,426.43	563-2 – 30503	563-2 – 31930	563-2 – 25223	563-2 – 37210	2.27	Robertson, TN	5	1965	DSAW	936		
136 (KM 258)	36	500-2	303.7	563-2 – 42134	563-2 – 42438	563-2 – 36854	563-2 – 47718	2.06	Robertson, TN	2	1965	DSAW	936		
137 (KM 259)	36	500-2	3,257.08	563-2 – 42518	563-2 – 46423	563-2 – 37238	563-2 – 51703	2.62	Robertson, TN	6	1965	DSAW	936		

M2 – Confirm pipe in special permit segment was manufactured by Republic or National Tube. Any A.O. Smith EFW pipe or LF-ERW pipe found or identified must be replaced as a ***Type A special permit segment***.

Special Permit Segment Number	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (Valve - SS)	End Survey Station (Valve - SS)	Inspection Area Start SS (Valve – SS)	Inspection Area End SS (Valve – SS)	Inspection Area Length (Miles)	County or Parish, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)	Pressure Test – Condition 1(b) required	Material Records – Condition 13(d) required
138 (KM 260)	36	500-2	1,899.22	564-2 – 14427	564-2 – 16326	564-2 – 9147	564-2 – 21606	2.36	Robertson, TN	4	1965	DSAW	936	Yes	
139 (KM 261)	36	500-2	219.1	564-2 – 20671	564-2 – 20890	564-2 – 15391	564-2 – 26170	2.04	Robertson, TN	4	1965	DSAW	936	Yes	
140 (KM 262)	36	500-2	2,970.93	564-2 – 20965	564-2 – 23936	564-2 – 15685	564-2 – 29216	2.56	Robertson, TN	6	1965	DSAW	936	Yes	
141 (KM 271)	30	800-1	384.62	861-1 – 44265	861-1 – 44649	861-1 – 38985	861-1 – 49929	2.07	Cheatham, TN	1	1954	EW	936		
142 (KM 272)	30	800-1	581.5	861-1 – 99945	861-1 – 100526	861-1 – 94665	863-1 – 3910	2.11	Cheatham, TN	2	1954	EW	936		
143 (KM 273)	30	800-1	1,104.3	863-1 – 94	863-1 – 1199	861-1 – 96711	863-1 – 6479	2.21	Cheatham, TN	6	1954	EW	936		
144 (KM 275)	30	800-1	1,366.34	863-1 – 6197	863-1 – 7564	863-1 – 917	863-1 – 12844	2.26	Cheatham, TN	1	1954	EW	936		
145 (KM 276)	30	800-1	968.97	864-1 – 29457	864-1 – 30426	864-1 – 24177	864-1 – 35706	2.18	Robertson, TN	4	1954	EW	936		
146 (KM 277)	30	800-1	1,797.26	864-1 – 30649	864-1 – 32446	864-1 – 25369	864-1 – 37726	2.34	Robertson, TN	5	1954	EW	936		
147 (KM 278)	30	800-1	4253	864-1 – 42177	864-1 – 46430	864-1 – 36897	864-1 – 51710	2.81	Robertson, TN	10	1954	EW	936		
148 (KM 279)	30	800-1	1,978.36	865-1 – 14349	865-1 – 16327	865-1 – 9069	865-1 – 21607	2.37	Robertson, TN	4	1954	EW	936		
149 (KM 280)	30	800-1	3,133.48	865-1 – 20783	865-1 – 23888	865-1 – 15503	865-1 – 29168	2.59	Robertson, TN	6	1954	EW	936		
154 (KM 293)	24	100-1	1,539.3	36-1 – 18211	36-1 – 19750	36-1 – 12931	36-1 – 25030	2.29	Sabine, TX	8	1964	DSAW	750	Yes	Yes – M3
155 (KM 294)	24	100-1	573.4	36-1 – 20133	36-1 – 20706	36-1 – 14853	36-1 – 25986	2.11	Sabine, TX	3	1964	DSAW	750	Yes	Yes – M3
156 (KM 295)	30	100-2	1,574.15	19-2 – 20806	19-2 – 23619	19-2 – 15526	19-2 – 28898	2.30	Waller, TX	4	1948	DSAW	750		
157 (KM 297)	30	100-2	1,220.9	19-2 – 47755	19-2 – 48976	19-2 – 42475	20-2 – 5205	2.23	Harris, TX	8	1948	DSAW	750		
158 (KM 298)	30	100-2	1,962.45	20-2 – 0048	20-2 – 2010	19-2 – 43818	20-2 – 7290	2.37	Harris, TX	9	1948	DSAW	750		
159 (KM 299)	30	100-2	2,597.7	36-2 – 17089	36-2 – 19687	36-2 – 11809	36-2 – 24967	2.49	Sabine, TX	7	1949	SAW	750		
163 (KM 303)	30	100-3	217	20-3 – 61	20-3 – 278	19-3 – 43960	20-3 – 5558	2.04	Harris, TX	8	1952	DSAW	750	Yes	
164 (KM 304)	30	100-3	1,733.65	20-3 – 398	20-3 – 2162	19-3 – 44297	20-3 – 7442	2.33	Harris, TX	8	1952	DSAW	750	Yes	
165 (KM 306)	30	100-3	1,101.34	20-3 – 36121	20-3 – 37211	20-3 – 30841	20-3 – 42491	2.21	Harris, TX	2	1952	DSAW	750	Yes	
166 (KM 307)	30	100-3	1,502.4	36-3 – 18156	36-3 – 19658	36-3 – 12876	36-3 – 24938	2.28	Sabine, TX	8	1964	DSAW	750		
173 (KM 318)	20	100-1	1,349.06	118-1 – 50528	118-1 – 51883	118-1 – 45216	118-1 - 57075	2.26	Kanawha, WV	2	1984	DSAW	910		
174 (KM 319)	20	100-1	1,228.73	118-1 – 54017	118-1 – 55245	118-1 – 48737	118-1 – 60525	2.23	Kanawha, WV	3	1984	DSAW	910		
175 (KM 320)	20	100-1	584.46	118-1 – 70516	118-1 – 70534	118-1 – 64688	118-1 – 75964	2.11	Kanawha, WV	1	1984	DSAW	910		
176 (KM 322)	20	100-1	2,249.91	121-1 – 19064	121-1 – 21305	121-1 – 13822	121-1 – 26546	2.43	Kanawha, WV	3	1984	DSAW	936		

M3 – Material records received do not match the pipe specifications that were provided. Are shown to be Flash Welded 0.25 wall pipe. Any A.O. Smith EFW pipe or LF-ERW pipe found or identified must be replaced as a ***Type A special permit segment***.

Special Permit Segment Number	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (Valve - SS)	End Survey Station (Valve - SS)	Inspection Area Start SS (Valve – SS)	Inspection Area End SS (Valve – SS)	Inspection Area Length (Miles)	County or Parish, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)	Pressure Test – Condition 1(b) required	Material Records – Condition 13(d) required
182 (KM 330)	30	100-3	1,415.75	118-3 – 25714	118-3 – 27130	118-3 – 20434	118-3 – 32410	2.27	Putnam, WV	2	1972	DSAW	910		
183 (KM 331)	30	100-3	891.2	118-3 – 31972	118-3 – 32863	118-3 – 26692	118-3 – 38143	2.17	Putnam, WV	2	1972	DSAW	910		
188 (KM 341)	30	100-4	497.5	83-4B – 114836	83-4B – 115333	83-4B – 109556	84-4 – 3287	2.09	Cheatham, TN	7	1952	DSAW	750		
189 (KM 342)	30	100-4	1,342.49	103-4 – 7517	103-4 – 8889	103-4 – 2237	103-4 – 14169	2.25	Madison, KY	1	1951	DSAW	750		
190 (KM 343)	30	100-4	242.74	103-4 – 9445	103-4 – 9687	103-4 – 4165	103-4 – 14967	2.05	Madison, KY	1	1951	DSAW	750		

Note: **DSAW** is double submerged arc welded pipe longitudinal seam.
EW is a submerged arc welded pipe longitudinal seam.
SAW is single submerged arc welded pipe longitudinal seam.
SMLS is seamless longitudinal seam.

Table 3 – Special Permit Segments – Now Compliant with 49 CFR 192.611(a)											
Special Permit Segment Number	OD (inches)	Line Name	Segment Length (feet)	Start Survey Station (Valve - SS)	End Survey Station (Valve - SS)	County or Parish, State	No. Dwellings	Year Installed	Seam Type	Compliant with 49 CFR 192.611 Method	Date Compliant
5 (KM 73)	26	100-2	1,596.90	106-2 – 33922	106-2 – 35519	Bath, KY	11	1948	FW	Replaced	9/26/2018
9 (KM 77)	26	100-2	3,157.39	109-2 – 19148	109-2 – 22306	Rowan, KY	11	1948	FW	Replaced	12/8/2018
16 (KM 85)	26	100-3	3,142.35	109-3 – 24240	109-3 – 27383	Rowan, KY	16	1949	FW	Replaced	8/14/2021
22 (KM 100)	30	100-1	1,849.64	36-1 – 45060	36-1 – 46910	Sabine, LA	18	1944	FW	Replaced	3/29/2019
25 (KM 103)	24	100-1	610.76	40-1D – 25649	40-1D – 26260	Natchitoches, LA	9	1944	SMLS	Class Drop	7/30/2021
26 (KM 105)	30	100-2	1,653.31	36-2 – 45462	36-2 – 47125	Sabine, LA	15	1949	DSAW	Replaced	11/30/2018
30 (KM 110)	30	100-3	1,804.93	36-3 – 45072	36-3 – 46877	Sabine, LA	15	1951	DSAW	Replaced	10/4/2018
35 (KM 117)	24	500-1	2,205.49	511-1 – 8439	511-1 – 10644	Vermilion, LA	17	1956	DSAW	Replaced	7/4/2021
39 (KM 121)	30	800-1	3,111.52	821-1A – 70063	821-1A – 73174	Calcasieu, LA	11	1955	DSAW	Replaced	11/1/2016
40 (KM 122)	30	800-1	206.64	821-1A – 73870	821-1A – 74077	Calcasieu, LA	4	1955	DSAW	Replaced	11/1/2016
54 (KM 143)	30	500-1	2,976.80	540-1 – 83303	540-1 – 86280	Lauderdale, MS	12	1959	SAW	Replaced/Tested	10/1/2021
56 (KM 146)	30	500-1	689.80	545-1 – 66055	545-1 – 66745	Lowndes, MS	5	1959	SAW	Replaced	1/16/2015
57 (KM 147)	30	500-1	941.20	545-1 – 72300	545-1 – 73241	Lowndes, MS	4	1959	SAW	Replaced	1/16/2015
63 (KM 155)	36	500-2	2,943.90	540-2 – 83326	540-2 – 86270	Lauderdale, MS	13	1966	ERW	Replaced/Tested	8/24/2021
73 (KM 168)	24	300-1	1,841.60	328-1 – 29030	328-1 – 30884	Bergen, NJ	12	1955	DSAW	Replaced/Tested	9/17/2021
74 (KM 177)	24	200-1	1,723.32	236-1 – 5396	236-1 – 7119	Ontario, NY	11	1951	FW	Replaced	8/25/2021
76 (KM 179)	24	200-1	4,060.14	243-1 – 11491	243-1 – 15551	Madison, NY	12	1951	DSAW	Replaced/Tested	11/10/2020
78 (KM 181)	24	200-1	557.12	244-1 – 21246	244-1 – 21803	Oneida, NY	2	1951	DSAW	Replaced/Tested	9/25/2019
81 (KM 186)	26	200-1	4,139.46	213-1 – 27955	213-1 – 32095	Carroll, OH	12	1950	FW	Replaced	8/29/2021
87 (KM 192)	26	200-2	4,503.91	213-2 – 27040	213-2 – 31544	Carroll, OH	27	1952	FW	Replaced/Tested	10/1/2019
91 (KM 196)	26	200-3	2,819.20	213-3 – 28311	213-3 – 31130	Carroll, OH	18	1956	DSAW	Replaced	7/1/2019
93 (KM 198)	36	200-4	4,194.03	213-4 – 27918	213-4 – 32112	Carroll, OH	12	1963	DSAW	Replaced/Tested	8/29/2021
150 (KM 289)	24	100-1	25.02	1-1D – 32112	1-1D – 32137	Nueces, TX	6	1944	FW	Replaced	10/1/2018
167 (KM 310)	26	400-2	1,104.09	405-2 – 23830	405-2 – 24934	Brooks, TX	1	1953	DSAW	Class Drop	5/21/2018
168 (KM 311)	26	400-2	1,358.83	405-2 – 32982	405-2 – 34341	Brooks, TX	1	1953	DSAW	Class Drop	3/12/2020
170 (KM 313)	24	409A-100 Donna Line	2,750.04	409A-101.1 – 13130	409A-101.1 – 15880	Hidalgo, TX	13	1950	FW	Replaced	10/29/2021
179 (KM 327)	24	100-2	3,428.57	119-2 – 13276	119-2 – 16704	Putnam, WV	16	1948	FW	Replaced	10/27/2017
180 (KM 328)	26	100-3	969.77	115-3 – 52772	115-3 – 53741	Cabell, WV	2	1959	FW	Replaced	5/10/2018
184 (KM 334)	24	100-1	3,429.29	19-1 – 40866	19-1 – 44295	Waller, TX	11	1944	FW	Replaced	8/26/2020
192 (KM 360)	30	800-1	1,913.54	821-1A – 76685	821-1A – 78674	Calcasieu, LA	17	1955	DSAW	Replaced	11/1/2016

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
1, 2, 3 (KM 69, 70, 71)	591+24.4 (MP 11.20)	Upstream Isolation Valve	102-1A	24	MANUAL	RCV
	591+24.5	MLV Bypass	102-1ABD1	8	MANUAL CLOSED	CLOSED or RCV
	591+30.4	Lateral	102A-101.1A	12	MANUAL OPEN	CLOSED or RCV
	825+55.5	CROSSOVER	103-1X4	12	MANUAL OPEN	CLOSED or RCV
	825+71.9	MLV BYPASS/TIE OVER	103A-101.1	8	MANUAL CLOSED	CLOSED or RCV
	825+71.9	TIE OVER	N/A	2	MANUAL OPEN	CHECK, CLOSED, or RCV
	825+78 (MP 15.64)	Downstream Isolation Valve	103-1	24	MANUAL	RCV
4, 6, 7 (KM 72, 74, 75)	465+12 BACK 0+00 AHEAD (MP 8.81 BACK/0.00 AHEAD)	Upstream Isolation Valve	108-2	26	LINE BREAK	RCV
	0+07.55	MLV Bypass	108-2BD1	8	MANUAL CLOSED	CLOSED or RCV
	0+12.59	CROSSOVER	108-2XA3	12	MANUAL OPEN	CLOSED or RCV
	269+81.1 (MP 5.11)	LATERAL	108A-101.2	12	MANUAL OPEN	CLOSED or RCV
	495+73	LATERAL	109B-101.2	12	MANUAL OPEN	CLOSED or RCV
	495+78	MLV BYPASS	109-2BD	8	MANUAL CLOSED	CLOSED or RCV
	495+83	Downstream Isolation Valve	109-2	26	LINE BREAK	RCV
8 (KM 76)	495+83 BACK 0+00 AHEAD	Upstream Isolation Valve	109-2	26	LINE BREAK	RCV
	0+05	MLV BYPASS	109-2BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+10	LATERAL	109B-101.2A	12	MANUAL OPEN	CLOSED or RCV
	0+15	LATERAL	109D-101.7	12	MANUAL OPEN	CLOSED or RCV
	296+72.3	MLV BYPASS	109-2ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	296+80.28 (MP 5.62)	Downstream Isolation Valve	109-2A	26	LINE BREAK	RCV
10 (KM 78)	581+53 BACK 0+00 AHEAD (MP 11.01)	Upstream Isolation Valve	102-3	30	LINE BREAK	RCV
	0+08.29	MLV BYPASS	102-4BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+12.96	Pig Valve	102-2E	8	MANUAL OPEN	CHECK, CLOSED, or RCV

[71] Any isolation valve that is not an RCV or check valve must be blinded or closed. Isolation valve(s) shown as CLOSED, when opened, must be manned by TGP personnel. **Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures** is applicable to all crossover valves, valve spacing, and lateral tie-ins. Any check valve used for isolation must close in a proper direction to isolate the isolation segment from incoming gas.

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	0+12.96 (MLV 11.14)	MLV	102-2	26	MANUAL OPEN	CLOSED or RCV
	541+30.9	MLV BYPASS	103-3BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	541+39 (MP 10.25)	Downstream Isolation Valve	103-3	30	LINE BREAK	RCV
11, 12 (KM 79, 80)	541+39 BACK 0+00 AHEAD (MP 0.00)	Upstream Isolation Valve	103-3	30	LINE BREAK	RCV
	0+07.6	MLV BYPASS	103-3BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	437+77.31	MLV BYPASS	104-3BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	437+86 (MP 8.29)	Downstream Isolation Valve	104-3	30	LINE BREAK	RCV
13, 14 (KM 82, 83)	474+64 BACK 0+00 AHEAD (MP 0.00)	Upstream Isolation Valve	108-3	26	LINE BREAK	RCV
	0+05	MLV BYPASS	108-3BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+10	CROSSOVER	108-2XA3		MANUAL OPEN	CLOSED or RCV
	543+54	CROSSOVER	109-3X4	12	MANUAL OPEN	CLOSED or RCV
	543+64	CROSSOVER	109-3X5	12	MANUAL OPEN	CLOSED or RCV
	543+74	MLV BYPASS	109-3BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	543+84 (MP 10.30)	Downstream Isolation Valve	109-3	26	LINE BREAK	RCV
15 (KM 84)	0+00 (MP 0.00)	Upstream Isolation Valve	109-3	26	LINE BREAK	RCV
	0+10	MLV BYPASS	109-3BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+20	CROSSOVER	109-3XA5	12	MANUAL OPEN	CLOSED or RCV
	0+30	CROSSOVER	109-3XA4	12	MANUAL OPEN	CLOSED or RCV
	287+14.49	MLV BYPASS	109-3ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	287+14.49	TIE OVER	N/A	2	MANUAL OPEN	CHECK, CLOSED, or RCV
	287+23.2 (MP 5.44)	Downstream Isolation Valve	109-3A	26	LINE BREAK	RCV
17 (KM 86)	1767+28 Back 0+00 Ahead (MP 33.47)	Upstream Isolation Valve	112-3	26	MANUAL OPEN	RCV
	0+06	MLV BYPASS	112-3BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	208+72	LATERAL	112F-101.3	6	MANUAL OPEN	CHECK, CLOSED, or RCV
	484+59.3	LATERAL	112B-101.3	6	MANUAL OPEN	CHECK, CLOSED, or RCV
	484+64.3	MLV BYPASS	112-3ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	484+70.3 (MP 9.18)	Downstream Isolation Valve	112-3A	26	MANUAL OPEN	RCV
18 (KM 87)	484+70.3 (MP 9.18)	Upstream Isolation Valve	112-3A	26	MANUAL OPEN	RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	484+76.3	MLV BYPASS	112-3ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	484+81.3	LATERAL	112B-101.3A	6	MANUAL OPEN	CHECK, CLOSED, or RCV
	655+27.5	MLV BYPASS	113-3BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	655+41.8 (MP 12.41)	Downstream Isolation Valve	113-3	26	MANUAL OPEN	RCV
19, 20, 189, 190 (KM 88, 89, 342, 343)	466+09 BACK 0+00 AHEAD (MP 8.83)	Upstream Isolation Valve	103-4	30	LINE BREAK	RCV
	0+08.29	MLV BYPASS	103A-101.4A	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+35.7	CROSSOVER	103-1XA4	16	MANUAL OPEN	CLOSED or RCV
	476+46.39	MLV BYPASS	104-4BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	476+55 (MP 9.03)	Downstream Isolation Valve	104-4	30	LINE BREAK	RCV
21 (KM 90)	0+87.5 (MP 0.02)	Upstream Isolation Valve	874-2	36	LINE BREAK	CLOSED or RCV
	0+12	MLV BYPASS	874-2BD1	10	MANUAL CLOSED	CLOSED or RCV
	0+17	CROSSOVER	874-2XA1	12	MANUAL OPEN	CLOSED or RCV
	602+69.29	MLV BYPASS	874-2BBD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	602+77.37 (MP 11.41)	MIDSTREAM MLV	874-2B	30	MANUAL OPEN	CLOSED or RCV
	602+85.45	MLV BYPASS	874-2BBD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	874+61.57	LATERAL	875-AD2	30	EMER. SHUTDOWN VALVE	CLOSED or RCV
	874+84.26	MLV BYPASS	N/A	3	MANUAL CLOSED	CHECK, CLOSED, or RCV
	874+84.26	MLV BYPASS	874-2ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	874+91.85 (MP 16.56)	Downstream Isolation Valve	874-2A	36	MANUAL OPEN	CLOSED or RCV
23 (KM 101)	386+90 (MP 7.32)	Upstream Isolation Valve	36-1A	24	MANUAL	CLOSED or RCV
	386+98.22	MLV BYPASS	36-1ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	732+04.19	MLV BYPASS	37-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	732+11 (MP 13.87)	Downstream Isolation Valve	37-1	24	MANUAL	RCV
24 (KM 102)	517+83 BACK 0+00 AHEAD (MP 9.81)	Upstream Isolation Valve	39-1	24	MANUAL	RCV
	0+06.71	MLV BYPASS	39-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	27+97	CROSSOVER	39A-101.1	2	MANUAL OPEN	CHECK, CLOSED, or RCV
	658+88	PIG VALVE	40-1R	24	MANUAL CLOSED	CLOSED or RCV
	659+14.7	VENT	40-1US	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	658+88 (MP 12.48)	Downstream Isolation Valve	40-1S	24	EMER. SHUTDOWN VALVE	RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
27 (KM 106)	385+77.24 (MP 7.30)	Upstream Isolation Valve	36-2A	30	MANUAL OPEN	RCV
	385+86.14	MLV BYPASS	36-2ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	731+09.1	CROSSOVER	37-2X1	16	MANUAL CLOSED	CLOSED or RCV
	731+30.8	MLV BYPASS	37F-101.2	24	MANUAL OPEN	CLOSED or RCV
	731+44	MLV BYPASS	37-2BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	731+52 (MP 13.85)	Downstream Isolation Valve	37-2	30	OPP VALVE	RCV
28 (KM 108)	518+24 BACK 0+00 AHEAD (MP 9.82)	Upstream Isolation Valve	39-2	30	OPP VALVE	RCV
	0+08.3	MLV BYPASS	39-2BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+18	RELIEF VALVE	39-2RV	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	658+49	CROSSOVER	40-2SH	26	MANUAL OPEN	CLOSED or RCV
	658+51.82	VENT	40-2US	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	658+59.49	PIG VALVE	40-2R	30	MANUAL CLOSED	CLOSED or RCV
	658+67.36 (MP 12.47)	Downstream Isolation Valve	40-2S	30	REMOTE	RCV
29 (KM 109)	14+98 (MP 0.28)	Upstream Isolation Valve	47-2B	26	REMOTE	RCV
	14+99	PIG VALVE	47-2AT	26	MANUAL CLOSED	CLOSED or RCV
	376+00.3	CROSSOVER	47-2ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	376+06.8 (MP 7.12)	Downstream Isolation Valve	47-2A	26	LINE BREAK	CLOSED or RCV
31 (KM 111)	385+77.96 (MP 7.29)	Upstream Isolation Valve	36-3A	30	MANUAL OPEN	CLOSED or RCV
	385+86.85	MLV BYPASS	36-3ABD1	8	MANUAL CLOSED	CLOSED or RCV
	729+92	CROSSOVER	37-3X2	16	MANUAL OPEN	CLOSED or RCV
	730+19.1	MLV BYPASS	38-3BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	730+30 (MP 13.83)	Downstream Isolation Valve	37-3	30	MANUAL OPEN	RCV
32 (KM 113)	0+00 (MP 9.81)	Upstream Isolation Valve	39-3	30	MANUAL OPEN	RCV
	0+06.5	MLV BYPASS	39-3BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+33.2	CROSSOVER/LATERAL	39-3XA2	16	MANUAL OPEN	CLOSED or RCV
	27+81	CROSSOVER/LATERAL	39A-101.3	2	MANUAL OPEN	CHECK, CLOSED, or RCV
	656+83.2	VENT	39C-101.3	2	MANUAL CLOSED	CHECK, CLOSED, or RCV
	658+09.7	VENT	N/A	2	MANUAL CLOSED	CHECK, CLOSED, or RCV
	658+09.7	CROSSOVER	40-3SH	24	MANUAL OPEN	CLOSED or RCV
	659+34.33	VENT	40-3US	8	MANUAL OPEN	CHECK, CLOSED, or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	659+52.88	PIG VALVE	40-3R	30	MANUAL CLOSED	CLOSED or RCV
	659+49 (MP 12.49)	Downstream Isolation Valve	40-3S	30	REMOTE	RCV
33 (KM 115)	15+41.2 (MP 0.29)	Upstream Isolation Valve	47-3B	30	REMOTE	RCV
	15+37.63	PIG VALVE	47-3AT	30	MANUAL CLOSED	CLOSED or RCV
	376+15.63	CROSSOVER	47-3AX4	12	MANUAL OPEN	CLOSED or RCV
	376+21.2	LATERAL	47-3AX2	12	CLOSED/BLINDED	CLOSED or RCV
	376+28.9	MLV BYPASS	47-3ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	376+32.8 (MP 7.13)	Downstream Isolation Valve	47-3A	30	LINE BREAK	RCV
34 (KM 116)	15+68.7 (MP 0.30)	Upstream Isolation Valve	47-4B	30	REMOTE	RCV
	15+65.85	PIG VALVE	47-4AT	30	MANUAL CLOSED	CLOSED or RCV
	376+43.97	CROSSOVER	47-4AX3	12	MANUAL OPEN	CLOSED or RCV
	376+49.63	MLV BYPASS	47-4ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	376+55.5 (MP 7.13)	Downstream Isolation Valve	47-4A	30	LINE BREAK	RCV
36, 37 (KM 118, 119)	526+56 BACK 0+00 AHEAD (MP 9.98)	Upstream Isolation Valve	511-1	24	MANUAL OPEN	RCV
	0+30.9	VENT	N/A	N/A	MANUAL OPEN	CLOSED or RCV
	0+30.9	LATERAL	507G-105XA500	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	MP 1.47	VENT	511C-101.1	N/A	MANUAL CLOSED	
	579+11	MLV BYPASS	512-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	579+21.6 (MP 10.96)	Downstream Isolation Valve	512-1	24	MANUAL OPEN	RCV
38 (KM 120)	579+21.6 BACK 0+00 AHEAD (MP 10.97)	Upstream Isolation Valve	512-1	24	MANUAL OPEN	RCV
	0+8.3	MLV BYPASS	512-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	118+27.2	LATERAL	512B-101.1	2	MANUAL OPEN	CHECK, CLOSED, or RCV
	138+86	LATERAL	512A-101.1	12	MANUAL OPEN	CLOSED or RCV
	593+74.1	LATERAL	507G 107X500	12	MANUAL CLOSED	CLOSED or RCV
	593+84 (MP 11.25)	Downstream Isolation Valve	513-1	24	MANUAL OPEN	RCV
41, 42 (KM 124, 125)	275+85 BACK 0+00 AHEAD (MP 5.22)	Upstream Isolation Valve	834-1	24	MANUAL OPEN	RCV
	0+12	MLV BYPASS	834-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+02.37	PIG VALVE	834-1L	30	MANUAL CLOSED	CLOSED or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	0+46.1	LATERAL	AD-1	30	EMER. SHUTDOWN VALVE	CLOSED or RCV
	583+96.8	LATERAL	834C-101.1	16	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	585+42.86	LATERAL	834E-101.1	8	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	853+67.5	MLV BYPASS	835-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	853+92 (MP 16.17)	Downstream Isolation Valve	835-1	30	MANUAL OPEN	RCV
43 (KM 126)	853+92 BACK 0+00 AHEAD (MP 16.17)	Upstream Isolation Valve	835-1	30	MANUAL OPEN	RCV
	0+12	MLV BYPASS	835-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	MP 7.26	LATERAL	835A-101.1	2	MANUAL OPEN	CHECK, CLOSED, or RCV
	MP 10.00	LATERAL	835C-101.1	3	MANUAL CLOSED BLINDED (Abandoned)	CLOSED or BLINDED
	MP 11.73	LATERAL	835D-101.1	2	MANUAL CLOSED BLINDED (Abandoned)	CLOSED or BLINDED
	MP 14.58	LATERAL	835B-101.1	3	MANUAL CLOSED BLINDED (Abandoned)	CLOSED or BLINDED
	915+22	MLV BYPASS	836-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	915+32.28 (MP 17.34)	Downstream Isolation Valve	836-1	30	MANUAL OPEN	RCV
44, 45 KM 131, 132	759+32.9 (MP 14.38)	Upstream Isolation Valve	53-1B	26	REMOTE	RCV
	759+42	MLV BYPASS	53-1BBD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	760+27.47	CROSSOVER	53-1BREH	24	CONVENIENCE OPER. CLOSED	CLOSED or RCV
	1086+14.8	PIG VALVE	53-1R	24	MANUAL CLOSED	CLOSED or RCV
	1086+09.6 (MP 20.57)	Downstream Isolation Valve	53-1BR	24	MANUAL	RCV
46, 47 (KM 134, 135)	757+81.7 (MP 14.35)	Upstream Isolation Valve	53-2B	26	REMOTE	RCV
	759+18.6	MLV BYPASS	53-2BBD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	759+20.43	CROSSOVER	53-2BREH	24	CONVENIENCE VALVE	CLOSED or RCV
	1087+38.7	LATERAL	53B-101.2	12	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	1087+48.9	PIG VALVE	53-2R	26	MANUAL CLOSED	CLOSED or RCV
	1087+43.4 (MP 20.60)	Downstream Isolation Valve	53-2BR	26	MANUAL OPEN	RCV
48 (KM 136)	611+99 BACK 0+00 AHEAD (MP 11.59)	Upstream Isolation Valve	69-3	30	LINE BREAK	RCV
	0+08.7	CROSSOVER/LATERAL	69-3B1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	256+60.8	CROSSOVER/LATERAL	69B-101.3	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	742+11	CROSSOVER/LATERAL	70-3B	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	742+19 (MP 14.06)	Downstream Isolation Valve	70-3	30	LINE BREAK	RCV
49 (KM 137)	612+12 BACK 0+00 AHEAD (MP 11.59)	Upstream Isolation Valve	69-4	30	LINE BREAK	RCV
	0+08.7	MLV BYPASS	69-4B1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	743+35.5	MLV BYPASS	70-4B	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	743+45 (MP 14.08)	Downstream Isolation Valve	70-4	30	LINE BREAK	RCV
50 (KM 139)	1+26.62 (MP 0)	Upstream Isolation Valve	530-1L	30	CONVENIENCE VALVE	RCV
	1+59.54	LATERAL	AD-1	30	EMER. SHUTDOWN VALVE	CLOSED or RCV
	544+89.6	LATERAL	530F-101.1	4	MANUAL WITH CHECK VALVE	CHECK, CLOSED, or RCV
	??	LATERAL	530B-100-1	4	MANUAL CLOSED (Abandoned)	CLOSED or BLINDED
	??	LATERAL	530C-101.1	4	MANUAL CLOSED (Inactive)	CLOSED or BLINDED
	702+24	LATERAL	530A-101.1	12	MANUAL OPEN	CLOSED or RCV
	786+53	LATERAL	531-1X2	12	MANUAL OPEN	CLOSED or RCV
	786+63	MLV BYPASS	531-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	786+73 (MP 14.90)	Downstream Isolation Valve	531-1	30	CONVENIENCE VALVE	RCV
51, 52 (KM 140, 141)	626+71 BACK 0+00 AHEAD (MP 11.87)	Upstream Isolation Valve	535-1	30	CONVENIENCE VALVE	RCV
	0+06	MLV BYPASS	535-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+32	LATERAL	535-1XA2	12	MANUAL OPEN	CLOSED or RCV
	MP 0.48	LATERAL	535A-101.1	6	CLOSED MANUAL (Inactive)	CLOSED or BLINDED
	MP 1.42	LATERAL	535C-101.1	4	CLOSED MANUAL (Inactive)	CLOSED or BLINDED
	249+53.5	LATERAL	535B-101.1	6	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	588+02	LATERAL	535G-101.1	24	MANUAL OPEN	CLOSED or RCV
	590+58	LATERAL	535F-101.1	10	MANUAL OPEN	CLOSED or RCV
	590+68	LATERAL	535E-101.1	10	MANUAL OPEN	CLOSED or RCV
	592+59.7	LATERAL	535D-101.1	12	MANUAL OPEN	CLOSED or RCV
	812+88	LATERAL	536-1X2	12	MANUAL CLOSED	CLOSED or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	813+16.3	MLV BYPASS	536-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	813+22 (MP 15.40)	Downstream Isolation Valve	536-1	30	CONVENIENCE VALVE	RCV
53 (KM 142)	511+09.29 (MP 9.67)	Upstream Isolation Valve	540-1A	30	LINE BREAK	RCV
	511+18.17	MLV BYPASS	540-1ABD1	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	863+19.5	MLV BYPASS	541-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	863+34 BACK (MP 16.35)	Downstream Isolation Valve	541-1	30	LINE BREAK	RCV
55 (KM 144)	863+34 BACK 0+00 AHEAD (MP 16.35)	Upstream Isolation Valve	541-1	30	LINE BREAK	RCV
	0+06	MLV BYPASS	541-1ABD1	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	0+32.2	LATERAL	541-1XA2	12	MANUAL CLOSED	CLOSED or RCV
	1+06	LATERAL	541A-101.1	4	MANUAL OPEN with Check Valve	CHECK, CLOSED, or RCV
	422+28.9	MLV BYPASS	540-1ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	422+38 (MP 7.99)	Downstream Isolation Valve	541-1A	30	LINE BREAK	RCV
55, 58 (KM 148, 150)	2+24.2 (MP 0.04)	Upstream Isolation Valve	546-1BL	30	MANUAL OPEN	RCV
	2+19.9	PIG VALVE	546-1L	30	MANUAL CLOSED	CLOSED or RCV
	54+99.67	LATERAL	546E-101.1	4	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	470+23.13	MLV BYPASS	546-1ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	470+35.3 (MP 8.91)	Downstream Isolation Valve	546-1A	30	MANUAL OPEN	RCV
60 (KM 152)	2+02.14 (MP 0)	Upstream Isolation Valve	530-2BL	36	MANUAL OPEN	RCV
	2+10.7	PIG VALVE	530-2L	36	CONVENIENCE VALVE CLOSED	CLOSED or RCV
	5+44.31	CROSSOVER/LATERAL	530F-101.2	4	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	433+45.17 (MP 8)	LATERAL	530E-101.2	4	MANUAL CLOSED (Inactive/Buried)	CLOSED or BLINDED
	527+80.86	LATERAL	530G-101.2	3	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	702+37	LATERAL	530J-101.2	10	MANUAL CLOSED WITH CHECK VALVE	CLOSED or RCV
	785+06.26	CROSSOVER	531-2X3	12	MANUAL OPEN	CLOSED or RCV
	785+21.26	LATERAL	531-1X2	12	MANUAL OPEN	CLOSED or RCV
	785+27.9	MLV BYPASS	531-2BD	10	MANUAL CLOSED	CLOSED or RCV
	785+42 (MP 14.88)	Downstream Isolation Valve	531-2	36	CONVENIENCE VALVE	RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
61 (KM 153)	348+62.6 (MP 6.70)	Upstream Isolation Valve	535-2A	36	CONVENIENCE VALVE	RCV
61 (KM 153)	348+74.7	MLV BYPASS	535-2ABD1	10	MANUAL OPEN	CLOSED or RCV
61 (KM 153)	588+19.2	LATERAL	535G-101.2	24	MANUAL OPEN	CLOSED or RCV
61 (KM 153)	590+83.2	LATERAL	535F-101.2	10	MANUAL OPEN	CLOSED or RCV
61 (KM 153)	589+77	LATERAL	535E-101.2	10	MANUAL OPEN	CLOSED or RCV
61 (KM 153)	591+99.4	LATERAL	535D-101.2	12	MANUAL OPEN	CLOSED or RCV
61 (KM 153)	812+22.7	LATERAL	536-1X2	12	MANUAL CLOSED	CLOSED or RCV
61 (KM 153)	812+35.1	LATERAL	536-2X3	30	MANUAL OPEN	CLOSED or RCV
61 (KM 153)	812+49	MLV BYPASS	536-2BD	10	MANUAL CLOSED	CLOSED or RCV
61 (KM 153)	812+56 (MP 15.39)	Downstream Isolation Valve	536-2	36	LINE BREAK	RCV
62 (KM 154)	511+06.4 (MP 9.67)	Upstream Isolation Valve	540-2A	36	CONVENIENCE VALVE	RCV
62 (KM 154)	511+18.1	MLV BYPASS	540-2ABD1	10	MANUAL OPEN	CLOSED or RCV
62 (KM 154)	656+57	LATERAL	540A-101.2	3	MANUAL CLOSED WITH CHECK VALVE	CHECK, CLOSED, or RCV
62 (KM 154)	863+18.7	CROSSOVER	541-2X3	30	MANUAL OPEN	CLOSED or RCV
62 (KM 154)	863+27.6	MLV BYPASS	541-2BD	10	MANUAL CLOSED	CLOSED or RCV
62 (KM 154)	863+36 (MP 16.35)	Downstream Isolation Valve	541-2	36	LINE BREAK	RCV
64 (KM 157)	2+20.6 (MP 0.04)	Upstream Isolation Valve	546-2BL	36	MANUAL OPEN	RCV
64 (KM 157)	2+00.9	PIG VALVE	546-2L	36	MANUAL CLOSED	CLOSED or RCV
64 (KM 157)	54+91.2	LATERAL	546E-101.2	4	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
64 (KM 157)	263+26.01	LATERAL	546-2B3	36	MANUAL CLOSED BLINDED	CLOSED or RCV
64 (KM 157)	330+21.52	LATERAL	546-2BX3	36	MANUAL CLOSED BLINDED	CLOSED or RCV
64 (KM 157)	470+21.2	MLV BYPASS	546-2ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
64 (KM 157)	470+30.2 (MP 8.91)	Downstream Isolation Valve	546-2A	36	MANUAL OPEN	RCV
65 (KM 158)	0+00	Upstream Isolation Valve	530-3	30	MANUAL OPEN	RCV
65 (KM 158)	0+10.1	VENT	530-3B2	10	MANUAL CLOSED	CLOSED or RCV
65 (KM 158)	0+35.7	PIG VALVE	530-3L	36	CONVENIENCE VALVE	CLOSED or RCV
65 (KM 158)	1+05.2	LATERAL	AD-3	36	EMER. SHUTDOWN VALVE	CLOSED or RCV
65 (KM 158)	524+86	LATERAL	530G-101.3	3	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
65 (KM 158)	781+61.5	LATERAL	531-2X3	12	MANUAL OPEN	CLOSED or RCV
65 (KM 158)	781+65.5	MLV BYPASS	531-3BD	10	MANUAL CLOSED	CLOSED or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	781+74 (MP 14.81)	Downstream Isolation Valve	531-3	36	CONVENIENCE VALVE	RCV
66 (KM 159)	501+15 (MP 9.49)	Upstream Isolation Valve	324-1B	24	LINE BREAK	RCV
	501+21.2	MLV BYPASS	324-1BBD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	999+85.5	CROSSOVER	324B-101.1A	4	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	999+88.3	CROSSOVER/LATERAL	S-1	8	EMER. SHUTDOWN VALVE	CHECK, CLOSED, or RCV
	999+88.3	CROSSOVER/LATERAL	AS-1	24	EMER. SHUTDOWN VALVE	CLOSED or RCV
	1000+48	VENT	N/A	2	MANUAL CLOSED	CHECK, CLOSED, or RCV
	1000+48.82	PIG VALVE	325M 300-1T	24	MANUAL CLOSED	CLOSED or RCV
	999+98.36 (MP 18)	Downstream Isolation Valve	325M 300-1C	24	MANUAL OPEN	RCV
68, 69 (KM 162, 163)	2+59.75 (MP 0.05)	Upstream Isolation Valve	300-1C2	24	REMOTE	RCV
	2+65.15	PIG VALVE	325M 300-1L	24	MANUAL CLOSED	CLOSED or RCV
	190+50.25	MLV BYPASS	325-1ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	190+58.42 (MP 3.61)	Downstream Isolation Valve	325-1A	24	MANUAL OPEN	RCV
70 (KM 164)	190+58.42 (MP 3.61)	Upstream Isolation Valve	325-1A	24	MANUAL OPEN	RCV
	190+66.58	MLV BYPASS	325-1ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	191+13.6	LATERAL	325D-101.1	12	MANUAL CLOSED	CLOSED or RCV
	191+13.6	LATERAL	325D-101.1A	12	MANUAL CLOSED	CLOSED or RCV
	232+03.02	LATERAL	325A-101.1	3	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	413+81.82	LATERAL	326A-101.1	3	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	413+87.82	MLV BYPASS	326-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	413+96 (MP 3.61)	Downstream Isolation Valve	326-1	24	MANUAL OPEN	RCV
71, 72 (KM 166, 167)	413+96 BACK,0+00 AHEAD (MP 3.61)	Upstream Isolation Valve	326-1	24	MANUAL OPEN	RCV
	0+06.65	MLV BYPASS	326-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+08.28	LATERAL	326A-101.1A	3	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	374+37.9	LATERAL	327C-101.1	10	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	374+75.7	MLV BYPASS	327-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	374+84 (MP 7.10)	Downstream Isolation Valve	327-1	24	MANUAL OPEN	RCV
75	490+54.8 BACK, 0+00 AHEAD	Upstream Isolation Valve	236-1	24	MANUAL OPEN	RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
(KM 178)	(MP 9.29)					
	0+06	MLV BYPASS	236-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+16.1	LATERAL	236A-101.1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	298+57	LATERAL	236C-101.1	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	314+24	LATERAL	236B-101.1	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	473+05	VENT	N/A	2	MANUAL CLOSED	CHECK, CLOSED, or RCV
	473+05	VENT	N/A	2	MANUAL CLOSED	CHECK, CLOSED, or RCV
	473+05	VENT	N/A	2	MANUAL CLOSED	CHECK, CLOSED, or RCV
	473+05.49	PIG VALVE	237-1R	24	MANUAL CLOSED	CLOSED or RCV
	473+05.5 (MP 8.96)	Downstream Isolation Valve	237-1BR	24	MANUAL OPEN	RCV
77 (KM 180)	597+80 BACK, 0+00 AHEAD (MP 11.32)	Upstream Isolation Valve	243-1	24	MANUAL OPEN	RCV
	0+05.69	MLV BYPASS	243-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+10	CROSSOVER	243-1XA2	12	MANUAL CLOSED	CLOSED or RCV
	181+87.7	CROSSOVER/LATERAL	243C-101.1	12	MANUAL OPEN	CLOSED or RCV
	335+70	MLV BYPASS	243-1ABD	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	335+80.8 (MP 6.36)	Downstream Isolation Valve	243-1A	24	MANUAL OPEN	RCV
78, 80 (KM 182, 183)	568+74 BACK, 0+00 AHEAD (MP 10.77)	Upstream Isolation Valve	251-1	24	MANUAL OPEN	RCV
	0+05.3	MLV BYPASS	251-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+15	CROSSOVER	251-1XA2	12	MANUAL CLOSED	CLOSED or RCV
	0+25	CROSSOVER	251-1XA3	12	MANUAL CLOSED	CLOSED or RCV
	85+0.8 (MP 1.61)	LATERAL	251C-101.1	8	MANUAL CLOSED (Inactive)	CLOSED or BLINDED
	85+10.8 (MP 1.61)	LATERAL	251D-101.1A	8	MANUAL CLOSED (Inactive)	CLOSED or BLINDED
	0+35	CROSSOVER	251H-101.1	12	MANUAL OPEN	CLOSED or RCV
	203+06	CROSSOVER	251-1AX2	12	MANUAL CLOSED	CLOSED or RCV
	203+46	CROSSOVER	251-1AXA2	12	MANUAL CLOSED	CLOSED or RCV
	203+56	CROSSOVER/LATERAL	251B-101.1	10	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	214+75.2	CROSSOVER/LATERAL	251L-101.1	16	MANUAL OPEN	CLOSED or RCV
	377+38.5	CROSSOVER/LATERAL	251A-101.1	6	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	377+46.8	CROSSOVER/LATERAL	252-1BD	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	377+53 (MP 7.15)	Downstream Isolation Valve	252-1	24	LINE BREAK	RCV
82 (KM 187)	0+18 (MP 4.29)	Upstream Isolation Valve	213-1A	26	MANUAL OPEN	RCV
	0+28	MLV BYPASS	213-1ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	452+31	CROSSOVER/LATERAL	213C-101.1	12	MANUAL OPEN WITH CHECK VALVE	RCV
	529+37.1	PIG VALVE	213-1R	26	MANUAL CLOSED	CLOSED or RCV
	529+34.4 (MP 10.03)	Downstream Isolation Valve	213-1BR	26	MANUAL OPEN	RCV
83, 84 ,85 (KM 188, 189, 190)	608+53 Back, 0+00 Ahead (MP 11.53)	Upstream Isolation Valve	215-1	26	MANUAL OPEN	RCV
	0+06.73	MLV BYPASS	215-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+20.19	CROSSOVER	215-1XA4	12	MANUAL CLOSED	CLOSED or RCV
	0+30	MLV BYPASS	215-1XA2	12	MANUAL CLOSED	CLOSED or RCV
	513+34	LATERAL	215A-101.1	6	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	662+45	CROSSOVER	216-1X2	12	MANUAL CLOSED	CLOSED or RCV
	662+55	CROSSOVER	216-1X4	12	MANUAL CLOSED	CLOSED or RCV
	662+65.19	MLV BYPASS	216-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	662+72 (MP 12.55)	Downstream Isolation Valve	216-1	26	MANUAL OPEN	RCV
86 (KM 191)	604+51 Back, 0+00 Ahead (MP 11.45)	Upstream Isolation Valve	205-2	26	MANUAL OPEN	RCV
	0+06	MLV BYPASS	205-2BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+31.6	CROSSOVER	205-1XA2A	12	MANUAL CLOSED	CLOSED or RCV
	856+96.4	CROSSOVER	206-1X2A	12	MANUAL CLOSED	CLOSED or RCV
	857+19.9	MLV BYPASS	206-2BD	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	857+25 MP 16.24	Downstream Isolation Valve	206-2	26	LINE BREAK	RCV
88 (KM 193)	204+33.6 (MP 3.87)	Upstream Isolation Valve	213-2A	26	MANUAL OPEN	RCV
	204+43	MLV BYPASS	213-2ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	530+03.01	CROSSOVER	213-3F	12	MANUAL CLOSED	CLOSED or RCV
	530+18.61	PIG VALVE	213-2R	26	MANUAL CLOSED	CLOSED or RCV
	530+49.17	CROSSOVER	A-S2	24	ESD VALVE	CLOSED or RCV
	531+48.82	SENSOR TUBING	N/A	1 1/2	MANUAL OPEN	CHECK, CLOSED, or RCV
	531+48.82	MLV BYPASS	214-2BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	531+96 (MP 10.07)	Downstream Isolation Valve	214-2	26	DIFFERENTIAL PRESSURE VALVE	RCV
89 (KM 194)	665+02 BACK,0+00 AHEAD (MP 12.60)	Upstream Isolation Valve	216-2	26	MANUAL OPEN	RCV
	0+07	MLV BYPASS	216-2BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+14.8	CROSSOVER	216-2XA3	12	MANUAL CLOSED	CLOSED or RCV
	0+21	CROSSOVER	N/A	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	0+28	CROSSOVER	216-1XA2	12	MANUAL CLOSED	CLOSED or RCV
	261+15	CROSSOVER/LATERAL	216E-101.2	3	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	0+14.8	CROSSOVER	216-1XA2	12	MANUAL CLOSED	CLOSED or RCV
	594+02.6 2	CROSSOVER/LATERAL	216A-101.2	6	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	627+09	CROSSOVER/LATERAL	216C-101.2	12	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	781+96.8	LATERAL	216G-101.2	12	OPP VALVE WITH CHECK VALVE	CLOSED or RCV
	810+62.5	CROSSOVER/LATERAL	217A-201.2	12	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	810+66.39	CROSSOVER	217-2X3	12	MANUAL CLOSED	CLOSED or RCV
	810+83.69	CROSSOVER	217-1X2	12	MANUAL CLOSED	CLOSED or RCV
	810+83.69	CROSSOVER	217-2BDB	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	810+92.1	MLV BYPASS	217-2BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	810+99 (MP 15.36)	Downstream Isolation Valve	217-2	26	LINE BREAK	RCV
90, 92 (KM 195, 197)	242+52.3 (MP 4.59)	Upstream Isolation Valve	213-3A	26	MANUAL OPEN	RCV
	242+61.43	MLV BYPASS	213-3ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	528+75.95	PIG VALVE	213-3R	26	MANUAL CLOSED	CLOSED or RCV
	530+37.04	LATERAL	N/A	12	MANUAL CLOSED	CLOSED or RCV
	530+37.42	CROSSOVER	A-S3	24	ESD VALVE	CLOSED or RCV
	530+56.53	MLV BYPASS	214-3BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	530+60 (MP 10.05)	Downstream Isolation Valve	214-3	26	DIFFERENTIAL PRESSURE VALVE	RCV
94 (KM 200)	226+51.2 (MP 4.29)	Upstream MLV	213-4A	36	MANUAL OPEN	RCV
	226+61	MLV BYPASS	213-4ABD1	12	MANUAL CLOSED	CLOSED or RCV
	452+06	CROSSOVER/LATERAL	213C-101.4	12	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	528+45	PIG VALVE	213-4R	36	MANUAL CLOSED	CLOSED or RCV
	528+50.5 (MP 10.01)	Downstream Isolation Valve	213-4BR	36	MANUAL CLOSED	RCV
95,96,97 (KM 201,202,203)	607+94 BACK, 0+00 AHEAD (MP 11.51)	Upstream Isolation Valve	215-4	36	MANUAL OPEN	RCV
	0+09.87	MLV BYPASS	215-4BD1	12	MANUAL CLOSED	CLOSED or RCV
	0+18.19	CROSSOVER	215-1XA4	12	MANUAL CLOSED	CLOSED or RCV
	661+18.79	LATERAL	215B-101.4	8	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	662+06.13	CROSSOVER	216-1X4	12	MANUAL CLOSED	CLOSED or RCV
	662+13.8	MLV BYPASS	216-4BD	12	MANUAL CLOSED	CLOSED or RCV
	662+23 (MP 12.54)	Downstream Isolation Valve	216-4	36	MANUAL OPEN	RCV
98 (KM 205)	810+56 BACK, 0+00 AHEAD (MP 15.35)	Upstream Isolation Valve	217-1	26	LINE BREAK	RCV
	0+06.8	MLV BYPASS	217-1BD1	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	0+08	CROSSOVER/LATERAL	217A-101.1A	12	MANUAL OPEN	CLOSED or RCV
	0+22.4	CROSSOVER	217-1XA2	12	MANUAL CLOSED	CLOSED or RCV
	85+09	CROSSOVER/LATERAL	217B-101.1	6	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	105+13.7	CROSSOVER/LATERAL	217E-101.1	10	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	666+06.43	CROSSOVER	218-1X4	12	MANUAL CLOSED	CLOSED or RCV
	666+24.2	CROSSOVER	218-1X2	12	MANUAL CLOSED	CLOSED or RCV
	666+32.48	MLV BYPASS	218-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	666+40 (MP 12.62)	Downstream Isolation Valve	218-1	26	LINE BREAK	RCV
99,100 (KM 206,207)	153+33.53 (MP 2.90)	Upstream Isolation Valve	300-1A	24	MANUAL OPEN	RCV
	153+42.03	MLV BYPASS	300-1ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	572+01	CROSSOVER	301-1X2	12	MANUAL CLOSED	CLOSED or RCV
	572+11.53	MLV BYPASS	301-1BD	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	572+18 (MP 10.84)	Downstream Isolation Valve	301-1	24	LINE BREAK	RCV
101,102 (KM 208,209)	6+68.9 (MP 0.13)	Upstream Isolation Valve	219-3BL	30	MANUAL OPEN	RCV
	6+70.9	PIG VALVE	300-2L	30	MANUAL CLOSED	CLOSED or RCV
	340+72	LATERAL	219A-101.3	6	MANUAL OPEN	CLOSED or RCV
	572+57	CROSSOVER	301-1X2	12	MANUAL CLOSED	CLOSED or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	572+67	MLV BYPASS	301-2BD	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	572+77 MP 10.85	Downstream Isolation Valve	301-2	30	LINE BREAK	RCV
103 (KM 213)	0+65 BACK, 0+00 AHEAD (MP 0.01)	Upstream Isolation Valve	82-1C	24	DIFF. PRESSURE	RCV
	0+22.9	CROSSOVER	82-1CBD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	315+13.4	MLV BYPASS	83-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	315+29 (MP 5.97)	Downstream Isolation Valve	83-1	24	DIFF. PRESSURE	RCV
104,105,106 (KM 215,216,217)	570+79.7 (MP 10.81)	Upstream Isolation Valve	83-1A	24	MANUAL	RCV
	570+87.95	MLV BYPASS	83-1ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	1033+69.35	LATERAL	83A-101.1	8	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	1162+62.85	MLV BYPASS	84-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	1162+71 (MP 22.02)	Downstream Isolation Valve	84-1	24	MANUAL	RCV
107 (KM 220)	1162+71 BACK, 0+00 AHEAD (MP 22.02)	Upstream Isolation Valve	84-1	24	MANUAL	RCV
	0+05.6	MLV BYPASS	84-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	463+42	LATERAL	84A-101.1	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	498+57	LATERAL	85A-101.1	12	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	498+64.4	MLV BYPASS	85-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	498+71 (MP 9.45)	Downstream Isolation Valve	85-1	24	MANUAL	RCV
108 (KM 221)	498+71 BACK, 0+00 AHEAD (MP 9.45)	Upstream Isolation Valve	85-1	24	MANUAL	RCV
	0+06.7	MLV BYPASS	85-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	501+64.5	VENT	86-1X4	12	MANUAL CLOSED	CLOSED or RCV
	501+76.3	MLV BYPASS	86-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	501+84 (MP 9.50)	Downstream Isolation Valve	86-1	24	MANUAL	RCV
109,110 (KM 223, 224)	313+62.7 (MP 5.94)	Upstream Isolation Valve	82-2C	26	DIFF. PRESSURE VALVE	RCV
	313+67.7	CROSSOVER	82-2CBD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	629+41.6	CROSSOVER	83-2XHA	12	MANUAL CLOSED	CLOSED or RCV
	629+52 (MP 11.92)	Downstream Isolation Valve	83-2	26	DIFF. PRESSURE VALVE	RCV
111,112,113	833+97 Back, 0+00 Ahead (MP 15.79)	Upstream Isolation Valve	557-1	30	DIFF. PRESSURE VALVE	RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
(KM 226, 227,228)	0+06.7	MLV BYPASS	557-1BD1	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	0+22.9	LATERAL	557-1XA2	12	MANUAL CLOSED	CLOSED or RCV
	301+09.6	LATERAL	557B-101.1	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	641+78.5	LATERAL	557A-101.1	6	MANUAL CLOSED (Inactive)	CLOSED or BLINDED
	746+10	LATERAL	558-1X2	12	MANUAL OPEN	CLOSED or RCV
	746+02	VENT	558-1RUS	12	MANUAL CLOSED	CLOSED or RCV
	746+20.2	MLV BYPASS	558-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	746+28 (MP 14.13)	Downstream Isolation Valve	558-1	30	LINE BREAK	RCV
114,115,116, 117, 118 (KM 232,233,234, 235,236)	270+98.69 (MP 5.13)	Upstream Isolation Valve	560-1A	30	DIFF. PRESSURE LINE BREAK	RCV
	271+09.15	MLV BYPASS	560-1ABD1	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	434+01.6	LATERAL	560B-101.1	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	1004+44.76	CROSSOVER	561-1R2	16	MANUAL OPEN	CLOSED or RCV
	1005+31.5	CROSSOVER	862-1R561.1	16	MANUAL OPENI	CLOSED or RCV
	1005+38.8	MLV BYPASS	561-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	1005+47 (MP 19.04)	Downstream Isolation Valve	561-1	24	MANUAL OPEN	RCV
119, 120,121 (KM 237,238,239)	12+83 BACK, 0+00 AHEAD (MP 0.24)	Upstream Isolation Valve	562-1	24	MANUAL OPEN	RCV
	0+08.25	MLV BYPASS	562-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+12	CROSSOVER	562-1X562-2	12	MANUAL OPEN	CLOSED or RCV
	0+28.25	CROSSOVER	863-1X562-1	24	MANUAL OPEN	CLOSED or RCV
	190+0.8	CROSSOVER/LATERAL	562A-101.1	8	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	641+28.1	CROSSOVER	563-1X2	12	MANUAL OPEN	CLOSED or RCV
	641+43.8	VENT	N/A	8	CLOSED MANUAL	CHECK, CLOSED, or RCV
	641+43.8	CROSSOVER	864-1X500	12	MANUAL OPEN	CLOSED or RCV
	641+55.3	MLV BYPASS	563-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	641+61 (MP 12.15)	Downstream Isolation Valve	563-1	30	MANUAL OPEN	RCV
122,123 KM (240,241)	12+95.7 (MP 0.25)	Upstream Isolation Valve	563-1A	30	MANUAL OPEN	RCV
	13+03.24	MLV BYPASS	563-1ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	13+38.2	ESD VALVE BYPASS	N/A	3	MANUAL CLOSED	CHECK, CLOSED, or RCV
	13+38.2	LATERAL	563-AS1	30	MANUAL OPEN	CLOSED or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	304+65.6	LATERAL	563B-101.1	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	543+84	LATERAL	563B-101.1	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	544+36.8	LATERAL	563A-101.1	12	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	687+45.6	LATERAL	564-1X2	12	MANUAL OPEN	CLOSED or RCV
	687+45.6	CROSSOVER	563C-101.1	2	MANUAL OPEN	CHECK, CLOSED, or RCV
	687+52.7	CROSSOVER	865-1X500	12	MANUAL OPEN	
	687+53.07	MLV BYPASS	564-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	687+85 (MP 13.03)	Downstream Isolation Valve	564-1	30	MANUAL OPEN	RCV
124,125 (KM 242,243)	687+85 BACK, 0+00 AHEAD (MP 13.03)	Upstream Isolation Valve	564-1	30	MANUAL OPEN	RCV
	0+06	MLV BYPASS	564-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+17.5	CROSSOVER	564-1XA2	12	MANUAL OPEN	CLOSED or RCV
	687+45.6	CROSSOVER	564B-101.1	2	MANUAL OPEN	CHECK, CLOSED, or RCV
	687+45.6	CROSSOVER	865-1XA500	12	MANUAL OPEN	CLOSED or RCV
	402+33.6	CROSSOVER/LATERAL	564A-101.1	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	698+73	VENT	564-1BRB	8	MANUAL CLOSED BLINDED	CHECK, CLOSED, or RCV
	698+83.06	PIG VALVE	564-1R	30	MANUAL CLOSED	CLOSED or RCV
	698+78.72 (MP 13.23)	Downstream Isolation Valve	564-1BR	30	MANUAL OPEN	RCV
126,127 (KM 244,245)	0+00 (MP 15.78)	Upstream Isolation Valve	557-2	30	MANUAL OPEN	RCV
	0+11.8	MLV BYPASS	557-2BD1	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	0+16.8	CROSSOVER	557-2XA1	12	MANUAL CLOSED	CLOSED or RCV
	0+33.6	CROSSOVER	557-2XA3	12	MANUAL OPEN	CLOSED or RCV
	300+94.1	LATERAL	557B-101.2	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	744+89.5	CROSSOVER	558-2X3	12	MANUAL OPEN	CLOSED or RCV
	744+91.2	MLV BYPASS	558-2RUS	16	MANUAL CLOSED	CLOSED or RCV
	744+97	CROSSOVER	558-2X1	12	MANUAL OPEN	CLOSED or RCV
	745+11.6	MLV BYPASS	558-2BD	10	MANUAL CLOSED	CLOSED or RCV
	745+20 (MP 14.11)	Downstream Isolation Valve	558-2	30	CONVENIENCE VALVE	RCV
128,129,130	963+71 BACK, 0+00 AHEAD (MP 18.25)	Upstream Isolation Valve	560-2	30	DIFF. PRESSURE LINE BREAK	RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
(KM 250,251,252)	0+12	MLV BYPASS	560-2BD1	10	MANUAL OPEN	CLOSED or RCV
	0+19.2	CROSSOVER	560-1XA2	16	MANUAL CLOSED	CLOSED or RCV
	0+29	CROSSOVER	560-2XA3	12	MANUAL CLOSED	CLOSED or RCV
	434+01.6	LATERAL	56B-101.2	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	1000+30	LATERAL	561-1R2	16	MANUAL OPEN	CLOSED or RCV
	1000+41.3	CROSSOVER	862-1R561.2	14	MANUAL OPEN	CLOSED or RCV
	1000+59	MLV BYPASS	561-2BD	10	MANUAL CLOSED	CLOSED or RCV
	1000+69 (MP 18.95)	Downstream Isolation Valve	561-2	30	MANUAL OPEN	RCV
131,132,133 (KM 253,254,255)	13+20 BACK, 0+00 AHEAD (MP 0.25)	Upstream Isolation Valve	562-2	30	MANUAL OPEN	RCV
	0+06	MLV BYPASS	562-2BD1	10	MANUAL CLOSED	CLOSED or RCV
	0+16.7	CROSSOVER	562-1X562-2A	16	MANUAL OPEN	CLOSED or RCV
	18+96	LATERAL	562B-101.2	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	640+46.75	LATERAL	562A-101.2	8	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	640+55.65	MLV BYPASS	563-2BD	10	MANUAL CLOSED	CLOSED or RCV
	640+64 (MP 12.13)	Downstream Isolation Valve	563-2	30	MANUAL OPEN	RCV
134,135,136, 137 (KM 256,257,258, 259)	13+70.29 (MP 0.25)	Upstream Isolation Valve	563-2A	36	MANUAL OPEN	RCV
	13+80.46	MLV BYPASS	563-2ABD1	10	MANUAL CLOSED	CLOSED or RCV
	14+09.38	ESD VALVE BYPASS	N/A	3	MANUAL CLOSED	CHECK, CLOSED, or RCV
	14+09.38	LATERAL	563-AS2	36	EMER. SHUTDOWN VALVE	CLOSED or RCV
	543+84	LATERAL	563B-101.2	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	543+84	LATERAL	563A-101.2	12	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	686+49.4	CROSSOVER	564-1X2	12	MANUAL OPEN	CLOSED or RCV
	686+56.4	MLV BYPASS	564-2BD	10	MANUAL CLOSED	CLOSED or RCV
	686+68 (MP 13.01)	Downstream Isolation Valve	564-2	30	MANUAL OPEN	RCV
138,139,140 (KM 260,261,262)	686+68 BACK, 0+00 AHEAD (MP 13.01)	Upstream Isolation Valve	564-2	30	MANUAL OPEN	RCV
	0+12	MLV BYPASS	564-2BD1	10	MANUAL CLOSED	CLOSED or RCV
	0+19	CROSSOVER	564-1XA2	12	MANUAL OPEN	CLOSED or RCV
	402+33.1	LATERAL	564A-101.2	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	698+01.6	PIG VALVE	865-1R	36	MANUAL CLOSED	CLOSED or RCV
	698+15.05 (MP 13.22)	Downstream Isolation Valve	564-2BR	36	MANUAL OPEN	RCV
141,142 (KM 271,272)	965+55 BACK, 0+00 AHEAD (MP 18.29)	Upstream Isolation Valve	861-1	30	DIFF. PRESSURE LINE BREAK	RCV
	0+08.29	MLV BYPASS	861-1BD1	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	0+18	CROSSOVER	861-1XA560	12	MANUAL CLOSED	CLOSED or RCV
	1005+63.4	LATERAL	862-1R561.2	14	MANUAL OPEN	CLOSED or RCV
	1005+97.4	LATERAL	862-1R561.1	16	MANUAL OPEN	CLOSED or RCV
	1006+34.6	MLV BYPASS	862-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	1006+43 (MP 19.06)	Downstream Isolation Valve	862-1	24	MANUAL OPEN	RCV
143,144 (KM 273,275)	12+53 BACK, 0+00 AHEAD (MP 0.24)	Upstream Isolation Valve	863-1	24	MANUAL OPEN	RCV
	0+08.25	MLV BYPASS	863-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+41.6	CROSSOVER	863-1X562-1	24	MANUAL OPEN	CLOSED or RCV
	18+67.6 8	LATERAL	863B-101.1	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	540+76.8	LATERAL	863A-101.1	8	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	640+88.4	CROSSOVER	864-1X500	12	MANUAL OPEN	CLOSED or RCV
	641+12.95	MLV BYPASS	864-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	641+21 (MP 12.14)	Downstream Isolation Valve	864-1	30	MANUAL OPEN	RCV
145,146, 147 (KM 276,277, 278)	12+84.9 (MP 0.25)	Upstream Isolation Valve	864-1A	30	MANUAL OPEN	RCV
	12+93.28	MLV BYPASS	864-1ABD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	13+08.88	ESD VALVE BYPASS	N/A	3	MANUAL CLOSED	CHECK, CLOSED, or RCV
	13+08.88	LATERAL	864-AS1	30	EMER. SHUTDOWN VALVE	CLOSED or RCV
	304+65.6	LATERAL	864B-101.1	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	544+36.8	LATERAL	864A-101.1	12	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	687+28.71	CROSSOVER	865-1X500	12	MANUAL OPEN	CLOSED or RCV
	687+53.21	MLV BYPASS	865-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	687+62 (MP 13.02)	Downstream Isolation Valve	865-1	30	MANUAL OPEN	RCV
148,149	687+62 BACK, 0+00 AHEAD (MP 13.02)	Upstream Isolation Valve	865-1	30	MANUAL OPEN	RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
(KM 279,280)	0+08.29	MLV BYPASS	865-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+32.8	CROSSOVER	865-1XA500	12	MANUAL OPEN	CLOSED or RCV
	697+77.57	VENT	865-1BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	697+90.61	PIG VALVE	865-1R	30	MANUAL CLOSED	CLOSED or RCV
	697+86.11 (MP 13.22)	Downstream Isolation Valve	865-1BR	30	MANUAL OPEN	RCV
151 (KM 290)	545+45 BACK, 0+00 AHEAD (MP 10.33)	Upstream Isolation Valve	19-1	24	LINE BREAK	RCV
	0+08.3	MLV BYPASS	19-1BD1	8	PARTIALLY CLOSED	CHECK, CLOSED, or RCV
	51+11	LATERAL	19C-101.1	2	MANUAL OPEN	CHECK, CLOSED, or RCV
	250+50.31	MLV BYPASS	19-1ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	250+58.53, (MP 4.76)	Downstream Isolation Valve	19-1A	24	MANUAL	RCV
152 (KM 291,336)	490+04 BACK, 0+00 AHEAD (MP 9.28)	Upstream Isolation Valve	20-1	24	LINE BREAK	RCV
	0+08.29	MLV BYPASS	20-1BD1	8	PARTIALLY CLOSED	CHECK, CLOSED, or RCV
	387+97	VENT	N/A	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	388+07.33	PIG VALVE	20-1R	24	MANUAL CLOSED	CLOSED or RCV
	388+02.3 (MP 7.35)	Downstream Isolation Valve	20-1BR	24	MANUAL	RCV
153,154, 155 (KM 292,293, 294)	393+27 BACK, 0+00 AHEAD (MP 7.45)	Upstream Isolation Valve	36-1	24	LINE BREAK	RCV
	0+06.71	MLV BYPASS	36-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+17.5	CROSSOVER	36-1XA2	16	MANUAL OPEN	CLOSED or RCV
	0+25	VENT	N/A	4	MANUAL CLOSED	CHECK, CLOSED, or RCV
	180+12.42	PIG VALVE	36-1TXR	24	MANUAL OPEN	CLOSED or RCV
	180+16	PIG VALVE	N/A	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	180+20.08 (MP 3.41)	Downstream Isolation Valve	36-1TX	24	MANUAL OPEN	RCV
159 (KM 295)	545+52 BACK, 0+00 AHEAD (MP 10.33)	Upstream Isolation Valve	19-2	30	MANUAL OPEN	RCV
	0+08.9	MLV BYPASS	19-2BD1	8	PARTIALLY CLOSED	CHECK, CLOSED, or RCV
	48+59	CROSSOVER	19C-101.2	2	MANUAL CLOSED	CHECK, CLOSED, or RCV
	249+42.22	MLV BYPASS	19-2ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	249+53.55 (MP 4.73)	Downstream Isolation Valve	19-2A	30	MANUAL OPEN	RCV
157	249+53.55 (MP 4.73)	Upstream Isolation Valve	19-2A	30	MANUAL OPEN	RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
(KM 297)	249+64.88	MLV BYPASS	19-2ABD1	8	PARTIALLY CLOSED	CHECK, CLOSED, or RCV
	300+29.6	CROSSOVER/LATERAL	19H-101.2	10	MANUAL CLOSED	CLOSED or RCV
	339+07 (MP 6.42)	VENT	19E-101.2	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	346+36.8	LATERAL	19F-101.2	10	MANUAL OPEN	CLOSED or RCV
	490+42.64	MLV BYPASS	20-2BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	490+51 (MP 9.29)	Downstream Isolation Valve	20-2	30	LINE BREAK	RCV
158 (KM 298)	490+51 BACK, 0+00 AHEAD (MP 9.29)	Upstream Isolation Valve	20-2	30	LINE BREAK	RCV
	0+08.87	MLV BYPASS	20-2BD1	8	PARTIALLY CLOSED	CHECK, CLOSED, or RCV
	389+82.2 3	VENT	N/A	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	389+96.11	PIG VALVE	20-2R	30	MANUAL CLOSED	CLOSED or RCV
	389+92.1 (MP 7.38)	Downstream Isolation Valve	20-2BR	24	LINE BREAK	RCV
159 (KM 299)	390+59 BACK, 0+00 AHEAD (MP 7.40)	Upstream Isolation Valve	36-2	30	LINE BREAK	RCV
	0+08.9	MLV BYPASS	36-2BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+17	CROSSOVER	36-2XA3	12	MANUAL OPEN	CLOSED or RCV
	0+32.3	CROSSOVER	36-2XA1	12	MANUAL OPEN	CLOSED or RCV
	385+44	CROSSOVER/LATERAL	36B-101.2	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	385+68.34	MLV BYPASS	36-2ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	385+77.24 (MP 7.30)	Downstream Isolation Valve	36-2A	30	MANUAL OPEN	RCV
160 (KM 300)	546+32.9 BACK, 0+00 AHEAD (MP 10.35)	Upstream Isolation Valve	19-3	30	LINE BREAK	RCV
	0+08.9	CROSSOVER/LATERAL	19-3BD1	8	PARTIALLY CLOSED	CHECK, CLOSED, or RCV
	2+30	LATERAL	19K-101.3	3	MANUAL OPEN WITH CHECK VALVE (4” w/check DS of the 3” – 3” has no check)	CHECK, CLOSED, or RCV
	249+65.55 (MP 4.73)	Downstream Isolation Valve for ***special permit segment 160*** (KM 300)	19-3A	30	MANUAL OPEN	RCV
161,162 (KM 301,302)		Upstream Isolation Valve for ***special permit segments 161 and 162*** (KM 301 and 302)				
	300+67.7	CROSSOVER/LATERAL	19D-101.3	12	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	301+23.6	CROSSOVER/LATERAL	19H-101.3	10	MANUAL OPEN	CLOSED or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	340+28.7	VENT	19E-101.3	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	340+75	CROSSOVER/LATERAL	19G-101.3	12	MANUAL OPEN	CLOSED or RCV
	491+70.52	MLV BYPASS	20-3BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	491+79 (MP 9.31)	Downstream Isolation Valve	20-3	30	LINE BREAK	RCV
163,164, 165 (KM 303, 304, 306)	491+79 BACK, 0+00 AHEAD (MP 9.31)	Upstream Isolation Valve	20-3	30	LINE BREAK	RCV
	0+08.87 (MP 9.31)	MLV BYPASS	20-3BD1	8	PARTIALLY CLOSED	CHECK, CLOSED, or RCV
	158+45	VENT	20F-101.3	2	MANUAL CLOSED	CHECK, CLOSED, or RCV
	214+36.8	LATERAL	20J-101.3	12	MANUAL OPEN	CLOSED or RCV
	253+78	VENT	20A-101.3	N/A	MANUAL CLOSED	CLOSED or RCV
	389+31.5	VENT	N/A	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	389+45.31	PIG VALVE	20-3R	30	MANUAL CLOSED	CLOSED or RCV
	389+41.4 (MP 7.38)	Downstream Isolation Valve	20-3BR	30	MANUAL OPEN	RCV
166 (KM 307)	390+44 BACK, 0+00 AHEAD (MP 7.39)	Upstream Isolation Valve	36-3	30	LINE BREAK	RCV
	0+08.3	MLV BYPASS	36-3BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+30.3	CROSSOVER	36-3XA2	16	MANUAL OPEN	CLOSED or RCV
	385+44	CROSSOVER/LATERAL	36B-101.3	2	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	385+69.06	MLV BYPASS	36-3ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	385+77.96 (MP 7.29)	Downstream Isolation Valve	36-3A	30	MANUAL OPEN	RCV
169 (KM 312)	0+58.2 (MP 0.01)	Upstream Isolation Valve	409A-101BL	24	MANUAL OPEN	RCV
	0+58.04	PIG VALVE	409A-101L	24	MANUAL CLOSED	CLOSED or RCV
	1+29.1	LATERAL	409A-701	4	MANUAL WITH CHECK VALVE	CHECK, CLOSED, or RCV
	1+39.1	VENT	409A-131	6	MANUAL CLOSED	CHECK, CLOSED, or RCV
	17+21.5	RELIEF VALVE	409A-141	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	17+42.5	LATERAL	409A-151	4	BLINDED	CLOSED or BLINDED
	17+63.5	LATERAL	409A-161	6	MANUAL CLOSED BLINDED	CLOSED or BLINDED
	295+77	BLIND	409A-171	3	MANUAL CLOSED	CHECK, CLOSED, or RCV
	297+54	BLIND	409A-111	2	BLINDED (Removed)	CLOSED or BLINDED
	297+64	BLINDED	N/A	2	CAPPED	CLOSED (CAPPED) or BLINDED

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	297+74.6	LATERAL	409A-181	10	MANUAL OPEN	CLOSED or RCV
	361+68	LATERAL	409A-191	10	MANUAL CLOSED BLINDED	CLOSED or BLINDED
	389+13.6	VENT	409-101BBD	8	MANUAL CLOSED BLINDED	CLOSED or BLINDED
	389+14.35 (MP 7.37)	Downstream Isolation Valve	409A-101B	24	MANUAL OPEN	RCV
171,172 (KM 316, 317)	576+80 BACK, 0+00 AHEAD (MP 10.92)	Upstream Isolation Valve	409A-102	24	MANUAL OPEN	RCV
	0+06	MLV BYPASS	409A-102BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	93+98	LATERAL	409A-132	6	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	354+79.8	TO METER STATION	409A-112	4	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	476+25.6	LATERAL	409A-142	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	478+86.6	VENT	409A-401	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	478+96	LATERAL	409A-501	12	MANUAL OPEN WITH CHECK VALVE	CLOSED or RCV
	479+14.96	PIG VALVE	409A-103R	24	MANUAL CLOSED	CLOSED or RCV
	479+24.96 (MP 9.08)	Downstream Isolation Valve	409A-103	24	MANUAL OPEN	RCV
173,174 (KM 318,319)	0+00 (MP 0.00)	Upstream Isolation Valve	118-1	20	MANUAL	RCV
	0+07.5	MLV BYPASS	118-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+12	CROSSOVER	118-1XA3	16	MANUAL OPEN	CLOSED or RCV
	0+41.41	PIG VALVE	118-1L	20	MANUAL CLOSED	CLOSED or RCV
	569+75	LATERAL	118G-101.1	4	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	569+80.91	MLV BYPASS	118-1CBD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	569+85.92	Downstream Isolation Valve	118-1C	20	MANUAL	RCV
175 (KM 320)		Upstream Isolation Valve				
	569+90.83	MLV BYPASS	118-1CBD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	569+95	LATERAL	118F-101.1	4	MANUAL OPEN WITH CHECK VALVE	CHECK, CLOSED, or RCV
	MP 16.10	LATERAL/METER	118-1B101.1	4	MANUAL OPEN	CHECK, CLOSED, or RCV
	MP 16.15	LATERAL/METER	118D-101.1	4	MANUAL OPEN	CHECK, CLOSED, or RCV
	MP 16.17	LATERAL/METER	118-1B101	4	MANUAL OPEN	CHECK, CLOSED, or RCV
	743+81	VALVE BYPASS	N/A	3	MANUAL CLOSED	CHECK, CLOSED, or RCV
	743+81	LATERAL	118A-AD1	20	CONTROL VALVE	CLOSED or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	743+91.67	MLV BYPASS	118-1ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	743+98.85 (MP 10.79)	Downstream Isolation Valve	118A-1A	20	REMOTE	RCV
176 (KM 322)	566+69 BACK, 0+00 AHEAD (MP 10.73)	Upstream Isolation Valve	121-1	20	MANUAL	RCV
	0+05.6	MLV BYPASS	121-1BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	271+93.91	PIG VALVE	121-1R	20	MANUAL CLOSED	CLOSED or RCV
	271+92 (MP 5.15)	Downstream Isolation Valve	121-1BR	20	MANUAL	RCV
177 (KM 323)	259+46 Back, 0+00 Ahead (MP 4.91)	Upstream Isolation Valve	115-2	24	MANUAL OPEN	RCV
	0+05.5	MLV BYPASS	115-2BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+10.5	CROSSOVER	115-2XA3	12	MANUAL OPEN	CLOSED or RCV
	239+52.09	MLV BYPASS	115-2ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	239+60.46 (MP 4.54)	Downstream Isolation Valve	115-2A	24	MANUAL OPEN	RCV
178 (KM 326) No P&ID	1+07.92	Upstream Isolation Valve	119-2L	24	MANUAL OPEN	RCV
	1+01.92	PIG VALVE	119-2BL	24	MANUAL CLOSED	CLOSED or RCV
	1+20	LATERAL	119A-AD2	24	CONTROL VALVE	CLOSED or RCV
	1+20	VALVE BYPASS	N/A	3	MANUAL CLOSED	CHECK, CLOSED, or RCV
	361+22	MLV BYPASS	119A-2ABD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	361+32.51 (MP 10.79)	Downstream Isolation Valve	119A-2A	24	REMOTE	RCV
118 (KM 329)	935+16 Back, 0+00 Ahead (MP 7.40)	Upstream Isolation Valve	117-3	26	LINE BREAK	RCV
	0+08.3	MLV BYPASS	117-3BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+23.4	CROSSOVER	117-3XA2	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	560+94.9	CROSSOVER	118-3XH	16	MANUAL OPEN	CLOSED or RCV
	561+83.44	PIG VALVE	118-3BR	30	MANUAL CLOSED	CLOSED or RCV
	561+80.58	MLV BYPASS	118-3BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	561+80.59	CROSSOVER	118-3X1A	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	561+88 (MP 10.63)	Downstream Isolation Valve	118-3	30	MANUAL OPEN	RCV
182,183 (KM 330,331)	561+88 Back, 0+00 Ahead (MP 10.63)	Upstream Isolation Valve	118-3	30	MANUAL OPEN	RCV
	0+08.2	CROSSOVER	118-3X1A	8	MANUAL OPEN	CHECK, CLOSED, or RCV
	0+42.95	MLV BYPASS	118-3BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	0+42.95	PIG VALVE	118-3BL	30	MANUAL CLOSED	CLOSED or RCV

Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post / Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Valve Automation Methodology for Special Permit[71]
	671+54.19	PIG VALVE	119-2BR	30	MANUAL CLOSED	CLOSED or RCV
	671+51.33 (MP 12)	Downstream Isolation Valve	119-2R	30	MANUAL OPEN	RCV
187 (KM 340)	634+50 Back, 0+00 Ahead (MP 12.02)	Upstream Isolation Valve	121-2	24	MANUAL OPEN	RCV
	0+05	MLV BYPASS	121-2BD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	611+60.28	VENT	N/A	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	611+73.11	PIG VALVE	121-2R	24	MANUAL CLOSED	CLOSED or RCV
	611+68.28 (MP 11.58)	Downstream Isolation Valve	121-2BR	24	MANUAL OPEN	RCV
188 (KM 341)	680+57.2 (MP 12.89)	Upstream Isolation Valve	83-4B	30	MANUAL OPEN	RCV
	680+65.65	MLV BYPASS	83-4BBD1	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	1173+17.35	MLV BYPASS/CROSSOVER	84-4BD	8	MANUAL CLOSED	CHECK, CLOSED, or RCV
	1173+26 (MP 22.22)	Downstream Isolation Valve	84-4	30	MANUAL OPEN	RCV
191 (KM 348)	863+36 Back, 0+00 Ahead (MP 16.35)	Upstream Isolation Valve	541-2	36	LINE BREAK	RCV
	0+08	MLV BYPASS	541-2ABD1	10	MANUAL OPEN	CLOSED or RCV
	0+14.7	CROSSOVER	541-1XA2	16	MANUAL CLOSED	CLOSED or RCV
	0+35.5	CROSSOVER	541-2XA3	12	MANUAL OPEN	CLOSED or RCV
	421+62.42	MLV BYPASS	541-2ABD	10	MANUAL CLOSED	CLOSED or RCV
	421+74.02 (MP 7.98)	Downstream Isolation Valve	541-2A	36	CONVENIENCE VALVE	RCV

Note: Condition 12 is applicable to all crossover valves, valve spacing, and lateral tie-ins. If TGP has a ***special permit segment*** or ***special permit inspection area*** mainline valve spacing that is over 20 miles, a mainline valve must be installed to keep the isolation valve spacing below a 20-mile spacing. The isolation mainline valve must be installed within 24 months of the grant of this special permit.

Final Page of the Special Permit with Conditions