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

Special Permit Information:

Docket Number:	PHMSA-2019-0207
Requested By:	Gulf South Pipeline Company, LP
Operator ID#:	31728
Date Requested:	October 4, 2019
Original Issuance Date:	July 20, 2020
Effective Dates:	July 20, 2020 to July 20, 2030
Code Section(s):	49 CFR 192.611(a)

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 to Gulf South Pipeline Company, LP (GSPC).[2] This special permit waives compliance with the 49 Code of Federal Regulations (CFR) 192.611(a) for a Class 1 to Class 3 location change of GSPC's Index 817 Pipeline, which is a 42-inch diameter natural gas transmission pipeline, in Madison Parish, Louisiana. This special permit requires that GSPC implement additional conditions on the operations, maintenance, and integrity management of the Index 817 Pipeline.

I. Purpose and Need:

The special permit is needed for a Class 1 to Class 3 location change that has occurred on the 42-inch diameter Index 817 Pipeline located in Madison Parish, Louisiana. On the condition that GSPC complies with the terms and conditions set forth below, this special permit waives compliance from 49 CFR 192.611(a) for 214 feet of natural gas transmission pipeline on the 42-

[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] GSPC is a wholly-owned subsidiary of the Boardwalk Pipeline Partners, LP.

inch diameter Index 817 Pipeline. This special permit allows GSPC to continue to operate the ***special permit segment*** as defined below at its current maximum allowable operating pressure (MAOP) of 1,456 pounds per square inch gauge (psig) for the Index 817 Pipeline.[3]

The Federal pipeline safety regulations in 49 CFR 192.611(a) require natural gas transmission operators to either pressure test, replace the pipe with stronger pipe, or lower the MAOP when there is a Class 1 to Class 3 location change as defined in 49 CFR 192.5. The 214 feet of 42-inch diameter pipe in the GSPC special permit request operates at a stress level of 65.2% of specified minimum yield strength (SMYS) based upon a 1,456 psig MAOP. Without this special permit, in accordance with 49 CFR 192.611(a), GSPC would be required to replace the pipe segment or reduce the pipeline MAOP. The 214 feet of the 42-inch diameter Index 817 Pipeline was hydrostatically tested to a minimum pressure of 1,875 psig for 8 hours in late 2007, whereas 49 CFR 192.611(a) requires a minimum test pressure of 2,184 psig for a Class 3 location and the pipe design factor is greater than 60% of SMYS.

II. Special Permit Segments and Inspection Areas:

Madison Parish, Louisiana

This special permit applies to the ***special permit segment*** defined using the GSPC survey station (SS) references as follows:

- ***Special permit segment*** – Index 817 Pipeline – 4,638 feet, SS 9409+44 to SS 9455+82.

  Note: GSPC's special permit request was for 214 feet from SS 9431+56 to SS 9433+70. All procedures, surveys, assessments, remediation, and assessment intervals required in these special permit conditions for the ***special permit segment*** are applicable on either side of the ***special permit segment*** end points for a distance of two (2) times the potential impact radius (PIR), as defined in 49 CFR 192.903. The PIR for a 42-inch diameter, 1,456 psig MAOP pipeline is 1,106 feet. Two (2)

[3] This special permit is for a 214-foot segment of 42-inch diameter Index 817 Pipeline as requested by GSPC. The ***special permit segment*** includes additional pipeline footage beyond the 214 feet that extends the ***special permit segment*** which the special permit conditions are applicable. **Condition 14** will allow extensions beyond the 214 feet of pipeline should the Class 3 location extend further. PHMSA has granted this special permit due to the 214 feet of 42-inch diameter pipe operating at a stress level of 65.2% of specified minimum yield strength (SMYS) based upon a 1,456 psig MAOP. Pipelines with a MAOP of over 72% SMYS are not allowed to operate in a Class 3 location. This special permit is not for pipe operating above 72% SMYS.

times the PIR would be 2,212 feet. The ***special permit segment*** total footage is 4,638 feet. PHMSA extended this special permit request from a 214-foot special permit segment to a 4,638-foot special permit segment since this pipeline has an existing Alternative MAOP special permit[4] to operate up to 80% SMYS in Class 1 locations.

This special permit applies to the ***special permit inspection area*** defined using the GSPC SS references as follows:

- ***Special permit inspection area*** – Index 817 Pipeline – SS 8898+40 to 10752+83, approximately 35.1 miles.

The ***special permit inspection area*** is in Madison Parish, Louisiana, and Warren and Hinds Counties, Mississippi. The ***special permit inspection area*** starts at the Tallulah, Louisiana Compressor station and ends at a pointed located in Hinds County, Mississippi for a length of approximately 35.1 miles and includes the ***special permit segment***. **Attachments A** and **B** include Index 817 Pipeline route maps showing the ***special permit segment*** and ***special permit inspection area.***

PHMSA grants this special permit 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 its entirety in Docket No. PHMSA-2019-0207 in the Federal Docket Management System located on the internet at www.regulations.gov.

III. Conditions:

PHMSA grants this special permit to GSPC subject to GSPC implementing the following conditions on the Index 817 Pipeline as detailed below:

1) Maximum Allowable Operating Pressure for the Special Permit:

a) **MAOP**: GSPC must continue to operate the ***special permit segment*** and ***special permit inspection area*** at or below the existing MAOP of 1,456 psig.

b) **Alternative MAOP**: GSPC must continue to implement the conditions in the Alternative MAOP ***special permit*** (PHMSA-2006-26533) for both the ***special permit segment*** and

[4] PHMSA-2006-26533.

the ***special permit inspection area***. The ***special permit inspection area*** is defined in this special permit (PHMSA-2019-0207).

2) **<u>Integrity Management Program</u>:** GSPC must incorporate the requirements of this special permit into its written integrity management program and standard operating procedures (SOPs).

   a) GSPC must treat the ***special permit segment*** as a "covered segment" in a "high consequence area (HCA)" in accordance with 49 CFR Part 192, Subpart O. Reassessments of the ***special permit segment*** and ***special permit inspection area*** using high resolution magnetic flux leakage (HR-MFL) and high resolution (HR) Deformation inline inspection (ILI) must be conducted at the frequency specified for HCAs in 49 CFR 192, Subpart O.

   b) If GSPC identifies threats within the ***special permit segment*** and ***special permit inspection area*** that require running additional ILI tools, pursuant to 49 CFR Part 192, Subpart O, such as for crack detection[5] or pipe movement from soil or geologic stresses, GSPC must use the appropriate ILI tools or other evaluation methods for pipeline assessments.

3) **<u>Operations and Maintenance Manual</u>**: GSPC must amend applicable sections of its operations and maintenance (O&M) Manual(s) and Procedures to incorporate the procedures, inspections, assessments, reassessments, remediation, reporting, documentation, permitting, and timing or time intervals required by the special permit conditions. The O&M Manual and Procedures must include requirements to address each condition in this special permit for the ***special permit segment*** and the ***special permit inspection area.***

4) **<u>Close Interval Surveys</u>**:

   a) **<u>CIS</u>**: GSPC must conduct close interval surveys (CIS) at a maximum 5-foot spacing and with interrupted on/off current on the ***special permit segment*** and ***special permit inspection area*** in accordance with 49 CFR 192.463 and 192.465.

   b) **<u>CIS Timing</u>**: GSPC must perform periodic CIS of the ***special permit segment*** and ***special permit inspection area*** at the applicable reassessment interval(s) for a "covered segment" determined in concert and integrated with ILI in accordance with 49 CFR 192,

[5] "Pipe Crack" activity shall be defined as over both 20% wall thickness depth and 2-inches in length.

Subpart O, reassessment intervals as required in 49 CFR 192.937(a) and (b) and 192.939. If a CIS was not conducted with the last ILI survey, it must be conducted within one (1) year of issuance of this special permit.

c) **CIS Timing Delay**: If environmental permitting or right-of-way factors beyond GSPC's control prevent the completion of the CIS and remediation[6] within six (6) months from the issuance of this special permit, GSPC must complete the CIS and subsequent remediation including coating repair as soon as practicable. GSPC must submit a letter justifying the CIS and remediation delays, no later than one (1) month prior to the end of six (6) month interval, and must provide the anticipated date of completion to the Director, PHMSA Central Region.[7]

d) **CIS Reassessments**: GSPC must perform periodic CIS of the ***special permit segment*** and ***special permit inspection area*** at the applicable reassessment interval(s) for a "covered segment" determined in concert and integrated with ILI in accordance with 49 CFR 192, Subpart O, reassessment intervals as required in 49 CFR 192.937(a) and (b) and 192.939. CIS assessments within the reassessment interval are not required to be performed in the same year as ILI reassessments.

5) **Cathodic Protection Test Stations**:

a) **Test Station Locations**: At least one (1) cathodic protection (CP) pipe-to-soil test station must be located within the ***special permit segment*** with a maximum spacing of one-half mile between test stations. In cases where obstructions or restricted areas prevent test station placement, the test station must be installed in the closest practical location.

b) **Monitoring**: Annual monitoring of cathodic protection pipe-to-soil test stations must be performed in accordance with 49 CFR 192.463 and 192.465.

6) **Annual Cathodic Protection Test Station Readings**:

a) **CP Findings**: If any annual CP test station readings on the ***special permit inspection area*** fall below 49 CFR Part 192, Subpart I requirements, remediation must occur within

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

[7] Upon notice to GSPC by the Director, PHMSA Central Region, PHMSA may change the reporting responsibilities for this special permit to another PHMSA Region Director.

six (6) months of the survey and must include a CIS on each side of the affected test station to the next test station. GSPC must implement corrosion system modifications that are identified through the CP test station readings and remediation findings to ensure corrosion control.

b) **Remediation Timing**: If factors beyond GSPC's control prevent the completion of remediation within six (6) months, GSPC must complete the remediation as soon as practicable and submit a letter justifying the delay with the anticipated date of completion to the Director, PHMSA Central Region, no later than one (1) month prior to the end of the six (6) month remediation period. GSPC must receive a letter of "No Objection" from the Director, PHMSA Central Region, prior to implementing an extended remediation interval.

7) **Interference Currents Control**: GSPC must incorporate measures to control induced alternating current (AC) from parallel electric transmission lines and other interference issues in the ***special permit inspection area***, that may affect the pipeline. An induced AC program to protect the pipeline from corrosion caused by stray currents must be in place within one (1) year of the date of this special permit.

8) **Anomaly Assessment and Remediation**:

a) **General**: GSPC must conduct anomaly assessments using ILI that meets the assessment intervals of special permit PHMSA-2006-26533 and 49 CFR Part 192, Subpart O. GSPC must account for ILI tool tolerance[8,9] and corrosion growth rates in scheduled response times and repairs, and document and justify the values used.

[8] ILI tool 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. 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, <u>if the continuous ILI segment is longer</u> than the ***special permit inspection area***. A minimum of four (4) calibration excavations must be used for unity plots or as an alternative a minimum of one (1) calibration excavation and compliance with API 1163-2013, In-Line Inspection Systems Qualification Standard (API 1163), Level 1 criteria must be used. For API 1163, Level 1 criteria to be used, all anomalies greater than 20-percent wall loss must be excavated and remediated unless Director, PHMSA Central Region gives GSPC a "No Objection" to an alternative ILI tool calibration procedure (*see* Footnote 9).

b) **Dents**: GSPC must repair dents to the Index 817 Pipeline in the ***special permit inspection area*** in accordance with the 49 CFR 192.933 repair criteria. The ***special permit inspection area*** must have a high resolution (HR) deformation tool inspection as part of the ILI. The HR deformation ILI can be from past inspections. The timing for these dent repairs should follow GSPC's O&M Procedures, but must not be longer than one (1) year after discovery.

c) **Anomaly Evaluation Repair Criteria and Timing**: The following provisions provide the required timing for excavation and investigation of anomalies based on ILI results. GSPC must evaluate ILI data by using either the ASME Standard B31G, "*Manual for Determining the Remaining Strength of Corroded Pipelines"*,[10] the modified B31G (0.85dL) or R-STRENG for calculating the predicted failure pressure ratio (FPR) to determine anomaly responses.

i) ***Special permit segment***:

- **Immediate response time – repair immediately**:
  - Any anomaly within a ***special permit segment*** that meets either: (1) a FPR equal to or less than 1.25; or (2) an anomaly depth equal to or greater than 60% wall thickness loss.
- **One-year response**:
  - Any anomaly within a ***special permit segment*** with pipe operating over 56% SMYS and up through 67% SMYS that meets either: (1) a FPR equal to or less than 1.50; or (2) an anomaly depth equal to or greater than 40% wall thickness loss.

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[9] **Note:** Other known and documented pipeline features that are appropriate for the type 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 GSPC must submit a plan for using known and documented pipeline features as calibration excavations to, and receive a "No Objection" from the Director, PHMSA Central Region, prior to performing the ILI tool calibration using pipeline features. PHMSA must reply to GSPC within 90-days of GSPC's request. The plan must include at least the following information: **(1)** reason that known and documented pipeline features will be used in place of anomalies on the pipelines; the pipeline features that will be used for the ILI tool calibration, and the technical justification for using the pipeline features for ILI tool calibration; and **(2)** submit a report to the Director, PHMSA Central Region and to the Director, PHMSA Engineering and Research 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. GSPC must submit the report to PHMSA within 90-days after completion of the ILI tool calibration.

[10] Standards used in this special permit must be the edition incorporated by reference in 49 CFR 192.7.

- Any anomaly within a ***special permit segment*** with pipe operating over 67% SMYS and up through 72% SMYS that meets either: (1) an FPR equal to or less than 1.39; or (2) an anomaly depth equal to or greater than 40% wall thickness loss.
- Any anomaly within a ***special permit segment*** with pipe operating over 72% SMYS and up through 80% SMYS that meets either: (1) an FPR equal to or less than 1.25; or (2) an anomaly depth equal to or greater than 40% wall thickness loss.
- Any anomaly within a ***special permit segment*** with pipe operating up through 56% SMYS that meets either: (1) an FPR equal to or less than 1.80; or (2) an anomaly depth equal to or greater than 40% wall thickness loss.

– **Monitored response**:

- Any anomaly within a ***special permit segment*** with pipe operating over 56% SMYS and up through 67% SMYS that meets either: (1) an FPR over 1.50; or (2) an anomaly depth less than 40% wall thickness loss.
- Any anomaly within a ***special permit segment*** with pipe operating over 67% SMYS and up through 72% SMYS that meets either: (1) an FPR over 1.39; or (2) an anomaly depth less than 40% wall thickness loss.
- Any anomaly within a ***special permit segment*** with pipe operating over 72% SMYS and up through 80% SMYS that meets either: (1) an FPR over 1.25; or (2) an anomaly depth less than 40% wall thickness loss.
- Any anomaly within a ***special permit segment*** with pipe operating up through 56% SMYS that meets either: (1) an FPR over 1.80; or (2) an anomaly depth less than 40% wall thickness loss.

ii) ***Special permit inspection area***:

– **Immediate response time – repair immediately**:

- Any anomaly within a ***special permit inspection area*** that meets either: (1) an FPR equal to or less than 1.10; or (2) an anomaly depth equal to or greater than 80% wall thickness loss.

– **One-year and monitored response**:

- The anomaly assessment remediation and response time for a ***special permit inspection area*** must be in accordance with: **(1)** 49 CFR Part 192, Subpart O;

(2) Special Permit PHMSA-2006-26533, **Condition 43**, for the Index 817 Pipeline; and **(3)** 49 CFR 192.620(d)(11). The assessment response that has a shorter repair timing or more conservative anomaly remediation requirements must be implemented by GSPC.

- Any anomaly within the ***special permit inspection area*** with a depth equal to or greater than 40% wall thickness loss must be remediated within one-year of GSPC finding the anomaly.

9) **Damage Prevention Program**: GSPC must ensure its damage prevention program incorporates the applicable best practices of the Common Ground Alliance within the ***special permit inspection area***.

10) **Annual Report to PHMSA**: Annually,[11] after the grant of this special permit, GSPC must submit an annual pipeline integrity report to the Director, PHMSA Central Region, summarizing any significant integrity threats and the following items:[12]

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

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

c) Any new integrity threats identified during the previous year in the ***special permit segment***, and the results of any ILI or direct assessments performed (including any remediated anomalies with the associated wall loss, length, and unrepaired failure pressure; any un-remediated anomalies over 30% pipe wall loss and the associated wall loss, length and failure pressure; cracking found in the pipe body; weld seam or girth

[11] Annual reports must be received by PHMSA by the last day of the month in which the special permit is granted. For example, the annual report for a special permit granted on July 15, 2020, must be received by PHMSA no later than July 31 each year beginning in 2021.

[12] GSPC must submit a copy of the annual reports on the special permit docket - PHMSA-2019-0207, at www.regulations.gov.

welds; and dents with metal loss, cracking or stress riser) during the previous year in the ***special permit segment***;

d) Summaries of any close interval surveys that resulted in low cathodic protection levels in the ***special permit segment*** and a remediation schedule;

e) Any reportable incident or any leak normally indicated on the DOT Annual Report, and all repairs on the pipeline that occurred during the previous year in the ***special permit segment***;

f) Any pressure test leaks or failures with a description of the cause in the ***special permit segment***;

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

h) Any emergency events that cause closure of mainline valves as described in **Condition 12**, including the location (Mile Post) of valves and closure times.

11) ***Special Permit Segment*** **Specific Conditions**: GSPC must comply with the following requirements:

a) **Line-of-Sight Markers**: GSPC must install and maintain line-of-sight markers within the ***special permit inspection area*** in accordance with 49 CFR 192.620(d)(4)(iv) to the extent practicable. Line-of-sight markers must be installed within three (3) months of issuance of this special permit and replaced as necessary by GSPC within 30 days of discovering the marker is removed or missing.

b) **Data Integration**: GSPC must maintain data integration of all special permit condition findings and remediation in the ***special permit inspection area***. 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)** CISs – most recent; **(11)** depth of cover surveys; rectifier readings – past five years; **(12)** cathodic protection test point survey readings – past five years; **(13)** AC/DC interference surveys; **(14)** pipe coating surveys; **(15)** pipe coating and anomaly evaluations from pipe excavations; **(16)** stress corrosion cracking excavations and findings; and **(17)** pipe exposures from encroachments.[13] Structures must be validated every three (3) years by obtaining new aerial imagery or by ground patrol.

i) Data integration must be performed in accordance with 49 CFR 192.917 for threat identification, evaluation, remediation, and mitigation.

ii) Data integration documentation and drawings, with four (4) years of prior data, to meet **Condition 11(b)**, must be completed and must be submitted, if requested by PHMSA, beginning with the 2nd annual report of this special permit.

iii) Data integration must be updated on an annual basis. GSPC must conduct, at least, an annual review of integrity issues to be remediated.

iv) GSPC must maintain data integration as a composite of all applicable data elements in a data viewer.

c) **Pipeline Patrolling**: Pipeline patrolling must be conducted at least monthly (12 times per calendar year), not to exceed 45 days, to inspect the ***special permit inspection area*** for excavation activities, ground movement, wash-outs, leakage or other activities and conditions affecting the safe operation of the pipeline.

d) **Environmental Assessments and Permits**: GSPC must evaluate the potential environmental consequences and affected resources of any land disturbances and water body crossings needed to implement the special permit conditions for ***special permit segment*** or ***special permit inspection area*** prior to the disturbance. If a land disturbance or water body crossings is required, GSPC must obtain and adhere to all applicable (Federal, state, and local) environmental permit requirements when conducting the special permit conditions activity.

e) **Root Cause Analysis for Failure or Leak**: If a leak or rupture (incident as defined by 49 CFR 191.3) occurs in any of the ***special permit inspection area,*** GSPC must notify the Director, PHMSA Central Region, within five (5) days of the leak or rupture. A root cause analysis must be performed to determine the cause of the failure and must be sent to the Director, PHMSA Central Region, and the Director, PHMSA Engineering and Research, within 90 days of the incident. If a root cause analysis cannot be performed

[13] Hydrostatic test failures, in-service ruptures, rectifier readings, cathodic protection 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.

within 90 days of the incident, GSPC must submit to the Director, PHMSA Central Region, a request for an extension of time. GSPC must receive a letter of "No Objection" from the Director, PHMSA Central Region, prior to implementing an extended timeframe to perform the root cause analysis. PHMSA will review the root cause analysis report to determine if revocation, suspension, or modification of the special permit is warranted based upon incident findings.

12) **Mainline Valve – Monitoring and Remote Control for Leaks or Ruptures**: GSPC must automate the nearest existing mainline valves on both sides of the ***special permit segment*** for closure, or demonstrate the capability to manually close the mainline valves in accordance with the requirements of **Condition 12**. The mainline valves must be within a maximum 20-mile total spacing, upstream and downstream, of the ***special permit segment***. GSPC mainline valves are located at Index 817 Pipeline Mile Posts 168.5 (SS 8897+01) and 183.06 (SS 9665+82). GSPC must develop and implement procedures to initiate closure of each mainline valve as follows:

  a) **Supervisory Control and Data Acquisition System and Remote Monitoring**: The ***special permit segment*** must be controlled by a supervisory control and data acquisition (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 of **Condition 12**;

  b) **Crossovers or Lateral Pipe Isolation**: If any crossover or lateral pipe for gas receipts or deliveries 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 segment*** is not isolated, isolation valves must be used;[14]

[14] Gas delivery pipelines must have a remote-controlled shutoff valve (gate or ball valve) either at the connection to the Index 817 Pipeline or at the delivery meter station. Any gas delivery or receipt station over 5 miles in length that is connected to the Index 817 Pipeline must have a remote-controlled shutoff valve within 5 miles of the Index 817 Pipeline. For gas delivery or receipt pipelines, manual shutoff valves can be used for isolation, but must be closed within 30 minutes from the pipeline leak or rupture confirmation.

c) **<u>Remote Control Valve Monitoring for Valve Status and Operating Pressure</u>**: Mainline valves must be constantly monitored for valve status (open, closed, or partial closed/open), upstream pressure, and downstream pressure;

d) **<u>Valve Closure for a Leak or Rupture</u>**: Closure of the appropriate valves following a pipeline leak or rupture meeting the criteria specified in this **Condition 12(d)(i)** must occur as soon as practicable from the time the pipeline leak or rupture location is confirmed, not to exceed 30 minutes from such confirmation;[15]

i) "Rupture" means a significant breach of a pipeline that results in a large-volume, uncontrolled release of gas. For purposes of this special permit, GSPC must treat any of the following as ruptures unless and until determined otherwise:

1) A release of gas observed or reported to the operator by its field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities, and that may be representative of an unintentional and uncontrolled release event defined in paragraphs (2) or (3) of this definition;

2) An unanticipated or unplanned pressure loss of 10 percent or greater, occurring within a time interval of 15 minutes or less, unless the operator has documented in advance of the pressure loss the need for a higher pressure-change threshold due to pipeline flow dynamics that cause fluctuations in gas demand that are typically higher than a pressure loss of 10 percent in a time interval of 15 minutes or less; or

3) An unexplained flow rate change, pressure change, instrumentation indication, or equipment function that may be representative of an event defined in paragraph (2) of this definition.

Note: Rupture identification occurs when a rupture, as defined in this section, is first observed by or reported to pipeline operating personnel or a controller.

ii) Within five (5) minutes of the initial notification to GSPC, GSPC must evaluate and identify a rupture, 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.

[15] The pipeline valve section location to be closed and isolated (if there should be a rupture) must be confirmed by GSPC 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.

e) **24-Hour Monitoring by Gas Control Center**: The GSPC Gas Control Center must monitor the ***special permit segment*** 24 hours a day, 7 days a week and must confirm the existence of a leak or rupture in accordance with **Condition 12(d)(i)** and as soon as practicable, in accordance with the GSPC pipeline operating procedures;

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

g) **Point-to-Point Verification**: GSPC 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), or an equivalent verification;

h) **Maintenance of Valves**: All valves used to isolate a leak or rupture must be maintained in accordance with this special permit and 49 CFR 192.745;

i) **Inoperable Valves**: GSPC 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 shut-off, 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 seven (7) 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 GSPC's control, GSPC must notify the Director, PHMSA Central Region, in writing of the reasons the schedule cannot be met and obtain a letter of "No Objection" from PHMSA prior to implementing the schedule change.

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

k) **<u>Notifications</u>**: GSPC must immediately and directly notify the appropriate public safety access point (9-1-1 emergency call center) or other coordinating agency for the communities and jurisdictions in which the pipeline is located when a release is indicated;[16] and

l) **<u>Operator Actions During an Emergency</u>**: GSPC must establish actions required to be taken by a pipeline controller, or the appropriate emergency response coordinator, during an emergency in accordance with these special permit conditions and as required in 49 CFR 192.615 and 192.631.

13) **<u>Documentation</u>**: GSPC must maintain the following records for each ***special permit segment***:

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

b) Documentation (mill test reports) showing that the pipe in the ***special permit segment*** meets the wall thickness, yield strength, tensile strength and chemical composition of either the American Petroleum Institute Standard 5L, 5LX or 5LS, *"Specification for Line Pipe"* (API 5L)[17] approved by 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, then the pipe meets the API 5L standard in usage at that time. Any ***special permit segment*** that does not have mill test reports for the pipe cannot be authorized per this special permit.

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

14) **<u>Extension of the *Special Permit Segment*</u>**: PHMSA may extend the ***special permit segment*** to include <u>contiguous segments</u> of the Index 817 Pipeline up to the limits of the ***special***

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

[17] Standards used for this special permit must be the edition incorporated by reference in 49 CFR 192.7.

permit inspection area pursuant to the following conditions. The ***special permit segment*** cannot be extended into pipe operating at over a 72% of specified minimum yield strength. GSPC must:

a) Provide at least 90 days advanced notice to the Director, PHMSA Central Region, and the Director, PHMSA Engineering and Research Division, of a requested extension of any Index 817 Pipeline ***special permit segment*** based on actual class location change and include a schedule of inspections and of any anticipated remedial actions. If PHMSA issues an objection to GSPC before the effective date of the requested ***special permit segment*** extension (90 days from receipt of the above notice), the requested special permit extension does not become effective.

b) Complete all inspections and remediation of the proposed ***special permit segment*** extension to the extent required of the original Index 817 Pipeline ***special permit segment***.

c) Apply all the special permit conditions and limitations included herein to all future extensions.

15) **Certification**: A GSPC senior executive officer, vice president or higher, must certify in writing the following:

a) The ***special permit segment*** and ***special permit inspection area*** meet the conditions described in this special permit;

b) The written manual of O&M procedures required by 49 CFR 192.605 for the GSPC Index 817 Pipeline has been updated to include all additional operating and maintenance requirements of this special permit; and

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

Within 12 months after the grant of this special permit, GSPC must send the certifications required in **Condition 15(a) through (c)** with special permit condition status and procedure completion date, compliance documentation summary, and the required senior executive signature and date of the signature to the PHMSA Associate Administrator for Pipeline Safety, with copies to Director, PHMSA Central Region; and to the Federal Register Docket (PHMSA-2019-0207) at www.regulations.gov.

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 GSPC 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 the ***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 GSPC to submit the certifications required by **Condition 15 (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 GSPC sells, merges, transfers, or otherwise disposes of all or part of the assets in the ***special permit segment*** or ***special permit inspection area***, GSPC must provide PHMSA with written notice of the change within 30 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the special permit if the transfer constitutes a material change in conditions or circumstances underlying the permit.

6) PHMSA grants this special permit to limit it to a term of no more than ten (10) years from the date of issuance. If GSPC elects to seek renewal of this special permit, GSPC must submit its renewal request at least 180 days prior to expiration of the ten (10) year period to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Central Region, and Director, PHMSA Engineering and Research Division. All requests for a renewal must include a summary report in accordance with the requirements in **Condition 10 (Annual Report to PHMSA)** and must demonstrate that renewal of the special permit would not be inconsistent with pipeline safety. PHMSA may seek additional information from GSPC prior to granting any request for special permit renewal.

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

Issued in Washington, DC on July 20, 2020.

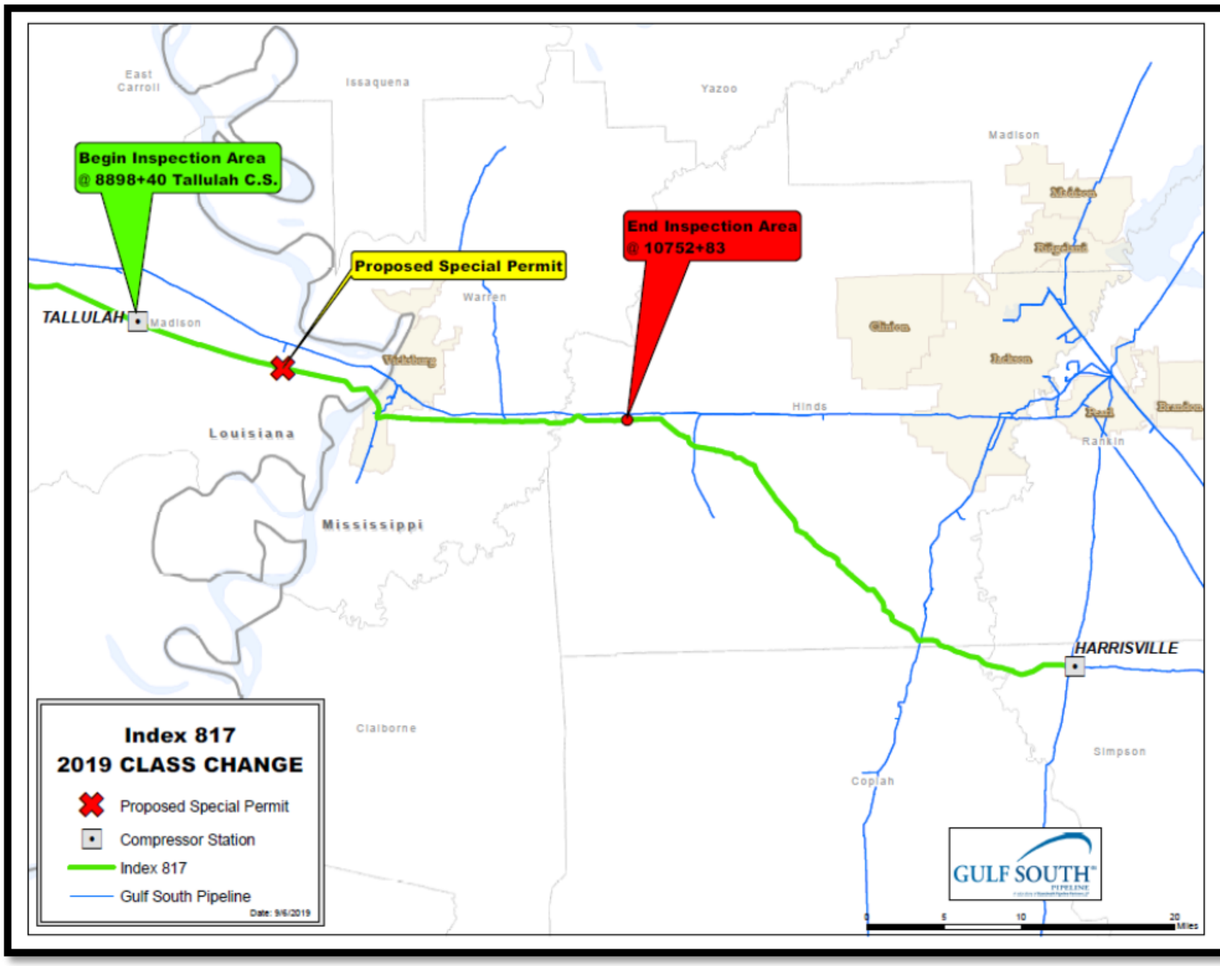
ALAN KRAMER MAYBERRY

Digitally signed by ALAN KRAMER MAYBERRY
Date: 2020.07.20 15:59:52 -04'00'

Alan K. Mayberry,

Associate Administrator for Pipeline Safety

Attachment A – 42-inch Diameter Index 817 Route Map
Special Permit Segment and Inspection Area



Attachment B – 42-inch Diameter Index 817 Route Map
Special Permit Segment