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

Special Permit Information:

Docket Number:	PHMSA-2018-0099
Requested By:	Gulf South Pipeline Company, LP
Operator ID#:	31728
Original Date Requested:	September 28, 2018
Original Issuance Date:	April 2, 2019
Effective Dates:	April 2, 2019 to April 1, 2029
Code Section(s):	49 CFR 192.611

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] waiving compliance from 49 Code of Federal Regulations (CFR) 192.611 for four (4) pipeline segments totaling approximately 4.65 miles of 30-inch diameter gas transmission pipeline in Ascension and Livingston Parishes, Louisiana, as described below. The Federal Pipeline Safety Regulations in 49 CFR 192.611 require natural gas pipeline operators to confirm or revise the maximum allowable operating pressure (MAOP) of a pipeline segment after a change in class location. This special permit is for a Class 1 to Class 3 location change.

Purpose and Need:

On the condition that GSPC complies with the terms and conditions set forth below, this special permit waives compliance from 49 CFR 192.611 for approximately 4.65 miles (24,527 feet) of natural gas transmission pipeline on the 30-inch diameter Index 130 Pipeline (Index 130 Pipeline).

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

This special permit is granted for the segments of the Index 130 Pipeline where the class location of the pipeline has changed from a Class 1 location to a Class 3 location in Ascension and Livingston Parishes, Louisiana.

This special permit allows GSPC to uprate the operating pressure on four (4) ***special permit segments*** and the ***special permit inspection area***, defined below, from its current MAOP of 780 pounds per square inch gauge (psig) to 936 psig. Due to changing operating conditions, GSPC seeks this special permit for Class 1 to Class 3 location changes and to regain the previously de-rated MAOP on these ***special permit segments*** of the Index 130 Pipeline, through 49 CFR 192.555, subpart K - Uprating, for the MAOP uprate from 780 psig to 936 psig.

I. Special Permit Segments and Inspection Area:

Ascension, Livingston, and St. Helena Parishes, Louisiana

Special Permit Segments:

This special permit applies to the ***special permit segment(s)*** defined as follows using the GSPC Index 130 Pipeline survey station references:

- ***Special permit segment 1*** – Index 130 — 1,522 feet, Survey Station 4408+56 to Survey Station 4423+78;
- ***Special permit segment 2*** – Index 130 – 5,294 feet, Survey Station 4519+98 to Survey Station 4572+92;
- ***Special permit segment 3*** – Index 130 – 2,486 feet, Survey Station 4729+62 to Survey Station 4754+48;[3] and
- ***Special permit segment 4*** – Index 130 – 15,225 feet, Survey Station 4894+00 to Survey Station 5046+25.

Special permit inspection area[4] is defined to mean the area that extends 220 yards on each side of the centerline along the entire 32.8 miles of the Index 130 Pipeline from:

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[3] Any survey station distance differences are due to a survey equation as follows: Survey Station 4729+93 Back (BK) = 4729+62 Ahead (AH), a total of 31 feet.

[4] There are seven (7) survey station equations in the ***special permit inspection area***, which explain the discrepancy between the reported length and the difference between the beginning and ending stations of the Inspection Area: BK=4520+07 AH=4519+98, BK=4589+34 AH=4589+31, BK=4729+93 AH=4729+62, BK=4799+52 AH=0+00, BK=12+75 AH=4812+62, BK=5373+44 AH=5373+32, and BK=5747+73 AH=5747+65.

- Survey station 4407+90 (valve site at Marchand Junction in Ascension Parish, Louisiana) to survey station 6139+99 at Montpelier Compressor Station located in St. Helena Parish, Louisiana. The Index 130 Pipeline ***special permit inspection area*** extends approximately 32.8 miles (173,237 feet) including field survey equations.
- High consequence areas (HCAs) located in the ***special permit inspection area*** are at the following survey stations:
  - Survey Station 4407+59 to 4436+05, (2,846 feet)
  - Survey Station 4451+96 to 4511+93, (5,996 feet)
  - Survey Station 4530+22 to 4559+81, (2,959 feet)
  - Survey Station 4572+17 to 4668+85, (9,671 feet)
  - Survey Station 4682+68 to 4708+63 (2,596 feet)
  - Survey Station 4785+26 to 0000+10, (1,436 feet)
  - Survey Station 4905+51 to 4926+92, (2,141 feet)
  - Survey Station 4962+63 to 4979+71, (1,708 feet)
  - Survey Station 4962+49 to 4979+57, (1,708 feet)

The ***special permit inspection area,*** which includes the ***special permit segments*** and HCAs, is located in Ascension, Livingston, and St. Helena Parishes, Louisiana. Attachments A and B are maps showing the Index 130 Pipeline ***special permit segments*** and ***special permit inspection area***, class locations and location of remote controlled valves.

PHMSA grants this special permit based on the findings set forth in the "Special Permit Analysis and Findings " document, which can be read in its entirety in Docket No. PHMSA-2018-0099 in the Federal Docket Management System (FDMS) located on the internet at www.regulations.gov.

II. Conditions:

PHMSA grants this special permit subject to the following conditions and the implementation of these conditions into the applicable Index 130 Pipeline procedures to meet 49 CFR 192.605: [5]

1) **Maximum Allowable Operating Pressure**: GSPC may uprate the 30-inch diameter Index 130 Pipeline ***special permit segments*** and ***special permit inspection area*** from an existing MAOP of 780 psig to 936 psig after completing the following:

[5] All special permit conditions that are applicable to the ***special permit inspection area*** are also applicable to the ***special permit segments*** and HCAs. Special permit conditions that are applicable to the ***special permit segments*** are not applicable to the ***special permit inspection area***, but are applicable to HCAs if they are located in the ***special permit segments.***

a) ***Special permit segments***, existing Class 2 and 3 locations, and HCAs must be remediated in accordance with Condition 20 and hydrostatically tested to 1301 psig (which is a minimum of 1.39 times the MAOP of 936 psig) for 8 continuous hours in accordance with 49 CFR Part 192, subpart J, prior to uprating from 780 psig to 936 psig.[6, 7, 8]

b) The ***special permit inspection area*** must be remediated to meet Condition 19.

c) All special permit conditions must be implemented, as required below, prior to uprating the MAOP, unless the condition allows completion after the uprating of MAOP above 780 psig.

d) Prior to uprating the Index 130 Pipeline pressure above 780 psig, GSPC must prepare an uprating plan that includes the requirements in 49 CFR 192.553 and 192.555.[9] The increase must be at a minimum of two (2) increments of 78 psig or less. The pipeline pressure in the ***special permit inspection area*** must be held constant and checked for gas leakage after each incremental pressure increase.

2) **Integrity Management Program**: GSPC must incorporate the ***special permit segments*** and ***special permit inspection area*** into its written integrity management program (IMP) as "covered segments" in a "HCA" in accordance with 49 CFR 192.903,[10] except for the reporting requirements contained in 49 CFR 192.945.

3) **Close Interval Surveys**: GSPC must perform a close interval survey (CIS)[11] along the entire length of the ***special permit inspection area***[12] no later than one (1) year after the granting of this

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6 GSPC reported that segments of the Index 130 Pipeline contained hard spots, but no actionable hard spot indications were found by the hard spot in-line inspection (ILI) tool run in 2015 through the ***special permit inspection area***. Should the hydrostatic pressure tests to 1301 psig find leaks or ruptures due to hard spot cracking, an ILI tool that can identify hard spots must be run within one (1) year of the test and during the 14-calendar year reassessment interval as a minimum, see Condition 9.

7 All Dresser Type 110 couplings installed over girth welds, dents, pipe gouging, or metal loss anomalies in the ***special permit inspection area*** must be replaced with pipe prior to the hydrostatic test.

8 Index 130 Pipeline was installed in 1952 and operated at an MAOP of 936 psig through the early 1990s. The MAOP was lowered to 780 psig for a Class 1 to 3 location change in late the 1990s to meet 49 CFR 192.611.

9 This permit allows GSPC to uprate the pressure in the ***special permit segments*** and ***special permit inspection area*** to an MAOP of 936 psig. The uprate must be conducted in accordance with 49 CFR 192.553 and 192.555, except GSPC can uprate to an MAOP of 936 psig, which is in accordance with 49 CFR 192.611.

10 GSPC is not required to report the mileage included as part of this special permit in its annual report in accordance with the requirements of 49 CFR 191.17, unless it is in a high consequence area.

11 CIS must be conducted at a maximum 5-foot spacing and with interrupted on/off current.

12 Each condition in this special permit that requires GSPC to perform an action with respect to the ***special permit inspection area*** shall also require GSPC to perform that action on all ***special permit segments*** within such areas.

special permit. GSPC must remediate any areas of inadequate cathodic protection prior to implementation of any MAOP uprating from 780 psig. If environmental permitting or right-of-way (ROW) factors beyond GSPC's control should prevent the completion of the CIS and remediation within one (1) year from the issuance of this special permit, a CIS and subsequent remediation including coating repair must be completed as soon as practicable, and a letter justifying the delay and providing the anticipated date of completion must be submitted to the PHMSA Southern Region Director[13] no later than two (2) months prior to the end of the one (1) year interval. GSPC must receive a "no objection" letter from the PHMSA Southern Region Director for a delay and cannot uprate the MAOP until this CIS and remediation is complete.

4) **Close Interval Surveys – Reassessment Interval**: GSPC must perform periodic CIS of the ***special permit inspection area*** at the applicable reassessment interval(s) for a "covered segment" determined in concert and integrated with in-line inspection (ILI) in accordance with 49 CFR Part 192, subpart O, reassessment intervals as contained in 49 CFR 192.937 (a) and (b) and 192.939, not to exceed the seven (7) calendar year reassessment interval in accordance with 49 CFR 192.939(a). CIS data must be integrated with ILI data. Condition 23(b) – Data Integration – gives a complete description of data integration information that an operator must maintain for the ***special permit segments*** and ***special permit inspection area,*** including CIS and ILI data. CIS assessments within the reassessment interval are not required to be performed in the same year as ILI reassessments.

5) **Coating Surveys and Remediation:** GSPC must perform a direct current voltage gradient (DCVG) survey or an alternating current voltage gradient (ACVG) survey of the ***special permit segments*** no later than one (1) year after the grant of this special permit and prior to implementation of any MAOP uprating from 780 psig to verify the pipeline coating conditions and to remediate any integrity issues in the ***special permit segments***. A DCVG or ACVG survey and remediation need not be performed on the ***special permit segments*** if GSPC has performed a DCVG or ACVG and remediation on the Index 130 Pipeline along the entire length of all ***special permit segments*** less than two (2) years prior to the grant of this special permit. GSPC must remediate any damaged coating indications found during these assessments that are classified as

[13] The GSPC Index 130 Pipeline located in Ascension, Livingston, and St. Helena Parishes, Louisiana is currently in PHMSA's Southern Region inspection area. PHMSA's Southern Region Director is the appropriate contact for the special permit conditions, unless GSPC is advised by PHMSA's Southern Region Director that another PHMSA Region Director has responsibilities over this special permit.

moderate (i.e. 35% IR and above for DCVG or 50 dBμV and above for ACVG) or severe based on NACE International Standard Practice 0502-2010, "Pipeline External Corrosion Direct Assessment Methodology, " (NACE SP 0502-2010).[14] A minimum of two (2) coating survey assessment classifications must be excavated, classified and/or remediated per each survey crew per each time the survey is performed. If factors beyond GSPC's control prevent the completion of the DCVG or ACVG survey and remediation within one (1) year, a DCVG or ACVG survey and remediation must be performed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the PHMSA Southern Region Director no later than one (1) month prior to the end of one (1) year after the grant of this special permit. GSPC cannot uprate the MAOP of the Index 130 Pipeline in the ***special permit segments*** until the DCVG or ACVG survey and remediation are complete.

6) **Stress Corrosion Cracking Direct Assessment**: Should GSPC find stress corrosion cracking (SCC) on the Index 130 Pipeline at any time, GSPC must evaluate the Index 130 Pipeline along the entire length of the ***special permit inspection area*** for SCC as follows:[15]

   a) GSPC must perform a stress corrosion cracking direct assessment (SCCDA) or other appropriate assessment method for SCC (such as a pressure test or ILI with a crack detection tool) along the entire length of the ***special permit inspection area*** according to the requirements of 49 CFR 192.929 and NACE SP 0204-2008 no later than one (1) year after of the grant of this special permit. The SCCDA or other approved method must address both high pH SCC and near neutral pH SCC. An SCCDA need not be performed if GSPC has performed an SCCDA of the Index 130 Pipeline along the entire length of the ***special permit inspection area*** less than four (4) years prior to the grant of this special permit.

      i) If factors beyond GSPC's control prevent the completion of the SCCDA survey and remediation within one (1) year, an SCCDA and remediation must be performed as soon as practicable and a letter justifying the delay and providing the anticipated date of

[14] When PHMSA adopts a revised edition of a referenced standard such as NACE International (NACE) or ASME standard into 49 CFR Part 192, the referenced requirements of those revised standards are automatically incorporated into these special permit conditions.

[15] **GSPC Informational Comment**: Index 130 Pipeline has not had any indications of SCC in the ***special permit inspection area***. Due to the distance from compression (more than 20 miles) GSPC does not consider the ***special permit segments*** to have a high risk of high-pH SCC.

completion must be submitted to the PHMSA Southern Region Director no later than one (1) month prior to the end of one (1) year after the grant of this special permit.

ii) GSPC may eliminate this Condition 6(a), provided GSPC provides an engineering assessment showing that the pipeline does not meet any of the criteria for both near neutral and high pH SCC per the applicable edition of the American Society of Mechanical Engineers Standard B31 .8S, "Managing System Integrity of Gas Pipelines (ASME B31.8S)[16] Appendix A3, or NACE SP 0204-2008, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology', Section 1.2.1.1 and 1.2.2.

b) If the threat of SCC exists as determined in Condition 6(a) and the Index 130 Pipeline is uncovered for any reason to comply with the special permit or integrity management activities in the ***special permit inspection area*** and the coating has been identified as poor during the pipeline examination, then GSPC must directly examine the pipe for SCC using an accepted industry detection practice such as dry or wet magnetic particle tests. Visual inspection is not sufficient to determine "poor coating." A holiday detection test at the correct voltage must be performed. Examples of "poor coating" include, but are not limited to coating that has become damaged and is losing adhesion to the pipe which is shown by falling off the pipe, is porous, has pin holes, and/or shields the cathodic protection. GSPC must keep coating records[17] at all excavation locations in the ***special permit inspection area*** to demonstrate the coating condition.

c) If SCC[18] activity is discovered by any means within the ***special permit inspection area*** in similar pipe and pipe coating vintage (in accordance with 49 CFR 192.917(e)), or has had an in-service or hydrostatic test SCC failure or leak, the ***special permit segments*** must be further assessed and mitigated, using one of the following methods, within one (1) year of finding SCC:

i) Hydrostatic test program:

A. The SCC hydrostatic test program must be performed at a reassessment interval no greater than seven (7) calendar years (but may be at a lesser interval in accordance with

[16] The applicable edition incorporated by reference is listed in 49 CFR 192.7.

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

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

the results of an engineering critical assessment) in the ***special permit segments***, and

B. If pipe in a ***special permit segment*** leaks or ruptures during a hydrostatic test due to SCC, all pipe in the ***special permit segments*** must be replaced with new pipe within 18 months. A successful SCC hydrostatic test must be completed prior to returning the ***special permit segments*** to operational service; or

ii) Crack detection tool assessment:

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

B. All SCC activity[19] found in the ***special permit segments*** must be replaced with new pipe within one (1) year of finding SCC; or

iii) Operating pressure must be lowered to 60% of the specified minimum yield strength (SMYS); or

iv) All affected pipe must be replaced to meet 49 CFR 192.611 in the ***special permit segments***.

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

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

ii) Include a technical justification that shows that the threat for SCC in the ***special permit segments*** is being addressed.

7) **<u>O&M Manual – In-line Inspections, Close Interval Survey Inspections, and Reassessment Intervals</u>**: GSPC must amend applicable sections of its operations and maintenance (O&M) manual(s) to incorporate the inspection and reassessment intervals by ILI including both high resolution metal loss and deformation/geometry tools, along the entire length of the ***special permit inspection area*** at a frequency consistent with 49 CFR Part 192, subpart O, but not to exceed a seven (7) calendar year reassessment interval as defined in 49 CFR 192.939(a).

8) **<u>Close Interval Survey Intervals in O&M Manuals</u>**: GSPC must amend applicable sections of its O&M manual(s) to incorporate the inspection and reassessment intervals by CIS of the ***special***

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

permit inspection area at a frequency consistent with 49 CFR Part 192, subpart O, reassessments.

9) **Inline Inspection**: The assessments of the ***special permit inspection area*** using ILI must conform to the required maximum reassessment intervals specified in 49 CFR 192.939.

   a) GSPC must conduct instrumented ILIs to meet 49 CFR 192.917 for threats and 49 CFR 192.939 for reassessment intervals in 2019 for the ***special permit inspection area***. ILI tools must include high resolution magnetic flux leakage (HR-MFL) tools and high resolution (HR) deformation tools with deformation extended sensor arms not limited by pig cups.

   b) If the hydrostatic tests conducted to 1301 psig in 2018 and 2019 show integrity threats in the ***special permit inspection area,*** such as cracking (pipe body, seam or girth weld), an Electro-Magnetic Acoustical Transducer (EMAT) ILI or appropriate ILI tool assessment for the type of cracking found must be conducted and the findings remediated, or a pipe cracking remediation plan must be submitted to the PHMSA Southern Region Director with a copy to the Director, PHMSA Engineering and Research Division no later than 60 days after the finding and prior to raising the MAOP above 780 psig. The plan must include:

      i) A pipe cracking remediation/repair plan with crack characterization and timing of any pipe remediation, future ILI or hydrostatic testing assessments, or

      ii) A technical justification that shows that the threat for pipe cracking in the ***special permit inspection area*** is being addressed.

      iii) For the pipe cracking remediation plan, whether (i) or (ii) above, GSPC must receive a "no objection" letter from the PHMSA Southern Region Director prior to implementation.

   c) If cracking from hard spots is discovered, an instrumented ILI to find hard spots must be run through the ***special permit inspection area*** prior to uprating the MAOP above 780 psig.[20] All hard spots with cracking or a hardness of 300 Brinell or greater and 2-inches in length or width must be cut-out of the special permit inspection area prior to increasing the MAOP above 780 psig. Any hard spots discovered after grant of the special permit with a hardness of 300 Brinell or greater and 2-inches in length or width must be remediated within 30 days

[20] **GSPC Informational Comment**: Previous GSPC ILI investigations have already investigated hard spots in the ***special permit inspection area***, finding no actionable anomalies.

of the finding and if the hard spot has any cracking if must be cut-out within 180 days of the finding.

10) **<u>Integrity Reassessment Intervals</u>**: GSPC must schedule ILI reassessment dates for the ***special permit inspection area*** according to 49 CFR 192.939 intervals by adding the required time interval to the most recent assessment date.

11) **<u>Damage Prevention Program</u>**: GSPC's damage prevention program must incorporate the applicable Common Ground Alliance (CGA) Best Practices within the ***special permit inspection area***.

12) **<u>Field Activity Notices to PHMSA</u>**: GSPC must give a minimum of 14-day notice to the PHMSA Southern Region Director to enable PHMSA to observe any excavations relating to Conditions 5, 6 (b), 18, 19, 20, 21 and 22 of field activities in the ***special permit inspection area***. Immediate response conditions do not require 14-day notice, but the PHMSA Southern Region Director should be notified by GSPC no later than two (2) business days after the immediate condition is discovered. The PHMSA Southern Region Director may elect to not require a notification for some activities.

13) **<u>HCA Assessments</u>**: This special permit does not impact or defer any of GSPC's assessments for HCAs under 49 CFR Part 192, subpart O.

14) **<u>Annual Report to PHMSA</u>**: Within three (3) months following the grant of this special permit and annually[21] thereafter, GSPC must report the following to the PHMSA Southern Region Director with copies to the Deputy Associate Administrator, PHMSA Field Operations; Deputy Associate Administrator, PHMSA Policy and Programs; Director, PHMSA Engineering and Research Division; and Director, PHMSA Standards and Rulemaking Division:[22]

    a) The number of new residences, other structures intended for human occupancy and public gathering areas built within the ***special permit inspection area*** during the previous year.

    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,

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[21] Annual reports must be received by PHMSA by the last day of the month in which the special permit is dated. For example, the annual report tor a special permit dated January 21, 2019, must be received by PHMSA no later than January 31, each year beginning in 2020.

[22] Annual reports must be placed by GSPC on the special permit docket - PHMSA-2018-0099 – in www.regulations.gov.

cracking found in the pipe body, weld seam or girth welds, and dents with metal loss, cracking or stress riser) during the previous year in the ***special permit segments*** including their survey station, failure pressure ratio, anomaly depth and length, class location and whether they are in an HCA.

c) 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 the ***special permit inspection area***.

d) Any on-going damage prevention initiatives affecting the ***special permit inspection area*** and a discussion of the success of the initiatives including DCVG or ACVG, CIS and SCCDA [or other approved methods of determining SCC] findings and remediation actions.

e) Annual data integration information, as required in Condition 23(b) - Data Integration, must be submitted beginning with the 2nd annual report that includes an annual overview of any new threats or, if requested by PHMSA, a full information package.

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

15) **<u>Cathodic Protection Test Stations</u>**: At least one (1) cathodic protection (CP) pipe-to-soil test station must be located within each HCA with a maximum spacing between test stations of one-half mile within an HCA. In cases where obstructions or restricted areas prevent test station placement, the test station must be placed in the closest practical location. This requirement applies to any HCA within the ***special permit inspection area***.

16) **<u>Annual CP Test Station Readings</u>**: If any annual CP test station readings within the ***special permit inspection area*** fall below 49 CFR Part 192, subpart I requirements, remediation must occur within six (6) months and include a CIS on each side of the affected test station to the next test station and any identified corrosion system modifications to ensure corrosion control. If factors beyond GSPC's control prevent the completion of remediation within six (6) months, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the PHMSA Southern Region Director no later one (1) month prior to the six (6) month remediation period ending. GSPC must receive a letter of "no objection" letter from PHMSA prior to implementing an extended remediation interval.

17) **<u>Interference Currents Control</u>**: GSPC must address induced alternating current (AC) from parallel electric transmission lines and other interference issues such as direct current (DC) in the ***special permit inspection area*** that may affect the pipeline. An induced AC or DC program and remediation plan to protect the pipeline from corrosion caused by stray currents must be in place within one (1) year of the date of this special permit.[23]

a) At least once every seven (7) calendar years but not exceeding 90 months, GSPC must complete an engineering analysis on the effectiveness of the AC and DC mitigation measures and must evaluate any AC interference between 20 and 50 Amps per meter squared. In evaluating such interference, GSPC must integrate AC interference data with the most recent ILI results to determine remediation measures. Any AC interference between 20 and 50 Amps per meter squared must be remediated within six (6) months of the finding. Remediation means the implementation of mitigation measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. If GSPC does not remediate AC interference between 20 and 50 Amps per meter squared, GSPC must provide an engineering justification for not remediating such interference one (1) month prior to the six (6) month period ending to the PHMSA Southern Region Director, who may accept or reject the justification and require remediation.

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

c) In areas within the ***special permit inspection area*** that have co-located high voltage alternating current (HVAC) power lines, GSPC must take interference readings (continuous 24-hour recordings) during the calendar quarter of the known or anticipated highest voltage reading and record the readings. If there are any significant increases to the amount of electricity/current flowing in any co-located HVAC power lines, such as from additional generation, a voltage

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[23] **<u>GSPC Informational Comment</u>:** Index 130 Pipeline has no high voltage power lines paralleling it in the ***special permit inspection area***, therefore this condition is not applicable at this time.

up-rating, additional lines, or new or enlarged substations, GSPC must perform an AC mitigation survey along the entire co-located pipeline ***special permit inspection area*** right of way within six (6) months of any such change.

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

18) **<u>Mainline Valve – Monitoring and Remote Control for Leaks or Ruptures</u>**: GSPC must automate for closure or close mainline valves during leaks or ruptures as shown in Attachment C of this document, and must develop and implement procedures for the isolation of the Index 130 Pipeline ***special permit inspection area*** as follows:

a) The ***special permit inspection area*** 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 in Condition 18;

b) If any crossover or lateral pipe 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 Index 130 Pipeline is not isolated, isolation valves must be used as noted in Attachment C;[24]

c) Remote control valves (RCVs) must be constantly monitored for valve status (open, closed, or partial closed/open), upstream pressure, and downstream pressure;

[24] Gas delivery pipelines must have a remote controlled shutoff valve (gate or ball valve) or check valve either at the connection to the Index 130 Pipeline or at the delivery meter station as shown on Attachment C. Any gas delivery or receipt station over 5-miles in length that is connected to the Index 130 Pipeline must have a remote controlled shutoff valve within 5-miles of the Index 130 Pipeline. For gas delivery or receipt pipelines manual shutoff valves can be used for isolation but must be closed within 30-minutes from pipeline leak or rupture confirmation. GSPC has the option to use check valves at gas delivery pipelines to isolate them from backflow into the Index 130 Pipeline during a leak or rupture event.

d) Closure of the appropriate valves following a pipeline leak or rupture meeting the criteria of Condition 18(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;[25]

   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) 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 the need for a higher pressure-change threshold in advance 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;

      2) An unexplained flow rate change, pressure change, instrumentation indication, or equipment function that in the operator's experience may be representative of a large-volume, uncontrolled release or failure; or

      3) An apparent large-volume, uncontrolled release or failure observed by either operator personnel, the public, or public authorities, and that is reported to the operator.

   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.

e) The GSPC Gas Control Center must monitor the pipeline 24 hours a day, 7 days a week and must confirm the existence of a leak or rupture as soon as practicable, in accordance with GSPC pipeline operating procedures;

f) 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;

[25] 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.

g) 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) All valves used to isolate a leak or rupture must be maintained in accordance with this special permit and 49 CFR 192.745;

i) 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 PHMSA Southern Region Director in writing of the reasons the schedule cannot be met and obtain a letter of "no objection"[26] from PHMSA prior to implementing the schedule change.

j) 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) 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;[27] and

l) 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.

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[26] For any special permit condition that requires GSPC to provide a notice for a "no objection" response from PHMSA, other notice, annual report, or documentation to the PHMSA Southern Region Director.

[27] 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.

19) **Anomaly Evaluation and Repair**:

a) **General**: GSPC must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs, and must document and justify the values used.

i) GSPC must demonstrate ILI tool tolerance accuracy for each ILI tool run by usage of calibration excavations[28] 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). GSPC 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 GSPC. GSPC 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.

ii) The unity plots must show actual anomaly depth versus predicted depth.

iii) ILI tool evaluations for metal loss must use "6t x 6t"[29] interaction criteria for determining anomaly failure pressures and response timing.

iv) Discovery date[30] must be within 150 days of any ILI tool run for each type ILI tool (e.g. HR-geometry, HR-deformation or HR-MFL tools).

b) **Dents**: GSPC must repair dents to the Index 130 Pipeline in the ***special permit inspection area*** in accordance with 49 CFR 192.933 repair criteria. The ***special permit inspection area*** must have a geometry tool inspection as part of the initial ILI. The high-resolution deformation /geometry tool results can be from past ILI inspections. The timing for these dent repairs should follow the GSPC O&M Manual but must be no longer than one (1) year after discovery or the timing intervals in 49 CFR 192.933(d), whichever is shorter.

c) **Repair Criteria**: Repair criteria for all anomalies located on the Index 130 Pipeline when they

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[28] 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 future ILI calibrations in the ***special permit inspection area***. 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***. A minimum of four (4) calibration excavations must be used for unity plots.

[29] "6t" means pipe wall thickness times six.

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

have been excavated and investigated in accordance with 49 CFR 192.485 and 192.933 are as follows:

i) ***Special permit segments – Class 1 to 3*** - repair any anomaly that meets either: (l) a failure pressure ratio (FPR) less than or equal to 1.39 for Class 1 or Class 1 location pipe in a Class 3 location operating up to 72% of the SMYS; or (2) an anomaly depth greater than 40% of pipe wall thickness.

ii) ***Special permit segments – Class 2 or Class 2 to 3*** - repair any anomaly that meets either: (l) an FPR less than or equal to 1.67 for Class 2 or Class 2 location pipe in a Class 3 location operating up to 60% of the SMYS; or (2) an anomaly depth greater than 40% of pipe wall thickness.

iii) ***Special permit segments – Class 3*** - repair any anomaly that meets either: (l) an FPR less than or equal to 2.0 for Class 3 location pipe in a Class 3 location operating up to 50% of the SMYS; or (2) an anomaly depth greater than 40% of pipe wall thickness.

iv) ***Special permit inspection area*** - the response time must be in accordance with 49 CFR Part 192, subpart O, the applicable edition of the American Society of Mechanical Engineers Standard B31.8S, *Managing System Integrity of Gas Pipelines* (ASME B31.8S)[31] and GSPC's Integrity Management Program, whichever has the shortest response interval.

v) ***Special permit inspection area*** - Anomaly evaluations and repairs in the ***special permit inspection area*** must be performed in accordance with 49 CFR 192.485 and 192.111 incorporating appropriate class location design factors; however, HCAs outside of the ***special permit segments*** may be repaired in accordance with 49 CFR 192.933, but must use the appropriate class location design factors for anomaly evaluations and repairs to evaluate the anomaly FPR to be at or above the Index 130 Pipeline MAOP.

[31] The applicable edition incorporated by reference is listed in 49 CFR 192.7.

vi) ***Special permit inspection area*** - All cracking exceeding 40% of the pipe wall thickness or that has a FPR below 1.39 must be remediated within 60 days of discovery.[32, 33]

vii) ***Special permit inspection area*** - At a minimum, wherever corrosion is discovered in an excavation, repair must be performed unless an engineering analysis shows that the anomaly will not affect the integrity of the pipeline until the next scheduled reassessment plus one (1) year (i.e. add 1-year corrosion growth rate).

d) **Response Time for ILI Results**: The following is 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 " (ASME B31G)[34], the modified B3 IG (0.85dL) or R-STRENG[35] for calculating the predicted FPR to determine anomaly responses.

i) **Immediate response**: ***Special permit segments*** - Any anomaly within a ***special permit segment*** operating up to 72% SMYS that meets either: (l) an FPR equal to or less than 1.1; or (2) an anomaly depth equal to or greater than 80% wall thickness loss.

ii) **One-year response**: ***Special permit segments* – Class 1 or Class 1 to 3** - Any anomaly within a ***special permit segment*** that meets either: (l) a FPR less than or equal to 1.39 for Class 1 or Class 1 location pipe in a Class 3 location operating up to 72% of the SMYS; or (2) an anomaly depth greater than 40% of pipe wall thickness.

iii) **One-year response**: ***Special permit segments* – Class 2 or Class 2 to 3** - repair any anomaly that meets either: (l) a FPR less than or equal to 1.67 for Class 2 or Class 2 location pipe in a Class 3 location operating up to 60% of the SMYS; or (2) an anomaly depth greater than 40% of pipe wall thickness.

iv) **One-year response**: ***Special permit segments* – Class 3** - repair any anomaly that meets either: (l) a FPR less than or equal to 2.0 for Class 3 location pipe in a Class 3 location

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[32] Should any cracking anomalies above 30% of the pipe wall thickness be found in the ***special permit segment***, GSPC must remediate the cracks or have a crack anomaly evaluation procedure submitted to the PHMSA Southern Region Director with a "no objection" reply prior to using the crack evaluation procedure for cracking anomalies left in the pipeline above 30% of the pipe wall thickness without remediation. If GSPC does not receive a "no objection" letter or request for additional review time from PHMSA within 90 days of the notification, GSPC may proceed.

[33] A fracture mechanics and pressure cycling evaluation is required where an un-remediated crack of 30% or more (of wall thickness) is detected by ILI or direct inspection tools. The pipe must have toughness tests (Charpy V-notch impact values) of the pipe body, seam, or girth weld so that fracture mechanics modeling can be used, if needed.

[34] The applicable edition incorporated by reference is listed in 49 CFR 192.7.

[35] The applicable edition incorporated by reference is listed in 49 CFR 192.7.

operating up to 50% of the SMYS; or (2) an anomaly depth greater than 40% of pipe wall thickness.

v) **Monitored response**: ***Special permit segments*** **– Class 1 or Class 1 to 3** - Any anomaly within a ***special permit segment*** with Class 1 or Class 1 location pipe in a Class 3 location operating up to 72% SMYS that meets both: (1) an FPR greater than 1.39; and (2) an anomaly depth less than 40% wall thickness loss. The schedule for the response must take tool tolerance and corrosion growth rates into account.

vi) **Monitored response**: ***Special permit segments*** **– Class 2 or Class 2 to 3** - Any anomaly within a ***special permit segment*** with Class 2 or Class 2 location pipe in a Class 3 location operating up to 60% SMYS that meets both: (1) an FPR greater than 1.67; and (2) an anomaly depth less than 40% wall thickness loss. The schedule for the response must take tool tolerance and corrosion growth rates into account.

vii) **Monitored response**: ***Special permit segments*** **– Class 3** - Any anomaly within a ***special permit segment*** with original Class 1 location pipe in a Class 3 location operating up to 60% SMYS that meets both: (1) an FPR greater than 2.00; and (2) an anomaly depth less than 40% wall thickness loss. The schedule for the response must take tool tolerance and corrosion growth rates into account.

viii) **Special permit inspection area**: The response time for remediating anomalies in the ***special permit inspection area*** must be in accordance with 49 CFR Part 192, subpart O, or GSPC's Integrity Management Program, whichever is shorter. Anomaly evaluations and repairs must be performed in accordance with 49 CFR 192.485 and 192.111 incorporating appropriate class location design factors; however, HCA's outside of a ***special permit segment*** may be repaired in accordance with 49 CFR 192.933, but must use the appropriate class location design factors for anomaly evaluations and repairs.

20) **Girth Welds**: GSPC must provide records to PHMSA to demonstrate the girth welds on the Index 130 Pipeline were nondestructively tested at the time of construction in accordance with:[36]

a) The Federal Pipeline Safety Regulations at the time the pipelines were constructed or at least 1% of the girth welds in each ***special permit segment*** were non-destructively tested after

[36] **GSPC Informational Comment**: There have been no reported in-service leaks or breaks in the girth welds on the Index 130 Pipeline within the ***special permit inspection area*** for the life of the pipeline.

construction but prior to the application for this special permit provided at least two (2) girth welds in each ***special permit segment*** were excavated and inspected.

b) If GSPC cannot provide girth weld records to PHMSA to demonstrate either of the above in Condition 20(a), GSPC must complete either (i) or (ii) and (iii) of the following:

   i) Certify to PHMSA in writing that there have been no in-service leaks or breaks in the girth welds on the Index 130 Pipeline within the entire ***special permit inspection area*** for the entire life of the pipelines; or

   ii) Evaluate the terrain along the ***special permit segments*** for threats to girth weld integrity from soil or settlement stresses and remediate all such integrity threats; and

   iii) Excavate[37], visually inspect, and nondestructively test at least two (2) girth welds on the Index 130 Pipeline in the ***special permit segments*** in accordance with the American Petroleum Institute Standard 1104, "*Welding of Pipelines and Related Facilities*" (API 1104) as follows:

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

      B. Using the edition of API 1104 recognized in the Federal Pipeline Safety Regulations at the time the pipelines were constructed; or

      C. Using the edition of API 1104 currently incorporated by reference in 49 CFR 192.7.

c) If any girth weld in the ***special permit segments*** are found unacceptable in accordance with API 1104, GSPC must repair the girth weld immediately and then prepare an inspection and remediation plan for all remaining girth welds in the ***special permit segments*** based upon the repair findings and the threat to the ***special permit segments***. GSPC must submit the inspection and remediation plan for girth welds to the PHMSA Southern Region Director, and remediate girth welds in the ***special permit segments*** in accordance with the inspection and remediation plan within 60 days of finding girth welds that do not meet this Condition 20(c).

d) GSPC must complete the girth weld testing, and the girth weld inspection and remediation plan, within six (6) months after the grant of this special permit. If factors beyond GSPC's control prevent the completion of these tasks within six (6) months, the tasks must be completed as soon as practicable and a letter justifying the delay and providing the anticipated

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[37]GSPC must evaluate for SCC any time the Index 130 Pipeline is uncovered in accordance with Condition 6(b) of this special permit.

date of completion must be submitted to the PHMSA Southern Region Director no later than one (1) month prior to the end of the six (6) month interval after the grant of this special permit. GSPC must receive a letter of "no objection" letter from PHMSA prior to implementing an extended girth weld inspection and remediation interval.

21) **Pipe Casings**: GSPC 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, DCVG, ACVG or AC Attenuation.[38]

a) **Metallic Shorts**: GSPC must clear any metallic short on a casing in a ***special permit segment*** no later than six (6) months after the short is identified.

b) **Electrolytic Shorts**: GSPC must remove the electrolyte from the casing/pipe annular space on any casing in a ***special permit segment*** that has an electrolytic short no later than six (6) months after the short is identified.

c) **All Shorted Casings**: GSPC 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. GSPC may then choose to fill the casing/pipe annular space with a high dielectric casing filler or other material which provides a corrosion inhibiting environment, provided an assessment and all repairs were completed.

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

[38] GSPC has identified a casing to carrier pipe short on the Index 130 Pipeline at Highway 442, Survey Station 5746+78. This casing short must be corrected prior to uprating above the 780 psig MAOP.

22) **Pipe - Seam Evaluations**: GSPC must identify any pipeline in the ***special permit inspection area*** that may be susceptible to pipe seam issues because of the vintage of the pipe, the manufacture of the pipe, or other issues.[39] Once GSPC has identified such issues, they must complete the following:

a) GSPC must perform an engineering analysis to determine if there are any pipe seam threats on the Index 130 Pipeline located in the ***special permit inspection area***. This analysis must include the documentation that the processes in: (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, were utilized along with other relevant materials. If the engineering analysis shows that the pipe seam issues on the Index 130 Pipeline located in the ***special permit inspection area*** are not a threat to the integrity of the pipeline, GSPC does not have to complete Conditions 22(b) through 22(e). If there is a threat to the integrity of the pipeline, then one or more of Conditions 22(b) through 22(e) must be completed;

b) If no 49 CFR Part 192, subpart J, hydrostatic test has been performed since 1971, GSPC must hydrostatically test the ***special permit segments*** to a minimum pressure of 100 percent SMYS, in accordance with 49 CFR Part 192, subpart J, requirements for eight continuous hours. This hydrostatic test must be completed within one (1) year of issuance of this special permit. The hydrostatic test must confirm there are no systemic issues with the weld seam or pipe. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced during the test to verify that it is not indicative of a systemic issue. The written results of this root cause analysis must be in provided to the PHMSA Southern Region Director where the pipe is in service within 60 days of the failure; or

c) If the pipeline in the ***special permit inspection area*** has experienced a seam leak or failure in the last five (5) years and no hydrostatic test meeting the conditions in accordance with 49

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[39] **GSPC Informational Comment**: While there are several different pipe types considered susceptible to seam threats, the special permit inspection area was tested in 1974 to more than 1.25 x MAOP, which confirms that there are no systemic issues with this pipeline. There have been no seam leaks or failures in the special permit inspection area since the 1974 pressure test. There are no known unresolved manufacturing or construction issues.

CFR Part 192, subpart J, was performed after the seam leak or failure, then a hydrostatic test must be performed within one (1) year after the grant of this special permit on the ***special permit segment*** pipeline; and

d) If the pipeline in a ***special permit segment*** has any LF-ERW seam or EFW seam conditions as noted in (i), (ii), or (iii) below, the ***special permit segment*** must be replaced, as follows:
   i) Pipe constructed or manufactured prior to 1954 and has had any pipe seam leaks or ruptures in the ***special permit inspection area***, or
   ii) Pipe has unknown manufacturing processes, or
   iii) 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, have had past leak and rupture issues, or any other systemic issues).

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

23) ***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 markings on the pipeline in the ***special permit inspection area*** 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 three (3) months of issuance of this special permit and replaced as necessary by GSPC within 30 days after identification of line-of-sight marker removal.

b) **Data Integration**: GSPC must maintain data integration of all special permit condition findings and remediations in the ***special permit inspection area***. Data integration must include the following information: pipe diameter, wall thickness, grade, and seam type; pipe coating; MAOP; class location (including boundaries on aerial photography); HCAs (including boundaries on aerial photography); hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; ILI survey results including HR-MFL, HR-geometry/caliper or deformation tools; CIS – most recent; 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. Structures must be validated every three (3) years by obtaining new aerial imagery or by ground patrol.

i) Data integration documentation and drawings, with four (4) years of prior data, to meet Condition 23(b) must be completed and must be submitted, if requested by PHMSA, beginning with the 2nd annual report of this modified special permit.

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

iii) GSPC must maintain data integration as a composite of all applicable data elements in "IntegraLink" or a comparable data viewer.

c) **Pipe Properties Testing**: GSPC must test the pipe in the ***special permit segments***, Class 2 or 3 locations, and HCAs if the pipe does not meet Condition 24(b) as follows:

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for any ***special permit segments***, Class 2 or 3 locations, and HCAs without pipe material records within one (1) year of issuance of this special permit.

ii) A minimum of two (2) destructive or non-destructive test methods must be performed at an excavation site. GSPC must conduct one (1) non-destructive yield test assessment using TD Williamson test procedures and ball indention methodology[40], or equivalent, and confirm yield strength through diameter tape measurements. If non-destructive testing 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 3000 pounds per square inch (psi) or more, then the yield strength of that individual pipe shall be confirmed using destructive test methods or the ***special permit segment*** pipe must be removed within 18 months of issuance of this special permit. Acceptance limits for the diameter tape measurements shall be in accordance with PHMSA Advisory Bulletin ADB-09-01.

iii) Assessments must be made with missing mill test reports (MTRs) or 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 two (2) year interval), and construction dates (within a two (2) year interval).

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[40] Non-destructive assessment method and procedures must be submitted by GSPC to the PHMSA Southern Region Director and PHMSA Director of Engineering and Research Division for review and receive a "no objection."

iv) The material properties determined from either destructive or non-destructive tests required by this condition cannot be used to raise the original grade or specification of the material, which must be based upon the applicable standard referenced in 49 CFR 192.7.

v) For a future ***special permit segment*** with missing MTRs or mill inspection reports, the above methodology shall be applied or GSPC may elect to remove pipe joints for destructive testing.[41] Such testing shall be performed within one (1) year of identification of the new ***special permit segment***.

d) **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[42] in a ***special permit segment***, GSPC must prepare a written plan that corresponds to those applicable criteria identified in PHMSA Advisory Bulletin (ADB-2014-04), "Guidance for Pipeline Flow Reversals, Product Changes and Conversion of Service" issued on September 18, 2014 (79 FR 56121, Docket PHMSA-2014-0040). The written flow reversal plan must be submitted to the PHMSA Southern Region Director with a copy of the plan submitted to the Federal Docket for this special permit at www.regulations.gov. GSPC must receive a "no objection" letter from the PHMSA Southern Region Director prior to implementing the pipeline system flow reversal through a ***special permit segment.***

e) **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 a ***special permit segment*** or a ***special permit inspection area*** prior to the disturbance. If a land disturbance or water body crossing is required, GSPC must obtain and adhere to all applicable (federal, state, and local) environmental permit requirements when conducting the special permit conditions activity.

f) **Depth of Cover**: GSPC must mitigate shallow pipe with cover less than 24-inches in depth. Depth of cover recorded by a CIS survey lists one (1) Index 130 Pipeline location with depth of cover being less than 24 inches in the **special permit inspection area**, which is a creek

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[41] GSPC must prepare a procedure in accordance with Condition 15(c) for material documentation and submit to PHMSA's Southern Region Director and receive a "no objection".

[42] 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.

exposure at Survey Station 5394+ 87 – Colyell Creek.

24) **Documentation**: GSPC must maintain the following records for the ***special permit segments***:

a) Documentation showing that the ***special permit segments*** were subject to a 49 CFR 192.505, subpart J, hydrostatic test for eight (8) continuous hours and at a minimum pressure of 1.39 times MAOP.[43] If GSPC does not have hydrostatic test documentation, then the ***special permit segments*** must be hydrostatically tested to meet this requirement within one (1) year of receipt of this special permit.

b) Documentation of mechanical and chemical properties (mill test reports) showing that the pipe in a ***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) approved by the 49 CFR Part 192 code at the time of manufacturing or if pipe was manufactured and placed in-service prior to the inception of 49 CFR Part 192, then the documentation must show that the pipe meets the API 5L standard in usage at that time. Any ***special permit segment*** that does not have mill test reports or does not meet Condition 23(c) 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.

25) **Extension of Special Permit Segment**: PHMSA may extend a ***special permit segment*** to include contiguous segments of the Index 130 Pipeline up to the limits of the ***special permit inspection area*** pursuant to the following conditions:

a) Any extensions of a ***special permit segment*** must meet the following requirements prior to the class location change or within one (1) year after the class location change:

i) All anomalies must be remediated in accordance with Conditions 9 and 19, and

ii) The ***special permit segments*** must be hydrostatically tested to 1301 psig (which is a minimum of 1.39 times the MAOP of 936 psig) for 8 continuous hours in accordance with 49 CFR Part 192, subpart J.

b) Provide at least 90 days advanced notice to the PHMSA Southern Region Director and PHMSA Headquarters of a requested extension of the Index 130 Pipeline ***special permit***

[43] Condition 1 requires a 1.39 times MAOP pressure test for 8 continuous hours for all ***special permit segments***.

segment based on actual class location change and include a schedule of inspections and of any anticipated remedial actions. If PHMSA Headquarters or the PHMSA Southern Region Director makes a written objection 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 until a "no objection" response from PHMSA is received by GSPC.

c) Complete all other inspections and remediation of the proposed ***special permit segment extension*** to the extent required by this special permit for an Index 130 Pipeline ***special permit segment*** within one (1) year of the Class location change.

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

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

a) The GSPC pipeline ***special permit inspection area***, ***special permit segments***, and HCAs meet the conditions described in this special permit;

b) The written manual of O&M procedures for the GSPC Index 130 Pipeline has been updated to include all additional operating and maintenance requirements of this special permit; and

c) GSPC has implemented all original conditions and the conditions of this modification as required by this special permit.

d) GSPC must send the certifications required in Condition 26(a) through (c) with completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator with copies to the Deputy Associate Administrator, PHMSA Field Operations; PHMSA Southern Region Director; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division; and to the Federal Register Docket (PHMSA-2018-0099) at www.regulations.gov within one (1) year of the issuance date of this special permit.

III. 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 Index 130 Pipeline ***special permit segments*** 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 26 (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 known as the Index 130 Pipeline in the ***special permit segments*** 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 Deputy Associate Administrator, PHMSA Field Operations; Deputy Associate Administrator, PHMSA Policy and Programs; PHMSA Southern Region Director; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division. All requests for a renewal must include a summary report in accordance with the requirements in Condition 14 (Annual Report to PHMSA) above and must demonstrate that the special permit is still

consistent with pipeline safety. PHMSA may seek additional information from GSPC prior to granting any request for special permit renewal.

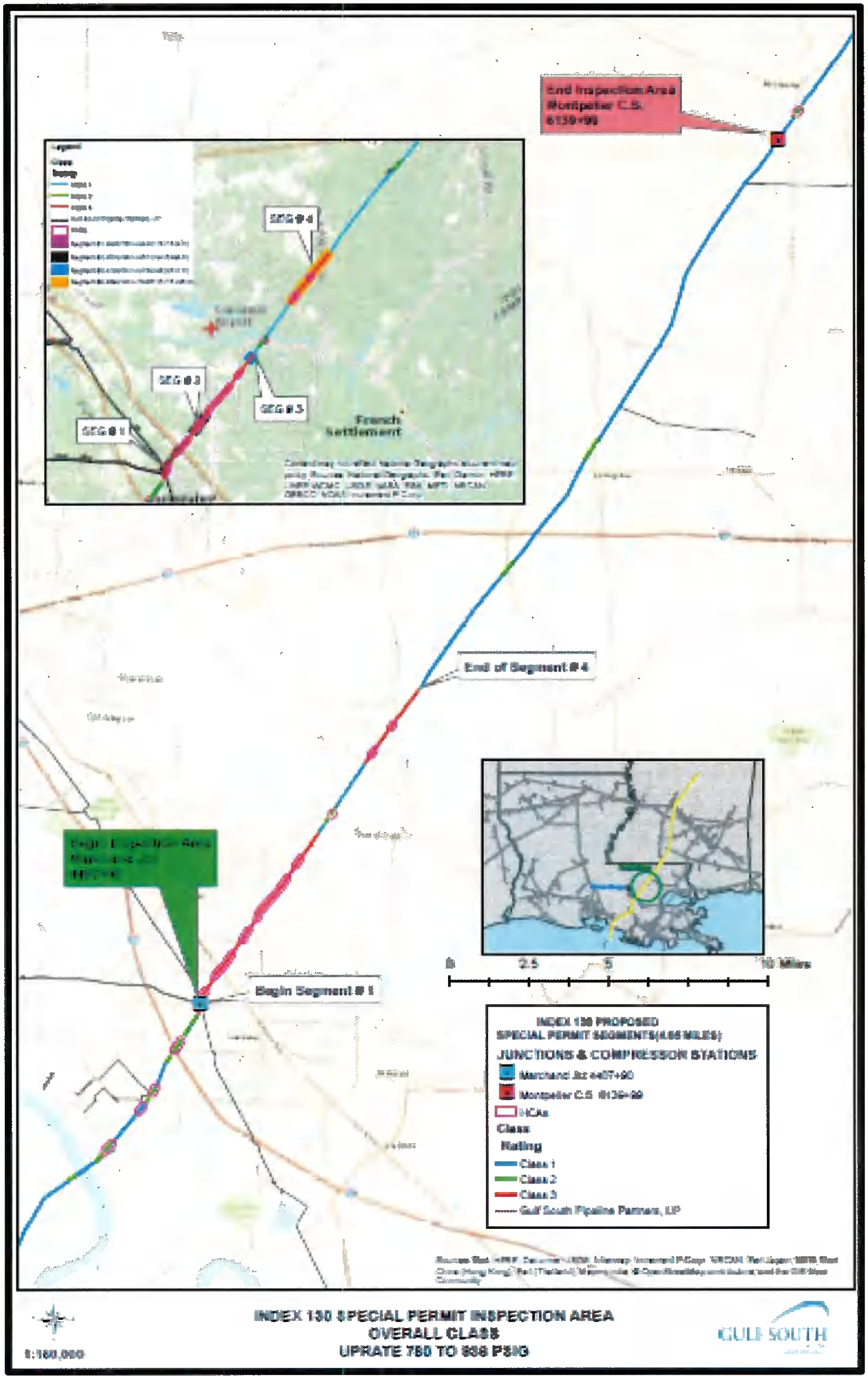
AUTHORITY: 49 U.S.C. 60118 (c)(1) and 49 CFR 1.97.

Issued in Washington, DC on MAR 2 2019.

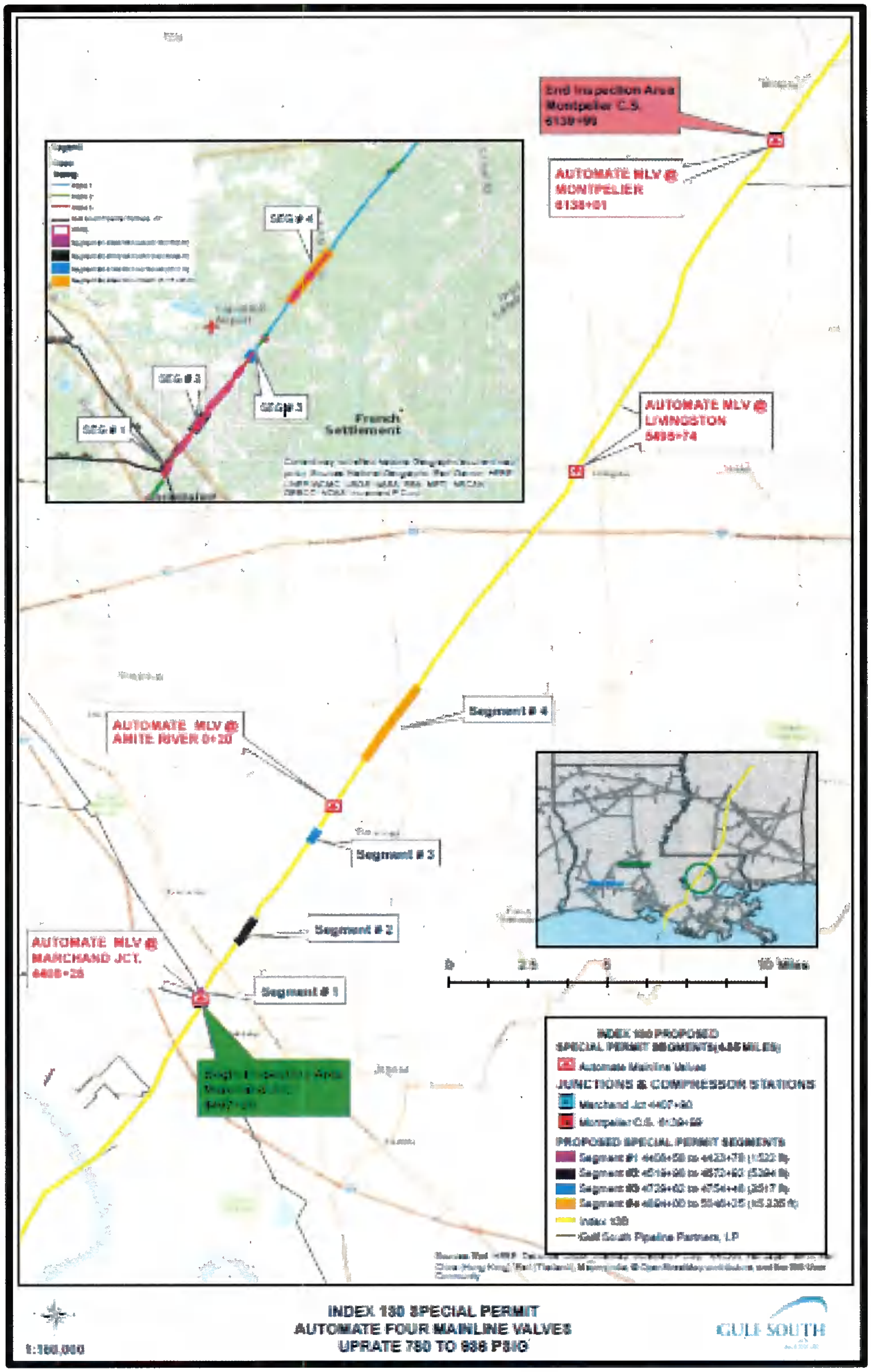
Alan K. Mayberry,

Associate Administrator for Pipeline Safety

Attachment A – 30-inch Index 130 Route Map
Special Permit Segments and Inspection Area with Class Locations and High Consequence Areas



Attachment B – 30-inch Index 130 Pipeline Route Map
Special Permit Segments and Inspection Areas with Automated Mainline Valves



Attachment C – 30-inch Index 130 Pipeline Schematic
Isolation Valves and Automated Valves for
Monitoring and Remote Control for Leaks or Ruptures

- Mainline valves that are normally closed (in red on the schematic drawing) must be closed or an alternative mainline valve must be closed for isolation of the pipeline segment. Valves color coded in red may be automated by GSPC in the future.
- Gas delivery pipelines must have a remote controlled shutoff valve either at the connection to the Index 130 Pipeline or at the delivery meter station.
- Any gas delivery or receipt pipeline over 5-miles in length must have a remote controlled shutoff valve within 5-miles of the Index 130 Pipeline.
- For gas delivery or receipt pipelines and the mainline, manual shutoff valves can be used for isolation but must be closed within 30-minutes from pipeline leak or rupture confirmation. GSPC has the option to use check valves at the below gas delivery pipelines to isolate them from backflow to the Index 130 Pipeline during a leak or rupture event.