U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Ave., S.E.
Washington, DC 20590

April 30, 2009

Mr. Walter Bennett
Senior Vice President of Operations
Boardwalk Pipeline Partners, LP
9 Greenway Plaza, Suite 2800
Houston, Texas 77046

Dear Mr. Bennett:

The enclosed Agreement modifies the special permits the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued to Boardwalk Pipeline Partners, LP and its subsidiaries, Gulf Crossing Pipeline Company LLC, Gulf South Pipeline Company, LP, and Texas Gas Transmission, LLC (collectively hereinafter, "Boardwalk") to operate certain pipelines at up to 80 percent SMYS in Class 1 locations provided that the conditions and safety requirements set forth in each of the special permits were met. The request letters, Federal Register notices and all other pertinent documents are available for review in Docket Nos. PHMSA- 2006-26533, PHMSA- 2007-28994, PHMSA- 2008-0068, PHMSA- 2008-0067, and PHMSA- 2006-26533 in the Federal Docket Management System (FDMS) located on the internet at www.Regulations.gov. The Boardwalk pipelines that received special permits are located in Louisiana, Texas, Mississippi, Arkansas, Oklahoma and Alabama and include: the 42-inch East Texas to Mississippi Pipeline; the 42-inch Mississippi Loop Pipeline; the 42-inch South East Pipeline; the 42-inch Gulf Crossing Pipeline; the 36-inch Fayetteville Lateral; and the 36-inch Greenville Lateral (collectively referred to as "Pipelines").

As you know, subsequent to the issuance of these special permits, Boardwalk reported to PHMSA that certain anomalies had been discovered in the Pipelines. Specifically, some of the X70 grade steel pipe used in constructing these pipelines appear to have exhibited low yield strength below the minimum level allowed by American Petroleum Institute Specification 5L, Specification for Line Pipe (API 5L). During the process of testing segments of the Mississippi Loop project, a hydrostatic test failure occurred in which the root cause was determined to be a switched plate inadvertently inserted into the plate rolling in the plate mill. As a result of the hydrostatic test failure, Boardwalk, in cooperation with PHMSA, ran deformation tools in all of the subject pipelines. Boardwalk has discovered anomalies in the Pipelines that appear not to be directly related to the initial root cause findings for the Mississippi Loop failure.

After being informed of these issues by Boardwalk, PHMSA initiated an inquiry and took immediate steps including field inspections and information collection. Through a number of meetings and conference calls, PHMSA expressed its concerns and Boardwalk took immediate steps to ensure the specified pipelines could be safely operated. Boardwalk is continuing its investigation, formulating a remediation fitness for purpose plan including the potential excavation and removal of certain anomalous pipe joints. We acknowledge Boardwalk's cooperation and commitment to performing corrective actions in response to PHMSA's concerns. The enclosed Agreement modifies the special permits by specifying interim pressure limits and other remedial actions in order to conservatively address the potentially low yield strength issues PHMSA has determined are necessary prior to implementing the alternative MAOP and to prudently operate the Pipelines. The Agreement must be signed and returned to PHMSA within 10 days of your receipt of this letter.

As the actions required under the Agreement are implemented, Boardwalk must review these operating parameters with PHMSA and submit a 30-day notice of intent to implement the alternative MAOP. Once PHMSA has determined that Boardwalk is in compliance with the requirements of the special permit for each pipeline, including the requirements specified in the enclosed Agreement, PHMSA will inform Boardwalk of approval to increase the operating pressure of a line or line segment to a pressure corresponding to the validated stress level.

Thank you for your cooperation.

Sincerely,

Jeffrey D. Wiese
Associate Administrator for Pipeline Safety

Enclosure

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

SPECIAL PERMIT MODIFICATION AGREEMENT

This Agreement modifies the special permits the Pipeline and Hazardous Materials Safety Administration (PHMSA) granted to Boardwalk Pipeline Partners, LP and its subsidiaries Gulf Crossing Pipeline Company LLC, Gulf South Pipeline Company, LP, and Texas Gas Transmission, LLC (collectively hereinafter, "Boardwalk") to operate certain pipelines located in Louisiana, Texas, Mississippi, Arkansas, Oklahoma and Alabama at up to 80 percent SMYS in Class 1 locations provided that numerous conditions and safety requirements were met. These pipelines are defined as: 42-inch East Texas to Mississippi Pipeline, 42-inch Mississippi Loop Pipeline, 42-inch South East Pipeline, 42-inch Gulf Crossing Pipeline, 36-inch Fayetteville Lateral and 36-inch Greeneville Lateral (collectively referred to as "Pipelines").

Subsequent to the issuance of these special permits, the X70 grade steel pipe used in constructing these pipelines appears to have exhibited low yield strength in field conditions and may be below the minimum level allowed by American Petroleum Institute Specification 5L, Specification for Line Pipe (API 5L). During the process of complying with the special permit for the Mississippi Loop project, a hydrostatic test failure occurred in which the root cause was determined to be a switched plate inadvertently inserted into the plate rolling in the plate mill. As a result of the hydrostatic test failure, Boardwalk, in cooperation with PHMSA, ran deformation tools in all of the subject pipelines and discovered additional potentially low yield strength anomalies in the Pipelines. While not all of these additional anomalies may be directly related to the initial root cause findings for the Mississippi Loop failure, Boardwalk is continuing its investigation, is formulating a remediation and fitness for purpose plan including the potential excavation and removal of certain of the anomalous pipe joints.

Based on the new information and changed circumstances surrounding the construction and operation of the Pipelines that PHMSA became aware of after the special permits were initially granted, PHMSA has determined that interim pressure limits and other remedial actions to address the potential low yield strength issues are necessary as part of the implementation of the special permit conditions to ensure the purpose of the conditions is met prior to implementing the alternative MAOP and to ensure the pipelines can be safely operated.

Having agreed that modification of the special permits to include additional conditions is necessary to address the potential low yield strength issue described above, Boardwalk agrees as follows:

I. General Provisions

1. Boardwalk acknowledges that, as operator of the specified pipelines, Boardwalk and its pipeline systems are subject to the jurisdiction of the pipeline safety laws, 49 U.S.C. 60101 *et*

seq., and regulations and administrative orders issued thereunder. Boardwalk and PHMSA hereby agree to the additional conditions set forth in this Agreement modifying the special permits and each party waives its rights to contest the validity of this Agreement. Boardwalk further waives any further procedural requirements it would otherwise have the opportunity to avail itself of under 49 C.F.R. § 190.341(h) in connection with the special permit modifications set forth in this Agreement, including any rights to administrative or judicial hearings or appeals.

2. Boardwalk agrees that the potential low yield strength issues described above exist and agrees to address them by completing the actions specified in Section II of this Agreement (Additional Special Permit Conditions) including any work plans and schedules which shall automatically be incorporated into this Agreement, certain aspects of which are subject to further discussion and mutual agreement of PHMSA and Boardwalk. This Agreement shall apply to and be binding upon Boardwalk, its officers, directors, and employees, and its successors, assigns, or other entities or persons otherwise bound by law. Boardwalk agrees to provide a copy of this Agreement and any incorporated work plans and schedules to all of its officers, employees, and agents whose duties might reasonably include compliance with this agreement.

3. For all transfers of ownership or operating responsibility of the specified pipelines, Boardwalk shall provide a copy of this Agreement to the prospective transferee at least 30 days prior to such transfer and simultaneously provide written notice of the prospective transfer to PHMSA.

4. Nothing in this Agreement affects or relieves Boardwalk of its responsibility to comply with all applicable requirements of the pipeline safety laws, 49 U.S.C. § 60101 *et seq.*, and regulations and orders issued thereunder. Nothing in this Agreement alters PHMSA's right of access, entry, inspection, and information gathering or PHMSA's authority to bring enforcement actions against Boardwalk pursuant to the pipeline safety laws, 49 U.S.C. § 60101 *et seq.*, regulations or orders issued thereunder, or any other provision of Federal or State law.

5. This Agreement does not waive or modify any other Federal, State, or local laws or regulations applicable to Boardwalk's pipeline systems. Boardwalk is responsible for achieving and maintaining compliance with all applicable Federal, State, and local laws, regulations and permits.

6. This Agreement does not create rights in, or grant any cause of action to, any third party not party to this Agreement. The U.S. Department of Transportation is not liable for any injuries or damages to persons or property arising from acts or omissions of Boardwalk or its officers, employees, or agents carrying out the work required by this Agreement. The U.S. Department of Transportation, its officers, employees, agents, and representatives are not liable for any cause of action arising from any acts or omissions of Boardwalk or its contractors in carrying out the work required by this Agreement.

II. Additional Special Permit Conditions

East Texas to Mississippi, Southeast Expansion, Mississippi Loop, Gulf Crossing, Fayetteville and Greenville Lateral Projects (Project(s))

1. Boardwalk is approved to operate its pipeline systems or *segment(s)* per the "Interim Operating Pressure" as defined in Table 1. Boardwalk must limit the operation of each pipeline project *segment* at or below the "Interim Operating Pressure" until each such pipeline *segment* has met the conditions contained within this Agreement. This pressure restriction will remain in effect until written approval to increase the pressure is obtained from the Director, Engineering and Emergency Support as set forth in Item 16.

Table 1 - Listing of Segments and Pressure Limitations

"*Project*[1]"	"*Segment*[2]"	PHMSA Region	Interim Operating Pressure (psig)	Interim Percent of % SMYS	72[3]% SMYS (psig)
East Texas to MS (PHMSA- 2006-26533)	Carthage Junction CS to Hall Summit	Southwest	1,066	64%	1,200
East Texas to MS (PHMSA- 2006-26533)	Hall Summit to Vixen CS	Southwest	964	58%	1,200
East Texas to MS (PHMSA- 2006-26533)	Vixen CS to Tallulah CS	Southwest	1,058	63%	1,200
East Texas to MS (PHMSA- 2006-26533)	Tallulah CS to Harrisville CS	Southwest/Southern	1,072	57%	1,340
Southeast Expansion (PHMSA- 2007-28994)	Entire line (Harrisville CS to Transco 85)	Southern	1065	57%	1340
Mississippi Loop (PHMSA- 2008-0068)	Entire line	Southwest/Southern	1340	72%	1340
Gulf Crossing (PHMSA- 2008-0068)	Sherman to Bennington[4]	Southwest	1340	72%	1340
Gulf Crossing (PHMSA- 2008-0068)	Bennington to Paris	Southwest	1340	72%	1340
Gulf Crossing (PHMSA- 2008-0068)	Paris to Mira	Southwest	1032	55%	1340
Gulf Crossing (PHMSA- 2008-0068)	Mira to Sterlington	Southwest	1032	55%	1340
Gulf Crossing (PHMSA- 2008-0068)	Sterlington to Tallulah	Southwest	902	48%	1340
Fayetteville (PHMSA- 2008-0067)	Grand View to Bald Knob	Southwest	1050	72%	1050
Fayetteville (PHMSA- 2008-0067)	Bald Knob to Lula	Southwest/Southern	810	52%	1125
Greenville (PHMSA-2008-0067)	Greenville to Kosciusko	Southern	1050	72%	1050
East Texas to MS (PHMSA- 2006-26533)	36" Carthage Header	Southwest	1204	72%	1204

1 A "*Project*" is defined as a complete pipeline project and all of its segments.

2 A "*Segment*" is defined as a section of pipe between defined points, compressor stations or the entire pipeline.

3 The 72% SMYS used in the pressure calculations in Table 1are based upon X70 (70,000 psi yield strength) pipe. If through testing under this agreement it is determined that X70 is not the appropriate strength value to use the table will be amended accordingly.

4 The Mississippi Loop Pipeline and Gulf Crossing Pipeline *segments* – Sherman to Bennington and Bennington to Paris - do not have any expanded pipe in them based upon either removal of pipe or Deformation tool results.

Actions that must be taken prior to increasing the pressure above the "Interim Operating Pressure" up to 72% SMYS

2. Prior to being allowed to operate any pipeline segment up to 72% specified minimum yield strength (SMYS) (as defined in Table 1) Boardwalk must evaluate that pipeline segment with a high resolution deformation tool specifically for identifying potentially expanded pipe. Once the pipeline deformation tool results from the Fayetteville and Greenville Lateral Pipelines[5] become available and are evaluated which is anticipated to occur during the summer of 2009, Boardwalk may elect to submit an alternative plan for remediating the Fayetteville and Greenville Lateral Pipelines. In such event, PHMSA will review and assess such plan, including reviewing the "Proposed Interim Operating Pressures" identified above.

3. Unless otherwise agreed to in writing by PHMSA or as set forth herein, Boardwalk must cut out all expanded pipe over API 5L tolerances on expansion, 0.25" or 0.60% of diameter for 42-inch pipe and 0.27-inch or 0.75% of diameter for 36-inch pipe. After cutting out the expanded pipe in any given *segment*, Boardwalk may request to operate that *segment* up to 72 percent SMYS. Boardwalk must submit requests to modify this agreement or to increase operating pressures in accordance with Item 16 below.

4. Boardwalk must submit a "Construction Plan" to the Director, Engineering and Emergency Support with copies to the Directors, PHMSA Southern and Southwestern Regions. The plan should contain any planned deformation tool runs and updated with the schedules for removal of any identified expanded pipe. For purposes of this Agreement, a Construction Plan shall mean the weekly reports that Boardwalk currently submits that outlines the work anticipated to occur during the following week. Boardwalk is to submit these Construction Plans each week.

5. The Construction Plan referenced in Item 4 must address the removal of the pipe joints containing the three horizontal directional drill anomalies identified on the 42-inch East Texas to Mississippi Pipeline[6] that appear to have expansion of approximately 1.0% to 2.25 %, five horizontal directional drill (HDD) anomalies on the 42-inch Southeast Expansion Pipeline[7] that appear to have an expansion of approximately 1.0%, and one horizontal directional drill anomaly on the Gulf Crossing Pipeline[8] that may have an expansion of approximately 1.0%.

---

[5] The 36" Fayetteville Lateral deformation tool run is scheduled for May 28 on the 66 mile section from Grandview to Bald Knob, AR. The 36" Greenville Lateral deformation tool run is scheduled for June 2 on the 97 mile section from Greenville to Kosciusko, MS. The 36" Carthage Header (part of the East Texas to Mississippi Pipeline Project) deformation tool run is scheduled for the week of May 4 for the entire 3 mile segment.

[6] The 42-inch East Texas to Mississippi Pipeline, Hall Summit to Vixen segment, has the following anomalies in HDDs: a) Saline Bayou West - 2 anomalies, b) Saline Bayou East - 1 anomaly, c) Dugdemona Creek – 1 anomaly.

[7] The 42-inch Southeast Expansion Pipeline has the following anomalies in HDDs: a) Campbell Creek – 1 anomaly, b) Leaf River – 1 anomaly, c) West Tallahalla Creek – 1 anomaly, d) Tallahalla Creek – 1 anomaly, and e) County Road 613 – 1 anomaly.

[8] The 42-inch Gulf Crossing Pipeline, Mira to Sterlington segment, has the following anomaly in a HDD: a) Dorcheat Bayou – 1 anomaly.

6. If any pipe that has been identified as "Expanded" (as defined in Item 3) is not removed, including any of the joints identified in Item 5, Boardwalk must submit to the Director, Engineering and Emergency Support with copies to the Directors, PHMSA Southern and Southwestern Regions, a technical justification why the expanded pipe can be operated safely at the higher operating pressures.

Actions that must be taken prior to increasing the pressure above the 72% SMYS up to MAOP Special Permit Conditions.

7. Boardwalk must continue with testing of pipe removed from the subject *segments* in order to establish the serviceability up to 80% SMYS operating parameters. For each 42-inch and 36-inch pipe steel supplier, rolling campaign, and slab source with an identified pipe expansion:
   a) A minimum of 4 pipe joints must be tested showing no expansion after hydrotest[9];
   b) A minimum of 4 pipe joints must be tested showing expansion between 0.6% of diameter[10] (0.75% of diameter for the 36" pipe) to 1.0% expansion after hydrotest;
   c) A minimum of 4 pipe joints must be tested showing expansion between >1.0 % to 2.0% expansion hydrotest;
   d) All pipe joints must be tested showing expansion greater than 2.0 % expansion after hydrotest;
   e) A minimum of 4 pipe joints must be tested that have not previously been hydrotested;
   f) If less than 4 pipe joints exists for a category listed above, only those meeting criteria that are removed will be tested.
   g) The total test pipe joints for non-expanded pipe in Items 7 (a) and (e), must total at least 10% of the removed expanded pipe joints for each such category, i.e. pipe supplier, rolling campaign and slab source.

   A metallurgical examination must be conducted including mechanical (yield, tensile, hardness, elongation, charpy impact and if necessary, drop weight tear test- DWTT), chemical composition, and cross-sectional and grain size. Test coupons (transverse) must be taken from 2 distant locations down the pipe joint for each metallurgical test item listed above and opposite the pipe seam. This testing must include full destructive testing as set forth in API 5L.

8. Boardwalk must continue to test pipe cut out from the pipeline *segments* as set forth above, to determine a "Technical Fitness for Purpose Repair and Operating Plan". This "Technical Fitness for Purpose Repair and Operating Plan" must be submitted to PHMSA within 180 days of operating each pipeline up to 72% SMYS. Until this plan is accepted, Boardwalk must limit operation of each pipeline *segment* at a pressure of at or below 72% SMYS. Boardwalk must submit requests to modify this Agreement or to increase operating pressures in accordance with Item 16 below.

9. Boardwalk must incorporate Items 10, 11 and 12 below into their O & M Plan or Construction Plan, as applicable, for each such *segment*.

---

[9] The hydrotest parameters are specified in the Special Permit.

[10] 0.6% equals 0.25" for 42" pipe.

10. Boardwalk must run close interval surveys (CIS) and remediate the pipe in each *segment* in accordance with 49 CFR Part 192 on a periodic basis not to exceed 45 months.

11. Boardwalk must run ILI Tools to evaluate for metal loss anomalies within 18 months of removing expanded pipe from each pipeline *Project or segment.*

12. Boardwalk must evaluate[11] all metal loss anomalies found on these pipeline *segments* in accordance with the following criteria until the Technical Fitness for Purpose Repair and Operating Plan is implemented. All anomaly evaluations and repairs for the 72% SMYS operations in the special permit *segment*, regardless of HCA status, must be performed, based upon the following:

    a) Anomaly Response Time: Immediately
        - Any anomaly within a *segment* operating up to 72% SMYS with either: (1) a failure pressure ratio (FPR) equal to or less than 1.25; (2) an anomaly depth equal to or greater than 50% wall thickness loss.
        - Any anomaly within a *segment* operating up to 60% SMYS with either: (1) an FPR equal to or less than 1.40; (2) an anomaly depth equal to or greater than 50% wall thickness loss.
        - Any anomaly within a *segment* operating up to 50% SMYS with either: (1) an FPR equal to or less than 1.5; (2) an anomaly depth equal to or greater than 50% wall thickness loss.

    b) Anomaly Response Time: Repair Within One Year
        - Any anomaly within a *segment* operating at up to 72% SMYS with either: (1) an FPR equal to or less than 1.39; (2) an anomaly depth equal to or greater than 40% wall thickness loss.
        - Any anomaly within a *segment* operating at up to 60% SMYS with either: (1) an FPR equal to or less than 1.67; (2) an anomaly depth equal to or greater than 40% wall thickness loss.
        - Any anomaly within a *segment* operating at up 50% SMYS with either: (1) an FPR equal to or less than 2.0; (2) an anomaly depth equal to or greater than 40% wall thickness loss.

    c) Anomaly Response Time: Monitored Conditions
        - Anomalies not requiring immediate or one year repairs above must be reassessed according to 49 CFR Part 192, Subpart O reassessment intervals.
        - Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per Boardwalk's Gas Integrity Management Program (IMP) to determine the maximum re-inspection interval.

    d) Anomaly Assessment Methods
        - Boardwalk must confirm the remaining strength (R-STRENG) effective area method, R-STRENG - 0.85dL, and ASME B31G assessment methods are valid for the pipe diameter, wall, thickness, grade, operating pressure, operating stress level, and operating temperature. Boardwalk must use the most conservative method until

[11] Evaluate means to review ILI data, excavate indication, evaluate (measure) actual anomaly and take appropriate repair actions.

confirmation of the proper method is made to the Director, Engineering and Emergency Support with copies to the Directors, PHMSA Southern and Southwestern Regions.

13. Boardwalk must complete the 36-inch Fayetteville Lateral Pipeline Project girth weld inspection and remediation plan as outlined below prior to operating the applicable segments above 72% SMYS as documented in Table 1.

Fayetteville Lateral Project Girth Weld Inspection and Remediation Protocol

Phase I – Program Development

1. Boardwalk must review the welding, weld repair and nondestructive testing (NDT) procedures that were used for the repair of the girth weld that failed during hydrostatic testing to ensure there are no technical problems with the procedures.

2. Boardwalk must review the Fayetteville Lateral Project construction records to identify, locate and catalog all girth weld repairs completed with the same procedures used on the failed girth weld.

3. Boardwalk must review the Fayetteville Lateral Project specifications and construction records regarding the actual placement of supports underneath the pipe at tie-ins, over-bends, sag-bends, and other areas of high stress to ensure that high stresses are not occurring on the Fayetteville Lateral Project as a result of inadequate pipe support.

4. The girth weld inspection and remediation program must include the nondestructive testing (NDT) and repair (if necessary) of girth welds along the Fayetteville Lateral Project with special emphasis on those areas of the pipeline subjected to the highest external loading. Boardwalk must identify, investigate and where necessary remediate previously repaired girth welds that meet the following criteria:

   a) On any previously repaired girth weld where welding and/or NDT procedures may not have been properly followed;
   b) On any repaired girth welds in the vicinity of the failed girth weld with a minimum re-inspection of three repaired girth welds upstream and three downstream of the failed girth weld;
   c) On any repaired girth welds in agricultural areas where heavy farm equipment may add to overburden stresses;
   d) On any repaired girth welds on the top and bottom of the pipe; and
   e) On any repaired girth welds near over-bends or sag-bends.

5. Boardwalk must submit the findings of the "Fayetteville Lateral Project Girth Weld Inspection and Remediation Protocol" Items 1, 2 and 3 above and the

framework of the girth weld inspection and remediation program (Item 4) to the Director, Engineering and Emergency Support with copies to the Directors, PHMSA Southern and Southwestern Regions for review prior to beginning any excavations.

Phase II – Program Implementation

1. Boardwalk must implement the program as described above.
2. If problems are discovered after the girth weld inspection and remediation program is implemented, Boardwalk must also address each of the following, as required:

   (a) Repair girth welds on hilltops;

   (b) Repair girth welds where hi-lo pipe alignment issues were not resolved by shims;
   (c) Repair girth welds at excessive depth locations;
   (d) Repair girth welds in the downstream section of compressor stations; and
   (e) Repair girth welds in other areas determined to be of high risk from excessive external forces such as bored crossings of highways/railroads and at valve settings.

3. Boardwalk must submit all the findings and results of the girth weld inspection and remediation program to the Director, Engineering and Emergency Support with copies to the Directors, PHMSA Southern and Southwestern Regions for review.

14. Should Boardwalk find, through the deformation tool evaluations and excavations of the identified anomalies, or develop any additional information, whether through the investigation or testing described otherwise herein, that may technically warrant a modification of any of the provisions of this agreement, Boardwalk may notify the Director, Engineering and Emergency Support with copies to the Directors, Southern and Southwestern Regions of these findings and request approval of the proposed modifications.

15. Boardwalk is to submit quarterly reports to the Director, Engineering and Emergency Support with copies to the Directors, Southern and Southwestern Regions that: (1) include available data and results of the testing and evaluations required by this Agreement; and (2) describe the progress of the repairs and other remedial actions being undertaken. The first quarterly report shall be due June 1, 2009.

16. The Director may allow the removal or modification of the pressure restriction set forth in the Agreement upon a written request from Boardwalk demonstrating that the potentially low yield strength risk has been abated and that restoring the affected pipeline, or portion thereof, to its otherwise applicable MAOP is justified based on a reliable engineering analysis or other mutually agreeable data, including industry publications or studies showing that the pressure increase is safe considering all known physical properties, and operating parameters of the pipeline.

III. Relationship to Original MAOP Special Permits

The additional conditions set forth in this Agreement are in addition to the conditions in the original special permits and Boardwalk must comply with both the original special permit terms and this Agreement. To the extent a term or condition in the original special permit and this Agreement are in conflict, the condition in this Agreement is controlling.

IV. Review and Approval Process

All submissions required or allowed under this Agreement should be submitted electronically in the absence of good cause to do otherwise. With respect to each submission that under this Agreement requires the approval of the Director, Engineering and Emergency Support, the Director may: (a) approve, in whole or in part, the submission, (b) approve the submission on specified conditions, (c) disapprove, in whole or in part, the submission, or (d) any combination of the foregoing. In the event of approval, approval in part, or approval with conditions, Boardwalk will proceed to take all action required by the submission as approved by the Director. In the event that the Director disapproves all or any portion of the submission, the Director will provide Boardwalk with prompt written notice of the deficiencies and the specific additional action needed to obtain approval. Boardwalk will correct all deficiencies within the reasonable time specified by the Director and resubmit it for approval.

V. Enforcement

This Agreement is incorporated into the special permits issued by PHMSA for the specified pipelines and is subject to all enforcement authorities available to PHMSA under 49 U.S.C. § 60101 *et seq.* and 49 C.F.R. Part 190, including administrative civil penalties under § 60122 of up to $100,000 per violation for each day the violation continues, if PHMSA determines that Boardwalk is not proceeding in accordance with terms of the agreement, determinations made by the Regional Director, or if appealed, decisions of the Associate Administrator. Any work plans and associated schedules shall be automatically incorporated into this Agreement and are enforceable in the same manner. Notwithstanding anything herein, Boardwalk shall have all of its legal rights to challenge, appeal or otherwise contest any proposed enforcement authority asserted for alleged non-compliance with this Agreement.

VI. Modification

The terms of this Agreement may be modified by mutual agreement of the parties. Such modifications shall be in writing and shall be signed by both parties.

VII. Termination

This Agreement shall terminate upon the completion of all terms set forth in Section II (Additional Special Permit Conditions). Boardwalk may request written confirmation from PHMSA when this Agreement is terminated. To the extent ongoing monitoring is required, PHMSA may terminate this Agreement with respect to all other requirements with the exception of such monitoring. Nothing in this Agreement prevents Boardwalk from completing any of the obligations earlier than the deadlines provided for herein.

VIII. Ratification

The parties undersigned representatives certify that they are fully authorized to enter into the terms and conditions of this Agreement and to execute and legally bind such party to this document.

On behalf of Boardwalk, I hereby agree to all conditions and terms of this Agreement and agree to implement this Agreement on the referenced pipeline *projects* and *segments*.

Walter Bennett
Senior Vice President of Operations
Boardwalk Pipeline Partners, LP

Date

JDWiese

Jeffrey D. Wiese
Associate Administrator for Pipeline Safety

Date 4/30/09

U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

SPECIAL PERMIT

Docket Number:	PHMSA-2008-0068
Requested By:	Gulf Crossing Pipeline Company, LLC and Gulf South Pipeline Company, LP [subsidiaries of Boardwalk Pipeline Partners, LP]
Date Requested:	December 31, 2007
Code Sections:	49 CFR §§ 192.111 and 192.201

Grant of Special Permit:

By this order, The Pipeline and Hazardous Materials Safety Administration (PHMSA) grants this special permit to the Gulf Crossing Pipeline Company, LLC (GCPC) and Gulf South Pipeline Company, LP (GSPC) [subsidiaries of Boardwalk Pipeline Partners, LP] subject to the conditions and limitations set forth below. The special permit waives compliance from 49 CFR § 192.111 and § 192.201 for the Gulf Crossing Project (GCP) pipeline, a proposed 353.2-mile, 42-inch diameter, natural gas transmission pipeline to be installed and operated by GCPC from Grayson County, Texas, to Madison Parish, Louisiana. The special permit also waives compliance from 49 CFR § 192.111 and § 192.201 for the Mississippi Loop (ML), a 17.8-mile, 42-inch diameter, natural gas transmission loop pipeline to be installed and operated by GSPC in Hinds, Copiah and Simpson Counties, Mississippi.

This special permit allows GCPC to design, construct and operate the GCP pipeline and the GSPC to design, construct and operate the ML pipeline in Class 1 locations using a design factor in § 192.111 up to 0.80 and at stress levels up to 80% of the specified minimum yield strength (SMYS), in Class 2 locations using a design factor in § 192.111 up to 0.67 and at stress levels up to 67% of SMYS and in Class 3 locations using a design factor in § 192.111 up to 0.56 and at stress levels up to 56% of SMYS. This would result in maximum allowable operating pressures (MAOP) of 1480 pounds per square inch gauge (PSIG).

This special permit also allows GCPC to design, install and operate pressure relief and limiting devices on the GCP pipeline and the GSPC to design, install and operate pressure relief and limiting devices on the ML pipeline with a capacity that would ensure the pressure in Class 1, Class 2 and Class 3 location pipeline segments would not exceed 104% of the MAOP or the pressure that produces a hoop stress of 83.2% SMYS in Class 1 locations, 69.7% SMYS in Class 2 locations or 58.2% SMYS in Class 3 locations during an overpressure event.

For the purpose of this special permit, the *"special permit area"* means the area consisting of the entire pipeline right-of-way for those segments of the GCP and ML pipelines that will operate above 72% SMYS in Class 1 locations, above 60% SMYS in Class 2 locations above 50% SMYS in Class 3 locations.

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-2008-0068 in the Federal Docket Management System (FDMS) located on the Internet at www.Regulations.gov.

Conditions

This special permit is granted subject to the following conditions:

1) Steel Properties: The skelp/plate must be micro alloyed, fine grain, fully killed steel with calcium treatment and continuous casting.
2) Manufacturing Standards: The pipe must be manufactured according to American Petroleum Institute Specification 5L, Specification for Line Pipe (API 5L), product specification level 2 (PSL 2), supplementary requirements (SR) for maximum operating pressures and minimum operating temperatures. Pipe carbon equivalents must be at or below 0.23% based on the material chemistry parameter (Pcm) formula.
3) Fracture Control: API 5L, the American Society of Mechanical Engineers B31.8 Standard (ASME B31.8) and other specifications and standards address the steel pipe toughness properties needed to resist crack initiation, crack propagation and to ensure crack arrest during a pipeline failure caused by a fracture. GCPC and GSPC must institute an overall fracture control plan addressing steel pipe properties necessary to resist crack initiation and crack propagation and to arrest a fracture within 8 pipe joints with a 99% occurrence probability or within 5 pipe joints with a 90% occurrence probability. The plan must include acceptable Charpy Impact and Drop Weight Tear Test values, which are measures

include acceptable Charpy Impact and Drop Weight Tear Test values, which are measures of a steel pipeline's toughness and resistance to fracture. The fracture control plan, which must be submitted to PHMSA headquarters, must be in accordance with API 5L, Appendix F and must include the following tests:

a) SR 5A - Fracture Toughness Testing for Shear Area: Test results must indicate at least 85% minimum average shear area for all X- 70 heats and 80% minimum shear area for all X- 80 heats with a minimum result of 80% shear area for any single test. The test results must also ensure a ductile fracture and arrest;
b) SR 5B – Fracture Toughness Testing for Absorbed Energy; and
c) SR 6 – Fracture Toughness Testing by Drop Weight Tear Test: Test results must be at least 80% of the average shear area for all heats with a minimum result of 60% of the shear area for any single test. The test results must also ensure a ductile fracture and arrest.

The above fracture initiation, propagation and arrest plan must account for the entire range of pipeline operating temperatures, pressures and gas compositions planned for the pipeline diameter, grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions associated with the *special permit area*. Where the use of stress factors, pipe grade, operating temperatures and gas composition make fracture toughness calculations non-conservative, correction factors must be used. If the fracture control plan for the pipe in the *special permit area* does not meet these specifications, GCPC and GSPC must submit to PHMSA headquarters an alternative plan providing an acceptable method to resist crack initiation, crack propagation and to arrest ductile fractures in the *special permit area.*

4) Steel Plate Quality Control: The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and inclusions that could affect the pipe quality. This program must include a plate or rolled pipe ultrasonic testing (UT) inspection program to check for imperfections such as laminations. UT inspection must be conducted on all factory beveled pipe ends. In addition, pipe body UT inspection must be conducted on a minimum of 100% of pipe joints and all ends, with a minimum coverage of 35% of the pipe body for those joints inspected. Any laminations identified by the UT inspection program must be evaluated in accordance

with the acceptance criteria defined in ASTM International Standard ASTM A578/A578M "*Standard Specification for Straight-Beam Ultrasonic Examination of Rolled Steel Plates for Special Applications (ASTM A578),*" Level B or API 5L Paragraph 7.8.10. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat (manufacturing run) of each sequence (approximately 4 heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible four or five scale are acceptable.

5) Pipe Seam Quality Control: A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API 5L for the appropriate pipe grade properties. A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of 280 Vickers hardness (Hv10). The hardness tests must include a minimum of 3 readings for each heat affected zone, 3 readings in the weld metal and 2 readings in each section of pipe base metal for a total of 13 readings. The pipe weld seam must be 100% UT inspected after expansion and hydrostatic testing per API 5L.

6) Mill Hydrostatic Test: The pipe must be subjected to a mill hydrostatic test to achieve a minimum stress level of 95% SMYS in the pipe for a minimum duration of 10 seconds. The 95% stress level may be achieved using a combination of internal test pressure and the application of end loads imposed by the hydrostatic testing equipment as allowed by API 5L, Appendix K.

7) Pipe Coating: The application of a corrosion resistant coating to the steel pipe must be subject to a coating application quality control program. The program must address pipe surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections and coating repair.

8) Field Coating: A field girth weld joint coating application specification and quality standards to ensure pipe surface cleanliness, application temperature control, adhesion

quality, cathodic disbondment, moisture permeation, bending, minimum coating thickness, holiday detection and repair quality must be implemented in field conditions. Field joint coatings must be non-shielding to cathodic protection (CP). Field coating applicators must use valid coating procedures and be trained to use these procedures.

9) Coatings for Trenchless Installation: Coatings used for directional bore, slick bore and other trenchless installation methods must resist abrasions and other damages that may occur due to rocks and other obstructions encountered in this installation technique.

10) Bends Quality: Certification records of factory induction bends and/or factory weld bends must be obtained and retained. All bends, flanges and fittings must have carbon equivalents (CE) below 0.42 or a pre-heat procedure must be applied prior to welding for CE above 0.42.

11) Fittings: All pressure rated fittings and components (including flanges, valves, gaskets, pressure vessels and compressors) must be rated for a pressure rating commensurate with the MAOP and class location of the pipelines. Designed fittings (including tees, elbows and caps) must have the same design factor as the adjacent pipe.

12) Design Factor - Pipelines: Pipe installed under this special permit in Class 1 locations may use a design factor of 0.80, in Class 2 locations may use a design factor of 0.67 and in Class 3 locations may use a design factor of 0.56.

13) Temperature Control: The compressor station discharge temperature must be limited to 120° Fahrenheit. A temperature above this maximum temperature of 120° Fahrenheit may be approved if GCPC and GSPC technical coating operating tests show that the pipe coating will properly withstand the higher operating temperature for long term operations. If the temperature exceeds 120° Fahrenheit GCPC and GSPC must also institute a coating monitoring program in these areas using ongoing Direct Current Voltage Gradient (DCVG) surveys or Alternating Current Voltage Gradient (ACVG) surveys or other testing to demonstrate the integrity of the coating. This program and results must be provided to the regional offices of PHMSA where the pipe is in service.

14) Overpressure Protection Control: Mainline pipeline overpressure protection must be limited to a maximum of 104% MAOP.

15) Welding Procedures: For automatic or mechanized welding the 19th Edition of API 1104, "Welding of Pipelines and Related Facilities", will be used for welding procedure

qualification, welder qualification and weld acceptance criteria. Operator must use the 19th Edition of API 1104 for all other welding processes. The appropriate PHMSA regional office must be notified within 14 days of the beginning of welding procedure qualification activities. Automated or manual welding procedure documentation must be submitted to the same PHMSA regional office.

16) Depth of Cover: The soil cover must be a minimum depth of 36 inches in all areas. In areas where threats from chisel plowing or other activities are threats to the pipelines, the top of the pipelines must be installed at least one foot below the deepest penetration above the pipelines. If routine patrols or other observed conditions indicate the possible loss of cover over the pipelines, GCPC and GSPC will perform a depth of cover study and replace cover as necessary to meet the minimum depth of cover requirements specified herein.

17) Construction Quality: A construction quality assurance plan to ensure quality standards and controls must be maintained throughout the construction phase with respect to: inspection, pipe hauling and stringing, field bending, welding, non-destructive examination (NDE) of girth welds, field joint coating, pipeline coating integrity tests, lowering of the pipeline in the ditch, padding materials to protect the pipeline, backfilling, alternating current (AC) interference mitigation and CP systems. All girth welds must be non-destructively examined by radiography or alternative means. The NDE examiner must have all required and current certifications.

18) Interference Currents Control: Control of induced AC from parallel electric transmission lines and other interference issues that may affect the pipelines must be incorporated into the design of the pipelines and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to PHMSA's attention by notifying the appropriate regional office. An induced AC program to protect the pipelines from corrosion caused by stray currents must be in place within six months after placing the pipelines in service.

19) Test Level: The pre-in service hydrostatic test must be to a pressure producing a hoop stress of at least 100% SMYS and 1.25 X MAOP in areas to operate up to 80% SMYS and at least 1.50 X MAOP in areas to operate to 67% SMYS and 56% SMYS. Short segments of pipe (up to one mile in length) having a design factor between 72% SMYS and less than 80% SMYS may be tested with 80% SMYS pipe provided the test pressure produces a

hoop stress of at least 1.25 X MAOP for all pipe tested.

20) Assessment of Test Failures: Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office.

21) Supervisory Control and Data Acquisition (SCADA) System Capabilities: A SCADA system to provide remote monitoring and control of the pipeline system must be employed.

22) SCADA Procedures: A detailed procedure for establishing and maintaining accurate SCADA set points must be established to ensure the pipelines operate within acceptable design limits at all times.

23) Mainline Valve Control: Mainline valves located on either side of a pipeline segment containing a High Consequence Area (HCA) where personnel response time to the valve exceeds one hour must be remotely controlled via the SCADA system. The SCADA system must be capable of closing these mainline valves and monitoring the valve position, as well as upstream pressure and downstream pressure at the mainline valve. As an alternative, a leak detection system for mainline valve control is acceptable.

24) Pipeline Inspection: The pipelines must be capable of passing in-line inspection (ILI) tools. All headers and other segments covered under this special permit that do not allow the passage of an ILI device must have a corrosion mitigation plan.

25) Gas Quality Monitoring: An acceptable gas quality monitoring and mitigation program must be instituted to not exceed the following limits:

a) H_2S (1.0 grain per 100 standard cubic feet or 16 parts per million (ppm), maximum);
b) CO_2 (3% maximum);
c) H_2O (less than or equal to 7 pounds per million standard cubic feet and no free water); and
d) Other deleterious constituents that may impact the integrity of the pipelines.

26) The pipelines must have an ongoing pigging and liquids sampling plan to identify, mitigate and remove deleterious constituents, where applicable.

27) If H_2S is above 8 parts ppm, the gas stream constituents must be reviewed for implementation of a quarterly pigging/inhibitor injection program, including follow up

sampling of liquids at receipt points.

28) Gas Quality Control: Separators or Filters/separators must be installed at locations where gas is received into the pipelines where the incoming gas stream quality includes potentially deleterious free liquids and/or particulates to minimize the entry of contaminants and to protect the integrity of downstream pipeline segments.

29) Gas Quality Monitoring Equipment: Equipment, including moisture analyzer, chromatograph and semi-annual H_2S sampling (quarterly sampling where H_2S is above 8 ppm), must be installed to permit the operator to manage and limit the introduction of contaminants and free liquids into the pipelines.

30) Cathodic Protection: The initial CP system must be operational within 12 months of placing any pipeline segment in service.

31) Interference Current Surveys: Interference surveys must be performed within six months of placing the pipeline in service to ensure compliance with applicable NACE International Standard Recommended Practices 0169 and 0177 (NACE RP 0169 and NACE RP 0177) for interference current levels. If interference currents are found, GCPC and GSPC will determine if there have been any adverse affects to the pipeline and mitigate the affects as necessary. GCPC and GSPC will report the results of any negative finding and the associated mitigative efforts to the appropriate PHMSA regional office.

32) Corrosion Surveys: Corrosion surveys of the affected pipelines must be completed within six months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP 0169. The survey will also address the proper number and location of CP test stations as well as AC interference mitigation and AC grounding programs per NACE RP 0177.

33) Verification of Cathodic Protection: An interrupted close interval survey (CIS) must be performed in concert and integrated with ILI in accordance with 49 CFR 192 Part, Subpart O reassessment intervals for all HCA pipeline mileage. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within an HCA. If any annual test station reading fails to meet 49 CFR 192 Part, Subpart I requirements, remedial actions must occur within six months. Remedial actions must include a CIS on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control.

34) Initial Close Interval Survey (CIS) - Initial: A CIS must be performed on the pipelines within two years of the pipeline in-service dates. The CIS results must be integrated with the baseline ILI to determine whether further action is needed.

35) Initial Coating Assessment – GCPC and GSPC must assess the integrity of the pipelines coating after completion of padding and backfill during construction through use of coating indirect assessment methods such as DCVG or ACVG surveys or equivalent methods. GCPC and GSPC must remediate any damaged coating found during these assessments that are classified as minor and at or above 15% IR for DCVG or at or above 30 dBμV ACVG, moderate, or severe based on NACE International Recommended Practice 0502-2002, *Pipeline External Corrosion Direct Assessment Methodology,* (NACE RP 0502-2002). A minimum of two coating survey assessment classifications must be excavated, classified and/or remediated per each survey crew and compressor station discharge pipeline section to verify survey results.

36) Pipeline Markers: GCPC and GSPC must employ line-of-sight markings on the pipelines in the *special permit area* except in agricultural areas or large water crossings such as lakes where line-of-sight markers are not practical. The marking of pipelines is also subject to Federal Energy Regulatory Commission orders or environmental permits and local restrictions.

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

38) Monitoring of Ground Movement: An effective monitoring/mitigation plan must be in place to monitor for and mitigate issues of unstable soil and ground movement.

39) Initial ILI: GCPC and GSPC must perform a baseline ILI in association with the construction of the pipelines using a high-resolution Magnetic Flux Leakage (MFL) tool to be completed within three years of placing a pipeline segment in service. GCPC and GSPC must perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipelines, (just prior to placing the pipelines in service) but no later than six months after placing the pipelines in service in accordance with the conditions allowed by the special permit.

40) Future ILI: A second high-resolution MFL inspection must be performed and completed on the pipe subject to this special permit within the first reassessment interval required by 49 CFR Part 192, Subpart O, regardless of HCA classification. Future ILI must be performed on a frequency consistent with Subpart O for the entire pipelines covered by this special permit.

41) Direct Assessment Plan: Headers, mainline valve bypasses and other sections in the *special permit area* that cannot accommodate ILI tools must be part of a Direct Assessment (DA) plan or other acceptable integrity monitoring method using External and Internal Corrosion Direct Assessment criteria (ECDA/ICDA).

42) Damage Prevention Program: The Common Ground Alliance's (CGA) damage prevention best practices applicable to pipelines must be incorporated into the GCPC and GSPC damage prevention program.

43) Anomaly Evaluation and Repair: Anomaly evaluations and repairs in the *special permit area*, regardless of HCA status, must be performed based upon the following:

   a) Anomaly Response Time: Repair Immediately
      - Any anomaly within a *special permit area* operating up to 80% SMYS with a failure pressure ratio (FPR) equal to or less than 1.1 and/or an anomaly depth equal to or greater than 80% wall thickness loss.
      - Any anomaly within a *special permit area* operating up to 67% SMYS with an FPR equal to or less than 1.25 and/or an anomaly depth equal to or greater than 80% wall thickness loss.
      - Any anomaly within a *special permit area* operating up to 56% SMYS with an FPR equal to or less than 1.4 and/or an anomaly depth equal to or greater than 80% wall thickness loss.

   b) Anomaly Response Time: Repair Within One Year
      - Any anomaly within a *special permit area* operating at up to 80% SMYS with a FPR equal to or less than 1.25.
      - Any anomaly within a *special permit area* operating at up to 67% SMYS with a FPR equal to or less than 1.5.
      - Any anomaly within a *special permit area* operating at up 56% SMYS with an FPR equal to or less than 1.8.

c) Anomaly Response Time: Monitored Conditions
   - Anomalies not requiring immediate or one year repairs per paragraphs a and b above must be reassessed according to 49 CFR Part 192, Subpart O reassessment intervals.
   - Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Gas Integrity Management Program (IMP) to determine the maximum re-inspection interval.

d) Anomaly Assessment Methods
   - GCPC and GSPC must confirm the remaining strength (R-STRENG) effective area method, 0.85dL and ASME B31G assessment methods are valid for the pipe diameter, wall
   - Thickness, grade, operating pressure, operating stress level and operating temperature. GCPC and GSPC must also use the most conservative method until confirmation of the proper method is made to PHMSA Headquarters.
   - Dents in the pipe in the *special permit area* must be evaluated and repaired per 49 CFR § 192.309(b) for the baseline geometry tool run and per 49 CFR § 192.933(d) for future ILI

44) Potential Impact Radius Calculation Updates: If the pipeline operating pressures and gas quality are determined to be outside the parameters of the C-FER Study, a revised study with the updated parameters must be incorporated into the IMP.

45) Reporting - Immediate: GCPC and GSPC must notify the appropriate PHMSA regional office within 24 hours of any non-reportable leaks occurring in the *special permit area.*

46) Reporting – 30 Day: At least thirty (30) days prior to the pipeline in- service date under this special permit, Operator shall report on its compliance with special permit conditions to PHMSA headquarters and the appropriate regional offices.

   a) Special Permit Conditions 1 through 25, 28, 29, 33, 35, 36, 44 and 46 must be completed and implemented with documentation available for PHMSA review prior to operating at the special permit MAOP.

   b) Special Permit Conditions 3, 7 through 14, 16, 18, and 21 through 47 must be included in the operator's written operating and maintenance (O&M) procedures manual concerning permit condition requirements with documentation available for PHMSA review prior to operating at the special permit MAOP.

47) Annual Reporting: GCPC and GSPC must report the following to the appropriate PHMSA regional offices annually[1]:

a) The results of any ILI or direct assessment results performed within the *special permit area* during the previous year;
b) Any new integrity threats identified within the *special permit area* during the previous year;
c) The number of new residences, other structures intended for human occupancy and public gathering areas built within the *special permit area*;
d) Any class or HCA changes in the *special permit area* during the previous year;
e) Any reportable incidents associated with the *special permit area* that occurred during the previous year;
f) Any leaks on the pipelines in the *special permit area* that occurred during the previous year;
g) A list of all repairs on the pipelines in the *special permit area* made during the previous year;
h) On-going damage prevention initiatives on the pipelines in the *special permit area* and a discussion of their success or failure;
i) Any changes in procedures used to assess and/or monitor the pipelines operating under this special permit; and
j) Any company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipelines to which this special permit applies.

Limitations:

PHMSA grants this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether GCPC and/or GSPC have complied with the specified conditions of this special permit.

[1] Annual reports must be received by PHMSA by the last day of the month in which the Special Permit is dated. For example, the annual report for a Special Permit dated March 4, 2008, must be received by PHMSA no later than March 31st each year beginning in 2009.

2) Should GCPC and/or GSPC fail to comply with any of the specified conditions of this special permit, PHMSA may revoke this special permit and require GCPC and/or GSPC to comply with the regulatory requirements in 49 CFR §§ 192.111 and 192.201.
3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1) and require GCPC and/or GSPC to comply with the regulatory requirements in 49 CFR §§ 192.111 and 192.201.
4) Should PHMSA revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1), PHMSA will notify GCPC and/or GSPC in writing of the proposed action and provide GCPC and/or GSPC an opportunity to show cause why the action should not be taken unless PHMSA determines that taking such action is immediately necessary to avoid the risk of significant harm to persons, property or the environment (see 49 CFR § 190.341(h)(2)).
5) The terms and conditions of any corrective action order, compliance order or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit in accordance with 49 CFR § 190.341(h)(4).

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

Issued in Washington, DC on NOV 19 2008.

William H Gute
for

Jeffrey D. Wiese,
Associate Administrator for Pipeline Safety