



U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

July 24, 2007

El Paso Pipeline Group
Attn: Dan Martin, Senior Vice President Operations
1001 Louisiana Street
P.O. Box 2511
Houston, Texas 77002

CPF 4-2007-1008M

Dear Mr. Martin:

During the weeks of April 17-21, May 1-5, and May 22-26, 2006, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected your integrity management program in Houston, Texas.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within El Paso Pipeline Group's (EPPG's) plans or procedures, as described below:

1. §192.909 How can an operator change its integrity management program?

(b) Notification. An operator must notify OPS, in accordance with § 192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

EPPG must revise its procedures to adequately define criteria in the IMP to establish what significant changes to the integrity management program, program implementation, or schedules, require PHMSA or the State or local pipeline safety authority notification within 30 days after EPPG has adopted the change.

2. §192.911 What are the elements of an integrity management program?

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

The EPPG MOC process and procedures must be revised and must require and develop documentation which adequately addresses procedures for:

- a. consideration of impacts of changes to pipeline systems and their integrity,
- b. analysis of the implications of planned changes,
- c. ensuring that integrity management program changes are properly reflected in the pipeline system and that pipeline system changes are properly reflected in the integrity management program, and
- d. requiring that equipment or system changes be identified and reviewed before implementation.

3. §192.911 What are the elements of an integrity management program?

(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

EPPG procedures must be revised and must adequately address the following components of a quality assurance process outlined by ASME B31.8S:

- a. Detailed responsibilities and authorities for all key elements of the integrity management program shall be adequately defined in IMP documentation.
- b. Criteria and guidance for the conduct of QA audits shall be adequately specified by EPPG. The IMP identifies program elements that "would" be appropriate for review without specifying the minimum set that must be reviewed in each annual review. Verification of threat identification, data, and risk results for specific segments indicated errors in process implementation:
 - SNG South Colquitt Line LN-03, HCA 1380 was incorrectly indicated as a production area in the internal corrosion evaluation.
 - CIG Line 59A HCA had the incorrect pipe type in the threat/risk data base.
- c. EPPG must develop adequate qualification requirements for outside contractors. When EPPG uses outside resources to conduct processes that affect the quality of the integrity management program, the quality of such processes shall be verified by EPPG and these processes shall be documented within the quality program.

4. §192.915 What knowledge and training must personnel have to carry out an integrity management program?

(a) Supervisory personnel. The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

EPPG'S training and qualifications program must be revised and must adequately address the following:

- a. EPPG must adequately specify the specific requirements such that supervisory personnel have the appropriate training or experience in order to perform their assigned responsibilities,
- b. EPPG must have provisions requiring documentation that is sufficiently explicit to verify the qualifications of personnel that carry out assessments and who evaluate assessment results,
- c. EPPG must develop and specify requirements for training and qualification requirements for personnel who execute the activities within the integrity management program.

5. §192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 2, which are grouped under the following four categories:

- (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;
- (2) Static or resident threats, such as fabrication or construction defects;
- (3) Time independent threats such as third party damage and outside force damage; and
- (4) Human error.

EPPG's must revise its procedures to ensure better documentation of its process for utilizing the TIP charts and related steps to evaluate threats and setting threat risk levels in order to assure consistent application by different analysts. As described by EPPG, this is a large-scope, complex task requiring the assembly, review, and application of multiple large data sets and the use of detailed technical decision logic; and the procedure requires clear and complete definition of all steps.

6. §192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(c) Risk assessment. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

EPPG must revise its procedures and "TIP" flow charts where the claim is made that the threats "do not exist" for segments specifically with regard to the following:

- a. Treatment of failure/leak history for both external and internal corrosion—the elimination from consideration of all segment leak/rupture history before ILI has been conducted on the segment has not been justified (Appendix A-1, A-2 TIP charts) and potentially leads to the non-conservative elimination of threats.
- b. Incorrect operations—this threat category was ruled out for all covered segments without a segment-specific evaluation of risk factors.

7. §192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(c) Risk assessment. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

EPPG must revise its procedures to ensure better documented support for the risk assessment approach documented in Chapter 3 in order to assure all objectives of risk assessment specified in ASME B31.8S, Section 5 are addressed. Specifically, the risk assessment must adequately support:

- a. Assessment of the benefits derived from mitigating action,
- b. Determination of the most effective mitigation measures for the identified threats,
- c. Assessment of the integrity impact from modified inspection intervals,
- d. Assessment of the use of or need for alternative inspection methodologies, and
- e. Facilitation of decisions to address risks along a pipeline or within a facility.

8. §192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(e) Actions to address particular threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(1) Third party damage. An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with § 192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline

assessment under § 192.921, or a reassessment under § 192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

EPPG must revise its procedures to ensure an adequate process exists to provide for the additional preventive measures appropriate for the threat of third party damage within an HCA.

9. §192.921 How is the baseline assessment to be conducted?

(a) **Assessment methods.** An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See §192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

EPPG must revise its procedures to better document evaluations required per ASME B31.8S section 6.2, regarding the general reliability of selected in-line assessment methods by looking at factors including but not limited to: detection sensitivity; anomaly classification; sizing accuracy; location accuracy; requirements for direct examination; history of tool performance; ability to inspect the full length and full circumference of the section; and ability to indicate the presence of multiple cause anomalies.

10. §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(b) **General requirements.** An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 6.4, and in NACE RP 0502-2002 (incorporated by reference, see § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§ 192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by § 192.917(e)(1).

(1) Preassessment. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 3, the plan's procedures for preassessment must include—

- (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and**
- (ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE RP0502-2002, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.**

EPPG must revise its procedures to more clearly specify the following ECDA requirements:

- a. The minimum data requirements that must be collected to support ECDA pre-assessment.
- b. The necessary data integration and analysis needed to conduct an ECDA feasibility assessment.
- c. The more restrictive criterion that must be applied when conducting an ECDA pre-assessment for the first time on a covered segment.

11. §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 6.4, and in NACE RP 0502-2002 (incorporated by reference, see § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§ 192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by § 192.917(e)(1).

(2) Indirect examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 4, the plan's procedures for indirect examination of the ECDA regions must include—

- (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;**
- (ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;**
- (iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and**

(iv) Criteria for scheduling excavation of indications for each urgency level.

EPPG must revise its procedures to provide sufficient detail to ensure the following:

- a. Applying criteria for classification of the severity of each indication and the urgency level with which excavation and direct examination of indications will be conducted based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion.
- b. Specifying more restrictive criterion that must be applied when conducting an ECDA indirect inspection for the first time on a covered segment.

12. §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 6.4, and in NACE RP 0502-2002 (incorporated by reference, see § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§ 192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by § 192.917(e)(1).

(3) Direct examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 5, the plan's procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE RP0502-2002), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502-2002);

(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE RP0502-2002.

EPPG must revise its procedures to more clearly develop the following:

- a. A structured process defining how the ECDA root cause analysis is conducted, who performs the analysis, or how the conclusions are documented. A process has not been adequately defined that precludes future external corrosion resulting from significant root causes.

- b. An established and implemented criteria and internal notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications, other than through the MOC process.
- c. Specific processes to consider the use of assessment methods other than ECDA (i.e., ILI or Subpart J pressure test) to assess the impact of defects other than external corrosion (e.g., mechanical damage and stress corrosion cracking) discovered during direct examination. Feedback mechanisms are expected to be more expedient than the EPPG "flags and alerts" process allows.
- d. A more restrictive criterion that must be applied when conducting an ECDA direct examination for the first time on a covered segment.

13. §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 6.4, and in NACE RP 0502-2002 (incorporated by reference, see § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§ 192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by § 192.917(e)(1).

(4) Post assessment and continuing evaluation. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

- (i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and**
- (ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939.**

EPPG's must revise its procedures to develop a more formal feedback process to ensure all appropriate opportunities throughout the ECDA process demonstrate feedback mechanisms and continuous improvement.

14. §192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(c) The ICDA plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.

(4) Post-assessment evaluation and monitoring. An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes--

(ii) Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with §192.933.

(A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

EPPG must revise its ICDA process and procedures to better address all §192.927(c)(4)(ii) requirements that must be taken if any evidence of corrosion products is found in a covered segment and specifically needs to address the following:

- a. Remediate the conditions the operator finds in accordance with §192.933, and
- b. Implement one of the two following required actions: (1) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe, or (2) assess the covered segment using another integrity assessment method allowed by Subpart O.

15. §192.933 What actions must be taken to address integrity issues?

(a) General requirements. An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure is reduced, an operator must determine the temporary reduction in operating pressure using ASME/ANSI B31G (incorporated by reference, see §192.7) or AGA Pipeline Research Committee Project PR-3-805 ("RSTRENG"; ibid, see §192.7) or reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. (See appendix A to this part 192 for information on availability of incorporation by reference information). A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

EPPG IMP must revise its procedures to better establish conditions when they are unable to meet time limits for evaluation and remediation of anomalous conditions. Procedures are required to determine the appropriate pressure reductions using ASME B31G, or "RSTRENG", or to reduce pressures to levels not exceeding 80% of the level at the time the anomalous condition was discovered.

16. §192.933 What actions must be taken to address integrity issues?

(b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

EPPG must revised its procedures to better describe responsibilities, guidance or criteria for what constitutes having adequate information to declare discovery of anomalous conditions or what is meant by the integrity assessment date (completion date).

17. §192.933 What actions must be taken to address integrity issues?

(c) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify OPS in accordance with § 192.949 if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(d) Special requirements for scheduling remediation.—

(1) Immediate repair conditions. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

EPPG must better define the following:

- a. The establishment of timeframes and the basis for such timeframes, for evaluation of vendor ILI reports in order to establish discovery of anomalies with special regard for immediate conditions.

- b. A process satisfying 192.933(c) & (d) or ASME B31.8S on how anomalies in HCAs are prioritized for remediation.

18. §192.933 What actions must be taken to address integrity issues?

(d) Special requirements for scheduling remediation.—

(1) Immediate repair conditions. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

EPPG must modify its procedures to ensure the following:

- a. Excavation of immediate repair conditions within 5 days of discovery and required pressure reduction for all immediate repair conditions as required by Subpart O. Reliance on the maximum pressure within the last 120 days is inappropriate – the pressure reduction must be based upon the pressure at the time the anomaly is identified.
- b. Related to immediate conditions, EPPG must include the following items taken directly from Section 7 of ASME B31.8S: 1) metal-loss indications affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding; 2) indications of stress corrosion cracks; or 3) indications that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline.

19. §192.933 What actions must be taken to address integrity issues?

(d) Special requirements for scheduling remediation.—

(3) Monitored conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

EPPG must revise its procedures to provide a more comprehensive definition of "monitored conditions." Additionally, the procedures must include a more descriptive process for monitoring anomalies classified as "monitored conditions" during subsequent risk or integrity assessments to identify status changes that would require remediation.

20. §192.935 What additional preventive and mitigative measures must an operator take to protect the high consequence area?

(a) General requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

With regard to P&M measures, EPPG must revise its procedures to make them more comprehensive with regard to the following:

- a. A systematic, documented P&M measures decision-making process to decide which measures are to be implemented, involving input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control.
- b. A P&M measures decision-making process that considers the consequences of pipeline failures.
- c. Identified and documented additional measures that have actually been implemented, or scheduled for implementation on a HCA specific basis. Measures have only been identified on a global system-basis.
- d. A comprehensive process for evaluating and documenting the need for Automatic Shut-off Valves or Remote Control Valves.

21. §192.935 What additional preventive and mitigative measures must an operator take to protect the high consequence area?

(b) Third party damage and outside force damage—

(1) Third party damage. An operator must enhance its damage prevention program, as required under § 192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum--

(i) Using qualified personnel (see §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP-0502-2002 (incorporated by reference, see § 192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and § 192.933 any indication of coating holidays or discontinuity warranting direct examination.

EPPG must revise its procedures to ensure than enhancements to the §192.614-required Damage Prevention Program with respect to covered segments to prevent and minimize the consequences of a release, and that detail the enhanced measures, must include all of the minimum requirements such as the use of some criterion for what is considered a holiday or a non-standard reading on the electrical survey, see §192.935(b)(1)(iv). The tool selected by EPPG's IMP Plan (CIS) is not the best for determining coating holidays per NACE RP 0502-2002.

22. §192.935 What additional preventive and mitigative measures must an operator take to protect the high consequence area?

(b) Third party damage and outside force damage—

(2) Outside force damage. If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

EPPG must revise its procedures in order to develop more comprehensive measures to mitigate outside forces in areas that FEMA has determined are prone to outside forces.

23. §192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) General. After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in §192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

With regard to the periodic evaluation process, EPPG must revise its procedures to better address the following:

- a. The periodic evaluation process is not specified to be conducted on a continuous basis or that periodic evaluations be conducted based on a data integration and risk assessment of the entire pipeline as specified in §192.917. It is recognized that EPPG has actions occurring on a routine basis but EPPG has not appropriately credited some of these actions in the IMP.
- b. Further, no periodic evaluations of data have been conducted for establishing reassessment methods and schedules.

In regard to Items 11, 12, 13, 14, and 23 listed above and for Item 5 related to the TIP charts A-1 External Corrosion and A-4 Manufacturing, EPPG provided finalized documentation via email to PHMSA on March 30, 2007 of various changes made to the IMP. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required on these items in response to this Notice.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for

confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 4-2007-1008M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,



R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*