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November 29, 2007

VIA COURIER

Mr. R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration
US Department of Transportation
8701 South Gessner, Suite 1110
Houston, TX 77074

Re: Notice of Amendment, CPF 4-2007-1008M
Response and Request for Hearing

Dear Mr. Seeley:

On or about July 30, 2007 El Paso Pipeline Group (EPPG) received the above referenced Notice. The Notice refers to inspections conducted on ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Southern Natural Gas Company, and Tennessee Gas Pipeline Company during 2006 by representatives of the Pipeline and Hazardous Materials Safety Administration ("PHMSA").

On or about August 29, 2007 PHMSA granted EPPG and ANR an extension till November 30, 2007 for the following:

- The period in which EPPG and ANR must request a hearing, note how inadequacies will be addressed, or submit written answers/objections on any or all of the 23 items specified in the Notice;
- The period EPPG and ANR have in which to revise their procedures as specified in the above referenced Notice;
- Any other deadlines resulting from the Notice which would otherwise expire on or about August 29, 2007 including but not limited to the time period in which to request a hearing.

At the time of the inspection, ANR Pipeline Company (ANR) was a member of the El Paso Pipeline Group. On February 22, 2007, ANR was acquired by a wholly owned subsidiary of TransCanada Corporation. As of this writing ANR is no longer part of EPPG. Pursuant to the terms of a transition services agreement, however, the Integrity Management Program and Baseline Assessment Plan will continue to be managed under the existing EPPG IMP Manual and processes during a transition period ending December 2007.

Hearing Request

As provided in 49 C.F.R. sec. 190.209 (a) (3) and 190.209 (b) (4), EPPG and ANR request a Hearing on items 18 and 22 in that Notice of Amendment.

EPPG and ANR will be represented by counsel at the Hearing.

Pursuant to 49 C.F.R. sec. 190.211 (e), EPPG and ANR request that the material in any case files or other files in the actual or constructive possession of PHMSA pertinent to Items 18 and 22 in the Notice be provided to EPPG as soon as possible, but no less than 30 days prior to the Hearing. This includes but is not limited to inspector notes, supporting documentation, and guidance materials provided to the inspectors.

EPPG and ANR intend to raise the following issues at the Hearing because these NOA items are outside the requirements of the rule and do not add to the safety or integrity of the pipeline system:

- NOA 18: Whether El Paso Pipeline Group (EPPG) and ANR complied with 192.933 for defining the response within 5 days of discovery for immediate repair conditions, determining the pressure reduction, and defining the immediate conditions per 192.933(d)(1).

- NOA 22: Whether EPPG and ANR must utilize FEMA data in order to comply with 192.935 as related to determing what areas are prone to outside forces.

We look forward to the opportunity to present information on these issues to PHMSA at the Hearing.

Response to NOA Items

The following is a list of each of the NOA items that have not been requested for hearing, Items 1 through 17, 19 through 21, and 23. Along with the text of the NOA item is EPPG and ANR's response to the item.

When EPPG is used from this point forward in the document it represents both EPPG and ANR.

NOA Item 1

Regulatory reference: 192.909(b)
Text of NOA: 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.

EPPG Response: As part of continuous improvement to the IMP processes, EPPG has modified Section 18.2 of the IMP Manual by adding examples of items that would constitute a significant change requiring notification to authorities. Specifically, the following items were added to the end of the second paragraph under the heading "Significant Changes to the program:"

> Examples of items that would be considered a significant change requiring notification are:
> - Change in HCA mileage for any one company by more than 20%.
> - Change in HCA calculation method for one operating company.
> - A single acquisition or divestiture of facilities resulting in a change in HCA mileage greater than 10%.

See attachment 1.

NOA Item 2

Regulatory reference: 192.911(k)
Text of NOA: 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.*

EPPG Response: EPPG has numerous policies, practices and procedures in place to ensure evaluation and communication of changes which may affect the pipeline system or the IMP. Some of these are specifically addressed in the IMP, i.e. Chapter 15 and Chapter 4; and through activities described in the IMP, i.e. the HCA annual review process (Figure 1-4). Other policies, practices and procedures are covered in other manuals or department guidelines and are referenced in sections 15.6 and 15.8. In addition, many of EPPG's manuals (Section 15.6) include their own Management of Change sections which include communication requirements designed to inform not only those responsible for the IMP program of any changes that may affect the program or pipeline integrity but any department or individual contributor who may need to be aware of changes in company procedures or facilities.

As part of continuous improvement, EPPG has modified the IMP Manual Chapter 15, Management of Change, by adding examples to the Physical Changes management of change section to more clearly identify processes meeting the requirements noted in this NOA item.

See attachment 2.

NOA Item 3

Regulatory reference: 192.911(l)
Text of NOA: 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. Verifaction of threat identification, data, and risk results for specific segments indicated errors in process implementation:*
    - *SNG South Colquitt Lnie 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.

EPPG Response:

a. On June 23, 2006 John Pepper e-mailed EPPG noting that this issue had been addressed. See Attachment 3.

b. To more clearly communicate the requirements of the annual Quality Control review, Section 16.5 of the IMP Manual was changed to clearly state all the items under each part of the IMP processess that would be included in this review. This was done by removing the "would" statements and replacing them with "that are used" statements and confirming the items included under each category.

   See attachment 4.

c. In Section 16.7 of the written IMP, EPPG explains that when EPPG hires a contractor to perform a covered task in conjunction with integrity management activities that the qualifications are documented through Veriforce, our contracted agent for maintaining OQ qualification records. These individuals are evaluated against El Paso task standards or equivalent by qualified evaluators. Other contractor qualifications that do not overlap with OQ and that EPPG believe are necessary are covered under the procurement specifications. Based on the above, EPPG believes adequate specifications are in place for contractor qualifications that could affect the quality of the program and are unaware of specific examples of where qualification specifications are missing. However, if PHMSA has specific examples of where EPPG is missing these specifications, EPPG would appreciate the feedback.

NOA Item 4

Regulatory reference: 192.915(a)
Text of NOA: 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.*

EPPG Response:

a. Rule 192.915 states "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 has existing procedures established in the Human Resources staffing process and performance evaluation process for these positions within the Company.

   To clearly tie this process to the IMP the following paragraph has been added to IMP Manual Section 20.3 under the "Supervisory Personnel" heading:

   > The training or experience requirements for someone performing a supervisory role are based upon EPPG's Human Resources staffing process and performance evaluation process for their position within EPPG. Management selects individuals based on their demonstrated knowledge, skills and abilities in performing position responsibilities (documented in the EPPG evaluation process) that would be applicable for performing in a supervisory role that includes IMP responsibilities.

b. Specific qualifications for personnel who carry out assessments and evaluate results are clearly and comprehensively established in Section 20.3 under the heading ""Persons who carry out assessments and evaluate assessment results." As part of continuous improvement and to document a process step that has already been taking place the sentence "The list of qualified persons will be reviewed each year and authorized by the IMP Committee" has been added to the end of this section.

c. As with individuals performing supervisory roles in the IMP described in response "a" above, training and qualifications of individuals executing activities within the IMP are specified in EPPG's Human Resource staffing processes. Individuals that execute IMP activities are selected based on management's assessment of their competency to perform these duties. These competencies are reviewed annually through the Performance Management Process. EPPG agrees, as part of continuous improvement, to add specific qualification for key positions within the IMP. These qualifications have been added to the IMP Manual Section 20.3 under a new heading entitled "Qualifications of IMP Team and Committee Leaders."

See attachment 5.

NOA Item 5

Regulatory reference: 192.917(a)
Text of NOA: EPPG 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.

EPPG Response: EPPG, as part of continuous improvement, will include additional detail for the Threat Identification Process (TIP) charts to describe criteria for decision boxes, tie specific data to questions, and provide additional explanatory notes as necessary. See attachment 6 for a draft of the detailed tables for the TIP charts to be included in Appendix A of the IMP Manual. These tables are being reviewed internally as part of the Management of Change process outlined in the IMP Manual Chapter 15. Once the MOC process is complete these changes will be published and we will provide PHMSA with a copy.

However, EPPG does consistently apply the TIP charts across the five pipelines and across all HCAs through centralized data collection and centralized initial answering of the TIP questions plus automated calculation of the threats. Then, after receiving the IMP Training to emphasize consistency, the Subject Matter Experts (SME) review the threats to each HCA. Any changes made to the TIP questions (during SME review or at anytime) require a comment to document the change. Without a comment, the IMP Database will not accept the change. Also, to ensure consistent application, the BAP MOC process in Chapter 4 is followed for approval and communication of changes to the Baseline Assessment Plan.

PHMSA noted in the NOA that TIP charts A-1 (External Corrosion) and A-4 (Manufacturing) were completed.

NOA Item 6

Regulatory reference: 192.917(c)
Text of NOA: 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.*

EPPG Response:
EPPG has modified the external corrosion TIP chart to indicate that external corrosion is a threat for each HCA. Also, the manufacturing threat in certain circumstances has been changed from a "No Threat" to a "Stable Threat" to indicate the threat exists but appropriate actions have been taken. For instance, if pre-1970 ERW pipe has been pressure tested, it is consider a stable threat. These changes to TIP charts A-1 and A-4 were provided to PHMSA on March 30, 2007.

a. EPPG's use of leak history in the external (A-1) and internal (A-2) corrosion TIPs is both valid and appropriately conservative based on the fact that ILI tools are a proven technology for evaluating both external and internal corrosion on a pipeline. Therefore, since ILI is a confirming evaluation of the external and internal corrosion threats in the pipeline segment at that point in time and both of these threats are time dependent threats, the ILI information supersedes the past corrosion leak history. Please note that past leak history is utilized if an ILI has not been conducted for an HCA.
b. EPPG has completed three reviews of the incorrect operations threat for the entire EPPG pipeline system and provided the first two reviews to PHMSA during the audit. The relevant information, processes, and procedures related to a review, analysis, and determination of the incorrect operations threat are broader than a specific pipeline segment. Therefore, it is appropriate to perform this type of review or study of the entire system to determine if any specific locations or operating areas have this threat. In the system wide review, if any areas are determined to have the incorrect operations threat, the HCAs in that area are designated with the incorrect operations threat. In fact, by not limiting the study to

HCAs or nearby locations and reviewing data on the entire system, this approach is more conservative. This process is described in Appendix A-8.

NOA Item 7

Regulatory reference: 192.917(c)
Text of NOA: 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 msut 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 form modifiedinspection 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.*

EPPG Response: EPPG has modified the list of objectives for risk assessment and threat identification to include all those listed in B31.8S and to add specific references to where these objectives are being met in the IMP Manual. The changes to Section 3.2 of the IMP Manual were provided to PHMSA on March 30, 2007.

NOA Item 8

Regulatory reference: 192.917(e)(1)
Text of NOA: 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.

EPPG Response: EPPG has revised the preventive and mitigative (P&M) measures selection process to provide additional definition for adequate levels of P&M for threats associated with an HCA, including third party damage. It includes a complete replacement of Table 12-1 with a more detailed table that is the new Appendix I. Also, the P&M measures for each individual HCA have been identified, documented in the IMP Database, and communicated to the Operating Areas. The changes to Chapter 12 and the new Appendix I were provided to PHMSA on March 30, 2007.

NOA Item 9

Regulatory reference: 192.921(a)(1)
Text of NOA: 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 tie presence of multiple cause anomalies.

EPPG Response: EPPG has over 20 years of experience in the utilization of ILI tools for the purposes of inspecting pipelines to locate areas of wall loss and/or dented pipe. In the BAP, the term ILI is intended to provide for caliper/deformation inspections as well as high resolution MFL inspections. These assessments will address the corrosion threats as well as some latent third party damage.

EPPG has working relationships with established ILI vendors who have demonstrated their ability to provide both capable tools and analysts to produce quality inspection results. Individual tool and system specifications are available and understood prior to awarding contracts. Individual pipeline segment data is provided to and reviewed by the vendors before inspection tools are mobilized and set up for the inspections.

As part of EPPG's ILI Technical Procurement Specification, tool vendors are required to provide specification summary sheets that address anomaly detection and sizing capabilities, location and orientation accuracy and anomaly classification criteria.

NOA Item 10

Regulatory reference: 192.925(b)(1)
Text of NOA: 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.*

EPPG Response: EPPG has modified language in Section 6.5 and Table 6-1 to better define which data elements are required for feasibility and which are required for tool selection and defining regions. Also, language was added to Section 6.5, Feasibility Assessment, to describe data integration and analysis for determining ECDA feasibility.

The language in each of the 4 steps of the ECDA process were modified to provide more guidance when applying the more restrictive criterion for first time ECDA assessments.

These changes to Chapter 6 were provided to PHMSA on March 30, 2007.

NOA Item 11

Regulatory reference: 192.925(b)(2)
Text of NOA: 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.*

EPPG Response: PHMSA noted that this item was complete based on the modifications made to Chapter 6 (ECDA) of the IMP Manual and the ECDA Workbook that is used when conducting an ECDA project.

NOA Item 12

Regulatory reference: 192.925(b)(3)
Text of NOA: 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 signficant 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.*

EPPG Response: PHMSA noted that this item was complete based on the modifications made to Chapter 6 (ECDA) of the IMP Manual.

NOA Item 13

Regulatory reference: 192.925(b)(4)
Text of NOA: EPPG 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.

EPPG Response: PHMSA noted that this item was complete based on the modifications made to Chapter 6 (ECDA) of the IMP Manual.

NOA Item 14

Regulatory reference: 192.927(c)(4)
Text of NOA: 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.*

EPPG Response: PHMSA noted that this item was complete based on the modifications made to Chapter 7 (ICDA) of the IMP Manual. These modifications included adding a new paragraph to Section 7.7 "Identification of Locations for Excavation and Direct examination" that describes the specific actions taken if internal corrosion is found during the ICDA process. They also included adding language specifying monitoring for internal corrosion for segments where ICDA was conducted and internal corrosion was found. Requirements for subsequent actions if internal corrosion is found during the ICDA process were included.

NOA Item 15

Regulatory reference: 192.933(a)
Text of NOA: 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.

EPPG Response: EPPG has revised pressure reduction calculations in the Pipeline Operating Procedures Manual (POP) Section 306 procedure. The modifications were provided to PHMSA on March 30, 2007. Also, see attachment 7.

NOA Item 16

Regulatory reference: 192.933(b)
Text of NOA: EPPG must revise 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).

EPPG Response: To provide clarity, EPPG modified the language in POP 306 to provide more detail and guidance to the reviewer of the ILI final report data on what is adequate information to declare "Discovery of Condition." It includes what information is required to be reviewed and correlated to determine whether immediate integrity concerns exist within an HCA and when discovery of condition is identified. The modifications were provided to PHMSA on March 30, 2007. Also, see attachment 7.

NOA Item 17

Regulatory reference: 192.933(c) and 192.933(d)(1)
Text of NOA: 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.*

EPPG Response: EPPG does define the maximum timeframe for evaluation of assessment data for ILI reports in section 10.4 of the IMP Manual and in practice promptly reviews the ILI results to trigger the Discovery of Condition. However, in the spirit of continuous improvement, EPPG has modified the POP 306 procedure to provide guidance on the expected timelines required for review of ILI data and the corresponding timelines associated with establishing a Discovery of Condition.

EPPG prioritizes anomalies in POP 306 as immediate, one-year, scheduled, and monitored conditions. In addition to performing remediation on immediate conditions before scheduled conditions within HCAs, it is EPPG's intention to perform all scheduled remediation within an HCA during the same mobilization, and all scheduled remediation will be completed on a pipeline piggable segment within two calendar years of the assessment date. Because of this quick action on all actionable anomalies per POP 306 an additional prioritization of scheduled anomalies does not add to the safety or integrity of the pipeline. If there are multiple HCAs within a pipeline piggable segment, EPPG uses work efficiency and practical construction scheduling to prioritize anomaly remediation.

The modifications to POP 306 were provided to PHMSA on March 30, 2007. Also, see attachment 7.

NOA Item 19

Regulatory reference: 192.933(d)(3)
Text of NOA: 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.

EPPG Response: EPPG does conduct a review of these monitored conditions to determine if excavation is warranted under the additional scheduled conditions step in POP 306. However, in the spirit of continuous improvement, EPPG added language and guidance for definition and identification of "monitored conditions" as part of the review of final ILI report data in POP 306. These "monitored conditions" will be listed in the final response report and documented such that they can be included in future risk assessments and monitored for change during any subsequent integrity assessment. This was primarily a nomenclature change. The modifications to POP 306 were provided to PHMSA on March 30, 2007. Also, see attachment 7.

NOA Item 20

Regulatory reference: 192.935(a)
Text of NOA: 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.*

EPPG Response: EPPG has revised the preventive and mitigative (P&M) measures selection process to provide additional definition for adequate levels of P&M for threats associated with an HCA. It includes a complete replacement of Table 12-1 with a more detailed table that is the new Appendix I. Also, the P&M measures for each individual HCA have been identified, documented in the IMP Database, and communicated to the Operating Areas as of June 2007. The changes to Chapter 12 and the new Appendix I were provided to PHMSA on March 30, 2007.

EPPG completed an initial Automatic Shut-off Valve (ASV) and Remote Control Valve (RCV) analysis and identified in the IMP Database the P&M measure for each HCA currently protected by one of these devices.

NOA Item 21

Regulatory reference: 192.935(b)(1)
Text of NOA: EPPG must revise its procedures to ensure that 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.

EPPG Response: Whenever EPPG is made aware of an excavation (in or out of HCAs) that could affect our pipeline (through One-Call or through direct notification), there is someone present to monitor excavations to ensure that the facilities are not damaged. When EPPG finds evidence of an excavation that was done without notification, EPPG generally excavates the area of indication to determine whether the pipeline was damaged. If such an area is not excavated by EPPG, an above-ground electrical survey is conducted to determine whether coating damage has occurred or whether additional investigations might be needed.

EPPG has modified language for above ground surveys related to unmonitored excavations near our pipeline (192.935(b)(1)(iv) situations) to remove close interval survey (CIS) and more clearly define our processes for above ground surveys if we do not dig the pipeline. This exact change was completed in IMP Manual Sections 12.5 and 12.10, plus in O&M Manual Section 301 Item 2. The revised IMP Manual sections were provided to PHMSA on March 30, 2007.

NOA Item 23

Regulatory reference: 192.937(a) & (b)
Text of NOA: 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.*

EPPG Response:

a. EPPG utilizes the HCA Final Review process described in section 11.4 of the IMP Manual as the primary action item for periodic evaluation. The HCA Final Review process goes into great detail about the assessment, follow-up mitigation, re-assessment interval, and preventive and mitigative measures review. This process will be completed within 2 years after the last assessment date for an HCA. In addition, at the beginning of each year EPPG collects and documents the assessment information on HCAs assessed in the previous year and re-evaluates the threats for those HCAs based on the assessment and immediate remediation data. At the time of the IMP Audit this was not specifically identified in the IMP Manual even though it was scheduled and tracked in EPPG's work management system (Maximo). This step has been officially added to Chapter 11 as "First Quarter HCA Integrity Assessment and Threat Review" and to the Calendar in Appendix D. The revised procedures in Chapter 11 and Appendix D were provided to PHMSA on March 30, 2007.

b. The HCA Final Review for all HCAs with integrity assessments and completed follow-up remediation were finished in August 2007.

If you have any questions or need additional information, please contact Charlie Childs at 713-420-4236.

Sincerely,

Dan Martin
Senior Vice President Operations
El Paso Pipeline Group

On Behalf of ANR Pipeline Company

David Montemurro
Vice President

cc:	D. Chittick	C. Childs
	D. Waterson	D. Bowmaster
	B. Friis	P. Carey
	J. Soto	

Attachments:

1. Chapter 18 modifications.
2. Chapter 15 modifications.
3. John Pepper 6-23-2006 E-mail.
4. Chapter 16 as modified.
5. Chapter 20 modifications.
6. Additional detail tables for Threat Identification Processes
7. POP 306 as modified

ATTACHMENT 1

CHAPTER 18 – MODIFICATIONS

Chapter 18 Notification of Regulatory Agencies

18.1 Scope

The Integrity Management Program includes provisions for notification to governmental authorities regarding the Company program. This chapter describes the notifications that are a part of the plan that are not already covered in other EPPG policies and procedures.

18.2 Company Compliance

EPPG will make notifications and reports to Office of Pipeline Safety (OPS) and state authorities as required in this chapter. Reporting related to integrity management issues on covered pipeline segments that are a part of EPPG's interstate facilities will be made to the OPS (and in some cases described below to a state pipeline safety authority). Reporting related to covered segments that are a part of EPPG's intrastate facilities will be made to the appropriate state pipeline safety authority.

These submittals include:

Risk analysis or written integrity management program

192.911(n); OPS Protocol N.1

At the request of OPS, a pipeline safety authority in a state where OPS has an interstate agent agreement, or a pipeline safety authority having jurisdiction over intrastate pipelines that are located in High Consequence Areas, EPPG will submit a copy of any of the following:

- The current risk analysis on a covered pipeline segment within the jurisdictional boundaries of the agency, or
- The written integrity management program

Use of other technology as an assessment method

192.921(a)(4); OPS Protocol B.1.g

If EPPG intends to use an integrity assessment method that it believes will provide an understanding of a pipeline's condition that is at least equivalent to that provide by internal inspection tools, pressure testing, or direct assessment, notification will be made at least 180 days before using the technology. EPPG will fully describe the method and document reasons for concluding that the method is suitable. A schedule for assessment will also be included. For interstate pipelines subject to this program, the notification will be made to OPS and to the pipeline safety authority in a state where OPS has an interstate agent agreement. For intrastate facilities, the notification will be made to the OPS and the state pipeline safety authority having jurisdiction.

Deviation from assessment schedule

192.943

If a waiver is needed because of delays to the assessment schedule due to inability to acquire the use of internal inspection tools or due to the adverse affect to the public as a result of the supply disruption that accompanies the assessment, it must be filed with the OPS (state pipeline safety authority for intrastate facilities) within 180 days of the scheduled assessment. If an unforeseen supply disruption issue arises where the 180 day submittal period is not practical, EPPG will file the petition as soon after the need for the waiver becomes known.

- For waiver requests submitted because of inability to obtain the use of an internal inspection device, EPPG will include with its waiver request documentation demonstrating that its efforts to obtain the devices justify the delay and a descriptions of what actions it will take in the interim to ensure the integrity of the covered segment.
- For waiver requests submitted because of an outage needed for the assessment of a covered segment will result in an unacceptable supply disruption, EPPG will document why supply cannot be maintained at acceptable levels.

Inability to meet remediation schedule

192.933(c); OPS Protocol C.3.c

If a condition exists on a covered segment that cannot be remediated within the time constraints described in Chapter 10, and EPPG is unable to temporarily reduce the operating pressure to a safe level or take other temporary measures to provide safety until the condition is remediated, notification will be filed as soon as practical after this is apparent. For interstate pipelines subject to this program, the notification will be made to OPS and to the pipeline safety authority in a state where OPS has an interstate agent agreement. For intrastate facilities, the notification will be made to the OPS and the state pipeline safety authority having jurisdiction. The notification will include documentation explaining why the schedule cannot be met and why temporary measures cannot be taken and how the health and environment will not be jeopardized as a result of delayed remediation. Schedules for repairs or other planned mitigative actions will be included in the notification.

Semi-annual performance reports

192.945

Performance measures described in Chapter 13 must be reported semi-annually to the OPS. Reports covering the performance of the program for the six months ending June 30 of each year must be submitted by August 31of the same year. For the six months ending December 31 of each year, the report must be submitted by the last day of February the following year.

Significant changes to the program

192.909(b); OPS Protocol K.1.b

EPPG will make notification within 30 days after implementation of any changes that materially and substantially affect the overall implementation of the program, and those that could result in significant changes in how or when elements of the program are accomplished. For interstate pipelines subject to this program, the notification will be made to OPS and to the pipeline safety authority in a state where OPS has an interstate agent agreement. For intrastate facilities, the notification will be made to the OPS and the state pipeline safety authority having jurisdiction. EPPG will include a description of each change made and an explanation for why the changes were made in its notification.

The IMP Committee will determine what changes to the Baseline Assessment Plan or IMP Manual are significant. Significant changes may include changes to the manual that modify the intent of EPPG's program, how the program is to be implemented, and changes due to regulatory updates. Significant changes do not include editorial changes, minor changes to content, or changes anticipated to occur to baseline assessment schedules due to circumstances such as weather, permitting delays, or re-ranking schedule priorities due to updated risk assessment information. Examples of items that would be considered a significant change requiring notification are:

- Change in HCA mileage for any one company by more than 20%.
- Change in HCA calculation method for one operating company.
- A single acquisition or divestiture of facilities resulting in a change in HCA mileage greater than 10%.

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18.3 Processes for Compliance

OPS and State Notifications

Whenever a change or notification or waiver request involves one or more specific pipeline segments in an HCA, EPPG will include a thorough description of the affected pipe segments and the HCA involved, including the threat(s) being addressed and any information that will allow the OPS (or state pipeline safety authority as applicable) to understand and evaluate the request. The name, title, telephone number, and e-mail address of the IMP Administrator will be provided in each notification, waiver request, or report for purposes of providing a central contact individual for EPPG.

The table 18-1 shows where and how notifications and reports may be filed with OPS.

Table 18-1 – OPS Notification Information

Type of Communication:	Method:	Contact Information
Notifications:	Mail:	Information Resources Manager Office of Pipeline Safety Research and Special Programs Administration U.S. Department of Transportation Room 7128 400 Seventh Street, SW Washington, DC 20590
	Facsimile:	Information Resources Manager (202) 366–7128
	Online:	Integrity Management Database (IMDB) Web site at http://primis.rspa.dot.gov/gasimp
Reports:	Mail:	Information Resources Manager Office of Pipeline Safety Research and Special Programs Administration U.S. Department of Transportation Room 7128 400 Seventh Street, SW Washington, DC 20590
	Facsimile:	(202) 366–7128
	Online Reporting System:	OPS Home Page at http://ops.dot.gov

The following shows the contact information for notifications and reports that are to be made to state pipeline safety authorities under this chapter:

Alabama

Alabama Public Service Commission
Gas Pipeline Safety
RSA Union Building
100 North Street, 9th Floor, Suite 986
Montgomery, AL 36104
Phone: 334.242.5778
Fax: 334.242.0687
Interstate Agent for OPS? No
Any EP Facilities Subject to this State's Jurisdiction? Yes

Arizona

Arizona Corporation Commission
Pipeline Safety Group
2200 North Central, Suite 300

Phoenix, AZ 85004
Phone: 602.262.5601
Fax: 602.262.5620
Interstate Agent for OPS? Yes
Any EP Facilities Subject to this State's Jurisdiction? Yes

Connecticut

Connecticut Department of Public Utility Control
10 Franklin Square
New Britain, CT 06051
Phone: 860.827.2604
Fax: 860.827.2613
Interstate Agent for OPS? Yes
Any EP Facilities Subject to this State's Jurisdiction? No

Florida

Florida Public Service Commission
Safety Division of Safety and Electric
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0868
Phone: 850.413.6650
Fax: 850.413.6651
Interstate Agent for OPS? No
Any EP Facilities Subject to this State's Jurisdiction? Yes

Georgia

Georgia Public Service Commission
Pipeline Safety Office
244 Washington Street, SW, Suite 524H
Atlanta, GA 30334-5701
Phone: 404.463.6526
Fax: 404.463.6532
Interstate Agent for OPS? No
Any EP Facilities Subject to this State's Jurisdiction? Yes

Iowa

Iowa Utilities Board
Safety and Engineering Section
350 Maple Street
Des Moines, IA 50319-0069
Phone: 515.281.5546
Fax: 515.281.5329
Interstate Agent for OPS? Yes
Any EP Facilities Subject to this State's Jurisdiction? No

Michigan

Michigan Public Service Commission
Safety Section
6545 Mercantile Way
Lansing, MI 48909
Phone: 517.241.6142
Fax: 517.241.6121
Interstate Agent for OPS? Yes
Any EP Facilities Subject to this State's Jurisdiction? Yes

New York

New York Public Service Commission
Safety Section
Office of Gas and Water
#3 Empire State Plaza
Albany, NY 12223-1350
Phone: 518.486.2496
Fax: 518.473.5625
Interstate Agent for OPS? Yes
Any EP Facilities Subject to this State's Jurisdiction? No

Ohio

Public Utilities Commission of Ohio
Gas Pipeline Safety Section
180 East Broad Street, 7th Floor
Columbus, OH 43215-3793
Phone: 614.644.8983
Fax: 614.728.4319
Interstate Agent for OPS? Yes
Any EP Facilities Subject to this State's Jurisdiction? Yes

South Carolina

Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, SC 29210
Phone: 803.896.5166 or 803.896.5193
Fax: 803.896.5199
Interstate Agent for OPS? No
Any EP Facilities Subject to this State's Jurisdiction? Yes

Texas

Railroad Commission of Texas
Gas Services Division
1701 N. Congress, 9th Floor, Room 9-160 C
Austin, TX 78701
Phone: 512.463.7058
Fax: 512.463.7319
Interstate Agent for OPS? No
Any EP Facilities Subject to this State's Jurisdiction? Yes

18.4 Roles and Responsibility

All submittals will be issued from the IMP Executive Steering Committee. Specific responsibilities for developing the report for review by the IMP Committee for submittal by the IMP Executive Steering Committee are shown in the table below:

Responsible Committee or Team(s)	Document
IMP Risk Assessment Team	Risk Analysis
IMP Committee	Integrity Management Program
IMP Implementation Team	Notification of Other Assessment Method
IMP Implementation Team	Deviation from Assessment Schedule
IMP Implementation Team	Deviation from Remediation Schedule
IMP Administrative Team	Semi-annual Performance Report
IMP Committee	Significant changes to the Integrity Management Program

ATTACHMENT 2

CHAPTER 15 – MODIFICATIONS

Chapter 15 Management of Change

15.1 Scope

This manual, as well as manuals, processes and procedures referenced in this manual include Management of Change Procedures which affects the Pipeline Integrity Program. This Management of Change Procedures includes the following fundamental elements.

1. Defined regular reviews of existing procedures and processes.
2. Procedures for requesting one time variances or "waivers" from procedures or processes.
3. Procedure for proposing changes to procedures and processes.
4. Identification of review teams.
5. Procedures for Communication of changes Including:
6. Maintenance of a historical record of all changes.

15.2 Background

This chapter identifies both major and minor changes to the pipeline systems which may impact the integrity of the pipeline. These changes may be considered permanent or temporary, general or site specific. The documentation of changes shall include each of the following:

1. Technical Changes
2. Physical Changes
3. Procedural Changes
4. Organizational Changes

15.3 Procedure for Changes and Waivers

192.909; 192.911(k); OPS Protocol K

IMP Manual Change Management Procedure

Changes

Changes may be made to the IMP Manual using the process outlined below.

1. The IMP Manual will be reviewed annually by the IMP Committee.
2. Any EPPG employee may submit a written request for change to the IMP manual to any member of the Pipeline Services Department.

3. This request will be transmitted to the IMP Committee for consideration.
4. The requested change shall include the following:
   a) The name and contact information of the requestor.
   b) The chapter and paragraph of the IMP Manual affected by the change
   c) A detailed description of the change requested, the reason for the suggested change and justification for the requested change
5. All Changes will be Approved or Denied by the IMP Committee and authorized by the Executive Pipeline Integrity Steering Committee.

Waivers

A waiver is defined as an approval for a deviation from a procedure contained in the IMP Manual. Waivers will be limited in time and in area of application, unless classified as a "blanket waiver" in anticipation of a procedure change. Waivers to specific provisions of the IMP Manual may be issued using the process outlined below.

1. Requests for Waivers to the IMP Manual may be made by any EPPG manager by submitting a Request for Waiver to any member of the Pipeline Services Department.
2. This request will be transmitted to the IMP Manual Review Team for consideration.
3. The request shall include the following minimum information.
   a) The name and contact information of the requestor.
   b) The chapters and sections of the IMP manual affected by the Waiver.
   c) Requested time limitations and area of application.
   d) A detailed description of the suggested Waiver, the reason for the suggested Waiver the justification for the requested Waiver.

All Waivers will be Approved or Denied by the IMP Committee and Authorized by the Executive Pipeline Integrity Steering Committee

15.4 Communication of Changes and Waivers

Communication of IMP Manual Changes shall be made as outlined below:

1. All Changes to the IMP Manual will be communicated to the Pipeline Integrity Committee, Operations Directors, Engineering Directors and the Directors of other departments who the Pipeline Integrity Committee believes may be affected by the change.
2. The Communication of Change to the IMP Manual will include

a) The effective date of the change

b) Description of the specific change made to the manual

c) Chapters of the IMP Manual that change will affect

d) Other Manuals that may be affected by the change along with a request for change to the effected manual or procedure in accordance with the appropriate change management process for that procedure or process.

3. The Director of each department receiving a change to the IMP Manual shall be responsible for communicating this change throughout their respective departments and making arrangement to accommodate any required training, qualifications, or evaluations.

4. The Department Director responsible for a manual which is affected by this change will be responsible for ensuring that any changes needed to the supporting manual or procedure are made and communicated in accordance with that manual's established Management of Change Process.

5. Significant changes to the IMP Manual shall be reported to the OPS and other State or Local authorities.

Communication of IMP Manual Waivers shall be made as outlined below:

1. Waivers to the IMP Manual will be communicated to the Pipeline Integrity Committee, Operations Directors, Engineering Directors and the Director of any other department who the Executive Pipeline Integrity Steering Committee believes may be affected by the change.

2. The Communication of Change to the IMP Manual will include

   a) Description of the waiver

   b) Chapters of the IMP Manual that waiver affects

   c) The limitations and area of application for the waiver.

   d) Other Manuals that may be affected by the Waiver along with a request for Waiver to the effected manual or procedure in accordance with the appropriate change management process for that procedure or process if appropriate.

3. The Director of each department receiving a Waiver to the IMP Manual shall be responsible for communicating this waiver throughout their respective departments.

In addition to the specific communications requirements of changes and waivers to the IMP Manual described above the provisions of the IMP Manual Chapter 17 (El Paso Communication Plan) shall be followed in their entirety.

15.5 Use of Record of Change Form

Recording Changes and Waivers to the IMP Manual

1. All Changes or Waivers of provisions in the IMP Manual will be permanently documented. This documentation shall include.
    - The provisions of the Change or Waiver
    - The reason for the Change or Waiver.
    - The communication Plan(s) followed for the Change or Waiver.
2. Changes to other Manuals, Procedures, Process, Engineering Records or Land Use Records shall be permanently documented utilizing the record or change process provided for these specific changes.

15.6 Results/ Documentation

The following manuals, procedures or processes are an integral part of the IMP program and are covered by the requirements of this chapter.

- Operations and Maintenance Manual
- Pipeline Operating Procedures Manual
- Corrosion Control Manual
- Coatings Manual
- Welding Manual
- NDE Manual
- Measurement Manual
- Manual of Engineering Standards
- Safety Handbook
- Technical Training Guidebook

15.7 Technical Changes

As integrity assessments are completed, changes to operations for the system may possibly be needed, e.g. improved cathodic protection. These changes may flow both from the system operations to the IMP and, as a result of determinations made by integrity management processes, from the IMP back to the system.

As new technologies are developed, some of these may be incorporated into IMP processes and procedures. These shall be communicated to appropriate staff and procedures for any new technology documented.

15.8 Physical Changes

Physical changes to the pipeline system which may affect Pipeline Integrity shall be documented and communicated in accordance with existing procedures and processes. The following is a listing of the procedures and processes currently in place to record and communicate these changes.

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Procedures	Location	Responsibility
Corrosion Control	Paradigm	Pipeline Services
Laboratory Results	TSIMS	Pipeline Services
Physical Changes and Inspections	As-Built Process Pipeline Inspection and Repair	Engineering
Abnormal Operations	AOR Reports	Compliance Services
Engineering Standards	MES Manual	Engineering Department

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Examples of management of change processes built into existing processes and the IMP processes are:

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1. Consideration of impacts of changes to pipeline systems and their integrity
    - Review and recalculation of HCA limits each year per IMP Manual Chapter 1 which includes consideration of impacts of new or changed structures, new or abandoned pipelines, and changes in OD or MAOP of existing pipelines.
    - Quarterly review of threat flags and alerts based on new and current data per IMP Manual Section 3.3 and Appendix A.
    - Annual Incorrect Operations and Equipment review which includes review that is detailed in Appendix A-6 and A-8.
    - Annual cyclic fatigue study done as part of the annual threat analysis process described in IMP Manual Chapter 3.
    - Gas Quality Waiver communication requirements in the Gas Quality Guidelines.
2. Analysis of the implications of planned changes, including review of equipment and system changes

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- MAOP Uprate process per O&M Manual Section 207.
- Process Safety Initiative Program.
- Hazardous Operations Plans - in Safety & Health Handbook

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3. Ensuring IMP changes are properly reflected in pipeline system and pipeline system changes are properly reflected in the IMP

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- The effect of IMP changes on the pipeline system are evaluated in sections 15.3, 15.4 and 4.9.
- Final Review for HCAs after integrity assessments and remediation is complete per IMP Manual Section 11.4.
- Future mitigation plans per POP 306 section 6.
- Review of maximum recommended discharge temperatures per Corrosion Control Mannual section CORR-015.
- Physical changes made to the pipeline or observations made concerning the condition of the pipeline are communicated through a variety of mechanisms such as the as-built records process, Pipeline Inspection Reports, Pipeline Encroachment Reports and Pipeline Repair Reports.

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15.9 Organization Changes

Organizational changes that would affect the IMP Manual will be documented and communicated as specified in Chapter 17.

15.10 Training to Changes and Communicating Changes

It is the responsibility of the director of a department affected by any change communicated as described in Section 15.4 to ensure that the change has been appropriately communicated to all subordinates in the department and to ensure that appropriate training is provided and qualification requirements are met.

15.11 Roles and Responsibility

The organizational titles of individuals responsible for ensuring compliance with this chapter are as follows:

Responsible Party	Reports To	Manuals
Director Compliance Services	Vice President Operations Services	O&M Manual Technical Training Guide

Responsible Party	Reports To	Manuals
Director Pipeline Services	Vice President Operations Services	POP Manual Corrosion Manual Coatings Manual NDE Manual Welding Manual
Director Measurement Services	Vice President Operations Services	Measurement Manual
Director Plant Services	Vice President Operations Services	Plant Operating Procedures Manual
Director of Engineering Services	Senior Vice President of Engineering and Chief Engineer	Manual of Engineering Standards
Director Environmental and Health Services	Sr. VP Operations	Safety and Health Handbook Environmental Handbook

ATTACHMENT 3

JOHN PEPPER E-MAIL (06-23-2006)

Childs, Charles C (Charlie)

From: John.Pepper@dot.gov
Sent: Friday, June 23, 2006 9:42 AM
To: Childs, Charles C (Charlie)
Cc: John.Pepper@dot.gov
Subject: RE: Questions on 1st Week Issues from IMP Audit - EPPG

Thanks Charlie. Your response below should be sufficient.

thanks.
John W. Pepper
CATS Project Manager
PHMSA, Pipeline Safety Program
8701 South Gessner, Suite 1110
Houston, Texas 77074
Office 713-272-2849
Cell 713-826-3575
Fax 713-272-2831
john.pepper@dot.gov

From: Childs, Charles C (Charlie) [mailto:Charlie.Childs@ElPaso.com]
Sent: Wednesday, June 21, 2006 3:00 PM
To: Pepper, John <PHMSA>; timf@cycla.com
Cc: Chin, John S; Carey, Patrick F (Pat); Bowmaster, David Lynn (Dave)
Subject: RE: Questions on 1st Week Issues from IMP Audit - EPPG

I hope you had a good vacation and are enjoying your training class.

We are finalizing our responses to the week three issues and I remembered that I was waiting for a response from you on one issue. Here it is:

48. Detailed responsibilities and authorities for some key elements of the integrity management program have not been defined in IMP documentation. [L.01.a]

EPPG Response: Waiting for Response from PHMSA (was 16 in week 1 audit):
On 4/24/2006 e-mailed John Pepper asking
"For item 16, neither I nor John Chin remembers reviewing that particular protocol. Were we planning on reviewing this next week? We do have responsibilities and authorities defined in the IMP. The overall responsibilities and authorities are laid out in the introduction under the IMP Administration section. Specific responsibilities are designated at the end of each chapter in the Roles and Responsibilities sections. Then some of the processes have even more detailed designations of responsibilities."

Is this response to this issue acceptable or do you have particular areas of the EPPG IMP where we did not define responsibilities clearly enough?

Welcome back!

Charlie Childs
Pipeline Integrity Consultant
elpaso
713-420-4236
Cell 281-732-1865
Charlie.Childs@elpaso.com

From: Childs, Charles C (Charlie)
Sent: Monday, April 24, 2006 2:48 PM
To: John Pepper (John.Pepper@DOT.gov); Tim Floyd (timf@cycla.com)
Cc: Chin, John S; Carey, Patrick F (Pat); Bowmaster, David Lynn (Dave)
Subject: Questions on 1st Week Issues from IMP Audit - EPPG

I wanted to thank you again for the professional manner of your audit team last week. I believe the information and discussions (debates too) were helpful for us and I hope you and your team got an accurate and clear picture of our IMP.

We have done a preliminary review of the issues and I have questions on two of the items.

1. On item 11 what objectives of risk assessment were not supported?
    11. The risk assessment approach documented in Chapter 3 does not support all objectives of risk assessment specified in ASME B31.8S, Section 5. [C.03.a]

2. For item 16, neither I nor John Chin remembers reviewing that particular protocol. Were we planning on reviewing this next week? We do have responsibilities and authorities defined in the IMP. The overall responsibilities and authorities are laid out in the introduction under the IMP Administration section. Specific responsibilities are designated at the end of each chapter in the Roles and Responsibilities sections. Then some of the processes have even more detailed designations of responsibilities.
    16. Detailed responsibilities and authorities for some key elements of the integrity management program have not been defined in IMP documentation. [L.01.a]

See you next Monday!!

Charlie Childs
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Charlie.Childs@elpaso.com

ATTACHMENT 4

CHAPTER 16 – (AS MODIFIED)

Print this Section

Integrity Management Program	Chapter 16
Quality Control	Revision Date 10/12/2007

Chapter 16 Quality Control

16.1 Scope

192.911 ; **B31.8S Section 12**

This chapter describes EPPG's Quality Control measures to verify the implementation and effectiveness of the Integrity Management Program.

16.2 Background

B31.8S 12.1

Quality control is the documented proof that all of the requirements of EPPG's Integrity Management Program are being met. A good quality control program includes the following.

B31.8S 12.2

1. Documentation, implementation and maintenance activities, including requirements that will:
   a. Identify the processes that will be included in the quality program.
   b. Determine the sequence and interaction of these processes.
   c. Determine the criteria and methods needed to ensure that both the operation and control of these processes are effective.
   d. Provide the resources and information necessary to support the operation and monitoring of these processes.
   e. Monitor, measure, and analyze these processes.
   f. Implement actions necessary to achieve planned results and continued improvement of these processes.
2. Within this IMP are some specific requirements that address quality control issues that are necessary components to a good quality control program. These requirements include the following:
   a. Determination the documentation requirements. Ensure that these documents are controlled and maintained at appropriate locations for the duration of the program. Examples of documented activities include risk assessments, the integrity management plan, and integrity management reports and data documents. (See Chapter 14, Record Keeping Requirements.)
   b. Clear and formal definition of the responsibilities and authorities under this program. (See Introduction and Roles and Responsibilities in each Chapter)
   c. Review of the integrity management program results and the quality control program at predetermined intervals, making recommendations for improvement. (Section 16.4 and 16.6)
   d. Use of competent people in implementing the integrity management program, making sure that they are aware of the program and all of its activities and that they are properly trained to execute the activities within the program. Documentation of such competence, awareness and qualification, and the processes for their achievement. (Section 16.5)

e. Determination of how to monitor the integrity management program to show that it is being implemented according to plan and document these steps and defining control points, criteria and/or performance metrics. (Section 16.5)

f. Periodic audit of the integrity management program and its quality plan. (Section 16.4 and 16.6)

g. Documentation of corrective actions for improving the integrity management program or quality plan. Monitoring for the effectiveness of their implementation. (Section 16.6)

16.3 Company Compliance

OPS Protocol L.1.a

The activities described in paragraph 16.2 are included in EPPG's quality control program. The IMP Administrative Team will ensure that each process, procedure, and schedule is reviewed and audited periodically under this quality control program.

The quality control program entails the review of the processes involved in carrying out the Integrity Management Program. The Quality Control process outlined in this chapter includes:

1. Program Evaluation
2. Annual audit and review of the Integrity Management Program
3. Corrective Action
4. Contractor Qualification

The interactions of the processes are described and illustrated in the Introduction Chapter of this written Integrity Management Program. The quality control program will assess whether these interactions are carried out in a satisfactory manner in addition to evaluating the individual aspects of the IMP as described in section 16.5.

The reviews under this program will be conducted as described in the Quality Control program evaluation and annual review processes described in sections 16.4 and 16.5 with any necessary enhancements to the Integrity Management Program made and documented in accordance with EPPG's Management of Change process.

16.4 Program Evaluation

OPS Protocol L.1.b

Quality assurance checks will be utilized to confirm that processes, procedures and schedules in the program are being followed. These checks will help identify areas where efforts need to be bolstered so that requirements of the program continue to be met or areas where program processes and procedures may need to be enhanced or fine tuned. Such quality assurance includes periodic analysis of program performance data to promote continual improvement.

Program evaluations are conducted on an ongoing basis. The IMP Administrative Team monitors program performance through periodic meetings of the IMP Committee and provides updates to the Pipeline Integrity Committee. The need for additional resources or adjustments to the program is discussed and actions approved at these update meetings for implementation.

Any needed program revisions that arise from these program performance reviews will be completed at least once each year or more often dependent upon the urgency of the change and will follow the Management of Change procedures in Chapter 15. Adjustments to processes, procedures or schedules will be assigned to the appropriate departments; technical teams or IMP teams by the Pipeline Integrity Committee through communications issued by the IMP Administrative Team. Insert any information about program evaluations already in place. For example, if Company has an audit process for existing procedures, that process should be incorporated in detail. Use of Integrity Management Program software should be detailed in this section. Describe software that generates reports to show changes in the lines as well as problem areas for additional preventive and mitigation actions and how this information is used in QA procedures. Any Company historical tracking of data should be detailed in this section.

16.5 Annual Review and Audit

Insert any information about annual reviews for existing procedures. EPPG's Integrity Management Program will undergo a formal annual review which will be completed no later than the end of 1st quarter each year.

This review will include the following items:

HCA Identification (Chapter 1)

OPS Protocol A.6

The following are check points that are used to determine whether processes and procedures are being followed for the HCA processes and procedures:

a. Determine if each HCA is adequately documented
b. Determine if usage for identified sites is adequately documented
c. Check to see that all HCAs that are documented are entered into the database
d. Check to see if that all HCAs are incorporated into the Integrity Management Program
e. Verify that the sources identified in Chapter 1, HCA Identification, for identifying identified sites were contacted
f. Determine if newly identified HCAs were missed during a previous review period
g. Determine if HCAs have been adjusted for any changes in pipe and maximum allowable operating pressures

Threat Identification / Risk Assessment (Chapters 2 and 3)

The following are check points that are used to determine whether the Threat Identification processes and procedures are being followed:

a. Verify that all nine threat categories been individually documented with rationale regarding whether the threat exists or not in each HCA.
b. Verify that the data gathered had been integrated and that it supports the conclusion regarding the existence of a threat.
c. Verify the risk assessment processes have been consistently applied to consider the threats in all covered segments in each HCA.
d. Check to see that prioritization is consistent with the risk ranking and that any deviation is documented with rationale.

Baseline Assessment Plan (Chapter 4)

The following are check points that are used to determine whether processes and procedures are being followed for the Baseline Assessment Plan:

a. Verify that the Baseline Assessment Plan is documented.
b. Confirm that milestone targets are scheduled in the plan (e.g., assessments of 50% of the segments are scheduled for completion by December 17, 2007)

c. Verify that any prior assessments used are documented as meeting the baseline assessment requirements for a covered segment.
d. Confirm that the assessment method chosen for any particular segment in an HCA is appropriate for the threat(s) being addressed.
e. If ECDA is used, verify that the surveys used are complementary.

Integrity Assessment (Chapters 5, 6, 7, 8, and 9)
The following are check points that are used to determine whether processes and procedures are being followed for Integrity Assessment:

a. Verify that assessments are or have been conducted as scheduled.
b. Confirm that any deviations from the schedule are documented with rationale and that appropriate notifications to OPS and state pipeline safety authorities have been made.
c. Verify that assessments performed by contractors follow EPPG policies and procedures.
d. Confirm that the assessment method chosen for any particular segment in an HCA is appropriate for the threat(s) being addressed.

Remediation (Chapter 10)
The following are check points that are used to determine whether processes and procedures are being followed for Remediation:

a. Verify that remedial measures are identified for integrity concerns discovered during the assessments and that they are categorized as immediate, scheduled and monitored.
b. Confirm that remediation is following the prescribed time restraints for immediate and scheduled conditions.
c. Verify that actions are adequately documented to show discovery date for each threat remediated, what method was used and when remediation was completed.

Final Review, Continual Evaluation and Assessment (Chapter 11)
The following are check points that are used to determine whether the Continual Evaluation and Assessment processes and procedures are being followed:

a. Verify that all segments that have been assessed are scheduled for re-assessment according to Chapter 11 guidelines.
b. Confirm that analysis used to support the re-assessment interval is documented.
c. Confirm that inspections and tests that suggest a pipeline condition different than assumed for establishing the re-assessment interval are evaluated for needed adjustments to the interval.

Preventive and Mitigative Measures (Chapter 12)
The following are check points that are used to determine whether processes and procedures are being followed for Preventive and Mitigative Measures:

a. Verify that preventive and mitigative measures are identified and documented for each pipeline segment in an HCA and that they exceed current regulatory requirements.
b. Confirm that qualifications for individuals locating, marking and monitoring excavations are

documented.

c. Verify that the risk analysis conducted to identify additional measures (e.g., ASV or RCV, computerized monitoring and leak detection systems, replacing with heavier wall pipe, additional emergency response training, and additional inspection and maintenance programs) for protecting the High Consequence Area are documented

d. Verify that areas subject to outside force damage are identified and that measures are identified for minimizing consequences.

e. Confirm that Class 3 and Class 4 locations that are not in HCAs are included in preventive and mitigative measures for pipelines operating under 30% of the SMYS.

Performance Plan (Chapter 13)

The following are check point tat are used to determine whether processes and procedures are being followed for the Performance Plan:

a. That the data is gathered for the identified metrics, including internal or external benchmarks.

b. If benchmarks are used, verify that their validity as measuring tools is documented.

c. That the evaluation of the metrics is accompanied with recommendations regarding changes to the Integrity Management Program.

d. That semi-annual report is filed on time with the OPS or the appropriate state pipeline safety authority.

e. That the semi-annual report covers the six-month periods ending June 30 and December 31 each year.

Management of Change (Chapter 15)

The following are check points that are used to determine whether the Management of Change processes and procedures:

a. That the rationale for all changes to the program is documented.

b. That the process for making a change was followed.

c. That the changes were communicated to the appropriate individuals in EPPG.

d. The significant changes are identified for notification to the OPS.

e. Utilization of IMP change log.

Communication Plan (Chapter 17)

The following are check points that are used to determine whether processes and procedures are being followed for the Communication Plan:

a. That any safety concerns raised by OPS or state pipeline safety authorities were addressed.

b. That any external communications are completed in accordance with any schedule that may be identified for its completion.

c. That internal communications are completed in accordance with Chapter 17.

d. That communications are documented.

Notification of Regulatory Agencies (Chapter 18)

The following are check points that are used to determine whether processes and procedures are being followed for Notification of Regulatory Agencies:

a. That the list of states and interstate agency status is current.
b. That the list of states having jurisdiction over EPPG facilities is current.
c. That contact information is current.
d. That all notifications, waivers and reports are filed to the appropriate agencies within the established time constraints.

Training and Operator Qualification (Chapter 20)

The following are check points that are used to determine whether processes and procedures are being followed for Training and Operator Qualification:

a. That individuals that performed covered tasks associated with the implementation of the program are documented as qualified in the Training Server and that the record is current.
b. That individuals that require qualification for tasks identified in 192.915(b) their credentials documented.
c. That training requirements are completed and documented.
d. That training records are up-to-date.

16.6 Corrective Action

OPS Protocol L.1.c

If the EPPG Integrity Management Program is found through this Quality Control process to be lacking in any aspect, changes to the Integrity Management Program shall be implemented according to the Management of Change process. Such changes shall be documented according to Chapter 15: Management of Change and the effectiveness of those changes shall be monitored via the Quality Control process.

16.7 Contractor Qualification

B31.8S 12.2; *OPS Protocol L.1.d*

When contractors are used to perform tasks that are associated with processes related to the implementation of the integrity management program (e.g., above-ground electrical surveys, in-line inspections of pipelines), they will be required to follow EPPG policies and procedures related to these activities. The qualifications of individuals that perform tasks subject to the Operator Qualification program will be documented in accordance with that program. Inspectors who oversee work performed by these contractors will report any observed deviations from these policies and procedures. Where inspectors are not used, the results of the work completed will periodically be reviewed for any indications of incorrect performance that could affect results.

16.8 Roles and Responsibility

The IMP Administrative Team is responsible for ensuring that the reviews required under this program are completed annually.

ATTACHMENT 5

CHAPTER 20 – MODIFICATIONS

Chapter 20 Training and Qualifications

20.1 Scope

192.915

This chapter describes the qualifications of personnel that perform supervisory and implementation roles in EPPG's Integrity Management Program.

20.2 Background

192.915; B31.8S 12.2.b.4

Supervisory personnel whose responsibilities relate to the integrity management program shall obtain and maintain a thorough knowledge of the program, in particular those elements for which they are responsible.

Persons who carry out assessments and evaluate assessment results must be qualified. This includes persons:

1. Who conduct an integrity assessment; or
2. Who review and analyze the results from an integrity assessment and evaluation; or
3. Who make decisions on actions to be taken based on these assessments.

Individuals that perform the following must be qualified:

1. Implement preventive and mitigative measures of this program, including the marking and locating of buried structures; or
2. Directly supervise excavation work carried out in conjunction with an integrity assessment.

20.3 Company Compliance

192.915; OPS Protocol L.2

Supervisory Personnel

All supervisors that have program responsibilities must complete Integrity Management Program Overview training and, every 5 years, complete a refresher. For new supervisors the training should be completed within 90 days.

The education, experience and training that a supervisor has may include, but is not limited to:

- Industry courses, symposiums, roundtables, or seminars
- Training conducted by technical vendors
- Internal training and development courses

- Courses or degree programs from an institution of learning
- On-the-job experience

The training or experience requirements for someone performing a supervisory role are based upon EPPG's Human Resources staffing process and performance evaluation process for their position within EPPG. Management selects individuals based on their demonstrated knowledge, skills and abilities in performing position responsibilities (documented in the EPPG evaluation process) that would be applicable for performing in a supervisory role that includes IMP responsibilities.

Persons who carry out assessments and evaluate assessment results

Individuals that are responsible for analysis of assessment results and/or decision making will be qualified to perform these tasks by proof of one of the following:

1. A minimum of a bachelor degree in engineering or a physical science, plus at least two years (24 months) experience applicable to the elements of the integrity management program for which responsible, or
2. A bachelor degree in any field, or an associate degree or completion of at least two years of study in engineering or a physical science, plus at least four years (48 months) experience applicable to the elements of the integrity management program for which responsible, or
3. At least six years (72 months) experience applicable to the elements of the integrity management program for which responsible, or
4. Authorization for the particular task by the Chairman of the Implementation Team

   Until an individual is qualified by these requirements, he or she can perform analysis and decision making work so long as his or her work is reviewed and approved by a qualified person. Documentation of this qualification will be kept in the Training Server or in files maintained by the Chairman of the Implementation Team.

The list of qualified persons will be reviewed each year and authorized by the IMP Committee.

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For ECDA and ICDA the individual must be qualified according to 192.453. ¶

Persons responsible for preventive and mitigative measures

Individuals who implement integrity management procedures, including the implementation of preventive and mitigative measures will be qualified through the same process as is used to qualify employees in El Paso's DOT Operator Qualification Program (e.g., locating and marking pipelines) or the El Paso Technical Competency Program. These qualifications are documented in the El Paso Training Server for employees. For contractors, the qualifications will be documented in a third-party database if the task is classified as a covered task under the El Paso's Operator Qualification Program.

An individual who is not qualified in any of these tasks can perform them as long as he or she is:

1. Directly observed while performing these tasks by a qualified person if performing a covered task under the Operator Qualification Program or
2. Under the supervision of a qualified person while performing the task if the task is not part of the Operator Qualification Program.

The EPPG Safety & Health Handbook provides the qualification requirement for individuals directly supervising excavation work carried out in conjunction with an integrity assessment.

Qualifications of IMP Team and Committee Leaders

Qualifications for persons that are responsible for specific IMP responsibilities as outlined in the Introduction must meet the qualifications established in this section. The qualifications of the people in these positions will be reveiwed annually by the IMP Committee and new personnel placed in these positions will be authorized by the IMP Committee.

IMP Committee Chairman

The individual(s) selected as chairman or co-chairman of the IMP Committee will be qualified to perform these tasks by proof of one of the following:

1. A minimum of a bachelor degree in engineering or a physical science, plus at least two years (24 months) experience in integrity management program implementation, or
2. A bachelor degree in any field, or an associate degree or completion of at least two years of study in engineering or a physical science, plus at least four years (48 months) experience in integrity management program implementation, or
3. At least six years (72 months) experience in integrity management program implementation, or
4. Authorization for this position by the Pipeline Integrity Committee

This position will be authorized by the Pipeline Integrity Committee

Chairman of the HCA Team

The individual selected as the chairman of the HCA Team will be qualified to perform these tasks by proof of one of the following:

1. A bachelor degree in any field, or an associate degree or completion of at least two years of study in engineering or a physical science, or
2. Experience related to HCA calculation or similar task, or
3. Authorization for this position by the IMP Committee

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Chairman of the Risk Management Team

The individual selected as the chairman of the Risk Management Team will be qualified to perform these tasks by proof of one of the following:

1. A minimum of a bachelor degree in engineering or a physical science, plus at least two years (24 months) experience in pipeline operations or engineering, or
2. A bachelor degree in any field, or an associate degree or completion of at least two years of study in engineering or a physical science, plus at least three years (36 months) experience in pipeline operations or engineering, or
3. At least five years (60 months) experience in pipeline operations or engineering, or
4. Authorization for this position by the IMP Committee

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Within one year of assignment to this position, this person should complete an industry course on pipeline risk assessment.

Chairman of the Implementation Team

The individual selected as the chairman of the Implementation Team will be qualified to perform these tasks by proof of one of the following:

1. A minimum of a bachelor degree in engineering or a physical science, plus at least two years (24 months) experience in pipeline operations or engineering with specific experience including in-line inspection, or
2. A bachelor degree in any field, or an associate degree or completion of at least two years of study in engineering or a physical science, plus at least three years (36 months) experience in pipeline operations or engineering with specific experience including in-line inspection, or
3. At least five years (60 months) experience in pipeline operations or engineering with specific experience including in-line inspection, or
4. Authorization for this position by the IMP Committee

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Within one year of assignment to this position, this person should complete an industry course on integrity assessments for natural gas pipelines, with emphasis on in-line inspection.

ATTACHMENT 6

ADDITIONAL DETAIL TABLES FOR THREAT IDENTIFICATION PROCESSES

Detailed Tables for Threat Identification Processes (TIP Charts)

Table A- 1 - External Corrosion TIP Detailed Information for Questions

EC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 1	Has an ILI been conducted?	In-Line inspection year, type (geometry, metal loss, etc.), resolution. – Implementation Team	Answer Yes if a metal loss in-line inspection has ever been conducted on the line pipe in the HCA. Otherwise answer No.	
TIP – 2	Has and ECDA been conducted?	ECDA project completion date and scope – Implementation Team	Answer Yes if an ECDA assessment has ever been completed on the line pipe in the HCA. Otherwise answer No.	
TIP - 3	Were External Corrosion (EC) Anomalies Found in the HCA?	Anomalies found during the ILI run and there location (typically the ILI Vendor's feature list) – Implementation Team.	Answer this Yes if there are any external metal loss indications listed in the in-line inspection vendor's feature list within the boundaries of the HCA. Otherwise answer No.	This is answered based upon the most recent ILI run only.
TIP - 4	Were all EC Anomalies in the HCA mitigated?	Anomaly remediation results and summaries – Implementation Team.	Answer this Yes if all external metal loss indications listed in the ILI vendor's feature list within the boundaries of the HCA were investigated and mitigated. If even one anomaly was not investigated, this answer will be N.	All repairs will be made according to Section 401 of the Operations and Maintenance (O&M) Procedures Manual and Section 401 of the POP Manual. This is answered based upon the most recent ILI run only.

Detailed Tables for Threat Identification Processes (TIP Charts)

EC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP - 5	Were all Scheduled anomalies per POP 306 remediated?	Anomaly remediation results and Final Response letter. Also, Pipe inspection reports – Implementation Team and GeoFusion.	Situation 1: If there were no immediate, one-year, or shceduled anomalies identified inside the HCA, then answer Yes. Situation 2: If there was at least one immediate, one-year, or shceduled anomaly identified inside the HCA, then - answer Yes if all these anomalies have been investigated and remediated or answer No if there are any of these anomalies are still to be investigated and mitigated.	POP 306 provides the definition for immediate, one-year and scheduled anomalies. The Final Response Letter lists the digs designated under one of these categories and if they fall inside an HCA or not. Pipe inspection form information and the Implementation team will be used to confirm investigation and mitigation of these anomalies inside the HCA boundaries.
Note: Unless otherwise noted, questions 6 through 11 only apply after the ILI run date and anomaly follow-up is complete.				
TIP - 6	Has there been a leak or rupture due to EC in the HCA or buffer area?	Leak Failure reports in GeoFusion	Answer Yes if an external corrosion leak has occurred after the most recent ILI Date. If it occurred as part of an anomaly remediation in an identified anomaly, then answer No. If no leaks have occurred after the date of the ILI, then answer No.	
TIP - 7	Does the pipeline have the same vintage pipe and coating as the HCA pipe?	Pipe In-service date and coating for the HCA and the leak location - GeoFusion	If the leak occurred in the HCA answer Yes. If the leak was in the buffer area and the HCA has pipe with the same coating and generally same age (typically within 10 years) as the leak location, then answer Yes. Otherwise, answer No.	This review is conducted by the Risk Management Team for each HCA with Question 6 as Yes.
TIP - 8	Has external corrosion (non-failure) been found, unrelated to anomaly follow-up, in the HCA or buffer area?	Pipe inspection forms - GeoFusion	Answer Yes if external corrosion has been found after the most recent ILI Date only if this finding was not part of an anomaly investigation. If it was found as part of an anomaly remediation, then answer No because this is known finding.	

Detailed Tables for Threat Identification Processes (TIP Charts)

EC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP - 9	Does the pipeline have the same vintage pipe and coating as the HCA pipe?	Pipe In-service date and coating for the HCA and the leak location - GeoFusion	If the external corrosion was found in the HCA answer Yes. If it was found in the buffer area and the HCA has pipe with the same coating and generally same age (typically within 10 years) as the EC location, then answer Yes. Otherwise, answer No.	This review is conducted by the Risk Management Team for each HCA with Question 8 as Yes.
TIP - 10	Have there been any remedial actions required on the CP system in the buffer area?	Request this information in the Annual Flags and Alerts data collection – From Corrosion Services	Answer this Yes if there has been "Required Remedial Action on the corrosion protection system" that could affect this HCA or be near this HCA (within 7 miles of the HCA). Examples: • Installation of new ground beds • Installation of new rectifiers or replacement with larger rectifiers • Recoating projects • Other items that are classified as "remedial action" in the corrosion program.	
TIP - 11	Has poor coating condition been found, before or after ILI run date, in the buffer area - same vintage pipe and coating as the HCA pipe?	Pipe inspection forms - GeoFusion	If poor coating has been found within the buffer area of this HCA at anytime in the life time of the pipe and the HCA coating and age (within 10 years, typically) match the location of the poor coating, then answer Yes. Otherwise, answer No.	This data is pulled directly from the coating condition field in the Pipe Inspection report.
TIP - 12	Has there been a leak or rupture due to EC within the HCA?	Leak Failure reports in GeoFusion	Answer Yes if an external corrosion leak has ever occurred within the HCA boundaries. If no EC leaks have occurred, then answer No.	
TIP - 13	Has external corrosion (non-failure) been found within the HCA?	Pipe inspection forms - GeoFusion	Answer Yes if external corrosion has ever been found within the boundaries of the HCA. Answer No if EC has not been found.	
TIP - 14	Has there been a leak or rupture due to EC - in the buffer area?	Leak Failure reports in GeoFusion	Answer Yes if an external corrosion leak has ever occurred within the Buffer Area. If no EC leaks have occurred, then answer No.	

Detailed Tables for Threat Identification Processes (TIP Charts)

EC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP - 15	Does the pipeline have the same vintage pipe and coating as the HCA pipe?	Pipe In-service date and coating for the HCA and the leak location - GeoFusion	If the HCA has pipe with the same coating and generally same age (typically within 10 years) as the leak location, then answer Yes. Otherwise, answer No.	This review is conducted by the Risk Management Team for each HCA with Question 14 as Yes.
TIP - 16	Has external corrosion (non-failure) been found - in the buffer area?	Pipe inspection forms - GeoFusion	Answer Yes if external corrosion has ever been found within the Buffer Area of the HCA. Answer No if EC has not been found.	
TIP - 17	Does the pipeline have the same vintage pipe and coating as the HCA pipe?	Pipe In-service date and coating for the HCA and the leak location - GeoFusion	If the HCA has pipe with the same coating and generally same age (typically within 10 years) as the leak location, then answer Yes. Otherwise, answer No.	This review is conducted by the Risk Management Team for each HCA with Question 16 as Yes.
TIP - 18	In the buffer area, is the pipe coated and have there been any coating inspections on pipe with the same coating?	Pipe inspection forms - GeoFusion	If there have been any pipe inspection reports within the Buffer Area for the HCA then answer this question Yes. Otherwise, answer No.	The assumption is that the pipeline is coated because EPPG as little to no bare pipe.
TIP - 19	Is the pipeline bare or does it have tape, asphalt, or unknown coating?	Coating type – GeoFusion	If there is any footage with coating type classified as bare, unknown, tape of any kind, or asphalt, then answer this question Yes. Otherwise, answer No.	Even one foot of this type coating will trigger a yes answer.
TIP - 20	Has poor coating condition been found in the segment or in the buffer area with the same vintage pipe and coating as per HCA pipe?	Pipe inspection forms - GeoFusion	If poor coating has been found within the buffer area of this HCA at anytime in the life time of the pipe and the HCA coating and age (within 10 years, typically) match the location of the poor coating, then answer Yes. Otherwise, answer No.	This data is pulled directly from the coating condition field in the Pipe Inspection report.
TIP - 21	Was CP installed within one year of the pipeline in-service date?	CP Installed Year – Paper records, summary data filed in PRISM Specific Database; Pipe In-service year - GeoFusion	If the CP was installed within one year of the pipe being placed in-service, then answer Yes. Otherwise, answer No.	

Detailed Tables for Threat Identification Processes (TIP Charts)

EC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP - 22	Was external corrosion found during ECDA direct examinations?	Results of ECDA - ECDA project completion files and ECDA Workbook, Implementation Team; Pipe Inspection Reports – GeoFusion	Answer Yes if external corrosion was found during ECDA direct examinations. If no external corrosion was found during the ECDA direct examination digs, then answer No.	
TIP - 23	Is the re-assessment interval determined in the ECDA post assessment step (Section 6.9) less than 7 years?	ECDA calculated re-assessmetn interval - ECDA project completion files and ECDA Workbook, Implementation Team	Answer Yes if the re-assessment interval determined in Section 6.9 is less than 7 years. Otherwise, answer No.	

Detailed Tables for Threat Identification Processes (TIP Charts)

Table A- 2 Internal Corrosion TIP Detailed Information for Questions

IC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 1	Has an ILI been conducted?	In-Line inspection year, type (geometry, metal loss, etc.), resolution. – Implementation Team	Answer Y if a metal loss in-line inspection has ever been conducted on the line pipe in the HCA.	
TIP – 2	Has in-line inspection of the contiguous segment demonstrated internal corrosion or the growth of internal corrosion?	Anomalies found during the ILI run and there location (typically the ILI Vendor's feature list) – Implementation Team and Internal Corrosion Team	Answer this Y if there are any internal metal loss indications listed in the in-line inspection vendor's feature list in the HCA's piggable segment.	This is answered based upon the most recent ILI run only. The Implementation Team and Internal Corrosion Team confirm that the indications are internal corrosion indications.
TIP – 3	Were the Internal Corrosion Anomalies located in the HCA?	Anomalies found during the ILI run and there location (typically the ILI Vendor's feature list) – Implementation Team and Internal Corrosion Team	Answer this Y if there are any internal metal loss indications listed in the in-line inspection vendor's feature list within the boundaries of the HCA.	This is answered based upon the most recent ILI run only.
Note: Unless otherwise noted, questions 4 through 8 only apply after the ILI run date and anomaly follow-up is complete.				
TIP – 4	Has there been a leak or rupture due to IC in the buffer area?	Leak Failure reports in GeoFusion	Answer Yes if an internal corrosion leak has occurred after the most recent ILI Date. If it occurred as part of an anomaly remediation in an identified anomaly, then answer No. If no leaks have occurred after the date of the ILI, then answer No.	

Detailed Tables for Threat Identification Processes (TIP Charts)

IC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 5	Has internal corrosion (non-failure) been found in the buffer area - unrelated to anomaly follow-up?	Pipe inspection forms - GeoFusion	Answer Yes if internal corrosion has been found after the most recent ILI Date only if this finding was not part of an anomaly investigation. If it was found as part of an anomaly remediation, then answer No because this is known finding.	
TIP – 6	If coupons or probes exist in the IC Buffer Area, have evaluations led to subsequent actions related to internal corrosion control?	Internal Corrosion Team	The Internal Corrosion Team will provide the instances where the coupon and probe results in the IC Buffer for this HCA required additional actions to be taken, such as more frequent coupon/probe review, installation of additional coupons/probes, additional operational pigging, etc.. This is applied for the IC Buffer that incorporates the HCA. However, if the Internal Corrosion Team determines a larger area was affected, then that area will be used.	This data is collected during the quarterly flags and alerts process.
TIP – 7	Have there been gas quality significant events in the IC Buffer area requiring an evaluation that led to subsequent actions related to internal corrosion control?	Internal Corrosion Team	The Internal Corrosion Team will provide the instances where the gas quality significant events in the IC Buffer for this HCA required additional actions to be taken, such as coupon/probe installation or increased frequency, additional operational pigging, etc.. This is applied for the IC Buffer that incorporates the HCA. However, if the Internal Corrosion Team determines a larger area was affected, then that area will be used.	This data is collected during the quarterly flags and alerts process.
TIP – 8	Have there been aqueous liquids in the IC Buffer area requiring an evaluation that led to subsequent actions related to internal corrosion control?	Internal Corrosion Team	The Internal Corrosion Team will provide the instances where the aqueous liquids have been found in the IC Buffer for this HCA and additional actions were required to be taken. These actions could be more frequent coupon/probe installation and review, additional operational pigging, etc.. This is applied for the IC Buffer that incorporates the HCA. However, if the Internal Corrosion Team determines a larger area was affected, then that area will be used.	This data is collected during the quarterly flags and alerts process.

Detailed Tables for Threat Identification Processes (TIP Charts)

IC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 9	Has there been a leak or rupture due to IC in the HCA or in the buffer area?	Leak Failure reports in GeoFusion	Answer Yes if an internal corrosion leak has ever occurred within the IC Buffer Area. If no IC leaks have occurred, then answer No.	
TIP – 10	Has Internal corrosion (non-failure) been found in the HCA or in the buffer area?	Pipe inspection forms - GeoFusion	Answer Yes if internal corrosion has ever been found within the boundaries of the IC Buffer or the HCA. Answer No if IC has not been found.	
TIP – 11	If coupons or probes exist in the IC Buffer area have evaluations led to subsequent actions related to internal corrosion control?	Internal Corrosion Team	The Internal Corrosion Team will provide the instances where the coupon and probe results in the IC Buffer for this HCA required additional actions to be taken, such as more frequent coupon/probe review, installation of additional coupons/probes, additional operational pigging, etc.. This is applied for the IC Buffer that incorporates the HCA. However, if the Internal Corrosion Team determines a larger area was affected, then that area will be used.	This data is collected during the quarterly flags and alerts process.

Detailed Tables for Threat Identification Processes (TIP Charts)

IC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 12	Is the HCA in the Production/Storage Area as defined for IC?	Internal Corrosion Team	Production Areas are: • ANR - FERC Designation Production Areas - upstream of Eunice and Greensberg • CIG LINE 147A Tumbleweed Lateral LINE 148A Palo Duro Lateral LINE 18A Gate 1 to Gate 2 LINE 193A Plum Creek Lateral LINE 194A Indian Creek Lateral LINE 3A Keyes to Fourway • EPNG - All Texas lines and San Juan lines upstream of valve city • SNG - Upstream of Franklinton and Upstream of Bear Creek Storage • TGP - Upstream of Station 17, Kinder, and Station 530 (Bay St. Louis) Storage is any lines in the storage fields and lines that directly feed and produce from storage fields (e.g. Muldon line, 8200 line on ANR, Washington Ranch Line on EPNG). The remaining lines are classified as Transmission.	
TIP – 13	Have there been gas quality significant events in the IC Buffer area requiring an evaluation that led to subsequent actions related to internal corrosion control?	Internal Corrosion Team	The Internal Corrosion Team will provide the instances where the gas quality significant events in the IC Buffer for this HCA required additional actions to be taken, such as coupon/probe installation or increased frequency, additional operational pigging, etc.. This is applied for the IC Buffer that incorporates the HCA. However, if the Internal Corrosion Team determines a larger area was affected, then that area will be used.	This data is collected during the quarterly flags and alerts process.

Detailed Tables for Threat Identification Processes (TIP Charts)

IC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 14	Have there been aqueous liquids in the IC Buffer area requiring an evaluation that led to subsequent actions related to internal corrosion control?	Internal Corrosion Team	The Internal Corrosion Team will provide the instances where the aqueous liquids have been found in the IC Buffer for this HCA and additional actions were required to be taken. These actions could be more frequent coupon/probe installation and review, additional operational pigging, etc.. This is applied for the IC Buffer that incorporates the HCA. However, if the Internal Corrosion Team determines a larger area was affected, then that area will be used.	This data is collected during the quarterly flags and alerts process.

Detailed Tables for Threat Identification Processes (TIP Charts)

Table A- 3 SCC TIP Detailed Information for Questions

SCC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 1	Has SCC been found in the HCA or in the buffer area?	SCC Spreadsheet/Database – Pipeline Services Pipe Inspection forms and Leak Failure Reports - GeoFusion	Answer Yes if at least one stress corrosion cracking (SCC) location has been found during pressure testing, pipeline inspections, or by leak or failure in the Buffer Area. Otherwise, answer No.	This data is collected during the quarterly flags and alerts process.
TIP – 2	Does the HCA contain pipe of the same operating stress level and age as the pipe where SCC was found? See note 1.	SCC Spreadsheet/Database – Pipeline Services Pipeline characteristics and pipe in service date - GeoFusion	Answer Yes if both the operating stress level and age are similar as noted below (this is Note 1 in the TIP): • Same operating stress level means both the HCA and the SCC piping operate above or below 60% SMYS. (e.g. if the SCC was found in pipe below 60% pipe and the HCA has pipe operating below 60%) • Same age means that both the HCA and the SCC piping are younger or older than 10 years.	
TIP – 3	Does the HCA segment operate above 60% SMYS?	Pipeline characteristics and MAOP - GeoFusion	If the maximum operating stress (MAOP/100% SMYS) within the limits of the HCA are above 60% then answer Yes. Otherwise answer No.	
TIP – 4	Is the pipeline within the HCA great than 10 years old?	Pipe in service date - GeoFusion	Answer Yes if the oldest pipeline within the HCA is older than 10 years. Otherwise answer No.	
TIP – 5	Is the pipeline in the HCA coated with FBE or equivalent?	Coating Type - GeoFusion	Answer Yes if the entire HCA is coated with FBE or equivalent coating. Otherwise, answer No.	See Note 3 on the TIP chart for the definition of "Equivalent to FBE coating."

Detailed Tables for Threat Identification Processes (TIP Charts)

SCC TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 6	Does the HCA segment operate above 60% SYMS?	Pipeline characteristics and MAOP - GeoFusion	If the maximum operating stress (MAOP/100% SMYS) within the limits of the HCA are above 60% then answer Yes. Otherwise answer No.	
TIP – 7	Is the pipeline coated with FBE or equivalent?	Coating Type - GeoFusion	Answer Yes if the entire HCA is coated with FBE or equivalent coating. Otherwise, answer No.	See Note 3 on the TIP chart for the definition of "Equivalent to FBE coating."
TIP – 8	Is the pipeline within the HCA greater than 10 years old?	Pipe in service date - GeoFusion	Answer Yes if the oldest pipeline within the HCA is older than 10 years. Otherwise answer No.	
TIP – 9	Is the pipeline coated with tape, asphalt, or unknown coating?	Coating type – GeoFusion	If there is any footage with coating type classified as unknown, tape of any kind, or asphalt, then answer this question Yes. Otherwise, answer No.	Even one foot of this type coating will trigger a yes answer.
TIP – 10	Is there a history of external corrosion within the HCA or Buffer area?	Pipe inspection forms and Leak Failure reports – GeoFusion ILI Reports – Pipeline Services	Answer Yes if external corrosion has ever been found within the HCA or Buffer Area. Answer No if EC has not been found.	
TIP – 11	Is the HCA within 20 miles from the discharge of a compressor station?	Pipe location - GeoFusion	Answer Yes if any of the HCA is within 20 miles of the discharge of a compressor station.	

Detailed Tables for Threat Identification Processes (TIP Charts)

Table A- 4 Manufacturing TIP Detailed Information for Questions

Manuf. TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
1 - Manufacturing Leak or failure in Buffer Area				
TIP – 1	Has there been a leak or rupture due to a seam or pipe body defect in the HCA or in the buffer area with the same pipe characteristics? See Note 1 & 2	Leak Failure Reports, pipe characteristics, pipe in service date - GeoFusion	Answer Yes if there has been a manufacturing leak or rupture within the Buffer Area of the HCA that is due to a long seam failure or a defect in the body of the pipe and the HCA piping has the same characteristics as the leak location. The same charateristics means (Note 2 on TIP chart) the same manufacturer, seam type, and pipe age (within 10 years) in the HCA that existed at the leak location. If the characteristics do not match, then answer No. If there are no leaks or ruptures in the Buffer area answer No.	
TIP – 2	Has the pipeline been pressure tested per 192 subpart J?	Pressure test data - GeoFusion	Answer Yes if the entire HCA has been pressure tested according to Subpart J sometime in the life of the pipeline. Details of qualifying for a Subpart J pressure test are specified in the regulations.	
TIP – 3	Has the pipeline been pressure tested per 192 subpart J - post failure?	Pressure test data - GeoFusion	Answer Yes if the entire HCA has been pressure tested according to Subpart J sometime after the date of the failure. Details of qualifying for a Subpart J pressure test are specified in the regulations.	If all the pipe in the HCA that has similar characteristics to the failure location have been tested, then answer Yes.
TIP – 4	Did the Engineering Analysis determine the threat was stable?	Engineering or Pipeline Services Study	Answer Yes if a formal, documented Engineering Analysis has been completed for this specific HCA that determines that the manufacturing threat is stable in the HCA. The Engineering Anaylsis must explain why the failure(s) in the Buffer Area either do not apply to the piping in the HCA or effective mitigation and assessment activities have occurred in the HCA to render the threat stable in the HCA.	The Engineering Analysis must be attached as a document in the IMP Database for the HCA.

Detailed Tables for Threat Identification Processes (TIP Charts)

Manuf. TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 5 & 8 & 13 & 14	Has the pipe been subjected to land movement, known frost heave, or removal of supporting backfill (other than normal operator controlled or monitored activities) since the last evaluation?	Subject Matter Expert input – Pipeline Services Pipeline Inspection Reports and Leak Failure Reports - GeoFusion	Answer Yes if significant erosion, land movement (sloughing, sink holes, earth quakes, etc.), or removal of supporting backfill that is not planned, controlled or monitored by the company. This does not include designed spans and spans that have been determined to be stable. Also, answer Yes if there is known frost heave that has affected the pipeline in this area. Otherwise, answer No.	This data is collected during the Annual review of the Threat Flags and Alerts study.
2 - Other Manufacturing Issues				
TIP – 6	Is there pipe in the HCA that is listed in Table A-4-2 – "Other pipe with a History of Manufacturing Failures?"	Manufacturer, seam, OD and in service date - GeoFusion	Answer Yes, if any of the pipe in the HCA match the characteristics of the pipe listed in Table A-4-2.	Table A-4-2 was developed as part of the "Pre-1970 ERW, Lap Welded, and Flash Welded Line Pipe Integrity Review" study completed on 10/25/2006. See IMP Database for this document.
TIP – 7	Has the pipeline been pressure tested per 192 subpart J?	Pressure test data - GeoFusion	Answer Yes if the entire HCA has been pressure tested according to Subpart J sometime in the life of the pipeline. Details of qualifying for a Subpart J pressure test are specified in the regulations.	If all the pipe that meets the characteristics of Table A-4-2 is tested, then this can be answered Yes even if other pipe in the HCA is not tested.
3 - Pre-1970 ERW, Lap Welded, and FW Pipe Issues [917(e)(4)]				
TIP – 9	Is the pipe low frequency ERW, flash weld, unknown seam with OD > 8", bessemer lap weld, electric fusion weld, open hearth lap weld or have a joint factor less than 1?	Manufacturer, seam, OD and in service date - GeoFusion	Answer Yes, if any of the pipe in the HCA meets the following characteristics: • Long seam is low frequency ERW, flash weld, lap welded (bessemer or open hearth), Furnace butt weld, or electric flash weld • Long seam is ERW and the pipe in-service date is prior to 1970 • Long seam is unknown and the OD is greater than 8.625" and the pipe in-service date is prior to 1970	

Detailed Tables for Threat Identification Processes (TIP Charts)

Manuf. TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 10	Has the pipeline been pressure tested per 192 subpart J?	Pressure test data - GeoFusion	Answer Yes if the entire HCA has been pressure tested according to Subpart J sometime in the life of the pipeline. Details of qualifying for a Subpart J pressure test are specified in the regulations.	If all pipe that meets the characteristics of Table A-4-1 or the characteristics in Question 9 is tested, then this can be answered Yes even if other pipe in the HCA is not tested.
TIP – 11 & 12	Is there pipe in the HCA that is listed in Table A-4-1 – Pre-1970 ERW, Lap Welded, or Flash Welded Pipe with a Failure History?	Manufacturer, seam, OD and in service date - GeoFusion	Answer Yes, if any of the pipe in the HCA match the characteristics of the pipe listed in Table A-4-1.	Table A-4-1 was developed as part of the "Pre-1970 ERW, Lap Welded, and Flash Welded Line Pipe Integrity Review" study completed on 10/25/2006. See IMP Database for this document.

Detailed Tables for Threat Identification Processes (TIP Charts)

Table A- 5 Construction TIP Detailed Information for Questions

Const. TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
1 – Coupled or Bell and Spigot Pipe				
TIP – 1	Does the pipe having couplings or bell and spigots?	Subject Matter Expert input and Lists – Pipeline Services, DOT Compliance, Engineering, and Field Operations Girth weld type – GeoFusion (secondary)	Answer Yes if any of the pipe in the HCA is joined by dresser couplings or bell and spigots. Otherwise answer No.	SNG has the only known coupled pipelines for EPPG. Obtain an updated list from DOT Compliance each year since this pipe is continually being abandoned or replaced. There are no known Bell and Spigot locations. The EPNG 1004 line, 1931 construction, was thought to be bell and spigot, but it is not. Instead it is swelled up welds to allow for chill rings.
TIP – 2	Has there been a leak or failure due to couplings or bell and spigots in the HCA or the buffer area?	Leak Failure Reports - GeoFusion	Answer Yes if there has been a leak or rupture within the Buffer Area of the HCA that is due to a couplings or bell and spigot joints. If there are no leaks or ruptures in the Buffer area due to these threats answer No.	
TIP – 3, 6, 10, 14, & 16	Has the pipe been subjected to land movement, known frost heave, or removal of supporting backfill (other than normal operator controlled or monitored activities) since the last evaluation?	Subject Matter Expert input – Pipeline Services Pipeline Inspection Reports and Leak Failure Reports - GeoFusion	Answer Yes if significant erosion, land movement (sloughing, sink holes, earth quakes, etc.), or removal of supporting backfill that is not planned, controlled or monitored by the company. This does not include designed spans and spans that have been determined to be stable. Also, answer Yes if there is known frost heave that has affected the pipeline in this area. Otherwise, answer No.	This data is collected during the Annual review of the Threat Flags and Alerts study.
2 - Pressure or Acetylene welded pipe				

Detailed Tables for Threat Identification Processes (TIP Charts)

Const. TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 4	Is the pipe constructed with pressure or acetylene welds?	Subject Matter Expert input and Lists – Pipeline Services, DOT Compliance, Engineering, and Field Operations Girth weld type – GeoFusion (secondary)	Answer Yes if any of the pipe in the HCA is joined using acetylene or pressure welds. Otherwise answer No.	TGP has the only known pressure welds in EPPG. These are located Line 100-1 from 1-1D up to 36- 1 if the pipe in-service date is in the early 1940's. Acetylene welds are located on the following lines: CIG - 20A line – 1931 construction. EPNG: • 2026 Line - 1936 construction • 2029 Line - 1941 construction • 1004 line - 1931 construction. • 1007 line – 1933 construction. • 1008 line – 1941 or earlier construction. SNG has acetylene welds on the following lines with 1930 construction dates. Each year get an update from DOT Compliance on exact remaining locations. • Onward Vicksburg line (MP 0 to 16.178) • West Point Line • Columbus Line • Cheney Lime Lateral Line • Talladega Line • Montgomery No. 1 Line • Rome Calhoun line (MP 59.266 to 66.778) • North Main Loop line associated with Couplings
TIP – 5	Has there been a leak failure due to pressure or acetylene welds in the HCA or the buffer area?	Leak Failure Reports - GeoFusion	Answer Yes if there has been a leak or rupture within the Buffer Area of the HCA that is due to a pressure weld or acetylene weld. If there are no leaks or ruptures in the Buffer area due to these threats answer No.	

Detailed Tables for Threat Identification Processes (TIP Charts)

Const. TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
3 – Wrinkle Bends				
TIP – 7	Are wrinkle bends present in the HCA?	Pipe In-service date – GeoFusion ILI data – Implementation Team	Answer No if it has been confirmed that there are no wrinkle bends in the HCA based upon ILI data. Otherwise, answer Yes if the HCA has pipe that was installed prior to 1950. Answer No if the pipe was installed in 1950 or after.	
TIP – 8	Has there been a leak or failure due to wrinkle bend in the HCA or the buffer area?	Leak Failure Reports - GeoFusion	Answer Yes if there has been a leak or rupture within the Buffer Area of the HCA that is related to a wrinkle bend. If there are no leaks or ruptures in the Buffer area due to wrinkle bends answer No.	
TIP – 9	Has the pipeline been pressure tested per 192 subpart J - post failure?	Pressure test data - GeoFusion	Answer Yes if the entire HCA has been pressure tested according to Subpart J sometime after the date of the failure. Details of qualifying for a Subpart J pressure test are specified in the regulations.	If all pipe in the HCA that has similar characteristics to the failure location have been tested, then answer Yes.
4 – Other Construction Issues				
TIP – 11	Has there been a leak or failure due to other construction issues in the HCA or the buffer area?	Leak Failure Reports - GeoFusion	Answer Yes if there has been a leak or rupture within the Buffer Area of the HCA that is not related to a wrinkle bends, couplings, pressure welds, acetylene welds or bell and spigot joints. If there are no leaks or ruptures in the Buffer area unrelated to these threats then answer No.	

Detailed Tables for Threat Identification Processes (TIP Charts)

Const. TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 12	Was the failure a rupture?	Leak Failure Reports - GeoFusion	If the leak failure form indicates a "rupture" answer Yes, otherwise anwer No.	The failure is a rupture if it is "a complete failure of a portion of the pipeline." The definition of a leak is "an event that involves the unintentional release of gas from a pipeline that requires immediate or scheduled repair. The source of the leak may be holes, cracks (which include propagating and non-propagating, longitudinal and circumferential), separation or pullout, and loose connections. Leaks that are either inconsequential or incidental to the operation of a pipeline and which can be checked or repaired under routine daily maintenance are not reportable leaks. Examples of such non reportable leaks include escape of gas through valve stem packing, through compressor rod packing, loosened connections and relief valves." Both of these definitions are from the "INSTRUCTIONS FOR FORM PHMSA F 7100.2 (01-2002) INCIDENT REPORT - GAS TRANSMISSION AND GATHERING SYSTEMS."
TIP – 13	Has the pipeline been pressure tested per 192 Subpart J post-failure?	Pressure test data - GeoFusion	Answer Yes if the entire HCA has been pressure tested according to Subpart J sometime after the date of the failure. Details of qualifying for a Subpart J pressure test are specified in the regulations.	If all pipe in the HCA that has similar characteristics to the failure location have been tested, then answer Yes.
TIP – 15	Has the pipeline been pressure tested per 192 subpart J?	Pressure test data - GeoFusion	Answer Yes if the entire HCA has been pressure tested according to Subpart J sometime in the life of the pipeline. Details of qualifying for a Subpart J pressure test are specified in the regulations.	

Detailed Tables for Threat Identification Processes (TIP Charts)

Const. TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 17	Has the pipeline been pressure tested per 192 subpart J?	Pressure test data - GeoFusion	Answer Yes if the entire HCA has been pressure tested according to Subpart J sometime in the life of the pipeline. Details of qualifying for a Subpart J pressure test are specified in the regulations.	

Detailed Tables for Threat Identification Processes (TIP Charts)

Table A- 9 Weather and Outside Forces TIP Detailed Information for Questions

WOF TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
1 – Weather and Outside Force				
TIP – 1	Is there or is there the potential for washout or undercut in the HCA	Subject Matter Expert input – Pipeline Services Pipeline Inspection Reports and Leak Failure Reports - GeoFusion	Answer Yes if the HCA is in an area that has the potential for washout or undercut. This is very specific to the location and is answered by the subject matter experts. Otherwise, answer No.	This data is collected during the Annual review of the Threat Flags and Alerts study along with the land movement data collection. It is also looked for during the review of the pipe inspection reports.
TIP – 2	Are measures in place to mitigate this threat at his HCA?	Subject Matter Expert input – Pipeline Services	If the Pipeline Services SMEs state that mitigative measures are in place for the specific threat at this location, then answer Yes. Otherwise answer No.	Note the designated mitigative measures for this HCA in the IMP Database.
TIP – 3	Is the HCA in a county rated high for Hurricane Wind or Tornado threat?	List of County rating for hurricane, wind, and tornado according to the ALA study.	If the county the HCA is located in is designated as High in the ALA study for hurricane, wind, and tornado threat, then answer Yes. Otherwise answer No.	This is based on the American Lifelines Alliance study entitled "Working Paper No. 2 Framework for Assessing the Performance of Oil and Natural Gas Pipeline Systems due to Natural and Human Threat Events – Final Draft" dated October 15, 2003. The associated map is located in this TIP chart.
2 – Earth Movement				
TIP – 4	Is there mining activity near or underneath the pipeline in the HCA?	Subject Matter Expert input – Pipeline Services	Answer Yes if there is mining activity near or underneath the HCA. This is very specific to the location and is answered by the subject matter experts. Otherwise, answer No.	This data is collected during the Annual review of the Threat Flags and Alerts study along with the land movement data collection.

Detailed Tables for Threat Identification Processes (TIP Charts)

WOF TIP Chart Reference	Question	Data Used and Source:	Criteria for Answers	Explanatory Notes
TIP – 5	Are measures in place to mitigate this threat at this HCA?	Subject Matter Expert input – Pipeline Services	If the Pipeline Services SMEs state that mitigative measures are in place for the specific threat at this location, then answer Yes. Otherwise answer No.	Note the designated mitigative measures for this HCA in the IMP Database.
TIP – 6	Are there subsidence areas within this HCA?	Subject Matter Expert input – Pipeline Services Pipeline Inspection Reports and Leak Failure Reports - GeoFusion	Answer Yes if the HCA is in an area that has or is experiencing subsidence. This is very specific to the location and is answered by the subject matter experts. Otherwise, answer No.	This data is collected during the Annual review of the Threat Flags and Alerts study along with the land movement data collection. It is also looked for during the review of the pipe inspection reports.
TIP – 7	Are measures in place to mitigate this threat at this HCA?	Subject Matter Expert input – Pipeline Services	If the Pipeline Services SMEs state that mitigative measures are in place for the specific threat at this location, then answer Yes. Otherwise answer No.	Note the designated mitigative measures for this HCA in the IMP Database.
3 – Earth Quake				
TIP – 8	Is the HCA in a county rated high for earth quake threat?	List of County rating for earth quake according to the ALA study.	If the county the HCA is located in is designated as High in the ALA study for earth quake threat, then answer Yes. Otherwise answer No.	This is based on the American Lifelines Alliance study entitled "Working Paper No. 2 Framework for Assessing the Performance of Oil and Natural Gas Pipeline Systems due to Natural and Human Threat Events – Final Draft" dated October 15, 2003. The associated map is located in this TIP chart.

ATTACHMENT 7

POP 306 (AS MODIFIED)

Pipeline Operating Procedures	Section 306
Operating and Maintenance In-Line Inspection and Data Analysis	Effective Date 05/15/2007 Issue Date 04/16/2007

Section 306 In-Line Inspection and Data Analysis

1. Scope

This procedure provides guidelines for performing in-line inspections, analyzing in-line inspection data and selecting anomalies for in-field evaluation and repair.

2. Inspection Tools

Pipe may be inspected in-line for corrosion-caused metal loss, dents, cracks, gouges, hard spots, ovality or other anomalies by a variety of tools including caliper/deformation pigs, magnetic flux leakage pigs or other "smart" pigs. Such inspections may be independent or in conjunction with each other. The Pipeline Services representative in charge of the project shall arrange with the vendor for delivery scheduling and interpretation of field logs, if required.

1. Caliper/Geometry tools: Designed to locate and size pipeline inside diameter, areas of ovality, and pipeline bends. Information obtained from these tools will be used to characterize dents.
2. Magnetic Flux Leakage (MFL) tools: Designed to locate and characterize pipeline anomalies associated with metal loss. Information obtained from these tools will be used to make decisions regarding metal loss anomalies.
3. Crack Detection Tools: Designed to locate and characterize pipeline anomalies associated with cracking and/or longitudinal seam defects. Information obtained from these tools will be used to make decisions regarding crack and/or longitudinal seam anomalies.
4. Hard Spot Detection Tools: (Under development)

3. Acceptance of Inspection

The Pipeline Services project coordinator shall discuss the acceptability of the run with the vendor's representative and may reject a run that fails to meet any of the following criteria:

1. Sensors: The malfunction of one or more sensor channels, distance channel, marker channel, or orientation channel may invalidate the data.
2. Velocity: Speed of travel outside the instrument's specifications may compromise the data quality and affect the accuracy of analysis. A rerun may be required if an unacceptable portion of the inspection or critical areas were surveyed outside the velocity guidelines.
3. Reference points: Aboveground markers are positioned approximately one mile apart and should appear on the inspection report. A rerun may be required if an adequate number of reference markers were not identified by the inspection tool.
4. Acceptable recording of welds, pipeline features, casings, and reference points generally would indicate satisfactory performance of the instrument.
5. The inspection vendor will review the acquired data and determine if a successful inspection was completed based on the vendor's quality control procedures. This review will be approved by a

Pipeline Services representative via formal notification to the vendor.

4. Analysis of Final ILI Vendor Report(s)

Each ILI vendor is expected to deliver the Final ILI Report within 30 to 60 days from the date the tool is run. The analysis of the Final ILI Report(s) will occur in two stages. First, the report will be reviewed for indications requiring immediate action. After the first stage is completed, all the indications will be reviewed and a follow-up plan developed. The analysis of the Final ILI Report(s) shall include data integration processes to correlate MFL data, Caliper/Geometry data, pipe materials data, MAOP data, and encroachment/foreign crossing data, particularly in high consequence areas (HCAs). In HCAs, evidence of encroachment/foreign crossing locations that correlate with relevant MFL/Caliper indications should result in excavation to determine if previous third party damage has occurred.

1. ***Analysis of Final ILI Report(s) for Immediate Repair Conditions*** - Pipeline Services shall review the Final ILI Report(s) to determine if any anomalies will require immediate action. This review will be completed in a period not to exceed 14 days from the date of the receipt of the vendor's Final Report. This review will culminate with an initial response memo from Pipeline Services to the Area Manager summarizing the initial review of ILI data and detailing any immediate action, if required. The date of this memo will be the "Discovery of Condition" date as required in the DOT integrity management regulations.

   a. For anomalies located ***within an HCA*** the following will be treated as immediate repair conditions:

      i. Any metal loss anomaly that has a predicted failure pressure (Pfail) less than or equal to 1.16 * MAOP (maximum allowable operating pressure) .

      ii. Any metal loss anomaly with a depth that is equal to or greater than 70% of the nominal pipe wall thickness AND that Pipeline Services feels is an immediate threat to the integrity of the pipeline.

      iii. Any dent that has an indication of metal loss, cracking, or a stress riser AND that is located in a HCA.

      iv. Any other anomaly that Pipeline Services feels warrants immediate action.

   b. For anomalies located ***outside an HCA*** the following will be treated as immediate repair conditions:

      I. Any metal loss anomaly that has a predicted failure pressure (P_{fail}) less than or equal to 1.10 * MAOP (maximum allowable operating pressure) .

      II. Any metal loss anomaly with a depth that is equal to or greater than 80% of the nominal pipe wall thickness AND that Pipeline Services feels is an immediate threat to the integrity of the pipeline.

      III. Any other anomaly that Pipeline Services feels warrants immediate action.

      P_{Fail} may be obtained using ILI vendor software or by performing an analysis using the Company approved programs, such as Coreval, the corrosion application within Pipeval, or RStreng® programs.

   c. If an anomaly is classified as an immediate repair condition, a pressure restriction must be taken as soon as possible, but not to exceed five (5) days from the "Discovery of Condition" date. The amount of restriction shall be determined as follows:

i. The temporary restriction in operating pressure will be determined using ASME/ANSI B31G or "RSTRENG" with the applicable safety factor applied, or by determining the most recent (120 days) maximum operating pressure (P_{Max}) for the area being reviewed and restrict the pressure to P_{Max} * 0.80 or less.

ii. Notify Compliance Services of all pressure restrictions. Compliance Services will determine if the restriction produces a safety related condition.

iii. Obtain written confirmation from Gas Control and/or Field Operations noting the restricted pressure and time the restriction was put in place.

iv. Once the anomaly has been excavated, evaluated and properly remediated, the maximum operating pressure can be restored.

v. A restriction in operating pressure shall not exceed 365 days.

vi. These restrictions are intended to provide a safety margin pending further analysis and remediation. This does not preclude other measures that may be warranted by more detailed analysis. In addition, a further pressure restriction may be warranted prior to actual excavation and evaluation of the anomaly(s). (Refer to POP 401 for guidance)

2. ***Analysis of Final ILI Report(s) for One (1) Year Conditions*** - Pipeline Services shall review the Final ILI Report(s) to determine if any anomalies will need to be evaluated and/or investigated within a one (1) year timeframe.

The following conditions will require an engineering strain analysis and/or remediation within one (1) year from the "Discovery of Condition" date:

a. A smooth dent located between 8 o'clock and 4 o'clock positions (upper 2/3 of pipe) with a depth greater than 6% of the pipe diameter (greater than 0.50" in depth for a pipe diameter less than 12") AND located within a HCA.

b. A dent with a depth greater than 2% of the pipe diameter (greater than 0.250" in depth for a pipe diameter less than 12") associated with a girth weld or longitudinal seam AND located within a HCA.

For anomalies meeting the one year condition, a pressure restriction may be required during excavation, evaluation and remediation based on detailed assessment by Pipeline Services. (Refer to POP 401 for guidance).

3. ***Analysis of Final ILI Report(s) for Scheduled Conditions*** - Pipeline Services shall review the Final ILI Report(s) and perform a detailed assessment to determine which anomalies will need to be investigated in addition to those previously identified as immediate or one (1) year repair conditions.

The following conditions will require a detailed assessment and/or remediation in a timeframe defined by Pipeline Services which will coincide with ASME B31.8S, Section 7, Figure 4.

a. For pipelines operating above 50% SMYS, any metal loss anomaly with a Pfail less than or equal to 1.39* MAOP.

b. For pipelines operating above 30% SMYS and at or below 50% SMYS, any metal loss anomaly with a Pfail less than or equal to 1.67*MAOP.

c. For pipelines operating at or below 30% SMYS, any metal loss anomaly with a Pfail less than or equal to 2.20*MAOP.

d. If specific growth rates are applied to metal loss anomalies, remediation must be scheduled in a timeframe that ensures an anomaly will not grow to an immediate integrity threat before the next scheduled in-line inspection.

The guidelines stated above will generally allow for a maximum ten (10) year timeframe before re-inspection is required for segments with documented HCA's. Pipeline Services will determine if an earlier re-inspection interval is necessary.

4. ***Special Considerations for Grandfathered Pipe (>0.72 Design Factor)*** - If the pipeline segment being analyzed has an established MAOP greater then 72% of the Specified Minimum Yield Strength (SMYS), the detailed assessment procedure shall be as follows:
   a. Any metal loss anomaly located inside on HCA that has a predicted failure pressure (Pfail) less than or equal to 1.16 * MAOP (maximum allowable operating pressure) will be classified as an immediate repair condition.
   b. Any metal loss anomaly located outside an HCA that has a predicted failure pressure (Pfail) less than or equal to 1.10 * MAOP (maximum allowable operating pressure) will be classified as an immediate repair condition.
   c. All other metal loss anomalies shall be evaluated using the following:

      An appropriate FPR threshold will be calculated for scheduled remediation conditions as follows:

      i. Calculate current design factor, DF. (MAOP/100%SMYS) or MAOP/(2*WT*Grade/OD)
      ii. FPR threshold is 1/DF

         Example: 16", 0.250"WT, Grade B with MAOP = 899 PSIG

         SMYS = 1,094

         DF = 0.822

         FPR threshold for scheduled conditions = 1/0.822 = 1.22

   d. Re-inspection interval for a segment containing grandfathered pipe shall be established based on consideration of the design factor of the pipe as it compares to Section 7, Figure 4 of ASME B31.8S.

5. ***Analysis of Final ILI Report(s) for Additional Scheduled Conditions*** - Pipeline Services will review the Final ILI Report(s) and perform a detailed assessment to determine which additional anomalies should be ***considered*** for investigation in addition to those previously identified as immediate, one year or scheduled repair conditions.

   The following conditions will require a detailed assessment, engineering strain analysis and/or remediation in a timeframe defined by Pipeline Services which will coincide with ASME B31.8S, Section 7, Figure 4:

a. Any metal loss anomaly with a depth that is equal to or greater than 70% of the nominal pipe wall thickness not previously evaluated.

b. Any metal loss anomaly with at least 40% wall loss associated with a casing, weld or wrinkle bend.

c. Internal metal loss features that are concentrated near the 6-o'clock position of the pipeline.

d. Metal loss or dent anomalies associated with pipe supports, clamps or other structural locations

e. Any dent greater than 6% of the pipe diameter (greater than 0.50" in depth for a pipe diameter less than 12") not previously evaluated. Additional consideration should be given to indications located between 8 o'clock and 4 o'clock (upper 2/3 of pipe).

f. Any dent greater than 2% of the pipe diameter (greater than 0.250" in depth for a pipe diameter less than 12") with associated metal loss, cracking, or weld AND NOT located within a HCA.

g. Any other anomalies detected, such as hard spots, cracks, mill defects, or high concentrations of minor metal loss anomalies, may be included for in-field investigation.

6. ***Detailed Assessment*** - Detailed assessment should be utilized to determine the practicality of including certain anomalous indications in the various stages of the remediation program. Pipeline Services personnel with knowledge of the particular inspection results as well as the pipeline design and operating history of the segment should conduct the detailed assessment. The approach to these detailed assessments may vary depending on the issues pertaining to individual anomalies.

   Some issues that may be considered during detailed assessment include but may not be limited to or completely inclusive of the following:

   a. Proximity to the general public via dwellings, gathering places, roads, or railroads. Particular attention to HCA's.

   b. Pipeline Design (MAOP as a %SMYS)

   c. Comparison of P_{Fail} to MAOP

   d. Further assessment using alternative failure pressure calculation methods

   e. Predicted mode of failure (leak/rupture)

   f. Operating History (pressure test history, failure history, cathodic protection history)

   g. Previous inspection results

   h. Anomaly characterization (pitting, general corrosion, dents, etc.)

   i. Corrosion Growth Analysis

   j. Operational/Commercial considerations

   k. Additional consultation with the inspection vendor

   l. Engineering strain analysis

   The detailed assessment will culminate with a scheduled response memo from Pipeline Services to the Area Manager describing those anomalies requiring in-field evaluation and/or remediation and the proposed schedule for completion of the remediation work.

   Any anomalies evaluated for remediation located on above ground piping should be highlighted in this memo for possible action by Field Operations. Any segments evaluated for remediation based on concentrations of internal metal loss anomalies near the 6 o'clock position should be highlighted in this memo for possible action by Corrosion Control Services.

7. ***Analysis of Final ILI Report(s) for Monitored Conditions*** - Pipeline Services shall review the Final ILI Report(s) to determine if any of the anomalies that meet the following conditions shall be classified as a "Monitored Conditions Anomaly." Monitored Condition Anomalies will not be scheduled for remediation, but will be recorded in the scheduled condition response memo. Pipeline Services will continue to monitor these anomalies during subsequent risk assessments and integrity assessments for any change that may require remediation.

    a. A smooth dent located between 4 o'clock and 8 o'clock positions (lower 1/3 of pipe) with a depth greater than 6% of the pipe diameter (greater than 0.50" in depth for a pipe diameter less than 12") AND located within a HCA.

    b. A smooth dent located between 8 o'clock and 4 o'clock positions (upper 2/3 of pipe) with a depth greater than 6% of the pipe diameter (greater than 0.50" in depth for a pipe diameter less than 12") AND located within a HCA. Must have a documented Engineering Strain Analysis.

    c. A dent with a depth greater than 2% of the pipe diameter (greater than 0.250" in depth for a pipe diameter less than 12") associated with a girth weld or longitudinal seam AND located within a HCA. Must have a documented Engineering Strain Analysis.

    d. Any other anomaly that Pipeline Services feels warrants monitoring.

5. Verification of Results

As anomaly evaluations are taking place, it is the responsibility of the evaluator to note the amount of correlation between ILI reported data and actual in-field measurements. Any significant discrepancies or problems with anomaly location, characterization, or sizing should be communicated to the ILI vendor and Pipeline Services support personnel to determine if any further data analysis or other actions are warranted. Documentation of these discussions by email is sufficient.

6. Future Mitigation

The need for future mitigation efforts should be evaluated. This evaluation should be conducted by Corrosion Control personnel within the Pipeline Services department and may require input from Area Operations and Pipeline Services personnel. The results of the evaluation should be communicated to the appropriate Area Operations Manager. A number of mitigation activities may be considered including, but not limited to:

1. Additional excavations
2. Follow up cathodic protection survey and/or modification of cathodic protection system.
3. Pipeline renovation or recoating
4. Installation of coupons for monitoring internal pipeline conditions
5. Establishing specific operational pigging guidelines
6. Follow up in-line inspection

7. Project Completion

After completion of each remediation project, the project coordinator will be responsible for completing a closeout package. The original of the package should be forwarded to Engineering/Drafting within 30 days of the completion of the project. A copy of the package should be sent to the Area Manager or his designee for filing in the appropriate location DOT file.

The minimum data to be included in the package is as follows:

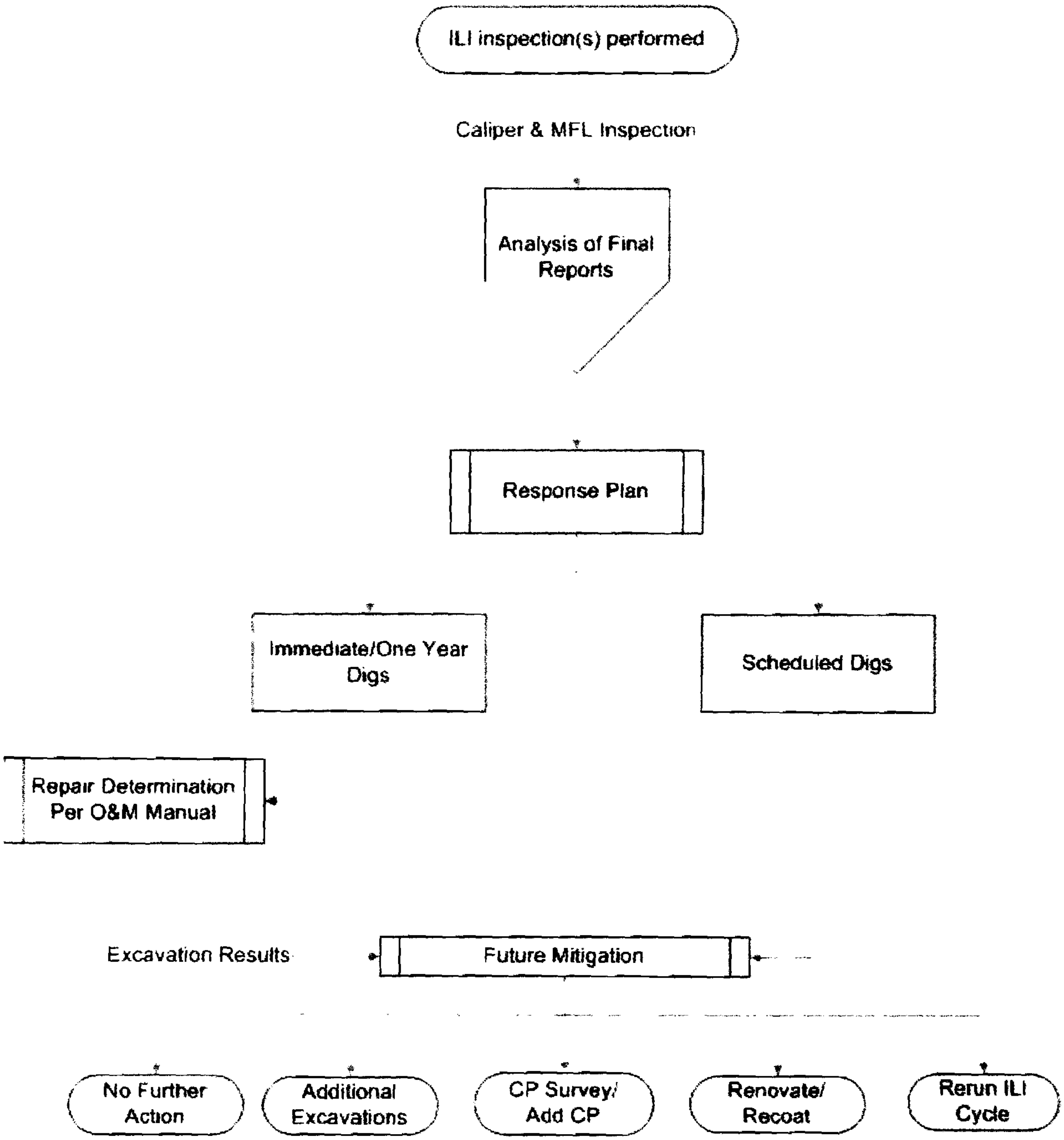
1. Project ID Close-Out Master Checklist
2. Pressure restriction information (including notifications to Gas Control and calculation method)
3. Inspection/Repair Reports
    a. Dig Sheets
    b. Pipe Inspection Forms
    c. Pipe Repair Forms
    d. Pipeval/Coreval reports
    e. NDE Inspection forms
4. Pipe Materials (if pipe is replaced or metal sleeve is installed)
    a. Mill Test Reports (MTRs)
    b. Pressure Test Record
5. Operator Qualifications
    a. Contract NDE technicians with written credentials
    b. EP OQ (Operator Qualification) program forms EN-0431 & EN-0432
6. Other Recommended Documentation - if applicable
    a. Red-lined drawings
    b. Pre-job and tailgate safety meeting notes
    c. Haz-Op Plans
    d. Waste Management Plan
    e. Clearance documentation
    f. Coating Analysis
    g. Other pertinent laboratory reports
    h. Photographs

8. Reference:

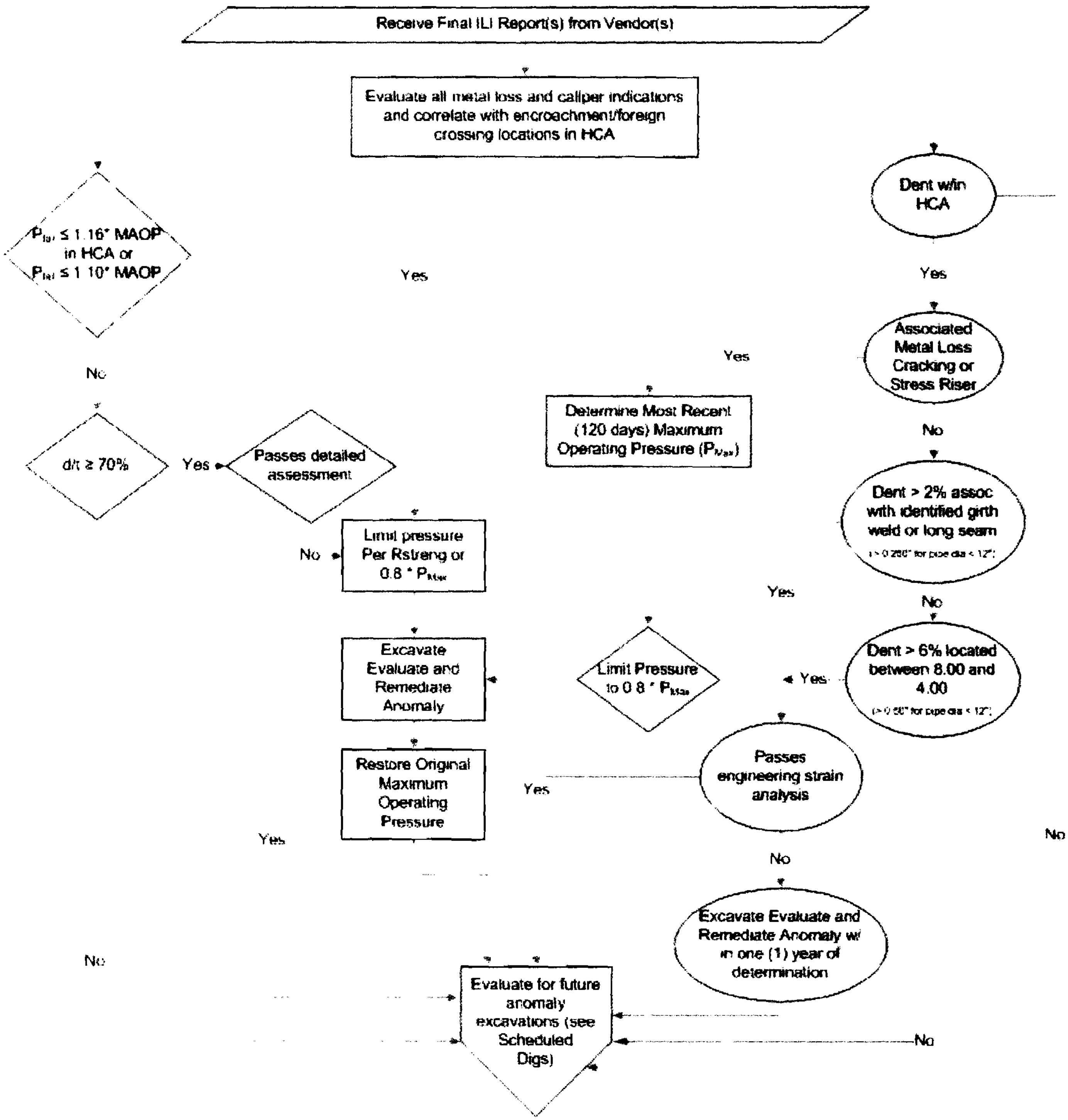
ASME B31.8S

ASME B31G - Manual for Determining the Remaining Strength of Corroded Pipelines

In-Line Inspection Anomaly Investigation
Overall Flow Chart



Immediate/One Year Anomaly Digs



Scheduled Anomaly Digs (10 Year Criteria)