ENERGY TRANSFER

Transwestern Pipeline Company

January 13, 2009

JAN 15 2009

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

Dear Mr. Seeley:

Re: CPF 4-2008-1012M NOTICE OF AMENDMENT

This is in response to your letter of August 1, 2008, in which you granted Transwestern Pipeline Company (TW) a time extension until January 14, 2009 to respond to the NOA which it received via Panhandle Energy. We appreciate you consideration in this matter.

Transwestern, unlike Panhandle Energy, does not espouse the use of white papers; therefore, none were used to support the IMP. The company utilizes the Integrity Compliance Activity Manager (ICAM) developed by P. I. Confluence Inc., and SOP's to manage all Pipeline Integrity activities as will be evident by the response to some of the items noted in the NOA. In addition, TW uses the Dynamic Risk Algorithm (IRAS) as its risk assessment program.

All the pertinent SOP's are submitted as attachments with this document

This response addresses each item cited in the NOA in chronological order as follows and is highlighted in **yellow:**

1. §192.905(a) General. To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method for its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See appendix E.I. for guidance on identifying high consequence areas.)

Panhandle Energy must amend SOP J-01 and SOP J-02 processes and procedures as they relate to the HCA identification process to ensure that it will specifically address integrity management for facilities. Additionally, Panhandle Energy must amend its HCA identification process to ensure that the HCA process utilizes information from routine operation and maintenance activities and input from public officials.

TW RESPONSE: SOP's J.01 and J.02 have been revised to emphasize integrity management for facilities including the utilization of information from routine operation and maintenance activities and input from public officials. Transwestern uses method (2) from §192.903, as defined in SOP J.01 to determine HCA's. The following are pertinent excerpts from the SOPs':

J.01

Procedure Description	This Standard Operating Procedure (SOP) describes the requirements for identifying locations meeting the requirements of a High Consequence Area (HCA) **through routine operation and maintenance activities,** such as surveillance activities and data analysis. The procedure also identifies a process for review of mitigative strategies to eliminate the potential existence of an HCA.

J.02

Procedure Description	This Standard Operating Procedure (SOP) provides instructions on contacting public officials who have safety, emergency response, or planning responsibilities that may be able to assist with the determination and verification of identified sites as High Consequence Areas (HCAs).
Scope	This SOP includes procedures for communicating with public officials during the process of determining identified sites that meet the requirements of an HCA. Federal regulations require operators to contact public officials with safety, emergency response, or planning responsibilities to assist with the determination and/or verification of identified sites that meet the requirements of an HCA. For those locations where officials do not possess the knowledge of identified sites, the operator is required to perform a search of publicly available records or databases
Applicabilty	This SOP applies to communication with public officials regarding the identification of HCAs.
Frequency	Periodic **(Not to exceed 3 years)**: Letter/ MAPS to Safety and Emergency Response officials requesting potential identified site information As required: Perform field verification of identified sites As required: Perform additional investigation of publicly available database

2. §192.917 (e)(4) ERW pipe. If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8 S, Appendices A4.3 and A4.4, and any covered or non covered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced

during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

Panhandle Energy must amend White Paper B2.c and SOP J-09 processes and procedures as they relate to the Facilities Risk Assessment processes (including its algorithms and risk ranking) to ensure that covered segments containing LF-ERW pipe not previously hydrostatically pressure tested, which experienced operating pressure increases above the maximum operating pressure during the preceding five years are prioritized as high-risk segments.

TW RESPONSE: Transwestern Pipeline Company does not have any LF-ERW pipe that has not been previously hydrostatically tested to pressures higher than the operating pressure. Nor does TW have any lap-welded pipe. In addition, it is company policy not to install any new LF-ERW pipe. Therefore, this is not an issue for TW.

3. §192.905(c) Newly-identified areas. When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

Panhandle Energy must amend White Paper B4.a and any relevant SOP process and procedures as they specifically relate to Newly-identified areas to ensure that they adequately describe how to identify newly identified areas as possible high consequence areas. The procedures need to adequately describe the requirements to obtain information concerning changing conditions along the pipeline that may require HCA updating.

TW RESPONSE: SOP J.01 "Determining High Consequence Areas" has been modified, defining HCA's and the information that is required to be documented for a potential HCA. Transwestern uses method (2) from §192.903, as defined in SOP J.01.

SOP B.13, "Surveillance for Class Location and HCA Determination" has also been modified to include surveillance for HCA's. Both SOP's have a required frequency for the surveillance "on a continuing basis and at least once a calendar year. See SOP B.13, paragraph 4.0. In addition, the form for collecting the data has been rewritten. It is now form B.13.A, available to the Asset Management Teams electronically. The form includes spaces for information like type of identified site, offset distance, GPS, and occupancy information. Plus, it dictates the requirement

for submission to the GIS department and the Pipeline Integrity Engineer for evaluation. Furthermore, it requires that any changes for each pipeline be updated annually, and that any newly identified HCA.s be incorporated in the BAP.

4. §192.917 (a) Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (ibr, see §192.7), section 2, which are as follows:

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

Panhandle Energy must amend White Papers C1a, C19,--rand any relevant SOP process and procedures involving the Threat Identification-process and procedures to ensure that there is consideration of interactive threats for each covered pipeline segment as required by ASME B31.8S, Section 2.2. The process shall ensure that near neutral pH stress corrosion cracking is addressed. Additionally, the basis for excluding external corrosion for pipelines less than 10 years must be justified and the basis for considering the threat of manufacturing-related defects as stable must adequately address the 5 year pressure history limitation per 49CFR 192.917(e)(3).

TW RESPONSE: Transwestern has identified five interactive threat scenarios that are monitored. The IRAS risk assessment program provides the capability to conduct queries against the IRAS database to determine if any of these interactive threat conditions are present. When the presence of an interactive threat has been identified, it is elevated to a higher risk ranking and given priority in subsequent BAP plans. These interactive threat conditions are as follows:

1. **Third party damage impacts causing coating damage and therefore exacerbating external corrosion**
2. **External corrosion causing selective seam corrosion on LF-ERW pipes**
3. **Outside force (ground movement) causing pipe movement and premature failure of external corrosion (resulting from bending or longitudinal stresses)**
4. **Manufacturing defects (seam defects) activated by pressure cycling**
5. **Construction threats (girth weld defects) activated by ground movement (resulting from bending or longitudinal strains)**

The IRAS Algorithm recognizes that both high pH and near neutral pH SCC exist, and combines the two sets of conditions resulting in a general form of an SCC susceptibility algorithm as follows:

$MPY_{Baseline,SCC}$ (0-10 mpy) = (S_{SCC}) * R_{SCC}

Where:

$MPY_{Baseline\ SCC}$ = The Baseline SCC Growth Rate (between zero and 10 mpy);
S_{SCC} = The SCC Susceptibility Factor (0 or 1);
R_{SCC} = The Expected SCC Growth Rate (0-10 mpy) and,
M_F = The Integrity Assessment Multiplication Factor (0 to 1)

The only factors which can cause a pipeline to be non-susceptible to SCC are an operating stress level below 45% SMYS (noting that this is more conservative than NACE RP0204 which considers 60% SMYS to be the lower bound for SCC susceptibility), and the other factor being a non-susceptible coating system (defined as those based upon a fusion bond epoxy mainline coating).

NACE RP02024 differentiates near-neutral pH and high pH SCC susceptibility based upon the exclusion/inclusion of a temperature factor (NACE RP0204 1.2.2) of 100°F. The TW algorithm does not discriminate susceptibility based on temperature, so in no way are any segments susceptible to near-neutral pH SCC excluded. The calculated SCC score accounts for both near-neutral and high-pH SCC.

The Dynamic Risk IRAS Model does not exclude external corrosion for any pipeline based on age.

Manufacturing related defects are considered as stable in the IRAS algorithm only if the following conditions are met:

1. **The hydrostatic test pressure was higher than 125% of the Maximum Operating Pressure. TW policy is to test old or new pipe to 100% SMYS for 8 hours.**
2. **The pipeline is not subjected to unusually severe pressure cycle magnitude and frequency, or the pipeline has not been subjected to an increase in MAOP in the preceding 5 years.**

Prior to the implementation of the IMP program, a survey was made to determine if there were any ERW/LF pipelines in HCA's. There were none. In the event that in the future the pressure in an HCA is increased that information will be captured in the Up-rating Plan and then entered in IRAS.

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

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

    (e)(1) Third party damage. An operator must utilize the data integration required in paragraph (b) of this section and ASME/ ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator

identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

Panhandle Energy must amend the SOP's "Encroachment Surveillance and Buried Pipe Inspections" process and procedures to ensure that Data gathering and integration procedures require the integration of encroachment and foreign line crossing location data with ILI or ECDA results to locate areas of potential third party damage.

TW RESPONSE: Form B.13A has been set up to include foreign line crossing information and encroachment information. SOP I.28, "Right-of-Way Encroachment" has been modified to require the use of this form for r/w encroachments and line crossings. SOP I.21 "Pipeline Surveillance" has been modified to require the use of Form B13.A when a pipeline patrol has found a line crossing or an encroachment. In addition, the requirements in SOP B.13 on "Surveillance for Class Location and HCA Determination" require the information to be submitted ongoing, but at least annually. The B.13A form gets submitted to GIS where it gets incorporated into the mapping data base with X-Y coordinates. On a regular basis, but at least annually, this information, the ILI data on all the segments, and CPDM data on bonds at foreign line crossings is loaded into IRAS to run the Risk algorithms. The potential for third party damage is factored into the risk calculations.

6. §192.933(a) General requirements. An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure is reduced, an operator must determine the temporary reduction in operating pressure

using ASME/ANSI B31G or RSTRENG or reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. (See Appendix A to this part 192 for information on availability of incorporation by reference information). A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

Panhandle Energy must amend White Paper E.0-2.a and SOP J-14 processes and procedures to ensure that immediate conditions shall be examined within five days after determination of the condition and that prompt pressure reduction shall be taken once an immediate repair condition is discovered. Additionally, the amended process and procedures must clearly define how the requirements for evaluation of monitored conditions for changes in conditions at future assessments will be carried out.

TW RESPONSE: SOP J.14 "ILI Data Integration Analysis and Response has been modified by the addition of Appendix B below, which covers the activities required by Item Number 6 above.

IMP RULE DEFECT RESPONSE/REPAIRS (ILI)

<u>NOTE:</u> The clock starts on the timing of repairs when there is sufficient information from the vendor to classify an anomaly as a repairable defect, either from credible information received from the vendor at any time prior to the final report, or when within 180 days from the date of assessment, the final report is evaluated and found acceptable.

<u>IMMEDIATE REPAIR CONDITIONS:</u>

<u>(Either repair in the 5 day time limit or promptly lower pressure to 80% of pressure at time of discovery, or to maximum safe pressure determined by RSTRENG. Pressure reduction may not exceed 365 days without technical justification.)</u>

- Corrosion – **(Calculated Failure Pressure), P_f** < or = 1.1(MAOP) RSTRENG (anywhere on pipe)
- Dent w/ metal loss, or crack, or stress riser (anywhere on pipe)
- Any defect the PL Integrity **Analysis Team** determines requires immediate action

<u>SCHEDULED REPAIR CONDITIONS PER B31.8S, SEC 7, TABLE 4:</u>

- All anomalies detected by a HRMFL tool which are deemed defects having an RPR >1.1, including one year conditions, and which have an RPR >1.1 and less than 1.4. The scheduled repair time is = to (RPR-1.1)/0.29 = Time in years which may elapse, in which repairs must be completed. Time may range from one year to 10 years or more. Any defect with a safe operating life of 7 years or more will be classified as a **monitored condition,** and will be re-evaluated at the next scheduled assessment.

ONE YEAR REPAIR CONDITIONS:

- Smooth Dent- (8 to 4 o'clock) Position- (Upper 2/3rds) w/depth 6% or > of Nom. Dia. (12"or >)
- Smooth Dent- (8 to 4 o'clock) Position- (Upper 2/3rds) w/depth > than ½" for (NPS < 12")
- A dent with depth > 2% of Nom. Diameter that affects pipe curvature at a girth weld or longitudinal seam weld.
- A dent with depth > .250" for (NPS <12") that affects pipe curvature at a girth weld or longitudinal seam weld.

MONITORED CONDITIONS:

(Re-evaluate at next scheduled assessment to check for growth. Growth rate will be determined by comparison of two consecutive ILI log runs and appropriate actions taken, if required.)

- All corrosion defects with an RPR = to or > 1.303 equivalent to (7 yrs.) or more
- Dent - (4 to 8 o'clock) Position- (Lower 1/3rd) w/depth 6% or > of Nom. Dia. (12"or >)
- Dent - (4 to 8 o'clock) Position- (Lower 1/3rd) w/depth > than ½" for (NPS <12")
- Dent- (8 to 4 o'clock) Position- (Upper 2/3rds) w/depth 6% or > of Nom. Dia. (12"or >) and engineering analysis of the dent demonstrates critical strain levels are not exceeded
- Dent- (8 to 4 o'clock) Position- (Upper 2/3rds) w/depth > ½" for (NPS < 12") and engineering analysis of the dent demonstrates critical strain levels are not exceeded

A dent with depth > 2% of Nom. Dia. (12"or >) that affects pipe curvature at a girth weld or longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded.

- A dent with depth > .250" for (NPS <12") that affects pipe curvature at a girth weld or longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded.

NOTE: If for any reason, the above schedule cannot be met, technical justification that public safety is not jeopardized is required. Notification as required by SOP J.06 must be made to PHMSA, and if applicable to a State Agent if the schedule cannot be met and a temporary reduction in operating pressure or other action cannot be accomplished.

7. §192.933(b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

Panhandle Energy must amend White Paper E1a and any relevant SOP process and procedures involving the requirements for discovery, evaluation and remediation of preliminary information from ILI vendors regarding potential immediate conditions to ensure that if preliminary data from an ILI vendor is received it will be handled appropriately and expeditiously to determine what action if any is required, including immediate excavation, examination and pressure reduction.

<u>TW RESPONSE:</u> The ILI Specification submitted to ILI vendors has been modified as follows: A preliminary report will be provided describing significant results discovered by the CONTRACTOR such as anomaly depth > 70% wt. or any other feature that may be of concern to the trained analyst within 30 days of receipt of data by the analyst and prior to release of the FINAL REPORT. No preliminary report is required if there are no significant results that would require notification to the COMPANY. The preliminary report will be released to the designated Company Representative (Pipeline Integrity Engineer).

SOP J.14 "ILI Data Integration Analysis and Response has been modified for immediate response activities, and includes further clarification as defined in Appendix B of J. 14 – a portion of which is highlighted below:

IMP RULE DEFECT RESPONSE/REPAIRS (ILI)

<u>NOTE:</u> The clock starts on the timing of repairs when there is sufficient information from the vendor to classify an anomaly as a repairable defect, either from credible information received from the vendor at any time prior to the final report, or when within 180 days from the date of assessment, the final report is evaluated and found acceptable.

<u>IMMEDIATE REPAIR CONDITIONS:</u>

<u>(Either repair in the 5 day time limit or promptly lower pressure to 80% of pressure at time of discovery, or to maximum safe pressure determined by RSTRENG. Pressure reduction may not exceed 365 days without technical justification.)</u>

- Corrosion – **(Calculated Failure Pressure), P_f** < or = 1.1(MAOP) RSTRENG (anywhere on pipe)
- Dent w/ metal loss, or crack, or stress riser (anywhere on pipe)
- Any defect the PL Integrity **Analysis Team** determines requires immediate action

<u>SCHEDULED REPAIR CONDITIONS PER B31.8S, SEC 7, TABLE 4:</u>

- All anomalies detected by a HRMFL tool which are deemed defects having an RPR >1.1, including one year conditions, and which have an RPR >1.1 and less than 1.4. The scheduled repair time is = to (RPR-1.1)/0.29 = Time in years which may elapse, in which repairs must be completed. Time may range from one year to 10 years or more. Any defect with a safe operating life of 7 years or more will be classified as a **monitored condition,** and will be re-evaluated at the next scheduled assessment.

ONE YEAR REPAIR CONDITIONS:

- Smooth Dent- (8 to 4 o'clock) Position- (Upper 2/3rds) w/depth 6% or > of Nom. Dia. (12"or >)
- Smooth Dent- (8 to 4 o'clock) Position- (Upper 2/3rds) w/depth > than ½" for (NPS < 12")
- A dent with depth > 2% of Nom. Diameter that affects pipe curvature at a girth weld or longitudinal seam weld.
- A dent with depth > .250" for (NPS <12") that affects pipe curvature at a girth weld or longitudinal seam weld.

MONITORED CONDITIONS:

(Re-evaluate at next scheduled assessment to check for growth. Growth rate will be determined by comparison of two consecutive ILI log runs and appropriate actions taken, if required.)

- All corrosion defects with an RPR = to or > 1.303 equivalent to (7 yrs.) or more
- Dent - (4 to 8 o'clock) Position- (Lower 1/3rd) w/depth 6% or > of Nom. Dia. (12"or >)
- Dent - (4 to 8 o'clock) Position- (Lower 1/3rd) w/depth > than ½" for (NPS <12")
- Dent- (8 to 4 o'clock) Position- (Upper 2/3rds) w/depth 6% or > of Nom. Dia. (12"or >) and engineering analysis of the dent demonstrates critical strain levels are not exceeded
- Dent- (8 to 4 o'clock) Position- (Upper 2/3rds) w/depth > ½" for (NPS < 12") and engineering analysis of the dent demonstrates critical strain levels are not exceeded

A dent with depth > 2% of Nom. Dia. (12"or >) that affects pipe curvature at a girth weld or longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded.

- A dent with depth > .250" for (NPS <12") that affects pipe curvature at a girth weld or longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded.

NOTE: If for any reason, the above schedule cannot be met, technical justification that public safety is not jeopardized is required. Notification as required by SOP J.06 must be made to PHMSA, and if applicable to a State Agent if the schedule cannot be met and a temporary reduction in operating pressure or other action cannot be accomplished.

8. §192.933(c) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (ibr, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify OPS in accordance with §192.949 if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State or local pipeline

safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

Panhandle Energy must amend White Paper E.0-3.c and SOP-J.06 (External Communication with PHMSA and State Agencies) processes and procedures to ensure that they require documentation justifying why an extended remediation schedule will not jeopardize public safety if PE cannot meet' the originally specified remediation schedule. Additionally, the amended process must contain notification provisions when it cannot meet the remediation schedule and cannot provide a temporary reduction in operating pressure or other action.

TW RESPONSE: SOP J.06 and Appendix B of SOP J.14 are revised as follows:

SOP J.06
Substantial Changes to IMP Implementation

Substantial changes to the implementation of the IMP are reported to PHMSA or a State pipeline safety authority (in a State where PHMSA has an interstate agent agreement).

The Codes Engineer follows these guidelines to determine "substantial" changes to the implementation of the IMP.

Substantial changes to Implementation:

- Inability to identify HCAs
- Inability to identify threats
- Inability to identify and assess risk
- Inability to conduct integrity assessments
- Inability to develop a required section of the IMP
- **Inability to meet remediation schedule. If the remediation schedule cannot be met, technical justification that public safety is not jeopardized is required.**
- **Inability to meet remediation schedule, and a temporary reduction in operating pressure or other action cannot be accomplished**

At the direction of the Director of Pipeline Integrity and Codes, the Codes Engineer reports any significant changes to the IMP or the schedule for carrying out the program elements using the following process below.

Step	Activity
1	**GATHER** and **EVALUATE** information.
2	**DETERMINE** if the change is "substantial."
3	**ACQUIRE** verification and approval from the Director of Pipeline Integrity and Codes.
4	**DEVELOP** notification information.
5	**DETERMINE** method of submittal.
6	**SUBMIT** notification to PHMSA and/or required State Agencies.
7	**RETAIN** documentation of notification and PHMSA or State Agency response of acknowledgement.

SOP J.14 Appendix B excerpts:

SCHEDULED REPAIR CONDITIONS PER B31.8S, SEC 7, TABLE 4:

- All anomalies detected by a HRMFL tool which are deemed defects having an RPR >1.1, including one year conditions, and which have an RPR >1.1 and less than 1.4 are classified as scheduled conditions. The scheduled repair time is = to (RPR-1.1)/0.29 = Time in years which may elapse, in which repairs must be completed. Time may range from one year to 10 years or more. Any defect with a safe operating life of 7 years or more will be classified as a **monitored condition,** and will be re-evaluated at the next scheduled assessment.

NOTE: If for any reason, the above schedule cannot be met, technical justification that public safety is not jeopardized is required. Notification as required by SOP J.06 must be made to PHMSA, and if applicable to a State Agent if the schedule cannot be met, and a temporary reduction in operating pressure or other action cannot be accomplished

9. §192.937(b) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

Panhandle Energy must amend White Papers F 01.a, & b and any relevant SOP process and procedures to specifically describe how periodic evaluations are focused on periodic evaluations .rather than re-assessments. The amended procedures must describe evaluation process specifics concerning its threat and risk analyses assessment, assessment methods review, and P&M reviews. Additionally, PE amended processes and procedures need to clearly show that they will be carried out on a periodic basis.

TW RESPONSE: Per modified SOP J.09, these are all managed within ICAM under the Annual Change of Management of each element. The following list is the outline of the tasks and (MOC) required annually in ICAM:

Annual Change Management of High Consequence Areas (HCA)

- HCA Identification Data Gathering Update
- HCA Determination Update
- Verification of Updated HCA Results

Annual Review of Threat Identification & Risk Assessment

- Regulatory Environment Review
- Threat Update
- Consequence Update
- Data Gathering Modifications
- Threat / Consequence Data Gathering
- Missing Data Management
- Data Integration
- Risk Assessment / Model Review
- Risk Model Update
- Execute the Risk Model

Annual Change Management of Assessment Planning

- Assessment Selection Update
- Baseline Assessment / Re-Assessment Schedule Review
- Baseline Assessment / Re-Assessment Schedule Update
- Addition of Reassessments to Assessment Schedule
- Update / Maintain Low Stress Reassessment Schedule (LSR Schedule)

Annual Change Management of Prevention & Mitigation Measures

- Review Threat List as Required by Changes in the Threat Identification & Risk Analysis
- Review of New Prevention & Mitigation Measures that have been developed to address known threats
- Evaluate & Select Prevention & Mitigation Measures to be Implemented Based on the New Information and Effectiveness
- Prevention & Mitigation Schedule Review
- Prevention & Mitigation Schedule Update

10. §192.935(a) General Requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917.) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S, Section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

Panhandle Energy must amend White Papers H1a, H8a, H8c and any relevant SOP process and procedures to ensure the development of preventive and mitigative measures process beyond a basic framework. The measures must specify how these evaluations will be consistently implemented involving input from relevant parts of the organization.

<u>TW RESPONSE:</u> The preventive and mitigative measures process is consistently implemented and managed within ICAM under the Annual Change Management for Preventive and Mitigative Measures as outlined below:

"At a Glance" Set Up Schedule Report Configuration Users System

Area Description Area Configuration Process List Area Header

Protocol Element Preventive & Mitigative Measures

Area Annual Change Management of Prevention & Mitigation Measur

Sequence 2

Font Size

B I U ABC

Design HTML

Responsibility		**Accountability**		**Authority**	
Group:	Management	Group:	Management	Group:	Management
User:	Jose DeLaFuente	User:	Jose DeLaFuente	User:	Mike Crump

Processes List **Show Description**

Reference links

Update Threat List as Required by Changes in the Threat Identification & Risk Analysis

- **Have any new threats been identified that were not previously addressed?**

Review of New Prevention & Mitigation Measures that have been developed to address known threats

- **Update P&M measure selection table**

Evaluate & Select Prevention & Mitigation Measures to be Implemented Based on the New Information and Effectiveness

- Review data collected as a result of all patrols / remediation
- On per threat basis, which measures were applied and how effective were they?
- Select P&M measure(s) from option list
- Review selection of P&M measures with operations, maintenance, engineering and corrosion where applicable

Prevention & Mitigation Schedule Review

- Review current mitigation schedule

Prevention & Mitigation Schedule Update

- Revise the prevention & mitigation schedule based on management approval
- Use ICAM e-mail to communicate approved P&M schedule changes to appropriate personnel

11. §192.935(b)(1) Third party damage. An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum

i. **Using qualified personnel (see §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.**
ii. **Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191.**
iii. **Participating in one-call systems in locations where covered segments are present.**
iv. **Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP-0502-2002 (ibr, see §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B318.S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.**

Panhandle Energy must amend White papers H2a, H2b and any relevant SOP process and procedures to ensure the requirement of excavation or the performance of an above ground survey using methods defined in NACE RP0502-2002 when there is physical evidence of encroachment involving unmonitored excavation near a covered segment. Additionally, the amended preventive and mitigative measures program must have provisions to apply additional preventive and mitigative measures if the threat of third party damage is identified by the results of the data integration process.

<u>TW RESPONSE:</u> SOP I.30 has been modified. The applicable paragraphs from the SOP I.30 are highlighted below:

Investigation of Mechanical Damage

The Asset Management Team investigates mechanical damage which is suspected from surveillance activities or where the mechanical equipment is still on site.

Step	Activity
1	If the mechanical equipment is still on site **EVALUATE** the need for immediate measures to protect the public and the equipment operator.
2	**DETERMINE** if "One-Calls" were made and if the pipeline was properly marked.
3	**OBTAIN** as much information as is known from the initial notification of damage so an assessment of the pipeline may begin.
4	**INVESTIGATE suspected mechanical damage if evidence exists on the ROW such as disturbed earth that crosses the pipeline.**
5	**CONSIDER in those cases either exposing the pipeline or running an electrical survey which can detect coating damage. CONTACT the Corrosion specialist for advice on the appropriate technique.**

CAUTION:

1. Impact damage caused by mechanical equipment can result in defect(s) which are unstable. Consider the need for an immediate pressure reduction prior to any other activity near the pipeline.
2. Immediately notify the Director of Technical Services and Principle Engineer of Codes and Compliance for additional direction.

Regarding preventive and mitigative measures, IRAS integrates the information for each pipeline segment, by capturing PIPE information, CPDM survey data, SME information, GIS data, ILI data, and SCADA to determine risk ranking. In addition, ICAM requires an annual review of the P&M measures under the Area of "Annual Change Managemnt of Prevention & Mitigation Measures". Under this element, the following processes are required:

- **Updating the threat list for new threats.**
- **Review of P&M measures to address known threats.**
- **Update the P&M selection table.**
- **Evaluate and select P&M measures to be implemented based on the new information and effectiveness of existing measures.**

12. §192.935(b)(2) Outside force damage. If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

Panhandle Energy must amend White Paper H5a and, any relevant SOP process and procedures to ensure the implementation of a program that identifies additional preventive and mitigative measures required for covered segments susceptible to outside force damage.

TW RESPONSE: SOP J.16, "Weather Related and Outside Force Surveys" and the form J.16.A have been modified. The SOP has the following language:

Implementation of Remedial Action Plan

The Asset Management Team, with the guidance of the Pipeline Integrity Engineer, implements the remedial action plan to mitigate identified threats.

Step	Activity
1	**REPAIR, REPLACE, and/or PERFORM additional mitigative measures of the pipeline facilities in accordance with the remedial action plan.**
2	RECORD the actions taken on *Form J.16A*.
3	SUBMIT a copy to GIS for data integration.

In addition, ICAM requires an annual review of the P&M measures for all threats, including Weather Related Outside forces. The processes and their descriptions are listed from ICAM:

- Process: Update Threat List as Required by Changes in the Threat Identification & Risk Analysis
- Process Description: Process includes the tasks required to keep the list of threats current for determination of mitigative measures following updates to the identified threats.
    - Task: Have any new threats been identified that were not previously addressed?
- Process: Review of New Prevention & Mitigation Measures that have been developed to address known threats
- Process Description: Process includes the task necessary to ensure that the latest P&M measures are being considered to address known threats.
    - Task: Update P&M measure selection table

- Process: Evaluate & Select Prevention & Mitigation Measures to be Implemented Based on the New Information and Effectiveness
- Process Description: Process includes the task required to measure the effectiveness of current remediation techniques.

  - Task: Review data collected as a result of all patrols / remediation

  - Task: On per threat basis, which measures were applied and how effective were they?

  - Task: Select P&M measure(s) from option list

  - Task: Review selection of P&M measures with operations, maintenance, engineering and corrosion where applicable

- Process: Prevention & Mitigation Schedule Review
- Process Description: Is designed to review the current mitigation schedule and document any proposed changes.

  - Task: Review current mitigation schedule

- Process: Prevention & Mitigation Schedule Update
- Process Description: Is designed to implement changes into the mitigation schedule.

13. §192.935(c) Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors - swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

Panhandle Energy must amend White Paper H7a,,and ,any relevant SOP process and procedures to provide sufficient detail to ensure the implementation of a consistent program, based on risk analysis, for evaluating the installation of additional Automatic Shutdown/Remote Control valves on a segment specific basis.

<u>TW RESPONSE</u>: Mainline block valves on the TW system are equipped with line break operators which automatically activate (ASV) and close the valves based on a preset rate of change pressure drop, isolating the pipeline segment between valves in the event of a gas release. While this complies with the intent of §192.935©, studies have shown that for natural gas, which has physical characteristics totally different from HVL's and other hazardous liquids; valve spacing and rapid valve closure have a negligible influence on pipeline safety.

14. §192.945(a) General. An operator must include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (ibr, see §192.7), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951. An operator must submit its first report on overall performance measures by August 31, 2004. Thereafter, the performance measures must be complete through June 30 and December 31 of each year and must be submitted within 2 months after those dates.

Panhandle Energy must amend White Paper I1b and relevant SOP J.07 process and procedures to ensure documentation of the threat-specific metrics Of ASME B31.8S, Appendix A in order to determine program effectiveness. The information must be collected and analyzed on a semi-annual basis as required by the IM rule §192.945(a).

<u>TW RESPONSE:</u> SOP J.07 has been modified to ensure documentation of the threat specific metrics as per the following:

7.3 Metrics Captured by Threat

The Pipeline Integrity Engineer provides these metrics to Interstate Natural Gas Association of America (INGAA) as requested. The performance measures for each threat are posted on a website report and reported to senior management annually. <u>Metrics will be scheduled in EAM and documented in Appendix B, Form J.07A</u>.

Performance Metrics for Integrity Plan

Appendix B
Form J.07A

January 1 - June 30 | 2009

The Asset Management Team documents the following performance measures for each threat semi-annually.

External Corrosion

1	Number of hydrostatic test failures caused by external corrosion
0	Number of repair actions taken due to In-Line Inspection (ILI) results, immediate and scheduled
0	Number of in-service external corrosion leaks
0	Number of Low Potential Areas

Internal Corrosion

0	Number of hydrostatic test failures caused by internal corrosion
0	Number of repair actions taken due to in-line inspection results, immediate and scheduled
0	Number of in-service internal corrosion leaks

Stress Corrosion Cracking (SCC)

0	Number of in-service leaks/failures due to SCC
0	Number of repair or replacements due to SCC
0	Number of hydrostatic test failures due to SCC
0	Number of locations with evidence of SCC from visual or Non-Destructive Examination (NDE) inspections

Manufacturing

0	Number of hydrostatic test failures caused by manufacturing defects
0	Number of in-service leaks due to manufacturing defects

Construction

0	Number of in-service leaks or failures due to construction defects
0	Number of girth welds/couplings reinforced/removed
0	Number of failed coupling bolts detected
0	Number of wrinkle bends removed
0	Number of wrinkle bend inspections
0	Number of fabrication welds repaired/removed

(Continued next page)

Equipment

- 0 • Number of in-service regulator valve failures
- 0 • Number of in-service relief valve failures
- 0 • Number of in-service gasket or o-ring failures
- 0 • Number of in-service leaks due to equipment failures
- 0 • Number of bolt fastener failures

Third Party Damage

- 0 • Number of in-service leaks or failures caused by third party damage
- 0 • Number of in-service leaks or failures caused by previously damaged pipe
- 0 • Number of in-service leaks or failures caused by vandalism
- 0 • Number of repairs implemented as a result of third party damage prior to a leak or failure
- 0 • Number of third party damage events, near misses, damage detected
- 0 • Number of Right-Of-Way encroachments
- 0 • Number of detected unauthorized crossings
- 0 • Number of pipeline hits by third parties without previous notification and locate requests
- 0 • Aerial/ground patrol incursion detections
- 0 • Number of excavations notifications received and their dispositions

Incorrect Operations

- 0 • Number of in-service leaks or failures caused by incorrect operations

Weather Related or Outside Forces (WROF)

- 0 • Number of in-service leaks that are weather related or due to outside force
- 0 • Number of repair, replacement, or relocation actions due to WROF threats

The task of compiling the metrics is scheduled in EAM (TW task scheduling tool) semi-annually as required by the IM Rule 192.945(a) and submitted to senior management.

The following sections of SOP J.07 address the semi-annual reporting measures and additional performance indicators for management.

7.1 Reporting Measurement of Assessment Activities for Prescriptive Program

The Codes Engineer is responsible for reporting the following four (4) overall performance measures:

- Number of miles of pipeline inspected versus program requirements
- Number of immediate repairs completed as a result of the integrity management inspection program
- Number of scheduled repairs completed as a result of the integrity management inspection program
- Number of leaks, failures and incidents, classified by cause

These metrics are tabulated and reported on the PHMSA website as described in *SOP J.06 External Communications with PHMSA and State Agencies on Integrity Management*.

7.2 Additional Metrics or Key Performance Indicators for Management

The company applies the following performance metrics of its assessment activities to verify that schedules, objectives, and commitments are being met. ICAM is used to track and organize data and evaluation tools. The Pipeline Integrity Engineer is responsible for evaluating the data. The results are posted on the Engineering Website.

- HCAs versus total system miles
- Miles inspected versus integrity management program requirement
- Miles assessed in excess of program requirements
- Number of integrity management program changes requested by authorities
- Jurisdictional reportable incidents/safety related conditions per unit of time
- Fraction of system included in the integrity management program
- Number of actions completed that impact safety
- Number of anomalies found requiring repair or mitigation
- Anomalies remediated which may have resulted in ruptures (RPR < 1.0)
- Number of anomalies remediated which may have resulted in leaks (reported wall loss > 80%)
- Number of unscheduled outages and impact on customers during the performance of integrity management assessments
- Number of scheduled outages exceeding the plan duration

15. §192.911 What are the elements of an integrity management program? An operator's initial integrity management program begins with a framework (see CFR: 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S for more detailed information on the listed element.)

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

A) Panhandle Energy must amend White Paper K2e and relevant SOP J.07process and procedures to ensure the procedures provide for review and analysis of impacts on the IMP prior to implementation of pipeline or system changes.

B) Panhandle Energy must amend White Papers B6a, B6b and any relevant SOP Process and procedures involving the ICAM element for the BAP to ensure he BAP is kept up-to-date with respect to newly arising information, applicable threats, and risks that may require changes to the segment prioritization or assessment method. The amended element must also include key management of change elements for documenting the reason for changes, authority for approving changes, analysis of implications and communication of changes to affected parties.

TW RESPONSE:

A) The review and analysis of impacts prior to implementation of pipeline or system changes is addressed in ICAM through the Management of Change process as follows:

Integrity Compliance Activity Manager

Suggestion Logout

"At a Glance" Set Up Schedule Report Configuration Users System

Area Description Area Configuration Process List Area Header

Protocol Element	Management of Change
Area	Physical MOC
Sequence	3

Font Size

Responsibility	Accountability	Authority
Group: Management	Group: Management	Group: Management
User: Jose DeLaFuente	User: Mike Crump	User: Mike Crump

Processes List Show Description

Reference links

Process / Task

Note Change Parameters and Analyze Implications

- Detail the Nature of the Change
- Document change parameters
- What is the primary driver to justify moving this suggested change forward?
- Analyze each of the following to determine their potential impact on the decision to implement this suggested change
- Will this change have an effect on the Integrity Management Program OR potentially require changes in other areas?
- Based on analysis of implications submit for management approval

Management Approval

- Based on analysis of implications submit to management approval
- Use ICAM e-mail to communicate status of proposed change to appropriate personnel

Submit Export Cancel

B) The Items noted in B) are addressed in ICAM in the following manner:

Element **Baseline Assessment Plan**

Area Annual Change Management of Assessment Schedule *

Sequence 2

Font Size

B I U ABC

Design HTML

Responsibility	Accountability	Authority
Group: Management	Group: Management	Group: Management
User: Jose DeLaFuente	User: Mike Crump	User: Mike Crump

Processes List Show Description

Reference links

Process / Task

Assessment Selection Update

- **Review new assessment methods**
- **Review new threats**
- **Update threat assessment methodology matrix to include new threats and new assessment methods**
- **Notify Jurisdictional Authorities if "Other Technology" has been added to the threat assessment matrix**

Assessment Schedule Review / Update

- **Were all new HCA identified for inclusion in the BAP?**
- **Do different assessment methods need to be assigned to any HCA segment**
- **Do any scheduled assessments require a change in the assessment date**
- **Did the annual review warrant changes to the Assessment Schedule?**
- **Submit request for reassessment waiver to Jurisdictional Authorities**
- **Notify appropriate personnel of changes to BAP**

Addition of Reassessments to Assessment Schedule

- **Determine if the reassessment method should be modified**
- **Schedule reassessments based on interval calculated**

16. §192.911 What are the elements of an integrity management program? An operator's initial integrity management program begins with a framework (see CFR: 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S for more detailed information on the listed element.)

I A quality assurance process as outlined in ASME/ANSI B31.8S, Section 12.

Panhandle Energy must amend White Papers L01b and L01c along with any relevant SOP J.07 process and procedures to ensure the implementation of a quality assurance program that will be conducted and reviewed on a periodic basis.

TW RESPONSE: SOP J.07 has been modified to include performance metrics for evaluating the effectiveness of the IMP. In addition, ICAM (Integrity Compliance Activity Manager) is updated regularly, but at least annually for the following quality assurance measures:

Regulatory Review

- **Review Regulations**
- **Review Frequently Asked Questions / Interpretations**

Personnel Qualifications

- **IMP Personnel Qualification Management**

Discovery of Condition

- **External Issue Discovery**
- **Internal Issue Discovery**

Condition Resolution

- **Determine Resolution to Safety Concern**
- **Implement Corrective Actions**

Operational Review for Effect on Integrity

- **Determine Physical Changes That May Affect Integrity**
- **Review Temporary Change Report**
- **Pressure Reduction Conditions Review**
- **Review Operational Events to Support Continuous Evaluation**
- **Field Notification of Instance**

Integrity Program Review

- **ILI Plan Management**
- **ILI Plan Update**
- **Pressure Test Plan Management**
- **Pressure Test Plan Update**
- **Integrity Procedures Management**
- **Integrity Procedures Update**
- **Required Notification for Change to Integrity Management Program**

Excavation Schedule Review & Update

- **Excavation Schedule Review**
- **Excavation Schedule Update**
- **Required Notification for Change in Remediation Schedule**

ICAM Processes are reviewed as part of Performance Measures

Threat / Risk Assessment Process Continuous Improvement

- **Process Review**

Assessment Planning Process Continuous Improvement

- **Process Review**

HCA Identification Process Continuous Improvement

- **Process Review**

Prevention & Mitigation Planning Process Continuous Improvement

- **Process Review**

ILI Process Continuous Improvement

- **Process Review**

Quality Assurance Process Continuous Improvement

- **Process Review**
- **ICAM Process / Task Update**

Communications Process Continuous Improvement

- **Process Review**

Document Submission Process Continuous Improvement

- **Process Review**

With this response, TW concludes all obligations subject to the NOA.

Sincerely,

Michael Crump
Director Technical Services
Transwestern Pipeline Company, LLC

Cc: Mike Spears – Sr. Vice President Operations and Engineering
Manny Gallegos - Sr. Vice President Shared Services
Ron Green - Vice President Operations Support
Jose de la Fuente – Code Compliance

Attachments:

Standard Operating Procedures:

- B.13 Surveillance for Class Location and HCA Determination
- I.21 Pipeline Surveillance
- I.28 Right of Way Encroachments
- I.30 Third Party Damage
- J.01 Determining High Consequence Areas
- J.02 HCA Identified Sites-Communication with Public Officials
- J.06 External Communications with PHMSA on Integrity Management
- J.07 Performance Metrics for Integrity Management
- J.09 Facility Risk Assessments
- J.14 ILI Data Integration Analysis and Response
- J.16 Weather Related and Outside Force Surveys