CHS

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November 15, 2007

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Mr. Chris Hoidal
Director, Western Region
Office of Pipeline Safety
Research and Special Programs Administration
12300 W. Dakota Avenue, Suite 110
Lakewood, CO 80228

Re: CPF No. 5-2007-5014M

Dear Mr. Hoidal:

This letter is in response to the Notice of Amendment, issued by OPS on April 4, 2007, and refers to the Integrity Management Inspection which occurred at our facilities on the dates of August 28th through the 31st of 2006.

Item number 1.A. of the NOA required CHS, Inc. to add detail regarding the application of airborn toxicity buffers in determining which pipeline segments could affect HCAs. CHS has revised the procedure in section 11.1.3 of the Integrity Management Program to address this request (See Attached).

Item number 1.B. of the NOA required CHS, Inc. to add a detailed description of the process used by CHS to analyze the overland flow of liquids released from potential pipeline failures to ensure that the results are repeatable. CHS has revised the procedure in section 11.1.3.1 of the Integrity Management Program to address this request (See Attached).

Item number 1.C. of the NOA required CHS, Inc. to document the technical justification used fro excluding tank volumes in the determination of facilities and adjacent piping that may impact HCAs. CHS did not exclude tank volumes in the original IMP, however, it did not specifically address how these were evaluated. This is currently being developed and reviewed as part of the Facility Risk Analysis per item 1. E. below.

Item number 1.D. of the NOA required CHS, Inc. to add provisions for assessing each pipeline segment's susceptibility to SCC. CHS has revised the procedure in section 4.6 of the Integrity Management Program to address this request (See Attached).

Item number 1.E. of the NOA required CHS, Inc. to add a facility risk analysis to the program. CHS is in the process of evaluating methods to complete a facility risk analysis and plans to submit that procedure upon completion (projected within the next 6 months).

Item number 1.F. of the NOA required CHS, Inc. to define discovery and add time constraints. CHS has revised the procedure in section 6.6 of the Integrity Management Program to address this request (See Attached).

Item number 1.G. of the NOA required CHS, Inc. to a requirement that immediate repair conditions be repaired as soon as possible. CHS has revised the procedure in section 6.1 of the Integrity Management Program to address this request (See Attached).

Item number 1.H. of the NOA required CHS, Inc. to eliminate the automatic default to five years for reassessments. CHS's IMP does not default to 5 years for reassessments (see section 5 of the Integrity Management Program). Based on the results of the baseline assessments that were completed to date at the time of the audit and each segment's associated risk factors, no segments indicated that a shorter than a 5 year interval was required. Therefore, all reassessments were scheduled for 5 years. If upon review of risk rankings, ILI results, and other data, this changes, the intervals will change accordingly.

Item number 1.I. of the NOA required CHS, Inc. to add a description of the process for examining causes of incidents, leaks, and near misses, making recommendations for corrective actions, and providing those lessons learned to appropriate company personnel. CHS has an existing procedure in the O&M Manual that addresses this (see Section F pages of the O&M Manual).

Item number 1.J. of the NOA required CHS, Inc. to add a description of the process that will be used to perform a leak detection evaluation, including documented basis for all operator reactions credited in the leak detection evaluation. CHS plans to complete the Leak Detection procedure within the next 6 months.

Item number 1.K. of the NOA required CHS, Inc. to describe a process for evaluating the need for additional EFRDs. CHS has revised the procedure in section CHS plans to complete the development of the process required within the next 6 months.

Item number 1.L. of the NOA required CHS, Inc. to revise the validation repair procedures to better define what anomalies will be chosen for validation. CHS has revised the procedure for ILI validation and eliminated the ranges to provide clarification on this. See Verification and Remediation Dig Form.

Item number 1.M. of the NOA required CHS, Inc. to provide additional detail about how the assessment results are integrated with pertinent pipeline risk-condition information to discover integrity issues that might not be evident from the assessment data alone. CHS plans to submit this within the next 6 months.

Item number 1.N. of the NOA required CHS, Inc. to add a requirement for there to be effective corrosion control in place and see that it is being effectively applied to sements where hydro tests are performed as assessments. CHS has revised the procedure in section 4.4 of the Integrity Management Program to address this request (See Attached).

Please contact CHS if you have any questions.

Very truly yours,

John Traeger

John Traeger
Manager of Pipelines and Terminals
CHS, Inc.
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11.1.3.1 Overland Flow

For segments or facilities not crossing an HCA but having potential to affect an HCA via overland flow, CHS uses the following procedure to establish a hazard buffer.

- The buffer spill quantity is the maximum drain down volume that could occur on that specific segment plus a quantity resulting from 20 minutes of continued pump flow before the leak is recognized and the mainline pumps shutdown.. The drain down volume is determined through an analysis of the pipeline alignment sheets that identifies the various high points and low points of a pipeline segment. The longest distance between high points with an intermediate low point establishes the maximum length of pipeline that will drain. This length and elevation difference between the high and low points is entered into the "Archie" [17] program for calculation of spill quantity, spill pool area and spill thickness.
- The spilled liquid is assumed to form into an elliptical shape on the ground and flow away from the rupture point. It is assumed that no product is absorbed into the soil and the flow of the spill is not impeded by vegetation.
- The ellipse's aspect ratio[18] is determined with the following process. The pipeline centerline is overlain on the USGSs National Elevation Dataset in an ARCGRID format that includes HCA locations. The elevation of the pipeline centerline is determined and recorded. The pipeline is then viewed on each side of the centerline for terrain that slopes away from the centerline. Where the terrain slopes away from the centerline, the elevation of the ground at 1000 foot and 2000 foot intervals is determined and recorded. The slope angle or angle of the downward slope is the calculated at the 1000 foot and 2000 foot intervals using the following formula:

  Slope angle = arctan (Δ elevation/Δ length) where the Δ elevation is the difference in pipeline centerline elevation and ground elevation at 1000 feet or 2000 feet and Δ length is 1000 feet or 2000 feet horizontal length away from the pipeline centerline.

  All slope angles are recorded for a segment and the largest slope angle is use to represent the entire pipeline segment. A preliminary aspect ration is determined based on the following Table.

SLOPE CATAGORY	SLOPE ANGLE RANGE[19]	ASPECT RATIO
Steep	$\geq 50°$ but $< 80°$	30% to 60%
Intermediate	$\geq 20°$ but $< 50°$	60% to 30%

17 The "Archie" program, Version 1.0, as approved by the Federal Emergency Management Agency, U.S. Department of Transportation and the U.S. Environmental Protection Agency.

18 Ratio of the short axis of the ellipse to the long axis of the ellipse.

19 Slope angles > 80° are considered impractical for aspect ratio determination.

Shallow	≥ 0° but < 20°	100% to 60%

Unless onsite terrain verification is completed for the segment and the possibility of small creeks, streams, drains, gullies etc eliminated, a minimum aspect ration ≥ 60% will be used.

The final aspect ratio will be either 60% or as selected from the table above.

- The resulting buffer is placed along each side of the line for its entire length and any HCA that is intersected is assumed to be affected by the spill represented by the buffer.

11.1.3.2 Air Dispersion Analysis

CHS uses the following procedure to determine if a hazard buffer resulting from a pool fire and/or vapor cloud fire/explosion or a toxic airborne hazard could affect an HCA.

- Follow the procedure above to find the spill quantity, spill pool size and spill pool thickness.
- When analyzing a vapor cloud fire/explosion the spill is then assumed to expand to its maximum size and then ignite. The magnitudes of a pool fire and/or vapor cloud fire/explosion are then determined using the "Archie" program. Safe separation distances related to radiation hazards[21] from the resulting fires/vapor cloud explosion are also determined using "Archie".
- When analyzing a toxic hazard, the spill is assumed to expand to its maximum size and the "Archie" program determines the hazard distance. CHS has evaluated toxic exposure for benzene for crude oil and gasoline and biphenyl for diesel. Toxic hazards are deemed capable of only affecting populated area HCAs. CHS uses the OSHA STEL for determining the size of the hazard buffer.

11.1.3.3 Affecting HCAs

CHS has established that a pipeline segment buffer or facility buffer that intersects an HCA is deemed capable of affecting that populated area HCA.

11.1.3.4 Waterborne Transport Analysis

CHS utilizes the procedure found in 40 CFR Part 112 Appendix C III 2.0 to determine the spill movement distance in onshore moving water. Spill movement velocities in the affected waterways range from 4-11 ft/sec based on USGS Real Time Water Data for the Nation (mean speed), A 10 hour response time per CHS response plan was also used in the calculations. Based on calculation results, CHS has utilized a 70 mile waterborne transport distance for all waterborne transport.

CHS has established that a release from a pipeline segment that intersects an HCA via waterborne transport is deemed capable of affecting that HCA.

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21 Radiation intensity of 1600 BTU/hr/ft² for determining injury zones and 3200 BTU/hr/ft² for determining fatality zones.

4.4. Assessment Methods

- CHS will select assessment methods based on requirements in §195.452(c)(1)(i). CHS will utilize its most current Risk Analysis for guidance in selecting an assessment method. When selecting ILI tools, the DOT Compliance Coordinator will utilize guidance in Flow Chart 1. CHS will assess the integrity of the line pipe using one or more of the following methods:
  - Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves (See Flow Chart 1 - In-Line Inspection Tool Selection);
  - External corrosion direct assessment,
  - Pressure test conducted in accordance with subpart E of §195. CHS will take additional measures such as a close interval survey or a cathodic protection performance evaluation to ensure the effectiveness of the cathodic protection program when using pressure testing for integrity assessment purposes.
  - Other technology that can provide an equivalent understanding of the condition of the line pipe. If other technology is utilized, CHS will notify the Office of Pipeline Safety 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in §195.
- CHS is not utilizing any assessments prior to March 31, 2002 as baseline assessments.
- The methods selected to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure will be capable of assessing seam integrity and of detecting corrosion and deformation anomalies. (No CHS pipe is deemed susceptible[1].)
- If CHS chooses to conduct an assessment using an MFL tool without a concurrent deformation tool, CHS will direct its ILI vendor to identify all potential dents. All such potential dents will then be excavated and examined, and those meeting rule repair criteria will

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[1] Per 195.303(d) all pre 1970 ERW pipe is deemed susceptible to seam failure and requires a seam assessment or an engineering analysis showing the specific seam is not susceptible. All pre-1970 ERW pipe seams in CHS piping are not susceptible to longitudinal seam failures based on CC Technologies Report (CC Technologies Report – June 17, 2004. Final Report M-3334-27N – "Integrity Assessment of a 426 Mile Long Hazardous Liquids Pipeline, LLC, Laurel, MT").

assessment using a deformation tool or a hydrostatic test will be conducted on an expedited basis.

- The schedule for Baseline assessments is based on the risk ranking of the pipeline segments and the other segments in proximity (i.e. segments in the same piggable section are assessed together.).

4.5. Assessment Planning

Prior to conducting integrity management assessments, the DOT Compliance Coordinator and Engineering Manager will coordinate the development of procedures and processes for each assessment (see section 7.8). The process to validate ILI data (number of verification digs, type of defects that need validation, representative sample specification, required degree of confidence, validation requirements when no anomalies identified, etc.) is located in CHS Procedure - ILI Data Validation and Integration. The process for conducting validation and remediation digs is located in CHS Procedure - Verification and Remediation Digs.

4.6. Stress Corrosion Cracking

CHS has not found stress corrosion cracking (SCC) to be a viable threat to its pipelines and takes the following measures to evaluate this integrity threat on a continual basis.

- Evaluate the risk of the SCC threat annually in the risk analysis. The risk model contains a risk factor in the Corrosion Threat category for identification of stress corrosion cracking criteria present on each pipeline segment. The criteria evaluated are those specified in Appendix A3.3 of ANSI B31.8S. These criteria are the following: (i) operating stress > 60% SMYS, (ii) operating temperature > 100°F, (iii) distance from pump station ≤ 20 miles, (iv) age ≥ 10 years and (v) corrosion coating system other than fusion bonded epoxy installed. Per guidance in that standard, all five criteria must be present for SCC to be considered a viable threat. Information regarding these factors for each pipeline is located in the Document CHS Pipeline Information and is updated annually per Article 10.1 by the DOT Compliance Coordinator.

- Inspect with magnetic particle testing each pipe section for evidence of cracks when exposed during an excavation. The procedure for conducting this testing is contained in CHSs Operating and Maintenance manual.

In the event CHS determines that SCC is a viable threat or experiences a leak or rupture attributable to SCC on one of its pipelines, CHS will conduct an integrity assessment of the affected pipeline following the guidance found in ANSI B31.8S Appendix A3.4.

3. An anomaly abrupt in nature.
4. An anomaly longitudinal in orientation.
5. An anomaly over a large area.
6. An anomaly located in or near a casing, a pipeline crossing or an area with suspect cathodic protection.

6.5. Repair Procedures

Repair and Remediation procedures, including dig criteria, can be found in the CHS Pipeline Operations, Maintenance and Emergency Procedures Manuals and CHS Procedure – ILI Data Validation and Integration and CHS Procedure - Verification and Remediation Digs.

All repairs and remediation shall be done in accordance with §195.422.

6.6. Discovery of a Condition

Discovery of a Condition occurs when the Manager Pipelines and Terminals has adequate information about a Condition to determine that the Condition presents a potential threat to the integrity of the pipeline segment. The following are examples of when Discovery of a Condition could occur:

1. Verification at a dig site of an anomaly correctly identified during ILI run or during an ECDA direct examination.
2. Receipt of notice from ILI vendor that an Immediate Repair condition exists.
3. During review of ILI vendor's preliminary or final report, identification of an anomaly having special[6] repair criteria.
4. Results from data integration process described in Article 7.9.

For assessment results not received directly by the DOT Compliance Coordinator from the assessment contractor, all assessment related information such as ILI run results, pressure test results and ECDA results shall be forwarded to the Manager, Pipelines and Terminals for review and analysis not more than five days after receipt by other CHS personnel.

For Discovery purposes, the Manager, Pipelines and Terminals will complete review of the Vendor's preliminary assessment report within thirty days after receipt unless this time frame cannot be met because of mitigating circumstances.

Discovery of a condition must be determined no later than 180 days after completing the integrity assessment, unless CHS can demonstrate and document that the 180 day period is impracticable. The integrity assessment is

[6] Immediate, 60day or 180 day repair conditions.

Article 6 - Repair and Remediation Criteria (Reference §195.452(h))

The Manager, Pipelines and Terminals is responsible for oversight of all repairs and for all remediation activities. CHS will take prompt action to address all anomalous conditions that are discovered through integrity assessment or information analysis. Action categories are described herein.

6.1. Immediate Repair Conditions

Upon discovery of an Immediate Repair Condition, the Manager, Pipelines and Terminals will ensure that the pipeline segment is either shut down or the operating pressure reduced until the immediate repair condition is repaired or remediated. Immediate repair conditions will be repaired as soon as possible, but in any case, an appropriate pressure reductin will be in place until such time as the repairs are made.

For corrosion anomalies, the reduction in operating pressure shall be determined by the formula in Section 451.7 of ASME/ANSI B31.4.

For all other types of anomalies, the minimum pressure reduction will not be less than twenty percent of the highest operating pressure occurring at the anomaly's location during the preceding sixty days.

Operating pressure reductions may not exceed 365 days while taking repair/remedial action without taking additional remedial action.

The following conditions are treated as Immediate Repair Conditions:

1. Metal loss greater than 80% of the nominal wall regardless of dimensions.
2. An anomaly where the calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly.[4]
3. A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or stress riser. A dent is defined as local change in surface contour.
4. A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.
5. Any other significant anomaly that in the judgment of the Manager, Pipelines and Terminals requires immediate action.

6.2. 60 Day Conditions:

The following conditions are treated as 60-day Repair Conditions:

1. A dent located on top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3% of the nominal pipe diameter

4 Calculation based on ASME/ANSI B31G or AGA PR-3-805 or equivalent.

Verification and Remediation Digs

1.0 Revision Record

Revision Number	Revision Date	Revisions	Approval

2.0 Scope

The procedure describes the process of validating ILI inspection data.

3.0 Responsibility for Management

Manager Pipelines and Terminals
Manager Engineering
DOT Compliance Coordinator

4.0 General

This document provides guidelines for the validation of ILI Inspection results for liquid transmission pipelines in the CHS system. The validation process is a two-step process for ensuring pipeline safety and covers the following in response to an ILI vendor's Preliminary Report and Final Report:

1 ILI Data Validation which is covered in CHS Procedure – Data Validation and Integration
2 ILI Inspection Validation by Excavation

5.0 Related Procedures

CHS Integrity Management Plan
API Standard 1163
NACE recommended Practice RP0102-2002 "In-line Inspection of Pipelines"
ASME B31.G 1999, Manual for Determining the Remaining Strength of Corroded Pipelines
CHS Procedure – Data Validation and Integration
49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

6.0 Records

CHS shall retain a copy of the in-line inspection report and all documents associated with validation for the life of the facilities.

7.0 Definitions

ANOMALY – Any possible deviation from sound pipe material or welds generated by nondestructive examination, such as ILI, and which may or may not be a defect.

DEFECT – An anomaly which has been confirmed to exist, for which measurements have been recorded and which has the potential to reduce the pressure-carrying capacity integrity of the line pipe or welds.

SEGMENT – A contiguous portion of a pipeline to be assessed using ILI.

8.0 Procedure

8.1 ILI Inspection Verification by Excavation

8.2 The process for the validation of the ILI inspection data consists of:

1 Site Selection,
2 Field Excavation, and
3 Acceptance.

This process should not be implemented until the data evaluation procedure as described in CHS Procedure - Data Validation and Integration has been completed.

8.2.1 Site Selection

CHS shall select two (2) anomalies to field verify. These two anomalies should be in the top 10% of the most severe anomalies reported.

8.2.2 Field Excavation

The excavation process should be carried out in accordance with Company procedure. It is essential for the proper validation of the ILI data that the following is recorded on the Dig Data Collection form(s):

1 A description of the anomaly at the location specified by the ILI vendor with respect to the relative distance of the anomaly to an upstream and downstream girth weld at the specified orientation.

2 A photographic record of the anomaly and surrounding anomalies within $\pm$ 3 feet and for $\pm$ 90 degrees of the target location. If the anomaly extends beyond this area further records should be made.
3 The perimeters of all anomalies should be marked on the pipe surface.
4 The maximum depth, length and width of each separate anomaly should be recorded.
5 The location of the maximum depth reading should be recorded.

8.2.3 Validation and Acceptance

The validation and acceptance of the ILI inspection results, based on the sample set described in Section 8.2.2 above and all of the unacceptable anomalies investigated as a result of assessing the Preliminary Report or the Final Report, if any, requires the following conditions to be met:

1 An anomaly is found at the location specified by the Preliminary or Final Report and within the ILI tool tolerances.
2 The anomaly description in the Preliminary or Final Report agrees with that found at the excavated location.
3 The maximum depth of the anomaly is within the tolerance specification provided by the ILI vendor.

If the above criteria are met the ILI data has been validated.

If any one of the above conditions is not satisfied, additional sites may be selected to obtain a larger data set on which to validate the ILI Final Report. The site selection process should be repeated and additional excavations carried out and the validation process in Section 8.2.3 repeated. The site selection process may be modified to focus on a specific anomaly category. It is not mandatory that additional sites are evaluated before proceeding with a course of action to rectify a cause for invalid results.

After repeating the process, a minimum of 70% of the applicable anomalies investigated should have field depths, and lengths within the tolerance specified by the ILI vendor for the anomalies investigated. The ILI report description of an anomaly at the specified location should not be in error more than 10% of the time.

If the above criteria are met, the ILI data has been validated.

If the data is determined to be acceptable a tolerance will be established that will be added to the ILI data. The tolerance will be based on the largest variance (to the conservative side) found during verification excavations. If there are no variances to the conservative side, the report data will be analyzed as reported and no tolerance will be added.

Data verification will continue during repair excavations. The tolerance

CHS excavates and repairs all Immediate Repairs, 60 day Repairs, and 180 day Repairs, and other conditions (see CFR 49 §195.452 (h)(4)). These digs are performed in accordance with CHS Field Excavation and Dig Procedures and repaired in accordance with CHS Operations and Maintenance Manuals.

11. Is the released liquid observable on any surface water?

12. Configuration of pipe at point of accident: (i.e. straight, sag, overbend, sidebend).

13. Was pipe coated?

14. Was pipe above or below the ground?

15. If below, measure cover from original grade.

16. Collect any necessary samples of failed pipe or equipment for metallurgical analysis or other forensic testing. Samples should be appropriately preserved both before and after testing. Samples of failed pipe or equipment should be retained permanently by CHS, unless determined by the Manager, Pipelines and Terminals to be unnecessary.

17. Make a sketch of accident location showing relationship to public or private buildings, highways, railroads, or other landmarks.

18. Measure the distance to closest line marker and record the information contained on the marker.

POST-ACCIDENT REVIEW AND ACTIONS

A. POST-ACCIDENT REVIEW

Any leak or accident, which is reported on DOT Form 7000-1, shall have a post-accident review (49 CFR 195.402 (C)(5)). The procedures for such a review are as follows:

1. The Manager, Pipelines and Terminals will meet with appropriate Supervisors within thirty (30) days after the leak or accident.

2. All information and data collected at the site will be reviewed.

3. Additional information required by DOT Form 7000-1 will be collected from records.

4. Interviews will be conducted with any CHS employee or contract employee involved.

5. Probable causes of the leak or accident will be determined. Consideration of metallurgical factors should be given to determine possible cause.

6. Practical corrective actions shall be recommended.

B. POST-ACCIDENT ACTIONS

After the post-accident review has been conducted, the Manager, Pipelines and Terminals will take any of the following actions considered necessary to minimize the possibility of a recurrence of a leak or accident of this type:

1. Correct design deficiencies.

2. Change operating procedures.

3. Improve personnel training system.

4. Disciplinary action against employees found in violation of established CHS operating procedures or common practices

5. Inform affected personnel of the outcome of the investigation and document that information transfer.

6. Any other actions shall be taken as necessary to ensure that similar failures do not re-occur.

7. Follow additional requirements found in the CHS Operator Qualification Program as required by 49 CFR 195 Subpart G.

ANNUAL REVIEW

1. The actions taken by personnel in response to accident conditions will be reviewed by DOT Compliance Coordinator before or during the annual operations manual review to determine the effectiveness of the operations and maintenance procedures.