Enterprise Products

ENTERPRISE PRODUCTS OPERATING LLC

October 31, 2007

Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety
8701 South Gessner, Suite 1110
Houston, TX 77074

Attn.: Mr. R. M. Seeley
Director, Southwest Region

Re: CPF No. 4-2007-5031M
Dixie Pipeline Company ("DPC")
Notice of Amendment from 2006 DPC IMP Audit

Dear Mr. Seeley,

The following response to the letter and Notice of Amendment ("NOA") dated August 2, 2007 (received August 7, 2007) is hereby submitted by Enterprise Products Operating LLC ("Enterprise"), the managing partner of DPC, on behalf of DPC. By submitting this response, neither Enterprise nor DPC expresses any view of and shall not be deemed to have made any admission as to the validity or enforceability of the regulatory interpretations upon which the NOA was based.

For the items cited in the NOA, DPC submitted a response on September 6, 2007; however, because of the complexity and size of the pipeline integrity program, the migration from a DPC Integrity Management Program which is referenced in the NOA to a new Integrity Management Program, and the development of the requisite documentation, DPC was unable to complete responses to all of the alleged inadequacies in the NOA prior to the original response deadline included in the NOA, as indicated in DPC's response of September 6, 2007. To the extent that any previous response to an issue raised by the NOA was incomplete, DPC has prepared the required documentation and encloses it as part of this response.

PHMSA Item 1:

DPC must include the Mississippi River idle line segment and all other idle pipeline segments in the Baseline Assessment Plan. Currently, DPC does not perform segment identification for idle lines that are filled with nitrogen or other non-hazardous liquid, and consequently, these idle lines are not listed as directly affecting HCAs. Direct intersections between High Consequence

Areas (HCA) and "purged and idled" lines must be identified, and these segments must be listed in the Baseline Assessment Plan. Integrity assessments or re-assessments of these "purged and idle" pipeline segments may be deferred as long as they remain idle.

DPC's Response:
Previously submitted.

PHMSA Item 2:

DPC must modify the buffer distances used in the segment identification process to ensure that the buffers conservatively bound the application of the results of the Baker Risk "cold weather" study on spill behavior and spread. The Baker Risk "cold weather" study had not been completed at the time of the inspection. DPC's air dispersion buffers are established from the Baker Risk Safe Site® third generation air dispersion analysis tool, and DPC's must include technical justification for the air dispersion buffer distances by confirming that the use of MOP and full pipe rupture always provide the highest LFL distance. DPC must also consider if an assumption of a lower pressure or smaller rupture size possibly result in greater LFL distance for the pressures and diameters applicable to the DPC system.

DPC's Response:
Dixie's IMP is in the process of being incorporated into a common IMP (the "Common IMP") for all of the companies operated or managed by Enterprise. In the Common IMP, the attached *Procedure for Identifying HCAs and HCA Segments* IMP-SEC1-01 addresses the procedure for identifying which pipeline segments could affect high consequence areas. The Baker Risk "cold weather" study (the "Baker Study") has been completed. To incorporate the results of the Baker Study, a new segment identification analysis for HCAs on the DPC system is scheduled to be performed in 2008.

The technical justification for the air dispersion buffer distances is outlined in Section 3.3 ("Direct and Indirect Impact of High Consequence Areas"), the Baker Risk "Gas Dispersion Analysis Revision 2", and the Baker Study The technical justification includes the following assumptions to predict the downwind-hazard-distances to bound pipeline releases:

- Using the diameter of the pipe, the type of product involved, and the line's internal pressure and considering the effects of cold weather temperatures, a buffer distance shall be calculated using industry accepted dispersion modeling such as Det Norske Veritas's PHAST, Baker Risk's Safe Site 3rd Generation and/or CANARY by Quest.
- The buffer distance is applied continuously along the length of the pipeline.
- In instances of multiple products traveling through the same pipe, the product with the largest buffer distance determines the buffer distances for the analysis.
- The buffer distance is then rounded up to the nearest 500-foot interval (e.g, 500', 1000', 1500').
- A single pipeline hole is assumed, equivalent to the full bore of the pipeline. In many cases, leaks may occur that will result in much smaller hazard distances. Typical leaks are more likely to involve pinholes due to corrosion or valve or joint leaks.

- The Maximum Operating Pressure ("MOP") is used to estimate mass flow rates for liquid releases. In most cases, releases will occur at the normal pipeline operating pressure, which is often less than full MOP.
- The initial mass flow rate is calculated using an orifice plate model, and friction losses within the pipeline are not accounted for in the calculations.
- Upstream of the orifice plate volatile liquids are assumed to remain liquid, only flashing at and downstream of the orifice plate. In reality, bubbles and vapor pockets are likely to form upstream of the orifice plate and would substantially reduce the mass flow rate of material venting from the pipeline.
- Releases are assumed to occur for a one-hour period: although, gases flashing from a volatile liquid release would reach a steady-state cloud size in a few minutes.
- No allowance is included for actions taken to mitigate a release, such as rapid isolation of a leak.
- Releases are modeled during an "average" day assuming wind speeds averaging 5 m/s with a D Pasquill stability class. For non-"cold weather" conditions, humidity is assumed to be 70%, and an air and ground temperature of 100 °F is assumed for the purpose of maximizing the amount of flashed material and, hence, the dispersion distances. In addition to modeling a release under daytime conditions, a nighttime release is also modeled using 1.5 m/s wind speed and an F Pasquill stability class. To obtain the largest release impact, a nighttime release is assumed, which results in a larger dispersion distance due to the stable atmospheric conditions that restrict the mixing ability of a released gas.
- Releases are assumed to travel in a downwind direction. This assumption maximizes the distance that the gas will travel.
- Gas releases are assumed to be horizontal and orientated perpendicular to the pipeline. This assumption maximizes the distance that gas will travel.
- Each release was modeled as a full-bore rupture at grade level and assumes the 3-feet or more of cover would have no impact on the gas release velocity or direction. This assumption maximizes the distance that the gas will travel.
- Releases are assumed to travel over a flat, obstacle-free ground surface. This assumption maximizes the distance that the gas will travel.

The assumptions noted above are utilized in the dispersion modeling to provide conservatively large predictions of the mass flow rates, discharge velocities, flashed fractions, gas temperature, and, ultimately, the downwind distance to the LFL.

Moreover, incorporation of the Baker Study the dispersion modeling generally results in a larger dispersion distance for the majority of the pipe diameters and pipe MOPs included in the "cold weather" study. Specifically in the case of the DPC assets, the dispersion distances resulting from the Baker Study are approximately 50% greater than those that would be produced through use of a non-"cold weather" study .

Based on the assumptions that were utilized to determine air dispersion buffer distances, DPC feels the results should conservatively bound pipeline releases.

PHMSA Item 3A:

DPC must document the methods and actions to be taken to integrate other pertinent and available data and information with the results of integrity assessment to support evaluation of the condition of the pipeline and to make decisions related to the repair or remediation of pipeline defects. All available information must be utilized and integrated, as appropriate (e.g., one call activity, foreign line crossings, CP surveys, leak history, local knowledge) when making these decisions. The process must be detailed sufficiently to ensure consistent application and repeatability.

DPC Response:
Previously submitted.

PHMSA Item 3B:
NOA states that DPC provided finalized documentation via email to PHMSA on November 16, 2006, of various changes made to the IMP. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required.

DPC Response:
None required.

PHMSA Item 4:

DPC's discovery process must be modified to describe in sufficient detail the specific steps taken following receipt of an ILI report to declare discovery to ensure consistent application. DPC's current definition of "discovery" for immediate repairs requires final validation of the ILI results before discovery of the condition is claimed. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition represents a potential threat to the integrity of the pipeline. In the case of an integrity inspection that was conducted by internal inspection, information in the internal inspection results, such as the percentage of metal loss from corrosion and the magnitude of dent-type deformations, are sufficient to enable a determination that the potential exists for an integrity threat. While the Inspection Team reviewed documentation demonstrating DPC's prompt actions in reducing pressure in response to the receipt of ILI information identifying an immediate condition, DPC's discovery date of the condition did not occur until three days later when the report was "validated."

DPC Response:
Previously submitted.

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PHMSA Item 5:
NOA states that DPC provided finalized documentation via email to PHMSA on November 16, 2006, of various changes made to the IMP. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required.

DPC Response:
None required.

PHMSA Item 6:
NOA states that DPC provided finalized documentation via email to PHMSA on November 16, 2006, of various changes made to the IMP. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required.

DPC Response:
None required.

PHMSA Item 7:
DPC must identify specific triggers, as required in 195.452(j)(2), for the initiation of the periodic evaluation to assure pipeline integrity to ensure consistent application. DPC identified the requirement to perform the periodic evaluation (Information Analysis) within three years following completion of an integrity assessment in IMP-SEC6-01, Section 1.2, or in response to an evaluation of consequences of a release on an HCA.

DPC Response:
Previously submitted

PHMSA Item 8:

DPC must detail the specific inputs used in the reassessment interval determination process to ensure the § 195.452(j)(3) requirements are met. For those segments for which a five year interval is to be justified, the significant threats must be evaluated; and for threats determined to be significant criteria, must be established to justify the assessment interval. In the case of external corrosion where the growth rate determination process is used, the determination in IMP-SEC3-02, Section 2.2.6, must be conservative (use of original construction date gives results far below default rates cited in NACE RP0502 or other industry standards). The processes used to justify a 5 year interval must be referenced in the interval determination process in IMP-SEC 6-0.

DPC's Response:
The DPC IMP is in the process of being incorporated into the Common IMP. The Common IMP addresses the requirements of 49CFR195.452(j)(3) as follows:

49CFR195.452(j)(3) ("Assessment Intervals") indicates that "an operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

Paragraph (e) indicates "the factors that an operator must consider include, but are not limited to" the following:

- *i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate. DPC addresses these in Sections 2.1.10 and 2.1.11 and specifically references these sections in Section 2.3.1 ("Reassessment Determination") of IMP-SEC6-01.*
- *ii) Pipe size, material, manufacturing information, coating type and condition, and seam type. DPC addresses these in Section 2.1.2 and specifically references this section in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*
- *iii) Leak history, repair history, and cathodic protection history. DPC addresses these in Sections 2.1.6 and 2.1.12 and specifically references these sections in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*
- *iv) Product transported. DPC addresses this in Section 2.1.3 and specifically references this section in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*
- *v) Operating stress level. DPC addresses this in Section 2.1.4 and specifically references this section in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*
- *vi) Existing or projected activities in the area. DPC addresses this in Section 2.1.7 and specifically references this section in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*
- *vii) Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic). DPC addresses these in Sections 2.1.6, 2.1.8, 2.1.10, and 2.1.12, and specifically references this section in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*
- *viii) Geo-technical hazards. DPC addresses this in Section 2.1.8 and specifically references this section in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*
- *ix) Physical support of the segment such as by a cable suspension bridge. DPC addresses this in Section 2.1.9 and specifically references this section in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*

Paragraph (g) indicates "an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure." This information includes the following:

1) *Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment. DPC addresses this in Section 2.1.7 and specifically references this section in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*
2) *Data gathered through the integrity assessment required under this section. DPC addresses this in Section 2.1.10 and specifically references this section in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*
3) *Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including corrosion control monitoring and cathodic protection surveys. DPC addresses this in Section 2.1.7, 2.1.8, 2.1.12, and 2.1.13, and specifically references this section in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*
4) *Information about how a failure would affect the high consequence area, such as location of water intake. DPC addresses this in Section 2.1.1. The HCAs are incorporated in the information analysis (collected in Section 2.1 and considered in Section 2.2) and the results of the information analysis are specifically referenced in Section 2.3.1 ("Reassessment Determination") in IMP-SEC6-01.*

Section 2.3 of IMP-SEC6-01 specifically addresses the justification of the reassessment interval. Section 2.3.1 notes that the "reassessment determinations may be recommended to address each specific threat identified to be a concern in the 'Integrity Assessment Method Selection Procedure.'"

The corrosion growth rate determination process outlined in Section 2.2.8 of the *ILI Report Analysis Procedure for HCAs* IMP-SEC3-02, attached, has been modified.

The reassessment determination for continually assessing the integrity of a pipeline segment is outlined in Section 2.3 of IMP-SEC6-01. This section specifically notes that the reassessment shall be established based upon several considerations, including the integrity assessment results outlined in Section 2.1.10. Section 2.1.10 includes the corrosion growth rate study.

If you have any comments or questions, please contact us at your convenience.

Sincerely,

Charles Brabson
Senior Vice President Engineering

1. PURPOSE

The purpose of this procedure is to standardize steps required to perform segment identification, including identification of high consequence areas and where operated liquids pipelines and facilities could affect a high consequence area.

2. LOCATING AREAS OF HIGH CONSEQUENCE

2.1. Data shall be downloaded from the National Pipeline Mapping System (NPMS), which has compiled a series of GIS shape files showing the extents of the high consequence areas (HCAs).

2.1.1. In addition to the NPMS HCAs, modifications of or additions to the NPMS HCA data set are identified through the "***HCA and HCA Segment Field Validation***" procedure.

2.2. Areas of pipeline that could affect an HCA are identified as follows:

2.2.1. Pipelines containing Non-HVL hazardous liquids

2.2.1.1. Areas where assets fall directly within HCAs

2.2.1.2. Areas where assets are within a 500 foot buffer around an HCA (indirect impact)

2.2.1.3. Areas where product flows downhill could reach an HCA as determined by overland spread analysis

2.2.1.4. Areas where product could be transported via streams or rivers to impact HCAs

2.2.2. Pipelines containing HVLs, (excluding Y-grade and NH3)

2.2.2.1. Areas where assets fall directly within a commercially navigable waterway (CNW), high population area (HPA), and other populated area (OPA), or an unusually sensitive area (USA), excluding drinking water USAs.

2.2.2.2. Areas where assets are within a distance defined by an aerial dispersion buffer to a CNW, HPA, OPA, or USA, excluding drinking water USAs.

2.2.3. Pipelines containing Y-grade.

2.2.3.1. Areas where assets fall directly within HCAs

2.2.3.2. Areas where assets are within a distance defined by an aerial dispersion buffer to a CNW, HPA, OPA, or USA, excluding drinking water USAs.

2.2.4. Pipelines containing NH3.

2.2.4.1. Areas where assets fall directly within HCAs

2.2.4.2. Areas where assets are within a distance defined by an aerial dispersion buffer to an HCA.

2.2.4.3. Areas where product could be transported via streams or rivers to impact HCAs.

2.2.5. Pipelines containing HVLs (excluding Y-grade directly within HCAs and excluding NH3).

2.2.5.1. An HVL release will have no impact on drinking water USAs based upon the findings and guidance provided in the December 31, 2002 Michael Baker Jr., Inc. Consequences of HVL Releases Final Report (TTO Number 1) and FAQ 3.25.

2.3. Idle Pipelines

2.3.1. Idle pipelines that contain hazardous liquids are included in the segment identification process.

2.3.2. Idle pipelines that have been purged and filled with an inert such as nitrogen shall only have direct intersections with HCAs identified.

3. METHODOLOGY

3.1. Acquire base data for overland spread and water transport calculation. Examples of such datasets include but are not limited to the US Geologic Survey National Hydrology Dataset (NHD), which is a network of streams and rivers, and the National Elevation Dataset (NED), which is digital elevation data.

3.2. The pipeline analysis shall consider all products transported.

3.3. Direct and Indirect Impact of High Consequence Areas

3.3.1. In order to determine whether the assets fall directly within HCAs, the HCA shape files are intersected with pipeline centerlines in a GIS software package. The engineering stationing of the impacts is then captured for the pipeline segments and recorded in a database. This engineering stationing reflects equations from alignment sheets and the three-dimensional length of the pipeline as installed, rather than a shorter two-dimensional length determined by GIS alone.

3.3.2. For indirect impact and aerial dispersion buffer impact, the HCA shape files are buffered, and the buffers are intersected with pipeline centerlines in a GIS software package. The engineering stationing of the impacts is then captured for the pipeline segments and recorded in a database in the same manner as 3.3.1.

3.3.3. A 500-foot indirect impact buffer shall be used for Non-HVLs to take into account potential discrepancies in the level of spatial accuracy.

3.3.4. Aerial dispersion shall be used to determine buffers for HVLs including Y-grade and NH3. Using the diameter of the pipe, the type of product involved, and the line's internal pressure, and considering the affects of cold weather temperatures a buffer distance shall be calculated using industry accepted dispersion modeling such as Det Norske Veritas's PHAST, Baker Risk's Safe Site 3rd Generation and/or CANARY by Quest. The buffer distance is then rounded up to the nearest 500-foot interval (500, 1000, 1500, etc). In instances of multiple products traveling through the same pipe, the product with the largest buffer distance determines the buffer distance for the analysis. Additionally, dispersion modeling may be based on a representative product that has similar dispersion characteristics to the product or products transported in the individual pipeline segment.

3.4. Overland spread analysis is applied to pipelines that could contain Non-HVL hazardous liquids.

3.4.1. Potential spill volumes are calculated assuming a full line rupture. The maximum flow rate during normal operations, maximum operating pressure data, location of valves and other facilities, a fifteen-minute maximum pipeline shutdown, and pipeline profile are used to calculate the maximum amount of product that will drain from the pipelines.

3.4.1.1. The use of a fifteen-minute maximum pipeline shutdown time period is conservative based upon the following considerations:

- During a full line pipeline rupture it is expected that the upstream pump would automatically shut down due to high flow conditions and the downstream pump would continue to pull down the pipeline pressure until it automatically shut down due to low pressure well within 15 minutes. Therefore, it is not expected that a pipeline that is experiencing a full bore diameter rupture will maintain its normal operating maximum flow rate as well as its maximum operating pressure for fifteen minutes.
- Release volume is not a determining factor in water transport impact analysis, Section 3.5.

3.4.2. Using the calculated potential spill volume, the overland spread impacts are determined based on a one-quarter inch product retention depth utilizing the shape of the land. Release locations shall include the beginning and end of the pipeline segment as well as every 500 feet along the segment.

3.4.3. The conservative methodology utilized in the overland spread modeling bounds the effects of farm field tiles and ditches along side roadways therefore, no additional analysis will be completed to account for farm field tiles or ditches along side roadways.

The conservative methodology includes:

- The indirect impact buffer used for Non-HVLs in Section 2.2.1.2 and 3.3.3 above,
- the conservative potential spill volume calculation in Section 3.4.1 above,
- the conservative product retention and release location determination in Section 3.4.2,
- the application of the US Geologic Survey National Hydrology Dataset (NHD),
- and, the application of the National Elevation Dataset (NED).

3.5. Water Transport

Water-born transport of Non-HVLs and NH3 entails the location of all areas where the pipeline intersects a river, stream, or significant drainage channel. In addition, overland spread paths, upon arriving at a river or stream will initiate a water transport analysis. Peak stream velocities and response times may be used to determine the distance downstream that an HCA can be affected.

3.5.1. Peak stream velocities may be calculated using data obtained from the USGS.

3.5.2. Response times utilized to determine the extents for water transport analysis are six hours for water transport locations in populated areas and twelve hours outside populated areas. Populated areas are defined as HPAs and OPAs.

3.5.2.1. The response times identified above are commensurate with response times utilized in spill prevention, control, and countermeasure plans for compliance with 40 CFR 112. Response time calculation utilizes the requirements of 40 CFR 112 such as on water and on land response speeds unless greater response speeds can be justified.

3.5.3. Where data is not available to determine stream velocity, a default value of ten miles is used. This value is the median of the downstream distances calculated in 3.5.1 and 3.5.2.

3.5.4. Widths of rivers, streams, or significant drainage channels may be identified in accordance with, but not limited to, the following: use of available and recognized established widths or width calculation from GIS basemap data. Where streams do not have GIS basemap data, a default width of 250 feet for major streams and 125 feet for minor streams may be used.

3.6. Pipeline segments determined to have no HCA impact will be documented to validate that the segment has been analyzed for potential HCA impact.

3.7. Pipeline Facilities

3.7.1. Pipeline pump stations and other types of facilities are considered to have the same impact on HCAs as the pipeline going into or out of the facility.

3.7.2. Pipeline facilities with Break Out Tanks could also be identified as "could affect an HCA" where a Break Out Tank release, using the appropriate Baker Risk tank release data and dispersion or transport method, is determined to impact an HCA.

3.7.3. Pipeline facilities whose containment measures are expected to prevent unintentionally released product from leaving the pipeline facility are considered to have no impact on HCAs.

3.7.4. Pipeline facilities whose dispersion or transport impact distances do not extend beyond that bounds of the facility are considered to have no impact on HCAs.

3.8. Documentation

3.8.1. Records generated in the process of implementing the current segment identification shall be retained on file.

4. **REFERENCES**:

4.1. Regulatory –

4.1.1. 49 CFR 195.452

4.1.2. 16 TAC 8.101

4.2. Related Policies/Procedures –

4.2.1. SECTION 1: Segment Identification

4.2.2. HCA and HCA Segment Field Validation procedure

4.3. Forms and Attachments –

4.3.1. N/A

5. **DEFINITIONS**:

5.1. Breakout Tank – as defined by 49 CFR 195.

CHANGE LOG

Date	Rev. #	Change Location	Brief Description of Change
9/15/04	1	Paragraph 3.4.3	Added paragraph
8/22/05	2	4.2.1	Remove "/Chapter"
8/22/05	2	Title Block	Added "EPOLP Pipeline Integrity Management Program"
8/22/05	2	1	Added "operated liquids" so it now reads "where EPOLP operated liquids pipelines and facilities".
11/7/06	3	Title Block	Changed Owner from Joe Cheek to Buford Barr
11/7/06	3	3.4.2	Replaced "determined based on supporting elevation grid resolution" with "every 500 feet".
11/7/06	3	3.4.3	Added verbiage to clarify how the overland spread modeling bounds the effects of farm field tiles and ditches along side roadways.
11/7/06	3	2.2.5	Added subsection 2.2.5 (which includes 2.2.5.1) - technical justification as to why HVLs do not affect Drinking Water HCAs.
11/7/06	3	2.3	Added subsection 2.3 "Idle Pipelines" (which includes 2.3.1, and 2.3.2) to indicate how idle P/Ls are to be addressed.
01/17/07	4	2.1	Added subsection 2.1.1 to allow for the incorporation of field input.
01/17/07	4	3.4.1 & 4.2.2	Deleted the reference to the Shell Spill Model as to how release volumes are calculated to align with the changes to Seg. Ident. process & procedures.
01/17/07	4	3.4.1	Added subsection 3.4.1.1 which clarifies why the use of a fifteen-minute maximum pipeline shutdown time period is conservative for a full bore rupture.
01/17/07	4	3.4.2	Modified 3.4.2 to include the beginning and end of a pipeline segment as release points.
01/17/07	4	3.5.2	Added 3.5.2.1 to provide support for the release response times in 3.5.2.
01/17/07	4	3.5.4	Added 3.5.4 to provide guidance as to waterway width determination.
01/17/07	4	3.6	Replaced existing 3.6 with "Pipeline Facilities" and added subsections 3.6.1, 3.6.2, 3.6.3, and 3.6.4 to provide could affect determination guidance for pipeline facilities.
01/17/07	4	4.2.3	Added 4.2.3 which references the "HCA and HCA Segment Field Validation procedure".
01/17/07	4	5.1	Added "Breakout Tank – as defined by 49 CFR 195"
01/17/07	4	2.3.2	Added "purged and" to the existing statement to better define a P/L filled with inert.

3/28/07	5	3.3.4	Added "and considering the effects of cold weather temperatures" and "additionally, dispersion modeling may be based on a representative product that has similar dispersion characteristics to the product or products transported in the individual pipeline segment."
3/28/07	5	3.6	Added 3.6 which addresses the documentation of pipeline segments which are determined to have no HCA impact.
7/19/07	6	Title Block	Removed the reference to EPOLP and removed the Enterprise logo.

1.0 PURPOSE:

1.1 The purpose of this document is to establish a standardized procedure for the validation of ILI reports, analysis of report data, development of an evaluation and remediation schedule, assessing the ILI tool accuracy, and documentation.

2.0 PROCEDURE:

2.1 Receive and Validate ILI Assessment Reports

2.1.1 When an ILI assessment report is received, the Project Manager or Risk Data Coordinator shall indicate the date it was received on the report. If the report is received electronically, it shall be printed out and dated.

2.1.2 Validate the Preliminary ILI Assessment report – An ILI report will not be considered a Preliminary Report until the data is validated. The following will be verified by a Project Manager or Risk Data Coordinator to ensure that the vendor is providing accurate data:

2.1.2.1 AGMs have been entered correctly and that the benchmarks were set properly.

2.1.2.2 Slippage has been accounted for and calculated correctly.

2.1.3 When a Preliminary ILI Assessment report is validated, the Project Manager or Risk Data Coordinator shall document the date it was validated. The "ILI Final Report Validation Check List", Attachment A, may be used to document the date the Preliminary Report was validated, however it should indicate that the validation is for a preliminary report.

2.1.4 Validate the Final ILI Assessment report – The Project Manager or Risk Data Coordinator will complete the "*ILI Final Report Validation Checklist*", Attachment A. An ILI report will not be considered a Final Report until it has been validated.

2.1.5 If the Preliminary or Final report is determined to be invalid, a written notification will be provided to the ILI Vendor identifying required corrections and requesting appropriate changes. The ILI Vendor will submit all requested corrections as soon as practicable.

2.1.6 Discovery of the conditions listed in an ILI Assessment Report occurs on the date that the Project Manager or Risk Data Coordinator has determined the report to be valid. Discovery occurs no later than 180 days after completion of an assessment, unless it can be demonstrated that the 180-day period is impracticable. If discovery is to occur later than 180 days after completion of an assessment, this deviation shall be documented in accordance with the "***Change Management***" process.

2.2 Report Data Analysis

2.2.1 The Risk Data Coordinator or Project Manager shall correlate ILI tool data to the pipeline data by prorating ILI tool travel distance between AGMs and/or identifiable benchmark locations.

2.2.2 The Risk Data Coordinator or Project Manager shall re-calculate the pipeline stationing of the ILI tool indications supplied by the ILI Vendor.

2.2.3 The Risk Data Coordinator or Project Manager will take into account readily available additional sources of information. Additional information may include, but is not limited to, surrounding geography, land use, roads, railroads, rivers, foreign pipeline crossings, unintentional in-service releases, previous assessments, previous repairs, and casings.

2.2.4 The Risk Data Coordinator or Project Manager shall identify conditions listed in 195.452(h)(4)(iii) where not reported by ILI Tool Vendor and sufficient pipeline system information is available for determination.

2.2.5 All temporary reductions of operating pressure shall be determined in accordance with the "***Operating Pressure Procedure***".

2.2.6 The Risk Data Coordinator or Project Manager shall add the ILI Tool tolerance to all ILI Tool Report indication depths from ILI Tools utilized to address the threat of metal loss and deformation. These revised indication depths will be utilized for the sake of determining what metal loss or deformation indications meet the requirements of 195.452(h)(4)(i), 452(h)(4)(ii), 452(h)(4)(iii) and could affect HCAs. The ILI Tool tolerance utilized will be modified, as necessary, based on actual field measurement data of the indication depths or other means to verify ILI tool accuracy.

2.2.7 The Risk Data Coordinator or Project Manager shall identify the indications that meet conditions of 195.452(h)(4)(i), 452(h)(4)(ii), 452(h)(4)(iii) and could affect HCAs by cross-referencing all re-calculated ILI indication stationing against could affect HCA stationing. The ILI Vendor shall report all indications that meet conditions of 195.452(h)(4)(i), 452(h)(4)(ii), and 452(h)(4)(iii) as required by the "***ILI Data Analysis and Reporting Procedure***".

2.2.8 The Risk Data Coordinator or Project Manager shall perform a corrosion growth analysis for all metal loss indications that have an indicated safe working pressure equal to or greater than the MOP.

2.2.8.1 If available, previous metal loss ILI tool runs may be utilized to determine corrosion growth.

2.2.8.2 The corrosion growth rate may be determined by dividing the indicated metal loss depth by the theoretical corrosion life.

2.2.8.2.1 The theoretical corrosion life (P_{CORR}) is defined as follows:

2.2.8.2.1.1 $P_{CORR} = P_{LIFE} - 10$ years

For pipe where the difference between the year the pipe was constructed and the year the pipe was assessed (P_{LIFE}) > 25 years.

2.2.8.2.1.2 $P_{CORR} = P_{LIFE} - 5$ years

For pipe where the difference between the year the pipe was constructed and the year the pipe was assessed - 15 years < $P_{LIFE} \leq$ 25 years.

2.2.8.2.1.3 $P_{CORR} = P_{LIFE} - 0$ years

For pipe where the difference between the year the pipe was constructed and the year the pipe was assessed - $P_{LIFE} \leq$ 15 years.

2.2.8.3 Utilizing the corrosion growth rate, the metal loss indication is grown to failure. Failure is determined by utilizing the effective area method or the modified B31G method to calculate a failure pressure and is indicated when the pressure the grown metal loss indication can theoretically hold (P_{BURST}) becomes less than MOP or where the growth predicts wall loss greater than or equal to 100% ($P_{THRUWALL}$). The time to failure is calculated for P_{BURST} and $P_{THRUWALL}$ and the shorter time to failure is utilized.

2.2.8.4 All metal loss indications that have a time to failure of less than two times the desired reassessment interval will be identified as “other conditions” per 195.452(h)(4)(iv).

2.2.8.5 The calendar year in which each remediation shall be completed is based on half of the calculated time to failure.

2.2.9 The Risk Data Coordinator or Project Manager shall identify the indications that meet conditions of 195.452(h)(4)(iv) and could affect HCAs by matching the ILI indications identified in 2.2.7 with their re-calculated stationing and cross-referencing them against could affect HCA stationing.

2.2.10 For each metal loss ILI tool assessment, if no metal loss indications meet the repair criteria and no other means to verify ILI tool accuracy are available, one metal loss indication will be selected for excavation for ILI tool calibration purposes. In the event no metal loss indications are identified by the ILI tool assessment, no excavations will be scheduled for tool calibration purposes.

2.2.11 For each geometry ILI tool assessment, if no dent indications meet the repair criteria and no other means to verify ILI tool accuracy are available, one dent indication will be selected for excavation for ILI tool calibration purposes. In the event no dent indications are identified by the ILI tool assessment, no excavations will be scheduled for tool calibration purposes.

2.2.12 For each crack detection ILI tool assessment, if no crack like indications meet the repair criteria and no other means to verify ILI tool accuracy are available, one indication will be selected for excavation for ILI tool calibration purposes. In the event no crack like or potential crack indications are identified by the ILI tool assessment, no excavations will be scheduled for tool calibration purposes.

2.2.13 The Pipeline Integrity Engineer shall compare the field measurements of the indications against the ILI Vendor reported information. If field measurements of the indications demonstrate that the ILI Vendor reported information deviates from the accuracy tolerances specified in the Work Release, a written notification will be provided to the ILI Vendor identifying the accuracy deviations and requesting appropriate corrections. The ILI Vendor will submit all requested corrections as soon as practicable.

2.3 Evaluation and Remediation Schedule

2.3.1 The Risk Data Coordinator shall prepare a Dig List comprised of indications identified in section 2.2 and distribute to the appropriate Project Manager. The Dig List should include Feature ID number, tool odometer distance, re-calculated stationing, indication dimensions, and remediate-by date for each indication. Indications that occur in a common joint of pipe are generally grouped and listed as a single dig.

2.3.2 The Risk Data Coordinator or Project Manager shall prepare dig sheets for evaluation of the indications listed in the Dig List. Dig Sheet information should include: Pipeline Name, Segment Inspected, Upstream and Downstream References, Five Upstream and Downstream Joint Lengths, Anomaly Description, Property Description, Existing Pipe Description, and HCA Information. The dig sheets shall be distributed to the appropriate Project Manager.

2.4 Documentation

2.4.1 The Project Manager should file the following documentation: ILI Final Report Validation Checklist, corrosion growth calculations for metal loss indications, ILI Preliminary Reports, ILI Final reports, dig sheets and/or dig lists, documentation created during final vendor reports validation, and Hydrotest results reports.

2.4.2 OPS will be notified if the evaluation and remediation schedule as identified in 195.452(h)(4)(i), 452(h)(4)(ii), 452(h)(4)(iii), 452(h)(4)(iv) cannot be met and safety cannot be provided through a temporary reduction in operating pressure.

2.4.2.1 For Louisiana Intrastate Pipelines send copies of notifications sent to OPS to the Chief of the Louisiana Pipeline Safety Section, Louisiana Department of Natural Resources Office of Conservation Pipeline Division, 617 North Third Street, P.O. Box 94275, Baton Rouge, Louisiana 70804-9275, or to the facsimile number (225) 342-5529.

2.4.2.2 For Texas Intrastate Pipelines send copies of the notification sent to OPS to the Director of Pipeline Safety, Texas Railroad Commission, 1701 North Congress, (78701), P.O. Box 12967, Austin, Texas 78711-2967, or to the facsimile number (512) 463-7058.

3.0 REFERENCES:

3.1 **Regulatory -**

3.1.1 49 CFR 195

3.1.2 16 TAC 8.101

3.2 **Related Policies/Procedures -**

3.2.1 Integrity Assessment Results Review process (Section 3)

3.2.1 ILI Data Analysis and Reporting Procedure

3.2.2 Pipeline Defect Evaluation and Repair Procedure

3.2.3 Operating Pressure Procedure

3.3 **Forms and Attachments -**

3.3.1 Attachment A – ILI Final Report Validation Checklist

4.0 DEFINITIONS:

4.1 Discovery – Discovery for starting the timeline to repair indications in accordance with 49 CFR 195.452 occurs upon validation of a written report from an integrity assessment.

4.2 Failure Pressure – The pressure calculated for rupture of a corroded area using the Effective Area Methods of evaluation.

4.3 Indication – A potential irregular feature located in the pipeline initially detected though in-line inspection.

4.4 Safe Working Pressure – The calculated safe operating pressure of a corroded area determined by multiplying the calculated failure pressure by the appropriate design factor for the pipeline system.

4.5 HCA Stationing – The stationing on the pipeline segment that directly intersect and could affect an HCA as determined by the HCA analysis that was in place on the date the integrity assessment began.

⋗⋗⋗End of Procedure⋖⋖⋖

Change Log

Date	Rev. #	Change Location	Brief Description of Change
4/28/04	1	4.5	Added entire paragraph 4.5 – definition of HCA Stationing
4/28/04	1	4.1	Added - "Discovery occurs no later than 180 days after completion of an assessment, unless it can be demonstrated that the 180-day period is impracticable."
8/22/05	2	Title Block	Replaced Paul Klein with Joe Cheek as owner.
8/22/05	2	3.2.1	Removed "/Chapter".
8/22/05	2	3.2.4	Removed "Job Book Procedure".
8/22/05	2	2.4.1	Replaced "as required by Job Book Procedure" with a listing of the documentation to be filed.
8/22/05	2	Title Block	Added "EPOLP Pipeline Integrity Management Program".
8/22/05	2	2.4.2	Added 2.4.2.2 and 2.4.2.2.
8/22/05	2	2.0	Modifications to PI position titles performed to reflect recent changes in PI Group position titles.
8/22/05	2	2.2.10	Replaced "if no crack like indications are identified" with "if no crack like indications meet the repair criteria".
11/8/06	3	Title Block	Replaced Joe Cheek with H. Buford Barr as owner.
11/8/06	3	4.1	Moved "Discovery occurs no later than 180 days after completion of an assessment, unless it can be demonstrated that the 180-day period is impracticable." to 2.1.6.
11/8/06	3	2.1.6	In addition to discovery wording from section 4.1 described above, added "If discovery is to occur later than 180 days after completion of an assessment, this deviation shall be documented in accordance with the "Change Management" process."
3/28/07	4	2.2.5	Added 2.2.5 to address ILI tool tolerance
7/16/07	5	Title Block	Removed the reference to EPOLP and removed the Enterprise logo.
7/16/07	5	2.1.5, 2.2.12, 2.4.2, 4.1	Removed the reference to EPOLP and reworded the affected sentences as necessary.
8/27/07	6	2.2.3, 2.2.9	Added 2.2.3 to address the review of readily available additional sources of information. Revised section references in 2.2.9 from 2.2.6 to 2.2.7.
8/27/07	6	2.2.13	Revised 2.2.13 to replacing Project Manager with Pipeline Integrity Engineer
10/19/07	7	2.1.1	Added Risk Data Coordinator

10/19/07	7	2.2.8	Modified 2.2.8 to refine the corrosion growth model to take into account coating life