



ENTERPRISE PRODUCTS OPERATING LLC

September 6, 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, the managing partner of DPC, on behalf of DPC. By submitting this response, DPC expresses no view of and shall not be deemed to have made an admission as to the validity or enforceability of the regulatory interpretations upon which the NOA was based.

PHMSA Item 1:

Dixie Pipeline Company (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:

The DPC IMP is in the process of being incorporated into a common IMP (the "Common IMP") for Enterprise Products Operating LLC and all of the companies, including DPC, that it operates or manages. In the Common IMP, the attached Procedure for Identifying HCAs and HCA Segments IMP-SEC1-01 addresses segment identification for idle lines that are filled with nitrogen or other non-hazardous liquid. Section 2.3.2 of IMP-SEC1-01 states "Idle pipelines that

have been purged and filled with an inert such as nitrogen shall only have direct intersections with HCAs identified.”

The Mississippi River idle line (Line ID #123-R2) was evaluated for direct intersections with HCAs and added to the current DPC BAP as an idle pipeline segment on September 11, 2006. The attached amended DPC Pipeline Baseline Assessment Plan IMP-DPC2-02 was provided to PHMSA on September 14, 2006 before the completion of DPC’s IMP audit.

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:

DPC has initiated, but not yet completed, the review of the aerial dispersion buffer distances. This will be completed by October 31, 2007.

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:

The DPC IMP is in the process of being incorporated into a common IMP (the “Common IMP”) for Enterprise Products Operating LLC and all of the companies, including DPC, that it operates or manages. In the Common IMP, the attached ILI Report Analysis Procedure for HCAs IMP-SEC3-02 has been modified to address the integration of other pertinent and available data and information with the results of the integrity assessment to make decisions related to the repair or remediation of pipeline defects. Section 2.2.3 of IMP-SEC3-02 indicates the following:

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.

In the Common IMP, the attached Information Analysis – Line Pipe IMP-SEC6-01 addresses integration of other pertinent and available data and information with the results of integrity assessment.

Section 2.1 of IMP-SEC6-01 indicates the following information will be collected for the pipeline segment:

- 2.1.1 Proximity to HCA
- 2.1.2 Pipe Characteristics
- 2.1.3 Type of Product
- 2.1.4 Pressure
- 2.1.5 Potential Rate of Leakage and Volume Release
- 2.1.6 Unintentional In-Service Release History
- 2.1.7 Damage Prevention and Public Awareness
- 2.1.8 Geotechnical
- 2.1.9 Physical Supports
- 2.1.10 Integrity Assessment Results
- 2.1.11 Assessment Method Type/Capability
- 2.1.12 External Corrosion Control for Segment
- 2.1.13 Internal Corrosion Control for Segment
- 2.1.14 Pressure Monitoring/Swiftness of Leak Detection/Swiftness of Pipeline Shutdown Capabilities
- 2.1.15 Location of Response Personnel/Response Time
- 2.1.16 Operator Training
- 2.1.17 Other Management Controls

Section 2.2 of IMP-SEC6-01 addresses review of the data noted in Section 2.1 to evaluate reasonable program modifications to significantly reduce the impact to an HCA on the pipeline segment.

In the Common IMP, the attached Integrity Assessment Method Selection Procedure IMP-SEC2-01 addresses integration of other pertinent and available data and information in the process of selecting an assessment method. Section 2.1 of IMP-SEC2-01 indicates that information considered for the integrity assessment method selection may include the following:

- 2.1.1 Line ID with beginning and ending stationing
- 2.1.2 Coating type
- 2.1.3 Coating Condition
- 2.1.4 Quality of cathodic protection
- 2.1.5 Year of original construction
- 2.1.6 Does the normal operating temperature exceed 100°F?
- 2.1.7 Pipe characteristics

- 2.1.8 Number of known in-service seam ruptures and hydrostatic test related seam ruptures
- 2.1.9 Has the segment been tested for cracks?
- 2.1.10 Year and pressure of most recent hydrotest

Section 2.2 of IMP-SEC2-01 addresses the review of the data noted in Section 2.1 to evaluate for threat susceptibility.

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.

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:

The DPC IMP is in the process of being incorporated into a common IMP (the "Common IMP") for Enterprise Products Operating LLC and all of the companies, including DPC, that it operates or manages. In the Common IMP, the attached ILI Report Analysis Procedure for HCAs IMP-SEC3-02 addresses the steps taken following the receipt of an ILI report to declare discovery. Section 2.1.6 of IMP-SEC3-02 indicates "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." Section 2.1.4 indicates that "the Project Manager or Risk Data Coordinator will complete the 'ILI Final Report Validation Checklist', Attachment A." Upon completion of the entire "ILI Final Report Validation Checklist", the ILI Report will be accepted and be considered valid. The "ILI Final Report Validation Checklist" outlines the following specific steps required to be taken following the receipt of an ILI report to declare discovery:

- Correct analysis window(s) was utilized
- Correct outside pipe diameter(s) was utilized
- The nominal pipe diameter was utilized for dent depth calculations

- Correct nominal pipe wall thickness was utilized
- Correct pipe grade(s) was utilized
- Correct MOP was utilized
- Verify the specified Failure Pressure calculation method was utilized
- AGMs have been entered correctly and that the bench marks were set properly (also included as part of the minimum requirements for validating a preliminary report)
- Slippage has been accounted for and calculated correctly (also included as part of the minimum requirements for validating a preliminary report)
- Odometer starts at the beginning of the run and counts up in a predictable manner to the end of the run.
- Calculated station numbering from both the upstream reference (AGM) and the downstream reference (AGM) starts at the beginning of the run and counts up in a predictable manner to the end of the run.
- The report includes a complete listing of indications as specified in the “ILI Data Analysis and Reporting Procedure”

Completion of the “ILI Final Report Validation Checklist” is the point at which DPC has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. Section 2.1.6 of IMP-SEC3-02 indicates that “discovery occurs no later than 180 days after completion of an assessment, unless it can be demonstrated that the 180-day period is impracticable.”

As a point of reference, the “integrity assessment” that was referred to in Item 4 was the Deformation and MFL ILI assessment of the 6” 95 mile Albany to Alma pipeline segment. The assessment of this pipeline segment was successfully completed on February 15, 2006 utilizing Magpie’s Combination DEF/MFL ILI tool. The final ILI assessment report was dated April 24, 2006 and was received on April 26, 2006. The ILI Final Report Validation Checklist was completed and the report validated on April 28, 2006. Several features in the report met immediate repair criteria and a temporary pressure reduction was put in place on April 28, 2006.

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.

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.

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:

As an initial matter, Section 1.2 of IMP-SEC6-01 was amended on September 11, 2006 to indicate that “the information analysis will be performed within 24 months of the completion of a segment’s integrity assessment. All or a portion of the information analysis may also be performed in response to an evaluation of consequences of a release on an HCA.” The amended IMP-SEC6-01 was provided to PHMSA on September 14, 2006 before the completion of DPC’s IMP audit. This noted change has not yet been incorporated into the Common IMP. This change will be made and the amended IMP-SEC6-01 will be submitted by October 31, 2007.

The DPC IMP is in the process of being incorporated into a common IMP (the “Common IMP”) for Enterprise Products Operating LLC and all of the companies, including DPC, that it operates or manages. The Common IMP addresses the requirements of 49CFR195.452(j)(2) as follows (referenced Common IMP procedures are attached):

49CFR195.452(j)(2) (“Evaluation”) indicates that “an Operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions made about remediation, and preventive and mitigative actions (paragraphs (h) and (i) 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 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 of IMP-SEC6-01.
- iii) Leak history, repair history, and cathodic protection history. DPC addresses these in Sections 2.1.6, 2.1.10, and 2.1.12 of IMP-SEC6-01.
- iv) Product transported. DPC addresses this in Section 2.1.3 of IMP-SEC6-01.
- v) Operating stress level. DPC addresses this in Section 2.1.4 of IMP-SEC6-01.
- vi) Existing or projected activities in the area. DPC addresses this in Section 2.1.7 of IMP-SEC6-01.

- vii) Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic). DPC addresses these in Section 2.1.8 of IMP-SEC6-01.
- viii) Geo-technical hazards. DPC addresses this in Section 2.1.8 of IMP-SEC6-01.
- ix) Physical support of the segment such as by a cable suspension bridge. DPC addresses this in Section 2.1.9 of 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 of IMP-SEC6-01.
- 2) Data gathered through the integrity assessment required under this section. DPC addresses this in Section 2.1.10 of 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, and 2.1.12 of 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 of IMP-SEC6-01.

Paragraph (h) addresses the “anomalous conditions that the operator discovers through the integrity assessment or information analysis.” DPC addresses the evaluation of the rehab work performed due to the integrity assessment of information analysis in Section 2.1.10 of IMP-SEC6-01.

Paragraph (i) indicates “an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to” the following:

- i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area. DPC addresses these in Section 3.4 and 3.5 of IMP-SEC1-01. Please note that DPC exclusively transports propane, an HVL product, therefore, overland spread and water transport are not applicable.
- ii) Elevation profile. DPC addresses this in Section 3.4 of IMP-SEC1-01. Please note that DPC exclusively transports propane, an HVL product, therefore, overland spread and water transport are not applicable.

- iii) Characteristics of the product transported. DPC addresses this in Section 2.2 of IMP-SEC1-01.
- iv) Amount of product that could be released. DPC addresses this in Section 3.3.4 and 3.4.1 of IMP-SEC1-01.
- v) Possibility of spillage in a farm field following the drain tile into a waterway. DPC addresses this in Section 3.4.3 of IMP-SEC1-01. Please note that DPC exclusively transports propane, an HVL product, therefore, overland spread and water transport are not applicable.
- vi) Ditches along side a roadway the pipeline crosses. DPC addresses this in Section 3.4.3 of IMP-SEC1-01. Please note that DPC exclusively transports propane, an HVL product, therefore, overland spread and water transport are not applicable.
- vii) Physical support of the pipeline segment such as by cable suspension bridge. DPC addresses this in Section 2.1.9 of IMP-SEC6-01.
- viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure. DPC addresses this in Section 2.1.4 of IMP-SEC6-01.

Paragraph (i) also indicates that “an operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. ... Such actions may include, but are not limited to,” the following:

- 1) Implementing damage prevention best practices. DPC addresses this in Section 2.2.1 of IMP-SEC6-01.
- 2) Better monitoring of cathodic protection where corrosion is a concern. DPC addresses this in Section 2.2.2 of IMP-SEC6-01.
- 3) Establishing shorter inspection intervals. DPC addresses this in Section 2.2.2 and 2.2.3 of IMP-SEC6-01.
- 4) Installing EFRDs on the pipeline segment. DPC addresses this in Section 2.2.6 of IMP-SEC6-01.
- 5) Modifying the systems that monitor pressure and detect leaks. DPC addresses this in Section 2.2.5 of IMP-SEC6-01.
- 6) Providing additional training to personnel on response procedures. DPC addresses this in Section 2.2.4 of IMP-SEC6-01.
- 7) Conducting drills with local emergency responders. DPC addresses this in Section 2.2.4 of IMP-SEC6-01.
- 8) Adopting other management controls. DPC addresses this in Section 2.2.4 of IMP-SEC6-01.

**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

R.M. Seeley, Director  
September 6, 2007  
Page 9

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:

DPC has initiated, but not yet completed, the revision of the corrosion growth rate determination process. This will be completed by October 31, 2007.

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

Sincerely,



Charles Brabson  
Senior Vice President Engineering

	<b>PIPELINE INTEGRITY MANAGEMENT PROGRAM</b>	Owner: H. Buford Barr	IMP-SEC1-01	
		Revision No: 6	Revision Date: 7/19/07	Page: 1 of 8
Procedure: <b>PROCEDURE FOR IDENTIFYING HCAS AND HCA SEGMENTS</b>				

## 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 NH<sub>3</sub>. 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 3<sup>rd</sup> 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 NH<sub>3</sub> 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.

**PROCEDURE FOR IDENTIFYING HCAS AND HCA  
SEGMENTS**

IMP-SEC1-01

**CHANGE LOG**

<b>Date</b>	<b>Rev. #</b>	<b>Change Location</b>	<b>Brief Description of Change</b>
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.

<b>PROCEDURE FOR IDENTIFYING HCAS AND HCA SEGMENTS</b>	<b>IMP-SEC1-01</b>
--	--------------------

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.



**DIXIE PIPELINE COMPANY  
BASELINE ASSESSMENT PLAN**

Document Name:	<b>DIXIE PIPELINE COMPANY BASELINE ASSESSMENT PLAN</b>	Owner:	Buford Barr	Document No.:	IMP-DPC2-02
		Revision No.:	4	Revision Date:	9/11/2006

Line Order	Line ID	System	Segment Description	2003 RICA Miles	2006 Risk Score	Baseline Year	Total Test Miles	Integrity Testing Type	ILI Tool Type	Remarks
1	120	Mainline	Mont Belvieu to Sulphur (MB to SU)	36.28	8.17	2007	100	Hydrotest	NA	
2	120	Mainline	Sulphur to MS River (SU to MRTP-1)	33.99	8.28	2006	131	Hydrotest	NA	
3	120	Mainline	MS River to Grangeville (MRTP-1 to GR)	19.01	7.61	2001	32	Hydrotest	NA	
4	120	Mainline	Grangeville to Hattiesburg (GR to HA)	46.64	7.06	2002	104	Hydrotest	NA	
5	120	Mainline	Hattiesburg to Demopolis (HA to DM)	42.41	7.46	2006	120	ILI	MFL/EGP & UT Crack	
6	120	Mainline	Demopolis to Prattville	19.83	6.77	2004	73	Hydrotest	NA	
7	120	Mainline	Prattville to Opelika	41.39	8.21	2004	71	Hydrotest	NA	
8	120	Mainline	Opelika to Milner	39.32	8.33	2004	83	Hydrotest	NA	
9	120	Mainline	Milner to Norwood (ML to NW)	13.81	6.90	2003	91	Hydrotest	NA	
10	120	Mainline	Norwood to Lexington (NW to LX)	24.05	7.36	2003	97	Hydrotest	NA	
11	120	Mainline	Lexington to Bethune (LX to BE)	44.49	8.87	2003	60	Hydrotest	NA	
12	120	Mainline	Bethune to Cheraw (BE to CH)	13.11	6.86	2003	32	Hydrotest	NA	
13	120	Mainline	Cheraw to TP2 (CH to TP2)	51.96	8.18	2004	83	ILI	MFL/EGP	
14	120	Mainline	TP2 to TP3 (1980 pipe)	8.26	6.68	2004	13	ILI	MFL/EGP	
15	120	Mainline	TP3 to Apex (TP3 to AP)	0.01	7.09	2004	2	ILI	MFL/EGP	
16	119	Spurline	Opelika to Albany	48.47	6.99	2003	110	Hydrotest	NA	
17	119	Spurline	Albany to Alma (LB to AA)	29.01	7.72	2003	95	Hydrotest	NA	
18	118	Suburban	Bethune to Tirzah (Suburban Pipeline)	34.93	8.25	2005	62	ILI	MFL/EGP	
19	122	Lateral	Anse La Butte to Breaux Bridge (ALB to BB)	2.02	9.34	2006	3	Hydrotest	NA	

Sub-total 548.99 1362

Dixie Pipeline Company BAP Idle Pipeline Segments Table						
System	Line ID	Segment Description	From MP	To MP	Total Miles	Remarks
Mainline	123-R2	Mississippi River Spare Line	232.63	233.8	1.17	Line disconnected and filled with nitrogen
<b>Abandon Pipeline Segments Table</b>						
Mainline	123-R1	Mississippi River Abandoned Line	232.63	233.64	1.01	





	<b>Pipeline Integrity Management Program</b>	Owner: H. Buford Barr	Document No: IMP-SEC3-02	
		Revision No: 6	Revision Date: 8/27/07	Page: 1 of 7
Procedure: <b>ILI REPORT ANALYSIS PROCEDURE FOR HCAS</b>				

## 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 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 The corrosion growth rate is determined by dividing the indicated metal loss depth by the difference between the year the pipeline was constructed and the year it was

assessed.

- 2.2.8.2 The corrosion growth rate is multiplied by a corrosion growth time period, two times the desired re-assessment interval for example, and then added to the ILI wall loss readings along the metal loss indication.
  - 2.2.8.3 The new future wall loss values are evaluated using the effective area method or the modified B31G method to calculate a failure pressure at the future growth conditions.
  - 2.2.8.4 All metal loss indications that have a future growth failure pressure less than the MOP and all indications where growth predicts wall loss greater than or equal to 100% 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 determined by adding the lesser of one half of the growth period where failure pressure first drops below MOP or one half the growth period that first reaches 100% wall loss to the year the pipeline was assessed.
- 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 recalculated 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 through 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 intersects 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



	<b>Pipeline Integrity Management Program</b>	Owner: H. Buford Barr	Document No: IMP-SEC3-02A	
		Revision No: 3	Revision Date: 7/16/07	Page: 1 of 2
Attachment: <b>ILI FINAL REPORT VALIDATION CHECKLIST</b>				

AFE Number:

AFE Name:

ILI Assessment Report Title:

Date the ILI Assessment Report was received:

Validation Item	Yes	No	N/A
Correct analysis window(s).			
Correct outside pipe diameter(s).			
Used nominal pipe diameter for dent depth calculations.			
Correct nominal pipe wall thickness(s).			
Correct pipe grade(s).			
Correct MOP is used.			
Verify that the specified Failure Pressure calculation method was utilized.			
AGMs have been entered correctly and that the benchmarks were set properly.			
Slippage has been accounted for and calculated correctly.			
Odometer starts at the beginning of the run and counts up in a predictable manner to the end of the run.			
Calculated station numbering from both the upstream reference (AGM) and the downstream reference (AGM) starts at the beginning of the run and counts up in a predictable manner to the end of the run.			
The report includes a complete listing of indications as specified in the " <b>ILI Data Analysis and Reporting Procedure</b> ".			

Yes    No

<b>Has this ILI Assessment Report been determined Valid?</b>		
--	--	--

Validation Checklist completed by: \_\_\_\_\_

Date Validation Checklist was completed: \_\_\_\_\_



	<b>PIPELINE INTEGRITY MANAGEMENT PROGRAM</b>	Owner: H. Buford Barr	Document No: <b>IMP-SEC6-01</b>	
		Revision No: 7	Revision Date: 7/16/07	Page: 1 of 14
Procedure: <b>INFORMATION ANALYSIS – LINE PIPE</b>				

## 1.0 PURPOSE:

- 1.1. The purpose of this document is to define an information analysis procedure to support the preventive and mitigative requirements and continual process of evaluation and assessment requirements of DOT 49CFR195.452 for a pipeline segment.
- 1.2. The information analysis shall be performed within 3 years of the completion of a segment's integrity assessment. All or a portion of the information analysis may also be performed in response to an evaluation of consequences of a release on an HCA.
  - 1.2.1. For Western Operations and Texas and Eastern Operations segments whose integrity assessments were completed prior to February 1, 2003, the information analysis shall be performed within 5 years of the completion of a segments integrity assessment.
  - 1.2.2. The information analysis shall be performed within 2 years of the completion of a TEPPCO segment's integrity assessment for all integrity assessments completed after December 31, 2005.

## 2.0 PROCEDURE:

### 2.1 Collection of Pipeline Segment Data and Information

#### 2.1.1 Proximity to HCA

- 2.1.1.1 Identify the start and stop locations of the integrity assessment.
- 2.1.1.2 Identify the total miles of the integrity assessment.
- 2.1.1.3 Acquire the could affect HCA boundaries of the segment that were valid at the time of the integrity inspection.
- 2.1.1.4 Identify the types of HCAs the segment could affect.
- 2.1.1.5 Identify the segment's total could affect HCA miles.
- 2.1.1.6 Section 3.4.3 of the "***Procedure For Identifying HCAS and HCA Segments***" addresses the impact of locations where terrain surrounding the segment including drainage systems and small waterways, where spillage in a farm field could enter a waterway by following the field's existing drain tile, and locations on the segment where spillage could enter a waterway by following the ditches along side a roadway.

#### 2.1.2 Pipe Characteristics

- 2.1.2.1 Acquire the diameter, wall thickness, grade, coating type, manufacturer, and seam type of the segment.

### 2.1.3 Type of Product

- 2.1.3.1 Identify all of the products the segment currently transports.
- 2.1.3.2 Indicate if the normal operating temperature of any of the transported products exceeds 100°F.

### 2.1.4 Pressure

- 2.1.4.1 Identify the limiting MOP of the segment.
- 2.1.4.2 Identify the MOP percent of SMYS for the segment (exclude heavier wall pipe at river crossings, road crossings, etc.).
- 2.1.4.3 Identify the highest historical operating pressure in the segment over the last three years.

### 2.1.5 Potential Rate of Leakage and Volume Release

- 2.1.5.1 For pooling liquid products, consider the potential rate of leakage and potential volume of release. The volume utilized for the most recent segment identification may be used.
- 2.1.5.2 For non-pooling products, leakage rates and release volumes shall not be calculated.

### 2.1.6 Unintentional In-Service Release History

- 2.1.6.1 Indicate if any unintentional in-service releases have been recorded since the segment's previous integrity assessment.
- 2.1.6.2 Quantify the known causes of the unintentional in-service releases since the segment's previous integrity assessment.

### 2.1.7 Damage Prevention and Public Awareness

- 2.1.7.1 Indicate if a One Call system is in place and provides coverage for the segment.
- 2.1.7.2 Identify the number of pipeline "One Calls" recorded for the segment annually, if available. Annual "One Calls" value to be obtained from the most recent summarized "One Calls" report available.
- 2.1.7.3 Indicate if the segment presently has known locations where line markers are not located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of the pipeline so that its locations are accurately known.
- 2.1.7.4 Indicate if the Company public education program is presently being applied to the segment.
- 2.1.7.5 Identify the method(s) currently used to inspect the segment's right of way.
- 2.1.7.6 Identify the frequency of the right of way inspections.

2.1.7.7 Indicate if the segment presently has known locations where the condition of right of way does not allow for right of way inspection.

2.1.8 Geotechnical

2.1.8.1 Identify all known types of geotechnical features (subsidence, fault lines, dams/levees, etc.) presently affecting the could affect HCA portions of the segment.

2.1.8.2 Indicate if any management controls are currently in place to monitor the known geotechnical features. Examples of management controls may include but are not limited to strain monitoring and increased surveillance.

2.1.9 Physical Supports

2.1.9.1 Identify physical supports, such as a cable suspension bridge, in could affect HCA portions of the segment.

2.1.10 Integrity Assessment Results

2.1.10.1 Indicate if a tool to detect deformation anomalies was used to assess the segment.

2.1.10.1.1 Identify the total number of deformation indications.

2.1.10.1.2 Identify the number of deformation indications repaired.

2.1.10.2 Indicate if a tool to detect metal loss was used to assess the segment.

2.1.10.2.1 Indicate if the metal loss tool report discriminated between internal or external metal loss.

2.1.10.2.2 Identify the total number of metal loss indications (differentiate between internal and external if possible).

2.1.10.2.3 Identify the total number of internal metal loss indications repaired.

2.1.10.2.4 Identify the total number of external metal loss indications repaired.

2.1.10.3 Indicate if a corrosion growth study was performed in conjunction with the metal loss indication evaluation process.

2.1.10.3.1 Identify the earliest date that a non-repaired feature would fail based on the corrosion growth rate study.

2.1.10.4 Indicate if a tool that identifies crack-like defects was used to assess the segment.

2.1.10.4.1 Identify the total number of crack-like indications found.

- 2.1.10.4.2 Identify the total number of crack-like indications repaired.
- 2.1.10.5 Indicate if a hydrotest was used to assess the segment.
  - 2.1.10.5.1 Identify the test pressure
  - 2.1.10.5.2 Identify and classify the test failures along with any metallurgical analysis completed on failed sections.
- 2.1.10.6 Indicate if other technology was used to assess the segment.
  - 2.1.10.6.1 Identify the findings of the other technology integrity assessment.
- 2.1.11 Assessment Method Type/Capability
  - 2.1.11.1 Identify the type(s) of integrity assessments used.
  - 2.1.11.2 For tool assessments identify the tool Vender, model, and measurement tolerances.
- 2.1.12 External Corrosion Control for Segment
  - 2.1.12.1 Identify the total number of pipeline casings presently in the segment.
  - 2.1.12.2 Identify the total number of known shorted pipeline casings presently in the segment.
  - 2.1.12.3 Identify the date the most recent close interval survey was performed.
  - 2.1.12.4 Identify the number of pipe to soil potentials that were below 0.85 volts in the most recent completed annual survey.
  - 2.1.12.5 Indicate if tests for the presence of SCC have been performed on the segment. If tested, identify the number of SCC indications that were found.
- 2.1.13 Internal Corrosion Control for Segment
  - 2.1.13.1 Indicate if the segment's pipe is internally coated, if known.
  - 2.1.13.2 Indicate if corrosion inhibitor is presently being injected in the segment.
  - 2.1.13.3 Indicate if the segment presently has internal corrosion monitoring. Where corrosion coupons are being used, indicate if corrosion rates have exceeded 1 MPY during the last 3 years.
  - 2.1.13.4 Indicate if liquids and solids analysis for corrosion constituents are being performed on the segment.
  - 2.1.13.5 Indicate if cleaning pigs are being run in the segment at least once per year.

**2.1.14 Pressure Monitoring / Swiftness of Leak Detection / Swiftness of Pipeline Shutdown Capabilities**

- 2.1.14.1 Identify the location of all check valves and remote control valves presently on the segment.
- 2.1.14.2 Identify how frequently the remote control valves are inspected on the segment.
- 2.1.14.3 Indicate if the segment is currently monitored by a SCADA system.
- 2.1.14.4 Identify the estimated length of time the existing monitoring system should take to detect a pipeline rupture on the segment.
- 2.1.14.5 Identify the estimated length of time it should take to shutdown the segment.
- 2.1.14.6 Indicate if Pipeline Control knows of instances where incident investigation recommendations for modifications to the segment's leak detection system have not been implemented.

**2.1.15 Location of Response Personnel/Response Time**

- 2.1.15.1 Identify the currently assigned reporting location(s) of the response personnel responsible for the segment.
- 2.1.15.2 Identify the estimated response time, assuming normal conditions, of response personnel to all could affect HCA portions of the segment.
- 2.1.15.3 Identify the conditions that would impact response time to the segment.

**2.1.16 Operator Training**

- 2.1.16.1 Indicate if Pipeline Control personnel are current in their training program.
- 2.1.16.2 Indicate if Field Operations personnel are current in their training program

**2.1.17 Other Management Controls**

- 2.1.17.1 Indicate if emergency response and LEPC plans are established as required for the segment.
- 2.1.17.2 Identify if Field Operations or Pipeline Control know of other management controls, not identified elsewhere in this procedure, which are in place on the segment to prevent and/or mitigate the consequences of a pipeline failure. Examples of other management controls not identified elsewhere may include but are not limited to local release detection, containment, and remediation.

### 2.1.18 Pipeline Segment Data and Information - Proximity to HCA Could Affect Pipe

2.1.18.1 Present pipeline segment data and information collected so as to associate it with appropriate portions of the pipeline segment identified as could affect an HCA.

- An example of such a presentation may include but is not limited to the development of a map or chart identifying the could affect HCA boundaries of the segment, NPMS data, and road crossings. For those portions of the pipeline segment identified as could affect an HCA identify available casings, sleeves, ILI metal loss indications, ILI deformation indications, foreign line crossings, and un-intentional in-service release information.

## 2.2 Evaluation of Pipeline Segment Data and Information

2.2.1 The Pipeline Integrity Engineer, Pipeline Integrity Manager, Pipeline Integrity Director, or Corrosion Prevention Supervisor shall evaluate reasonable third party program modifications to significantly reduce the likelihood of third party damage.

2.2.1.1 The evaluation may consider, but is not limited to, the following data and information: Data collected in 2.1.7, 2.1.10.1, 2.1.11, 2.1.18, and the number of un-intentional in-service releases that were determined to be caused by third party damage since the previous assessment. If third party damage was the known cause of un-intentional in-service releases since the previous assessment and the incident investigation identified depth of cover as a contributing factor, consider known depth of cover issues on the segment.

2.2.1.2 Determine and document if the considerations of the collected data conclude modifications to existing third party damage prevention programs would significantly reduce the likelihood of third party damage. Examples of program modifications may include but are not limited to adopting successful damage prevention best practices utilized on other segments that have experienced similar third party damage risks.

2.2.2 The Pipeline Integrity Engineer, Pipeline Integrity Manager, Pipeline Integrity Director, or Corrosion Prevention Supervisor with guidance from the Corrosion Prevention Manager shall evaluate reasonable external corrosion prevention program modifications that would significantly reduce the likelihood of a release caused by external corrosion that could affect an HCA on the segment.

- 2.2.2.1 The evaluation may consider, but is not limited to, the following data and information: Data collected in 2.1.10, 2.1.11, 2.1.12, 2.1.18, type of pipe coating, and number of unintentional in-service releases that were determined to be caused by external corrosion or SCC since the previous assessment.
- 2.2.2.2 Determine and document if the considerations of the collected data conclude if modifications to existing external corrosion prevention programs would significantly reduce the likelihood of a release caused by external corrosion. Examples of program modifications may include but are not limited to better monitoring of cathodic protection, shorter inspection intervals, and modifications to existing coating systems.
- 2.2.3 The Pipeline Integrity Engineer, Pipeline Integrity Manager, Pipeline Integrity Director, or Corrosion Prevention Supervisor with guidance from the Corrosion Prevention Manager, shall evaluate reasonable internal corrosion prevention program modifications to significantly reduce the likelihood of a release caused by internal corrosion that could affect an HCA on the segment.
- 2.2.3.1 The evaluation may consider, but is not limited to, the following data and information: Data collected in 2.1.10, 2.1.11, 2.1.13, 2.1.18, number of unintentional in-service releases that were determined to be caused by internal corrosion since the previous assessment, and type of products transported.
- 2.2.3.2 Determine and document if the considerations of the collected data conclude if modifications to existing internal corrosion prevention programs would significantly reduce the likelihood of a release caused by internal corrosion. Examples of program modifications may include but are not limited to better monitoring of internal corrosion and shorter inspection intervals.
- 2.2.4 The Pipeline Integrity Engineer, Pipeline Integrity Manager, Pipeline Integrity Director, or Corrosion Prevention Supervisor shall evaluate the need to adopt reasonable “other management controls” to prevent and/or significantly reduce consequences of a pipeline failure that could affect an HCA on the segment.
- 2.2.4.1 The evaluation may consider, but is not limited to, the following data and information: Data collected in 2.1.8, 2.1.9, 2.1.17, 2.1.18, and number of unintentional in-service releases since the previous integrity assessment. If there were any releases since the previous assessment, determine if any reasonable management controls could have prevented and/or significantly reduced the

consequences of the release.

- 2.2.4.2 Determine and document if the considerations of the collected data conclude the need to adopt “other management controls” to prevent and/or significantly reduce the consequences of a pipeline failure that could affect an HCA on the segment. Examples of “other management controls” may include but are not limited to conducting drills with local emergency responders, local release detection, containment, strain monitoring, increased right of way surveillance, and remediation.
- 2.2.5 The Pipeline Integrity Engineer, Pipeline Integrity Manager, Pipeline Integrity Director, or Corrosion Prevention Supervisor shall evaluate the leak detection programs on the segment.
- 2.2.5.1 The evaluation may consider, but is not limited to, the following data and information: Data collected in 2.1.1, 2.1.7, 2.1.14, 2.1.15, 2.1.16, 2.1.18, type of product(s) carried, and length and diameter of the pipeline segment.
- 2.2.5.2 Corrective actions addressing leak detection that are implemented or recommended in accordance with Abnormal Operating Procedures are considered compliant with this procedure.

The Normal Operating Procedures address how to operate and monitor a pipeline during normal operating conditions. Normal Operating Procedures exists for transient and non-transient conditions. Normal transient conditions include pipeline startup, startup of an intermediate pumping unit on a currently operating pipeline, pipeline shutdown, and shutdown of an intermediate pumping unit on a currently operating pipeline. All procedures require the pipeline be monitored for abnormal conditions.

The Abnormal Operating Procedures define abnormal operating conditions and provide the guidance to address the conditions. Abnormal operating conditions associated with leak detection may include but are not limited to pressure/flow variations that cannot be explained, unexplained line imbalances as determined by routine over/short determinations, unintended operations of any safety device, and loss of communications. The procedures require documentation of the response to, investigation of, and the action taken to correct the cause of the abnormal condition. These procedures allow the equipment to be returned to service and eliminate risk for recurrence.

- 2.2.5.3 Determine and document if the considerations of the collected data conclude that reasonable modifications to the existing leak detection programs would significantly reduce the consequences of a pipeline failure that could affect an HCA. Examples of program modifications may include but are not limited to changes to any leak detection programs and additional training of personnel responsible for a leak detection program.
- 2.2.6 The Pipeline Integrity Engineer, Pipeline Integrity Manager, Pipeline Integrity Director, or Corrosion Prevention Supervisor shall evaluate installing additional EFRDs on the segment to significantly reduce the consequences of a pipeline failure that could affect an HCA.
- 2.2.6.1 The evaluation may consider, but is not limited to, the following data and information for segments carrying hazardous liquid products or Anhydrous Ammonia: Data collected in 2.1.14, 2.1.5, 2.1.15, 2.1.18, type of product(s) carried, topography or pipeline profile as identified in the overland spread analysis, the potential for ignition, proximity to power sources, specific terrain between the pipeline segment and the HCA as identified in 2.1.1, and benefits expected by reducing the release size. The evaluation may also consider the potential effects of additional EFRDs including conducting proper valve sequencing during intended EFRD activations, the ability to promptly detect and react to inadvertent EFRD activations, and possible elevated pressures caused by transient conditions during EFRD activations. If there were any unintentional in-service releases since the previous assessment, consider the cause and volume of the release.
- 2.2.6.2 Due to the vapor dispersion characteristics of HVLs, the maximum vapor cloud size is not dependent on the spacing of EFRDs. Reference “BERC Gas Dispersion Study” (2003 HCA Segment Identification project). This factor alone is sufficient consideration of the relevant factors that must be considered in identifying the need for EFRDs for pipeline segments that exclusively transport HVLs. Therefore, EFRDs will not reduce the area that could be affected by a pipeline release. No additional analysis will be conducted to identify the need for EFRDs on pipeline segments that exclusively transport HVLs.
- 2.2.6.3 Potential locations for EFRDs for segments carrying non-HVL hazardous liquid products may be prioritized based on the ratio of the volume that could reach an HCA, through overland spread or water transport to the potential release volume. The likelihood of significantly reducing the consequences of a pipeline failure that could affect an HCA

is highest where the overland spread or water transport studies indicate only a small volume of released product could reach an HCA.

2.2.6.4 Potential locations of EFRDs for segments carrying Anhydrous Ammonia may be prioritized based on the percentage of the HCA(s) that could be affected by vapor dispersion or water transport since toxicity is the issue with this product.

2.2.6.5 For segments carrying hazardous liquid products or Anhydrous Ammonia, determine and document if the considerations of the collected data conclude if installing additional EFRDs on the segment would significantly reduce the consequences of a pipeline failure that could affect an HCA.

### 2.2.7 Documentation and Tracking of Recommendations

2.2.7.1 The Pipeline Integrity Manager, Pipeline Integrity Director, Pipeline Integrity Engineer, and Corrosion Prevention Manager shall review the results of the pipeline segment data collection and subsequent modification (preventive and mitigative) recommendations.

2.2.7.2 Following the review in 2.2.7.1 all preventive and mitigative recommendation candidates shall be sent to representatives of Operations, Engineering, and Executive Management for review and approval.

2.2.7.3 Following the approval in 2.2.7.2 all preventive and mitigative recommendations requiring action shall be prioritized, addressed, and administered under the Company capital project or expense project process.

2.2.7.4 All pipeline segment data collected and preventive and mitigative recommendations shall be kept on file until superseded by the segment's next information analysis.

## 2.3 Reassessment Determination

2.3.1 The reassessment determination shall be established by the Pipeline Integrity Engineer, Pipeline Integrity Manager, Pipeline Integrity Director, Corrosion Prevention Manager, or Corrosion Prevention Supervisor, not to exceed five years except for situations identified in 2.3.3, for continually assessing the integrity of the segment's line pipe. The reassessment shall be established based upon the following considerations: data collected in 2.1.10, 2.1.11, 2.1.2, 2.1.6, 2.1.12, 2.1.13, 2.1.3, 2.1.4, 2.1.7, 2.1.8, 2.1.9, 2.1.14, and the preventive and mitigative recommendations made in section 2.2. Reassessment determinations may be recommended to address each specific threat

identified to be a concern in the ***“Integrity Assessment Method Selection Procedure”***.

### 2.3.2 Documentation and Tracking of Reassessment Determinations

2.3.2.1 The Pipeline Integrity Manager, Pipeline Integrity Director, Pipeline Integrity Engineer, and Corrosion Prevention Manager shall review the results of the proposed pipeline segment reassessment determination.

2.3.2.2 Following the review in 2.3.2.1 the proposed reassessment determination shall be sent to representatives of Operations, Engineering, and Executive Management for review and approval.

### 2.3.3 Variance from the 5-year intervals.

2.3.3.1 The Pipeline Integrity Engineer, Pipeline Integrity Manager, Pipeline Integrity Director, Corrosion Prevention Manager, or Corrosion Prevention Supervisor shall follow the guidelines for longer assessment interval submittals identified in 49CFR195.452(j)(4) including the 270 day “Engineering basis” and 180 day “Unavailable technology” notification submittal requirements. Notices will be sent to the address specified in 49CFR195.452(m).

## 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)

3.2.2 HCA Segment Identification process

3.2.3 Procedure for Identifying HCAs and HCA Segments

3.2.4 Integrity Assessment Method Selection Procedure

3.2.5 BERC Gas Dispersion Study

3.2.6 Normal Operating Procedures

3.2.7 Abnormal Operation Procedures

### 3.3 Forms and Attachments -

3.3.1 N/A

## 4.0 DEFINITIONS:

4.1 N/A

**➤➤➤End of Procedure<<<**

**Change Log**

<b>Date</b>	<b>Rev. #</b>	<b>Change Location</b>	<b>Brief Description of Change</b>
06/09/05	1	2.1.10.2.3	Deleted "Identify the total number of external metal loss indications at pipeline casings and foreign line crossings."
8/22/05	2	3.2.1	Removed "/Chapter 3".
8/22/05	2	2.2.1, 2.2.2, 2.2.3, 2.2.4, 2.2.5, 2.2.6, 2.3.1	Added "Corrosion Prevention Supervisor" as a candidate to perform each task.
8/22/05	2	Title Block	Added "EPOLP PIPELINE INTEGRITY MANAGEMENT PROGRAM".
8/22/05	2	2.2 & 2.3	Modifications to PI position titles performed to reflect recent changes in PI Group position titles.
9/12/05	3	2.2.6.1	Added verbiage regarding the consideration of the effects of additional EFRDs, second to last sentence.
9/12/05	3	Title Block	Changed owner from Joe Cheek to H. Buford Barr
11/07/06	4	2.1.1.7	Reworded to point to IMP-SEC1-01 to identify how farm tiles and roadway ditches are addressed in the segment identification process.
2/05/07	5	Title Block	Changed name of procedure from "Information Analysis" to "Information Analysis – Line Pipe"
2/05/07	5	2.1.1.6	Deleted 2.1.1.6 which required the collection of Facility data.
2/05/07	5	2.1.5.1	Replaced reference to Shell Spill Model with "the volume used for the most recent segment identification" to allow for the use of the volume from the currently applied spill model.
2/05/07	5	2.1.17.3	Deleted 2.1.17.3 which required the collection of Facility data.
2/05/07	5	2.1.18	Added new 2.1.18 "Pipeline Segment Data and Information - Proximity to HCA Could Affect Pipe".
2/05/07	5	2.2.1.1, 2.2.2.1, 2.2.3.1, 2.2.4.1, 2.2.5.1, 2.2.6.1	Added "2.1.18" into these sections so that the 2.1.18 information may be incorporated into Section 2.2 evaluations.
2/05/07	5	2.2.5.2	Added 2.2.5.2 which addresses abnormal operating conditions.
2/05/07	5	2.2.7.3	Replaced "EPOLP" with "Company".
2/05/07	5	3.2	Added references to "Procedure for Identifying HCAs and HCA Segments", "Normal Operating Procedures", and "Abnormal Operation Procedures".
3/28/07	6	1.2.2	Added 1.2.2 to address TEPPCO Information Analysis
7/16/07	7	Title Block	Removed the reference to EPOLP and removed the Enterprise logo.



	<b>PIPELINE INTEGRITY MANAGEMENT PROGRAM</b>	Owner: H. Buford Bar	Document No: IMP-SEC2-01	
		Revision No: 2	Revision Date: 7/25/07	Page: 1 of 4
Procedure: <b>INTEGRITY ASSESSMENT METHOD SELECTION PROCEDURE</b>				

## 1.0 PURPOSE:

The purpose of this procedure is to determine the method(s) required to assess the integrity of the line pipe.

## 2.0 PROCEDURE:

### 2.1 DATA GATHERING

Information considered for the integrity assessment method selection may include the following.

- 2.1.1 Line ID(s) with beginning and ending station if available
- 2.1.2 Coating type of the segment.
- 2.1.3 Coating Condition for the segment. Use the following descriptions for coating condition:
  - 2.1.3.1 Uncoated – Bare pipe with no protective coating.
  - 2.1.3.2 Poor – Partial or full disbondment with or without coating holidays/anomalies.
  - 2.1.3.3 Good - Fully bonded coating system with no or few holidays/anomalies.
- 2.1.4 Quality of cathodic protection (CP) for each segment: Use the following descriptions for CP quality
  - 2.1.4.1 Adequate – This section of line currently meets the minimum requirements set forth by the National Association of Corrosion Engineers Recommended Practice RP-0169 and adopted by reference in DOT 49 CFR, Part 195.571.
  - 2.1.4.2 Inadequate – This section of line does not currently meet at least one of the minimum requirements set forth by the National Association of Corrosion Engineers Recommended Practice RP-0169 and adopted by reference in DOT 49 CFR, Part 195.571.
- 2.1.5 Year of original construction.
- 2.1.6 Does the normal operating temperature of the segment exceed 100°F?
- 2.1.7 The pipe diameter, yield strength, wall thickness and seam type for the segment.
- 2.1.8 The number of known in-service seam ruptures and hydrostatic test related seam ruptures.

- 2.1.9 Has this segment been tested for cracks? If yes, have crack indications been found on this line segment?
- 2.1.10 The year and pressure of most recent hydrostatic test for the line segment, if applicable.

**2.2 EVALUATE FOR THREAT SUSCEPTIBILITY**

- 2.2.1 The Pipeline Integrity Engineer shall evaluate the segment to identify its susceptibility to Longitudinal Seam Failure
  - 2.2.1.1 The method used to determine each line's susceptibility to Seam failure is described in the paper by John F. Kiefner titled "Dealing With Low-Frequency-Welded ERW Pipe and Flash-Welded Pipe With Respect To HCA-Related Integrity Assessment", paper No. ETCE2002/PIPE-29029.
  - 2.2.1.2 Data from ASME publication, "The History of Line Pipe Manufacturing in North America" may be used to determine if pre-1979 ERW line pipe was manufactured with a high frequency mill process.
  - 2.2.1.3 Failures of longitudinal weld seams during the original construction hydrostatic test are classified as manufacturing defects and are not fatigue related failures.
- 2.2.2 The Pipeline Integrity Engineer shall evaluate the segment to identify its susceptibility to cracking mechanisms such as Stress Corrosion Cracking (SCC)
  - 2.2.2.1 The method used to determine each line's susceptibility to high pH SCC is described in ASME B31.8S Appendix A3.
  - 2.2.2.2 Near neutral pH SCC susceptibility evaluation of line segments may consider the following:
    - 2.2.2.2.1 Known history of SCC
    - 2.2.2.2.2 Normal operating stress greater than 60% SMYS
    - 2.2.2.2.3 Coating system classification of "Poor" per 2.1.3 of this document and shields cathodic protection
- 2.2.3 The Pipeline Integrity Engineer shall evaluate the segment to identify its susceptibility to Corrosion
- 2.2.4 The Pipeline Integrity Engineer shall evaluate the segment to identify its susceptibility to Third Party Damage

**2.3 ASSESMENT METHOD SELECTION**

- 2.3.1 The Baseline Assessment Plan tool selection shall comply with 49CFR195.452(c).
- 2.3.2 The Pipeline Integrity Engineer and the Project Manager shall identify

and select appropriate integrity assessment method or combination of methods to address the threats identified for the pipeline segment.

The assessment method(s) selection may consider:

- 2.3.2.1 The data collected in section 2.1 of this procedure
- 2.3.2.2 The susceptibility to the threats identified in section 2.2 of this procedure.
- 2.3.2.3 Effectiveness of the assessment method(s)
- 2.3.2.4 Availability of internal inspection tools or other tools capable of detecting metal loss and deformation anomalies.
- 2.3.2.5 Piggability of the line
  - 2.3.2.5.1 Bend radius
  - 2.3.2.5.2 Assessment segment length
  - 2.3.2.5.3 Trap configuration
  - 2.3.2.5.4 Product
- 2.3.2.6 Cost effectiveness of the assessment method
- 2.3.2.7 Schedule for completion of the integrity assessment
- 2.3.2.8 Need for ID/OD discriminator
- 2.3.2.9 Re-inspection recommendations
- 2.3.2.10 The MOP of the segment, as required.

**3.0 DOCUMENTATION**

- 3.1 The integrity assessment method(s) selected for the baseline assessment shall be documented on the Baseline Assessment Plan.
- 3.2 The current integrity assessment method determination documentation shall be kept on file until it is replaced by the next integrity assessment method determination.

**4.0 REFERENCES**

- 4.1 49 CFR Part 195
- 4.2 ASME B31.8S
- 4.3 “Dealing With Low-Frequency-Welded ERW Pipe and Flash-Welded Pipe With Respect To HCA-Related Integrity Assessment”, paper No. ETCE2002/PIPE-29029
- 4.4 ASME publication, “The History of Line Pipe Manufacturing in North America”

**>>>End of Procedure<<<**

**Change Log**

<b>Date</b>	<b>Rev. #</b>	<b>Change Location</b>	<b>Brief Description of Change</b>
8/22/05	1	Title Block	Replaced Paul Klein with Joe Cheek as owner.
8/22/05	1	Title Block	Added "EPOLP Pipeline Integrity Management Program".
8/22/05	1	2.3.2	Modifications to PI position titles performed to reflect recent changes in PI Group position titles.
7/25/07	2	Title Block	Removed the reference to EPOLP, removed the Enterprise logo, and changed the owner to H. Buford Barr.
7/25/07	2	2.2.2, 2.2.3, 2.3.2	Removed "Corrosion Prevention Supervisor".