LIQUID PIPELINE

INTEGRITY MANAGEMENT PROGRAM

AND

PROCEDURES MANUAL

Version 8

Revision Date: June 2017

Table of Contents

Introduction

Section 1: Segment Identification

Section 2: Baseline Assessment Plan

Section 3: Integrity Assessment

Section 4: Remedial Action

Section 5: Risk Analysis

Section 6: Preventative and Mitigative Measures

Section 7: Continual Improvement

Section 8: Program Evaluation

Appendices

Introduction

NuStar Energy, L.P., (NuStar) and its affiliated subsidiaries have developed a Pipeline Integrity Management Program (IMP) to protect people and the environment, and to advance the safe operating practices of company owned and/or operated pipelines. This section presents the authority, scope, applicability, and overview of this IMP and its correlation with other NuStar programs and documentation.

1. Authority

NuStar's Pipeline Integrity Management Program is owned, managed and executed through NuStar's Engineering and Technical Services department. Accountability for the execution of the program rests with the Vice President, Engineering and Technical Services.

2. Scope

On May 29, 2001, the United States Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA), adopted 49 CFR §195.452 as the rule (hereafter referred to as "the Rule") on pipeline integrity management in High Consequence Areas (HCAs). The Rule specifies regulations to assess, evaluate, repair, and validate the integrity of hazardous liquid pipeline segments, that in the event of a leak or failure, could affect HCAs, which are defined as any of the following:

- High population areas (greater than 50,000 people and greater than 1,000 people per square mile) and other populated areas (as defined by the U.S. Census Bureau)
- Commercially navigable waterways (defined by the National Waterways Network)
- Unusually Sensitive Areas (USAs), which include drinking water resources and ecologically sensitive areas (as defined in *49 CFR §195.6*)

In accordance with the Rule as revised through January 23, 2017, this document represents NuStar's written IMP and provides guidelines for the continual assessment of all pipeline segments that could adversely affect HCAs as defined in the Rule. This integrity assessment of NuStar's pipelines will be achieved through internal inspection, pressure testing, or other equally effective means guided by sound engineering practices and authorized by PHMSA and, if necessary, other governing agencies.

PHMSA, from time to time, issues Advisory Bulletins containing recommendations, guidance and other information. While these do not impose regulatory requirements, NuStar will review the bulletins and consider incorporating PHMSA's recommendations or guidance if applicable.

3. Applicability

The Rule is applicable to all PHMSA jurisdictional and state hazardous liquid pipelines owned and/or operated by NuStar (see Appendix A, NuStar Pipeline Systems). The Rule defines three categories of pipelines, and the effective dates of the Rule, as it applies to the written IMP for each category (see
Table 1).

Table 1. IMP Pipeline Categories

Pipeline	Description	Effective Date
Category 1	Pipelines existing on May 29, 2001, that were owned and/or operated by an operator who owned and/or operated a total of 500 or more miles of pipeline, subject to this part (interstate lines under the jurisdiction of PHMSA)	March 31, 2002
Category 2	Pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline, subject to this part	February 18, 2003
Category 3	Pipelines constructed or converted after May 29, 2001	Date pipeline begins operation (written IMP within one year)

NuStar, as a category 1 operator was compliant with the Rule's original implementation schedule regarding baseline evaluations. In addition, NuStar met all applicable requirements of §8.101 of the Texas Administrative Code by meeting 49 CFR Part 195 requirement which are more stringent for HCA segments.

All NuStar pipelines constructed or converted after May 29, 2001, are subject to the requirements for Category 3 pipelines. To fulfil these requirements, the Company

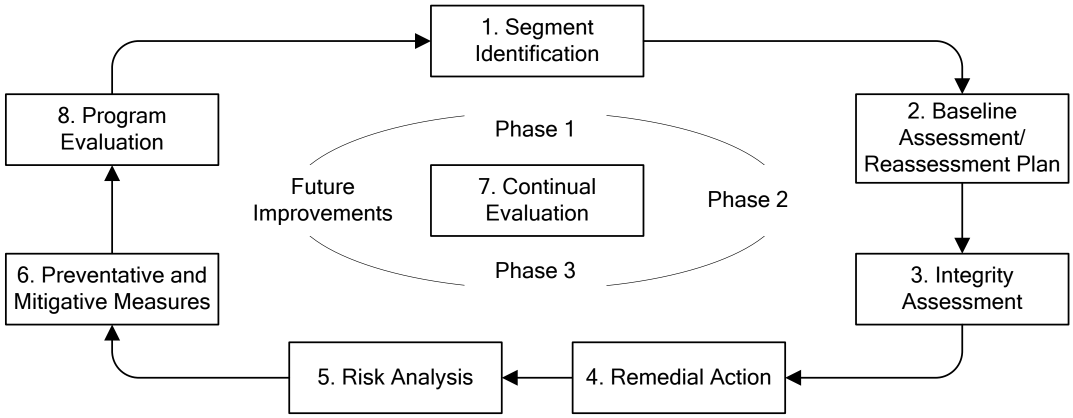
- identifes HCAs on the pipeline prior to the date the pipeline begins operation;
- performs a baseline assessment prior to the date the pipeline begins operation; and
- incorporates the segment(s) into the IM plan within one year of the date the pipeline begins operation.

4. *IMP Manual* Overview

4.1. Sections

The Rule specifies eight required elements for an effective IMP, as referenced in API 1160 and as illustrated in Figure 1.

Figure 1. IMP Flowchart



These eight elements correspond to the eight sections of the *NuStar Integrity Management Program Manual (IMP Manual)*, with procedures immediately following their sections.

- Section 1, Segment Identification—identifying all pipeline segments that could affect HCAs
- Section 2, Baseline Assessment Plan—scheduling the baseline assessments of HCA and Could Affect segments according to risk
- Section 3, Integrity Assessment—conducting assessments for scheduled HCA and Could Affect segments
- Section 4, Remedial Action—repair criteria and processes
- Section 5, Risk Analysis—integrating all pipeline integrity and failure consequence information to analyze risk of failure
- Section 6, Preventive and Mitigative Measures—proactively preventing and/or reducing the risk to HCA and Could Affect segments
- Section 7, Continual Evaluation—maintaining a process for continual integrity assessment/evaluation
- Section 8, Program Evaluation—measuring the performance effectiveness of the IMP

4.2. Appendices

Additional pertinent information is provided in the appendices.

- Appendix A, NuStar Pipeline Systems, groups all active and idle, company operated pipelines by NuStar's operating regions, with an explanation of how these pipelines are divided among PHMSA operator IDs.
- Appendix B, Important Time Frames lists dates and time frames associated with particular IMP tasks.
- Appendix C, Pipe Sample Handling and Analysis Processes, gathers some of the key IMP related procedures used by vendors.

- Appendix D, Anomaly Types, Detection Tools, and Assessment Methods, describes the options in these categories to help NuStar personnel select the best tools and methods for each situation.
- Appendix E, Documentation and References, lists the IMP-related sources referenced in this manual.
- Appendix F, Forms, containes blank examples of the forms used as part of the NuStar IMP.
- Appendix G, Preventative and Mitigative Measures–Risk Threats Matrices, contains tables indicating which measures are effective against which threat types.
- Appendix H, Glossary, defines key IMP terms and acronyms.
- Appendix I, SCC Management Plan, describes NuStar's program for screening and mitigating pipelines for susceptibility to stress corrosion cracking (SCC).
- Appendix J, SCC Site Assessment Procedure, outlines the roles and responsibilities for field technicians during the investigation for SCC on exposed buried pipe.
- Appendix K, Examinations of Exposed Portions of Buried Pipelines, outlines NuStar's guidelines for in-the-ditch defect assessment (extracted from the former *Corrosion Control Procedure Manual,* Section 7)
- Appendix L, Guidance for ILI Data Validation, Data Integration, and Repair Plan Development, provides guidance for the execution of an assessment project and development of a repair plan. This document was previously a stand-alone document.
- Version and Revision Logs, containing a table of the most current version of every part of the manual, and a set of manual revision tables (including one for the once-separate *IMP Procedure Guide*).

4.3. Correlation with Other NuStar Manuals and Documents

The *IMP Manual* is the primary document for NuStar's IMP, but other documents are also relevant.

- The *NuStar Operations and Maintenance Manual (O&M Manual)* provides written procedures for conducting normal pipeline operations and maintenance activities, and for handling abnormal operations and emergencies. A committee reviews the *O&M Manual* annually and updates it as necessary. The manual contains detailed policies and procedures for pipeline related activities. The procedures presented in the *O&M Manual* are essential to the assessment and response to pipeline integrity issues.
- The *NuStar Corrosion Control Manual* demonstrates how NuStar complies with regulatory requirements, and provides a standardized approach to corrosion control for all NuStar facilities.

- The *NuStar General Systems Manual provides procedures associated with continuous monitoring and control of jurisdictional pipelines, enhanced communication requirements, and leak detection systems.*
- The *NuStar GIS Data Governance Program* provides a framework for ensuring that data input into the NuStar GIS database is traceable, verifiable, and complete.
- NuStar spill response and emergency plans describe emergency response zones for the pipeline system and facilities, and present policies and procedures for detecting, responding to, and mitigating spills.

5. NuStar IMP-Related Personnel

NuStar employs personnel who are dedicated full time to the IMP, fulfill defined IMP roles, or who regularly perform IMP related tasks. Table 2 lists these personnel by role, along with the manual sections for which the IMP Team members are responsible. Qualifications, statements, and the Roles and Responsibilities Matrix are maintained on the IMP network drive.

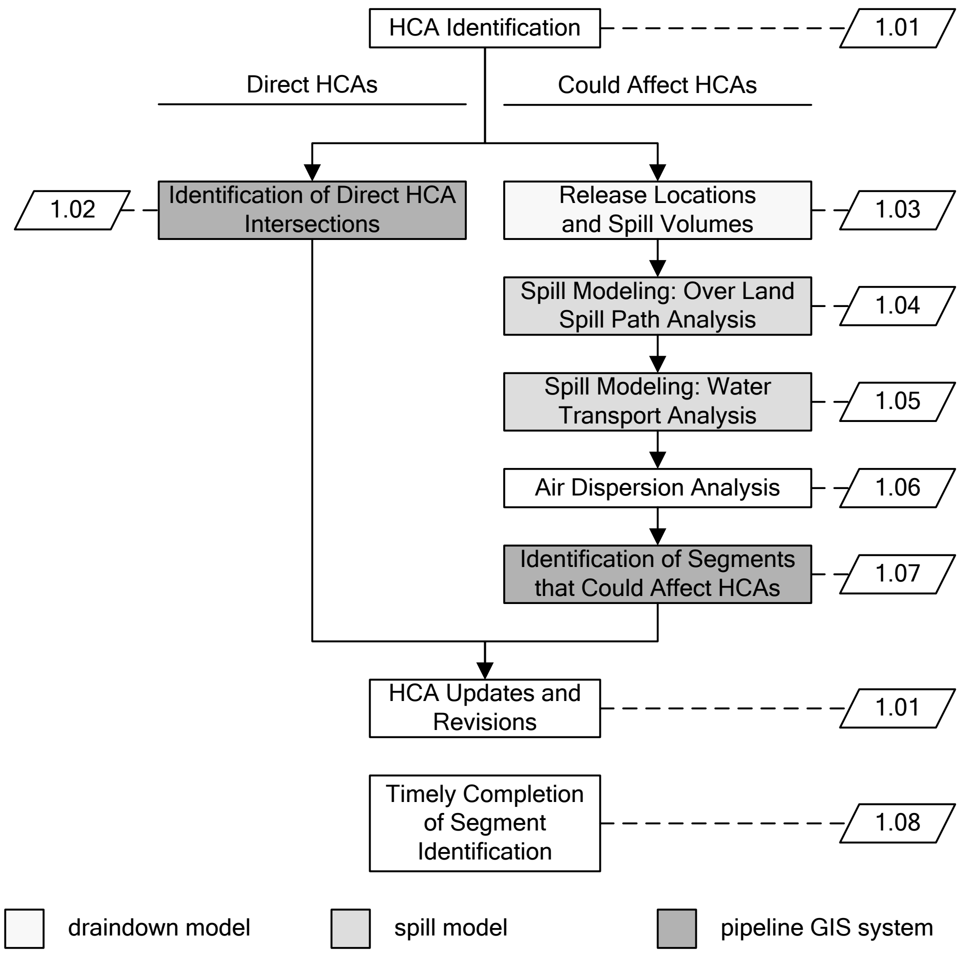
Table 2. IMP-Related Personnel

Role	Section(s)	Role	Section(s)
Sr. Mgr. Pipeline Integrity Engineering	all	P&M Coordinator	6
HCA Specialist	1		8
Assessment Engineer	2, 3, 7	Corrosion Manager	
Assessment Project Manager	4	GIS Manager	
Risk Engineer	5	HSE Manager	

1: Segment Identification

The first HCA requirement of the Rule is to define a process for identifying which pipeline segments intersect or could affect HCAs using all available information. Section 1 overviews the NuStar segment identification process as laid out in Figure 1-1 (with corresponding Protocols noted). See IMP Procedure 101, HCA Segment Identification for more detail on all processes discussed in this section.

Figure 1-1. Segment Identification Flowchart



1.1. HCA Identification

1.1.1. HCA Data from the National Pipeline Mapping System

The National Pipeline Mapping System (NPMS) maintained by PHMSA provides HCA data as GIS data files. NuStar downloads these files from the NPMS website, imports them into its pipeline GIS system, and uses them to identify pipeline segments that intersect or could affect an HCA.

NPMS provides four types of HCA data:

- High Population Areas (HPAs)—urbanized areas, as defined and delineated by the Census Bureau, that contain 50,000 or more people and have a population density of at least 1,000 people per square mile.

- Other Populated Areas (OPAs)—places, as defined and delineated by the Census Bureau, that contain a concentrated population, such as incorporated or unincorporated cities, towns, villages, or other designated residential or commercial areas.
- Commercially Navigable Waterways (CNWs)—waterways for which a substantial likelihood of commercial navigation exists.
- Unusually Sensitive Areas (USAs)—drinking water or ecological resource areas, as further defined in §195.6, that are especially sensitive to environmental damage from a hazardous liquid pipeline release.

1.1.1.1. Unavailable NPMS Data

If any NPMS data is currently unavailable (such as, initially, the New York drinking water USAs or the Pennsylvania ecological USAs), NuStar will gather the data needed for its HCA analysis.

1.1.2. Field Identification of Potential New HCAs

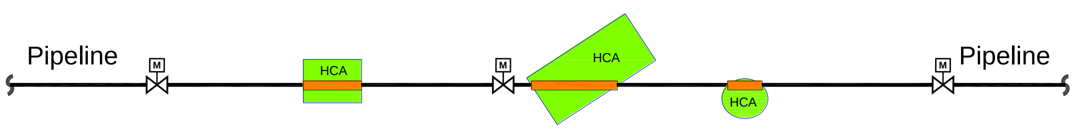
As a part of the HCA identification process, NuStar incorporates information obtained from employees' local knowledge of the pipeline right-of-way. Potential HCAs are identified as regular field activities discover new construction or as NuStar's Right of Way (ROW) department receives information regarding city annexing projects or zoning changes. Field personnel notify the HCA Specialist when they find evidence of new or expanding HCAs as part of their normal operations (see Part 101.2 of IMP Procedure 101).

With the aid of GIS aerial mapping databases, NuStar is able to identify population growth into areas that a spill could affect beyond those identified in the field. Local knowledge of new environmental data will be included as resources become available.

1.2. Identification of Direct HCA Intersections

Within GIS, NuStar overlays HCAs on top of every pipeline centerline to find the beginning and ending points for each pipeline-HCA intersection (see Figure 1-2) and on top of every facility to determine which directly affect an HCA. (Facilities include but are not limited to pump stations, meter stations, terminals, and breakout tanks.) For all direct HCA intersections, a unique ranged event (station–station data) is generated in GIS, which can output maps and/or tabular reports.

Figure 1-2. Direct Pipeline-HCA Intersections

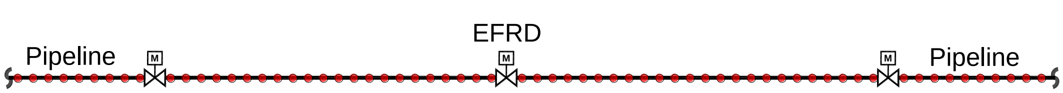


1.3. Release Locations and Spill Volumes

1.3.1. Release Locations

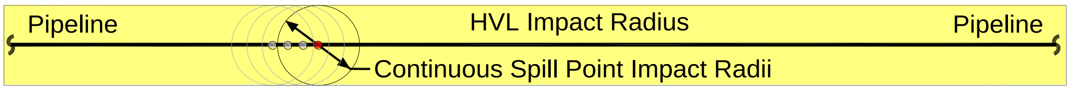
For liquid pipelines, NuStar calculates potential spill locations approximately every 100 feet (see Figure 1-3). NuStar considers this spacing adequate to account for water crossings and topography changes near the pipeline. For liquid pipelines, each spill point may have a different calculated spill volume.

Figure 1-3. Liquid Pipeline Release Locations



For HVL pipelines, qualified engineering vendors perform air dispersion modeling and NuStar applies the worst-case air dispersion distance as a continuous series of spill point impact radii that collectively form one HVL impact radius running the length of each pipeline isolation segment (see Figure 1-4).

Figure 1-4. HVL Pipeline Impact Radius



For breakout tank facilities, NuStar identifies the center of the breakout tank(s) as the spill location.

1.3.2. Spill Volumes

1.3.2.1. Liquid Pipeline Spill Volumes

For liquid pipelines, NuStar calculates the potential spill volume for every release location:

1) At every release location, assume the worst-case scenario—a rupture hole size equivalent to the nominal diameter (Notes A and B).
2) Multiply the maximum flow rate of the pipeline segment by the leak detection–isolation time (Note C).
3) Add the pipeline draindown volumes.
   a) For liquid pipelines, draindown is based on EFRD (Emergency Flow Restrictive Device) locations, pipe size, and pipeline elevations for each release location (see Figure 1-5).
   b)

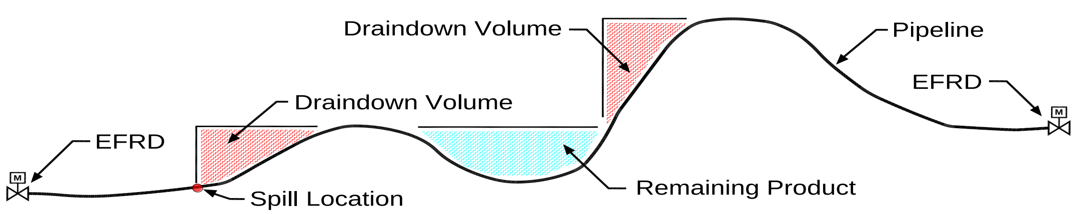
Total Spill Volume = (Leak Detection–Isolation Time) × Maximum Flow Rate + Draindown Volumes

Note A: This is worst case even for low-stress lines that would not typically fail due to hoop stress in this mode, because it is conceivable (even if unlikely) that mechanical damage could cause such a rupture.

Note B: Additional small-leak scenarios are calculated simultaneously using an orifice flow rate (considering max pressure) multiplied by the time to repair the leak. These scenarios are for sensitivity analysis only and even though some may be below the remote leak detection limit, the overland spill paths are considered more than adequate to encompass the spread that would result from such a low leak rate even though the leak may not be discovered until the next Right-of-Way patrol.

Note C: The leak detection–isolation time for each pipeline isolation segment is the time it takes NuStar Personnel to shut down the line and close the EFRDs; these values are available in a GIS web report.

Figure 1-5. Liquid Pipeline Spill Volumes



1.3.2.2. HVL Pipeline Spill Volumes

All HVL pipeline releases are modeled using the highest potential operating pressure and flow rate until leak detection and isolation is achieved. To simplify the analysis, the pipeline network may be grouped based on diameter, pressure, normal flow rate, and relationship to the system.

1.3.2.3. Facility Spill Volumes

For all facilities, NuStar determines that a facility can affect an HCA by identifying if the facility resides in an HCA or if the pipeline feeding the facility can affect an HCA.

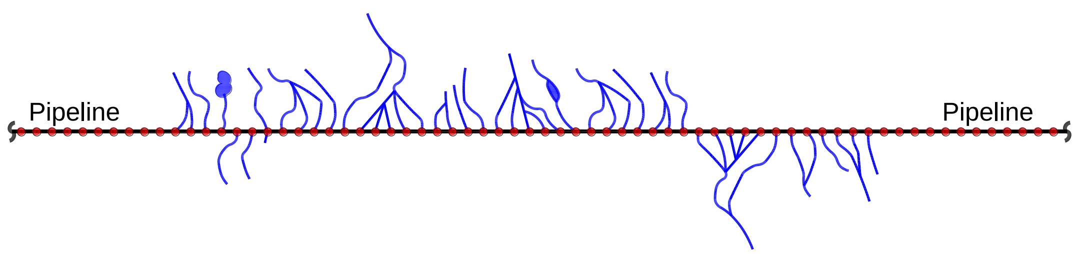
For facilities including breakout tanks, NuStar performs an additional HCA analysis. The individual breakout tanks are modeled the same way as the pipeline (see section 1.4., Spill Modeling). The spill volume used is derived from the calculated tank shell capacity plus 10% to account for pipeline fill volumes until shutdown is achieved. If the breakout tank contains an HVL, an air dispersion buffer is applied to the tank. This distance is derived from the air dispersion analysis used for the pipeline (see section 1.5 Air Dispersion Analysis).

To insure that the worst-case spill analysis is preformed, the analysis assumes that there is no tank containment. The results of the analysis are recorded on a spreadsheet and a facility map generated. These documents are stored on the IMP Intranet site.

1.4. Spill Modeling

After calculating spill volumes for all release locations for liquid pipelines, NuStar uses spill modeling to identify potential Could-Affects—pipeline segments and facilities that do not directly intersect an HCA but could affect one or more HCAs in the case of a spill. Spill modeling uses over land spill path analysis and water transport analysis to model realistically the movement of a spill from each release location over land and along surface water networks (see Figure 1-6). It calculates product loss and flow time of a release flowing out from the centerline of the pipeline and traveling downhill and downstream until the maximum release volume is consumed or response time has been met. The net results are spill paths (chains of polygons going out from the pipeline release locations) and vectors (the extent of downstream travel).

Figure 1-6. Liquid Pipeline Spill Modeling



1.4.1. Over Land Spill Path Analysis

Over land spill modeling takes into account the physical nature of the land surface, degree of slope, retention of product over the down-slope path, and pooling in large surface depressions. Evaporation to the atmosphere is not currently considered by NuStar in its HCA analysis.

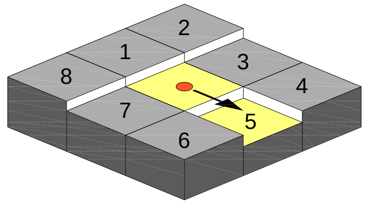
1.4.1.1. Elevation Grid

The topographic surface of the land over which a spill path travels is depicted by a gridded Digital Elevation Model (DEM). The standard DEM in the U.S. is the National Elevation Dataset (NED), which is developed and distributed by the U.S. Geological Survey (ned.usgs.gov) as a seamless, nationwide raster data set with a 30-meter (30m × 30m) grid. NuStar may also use higher resolution DEMs as available and/or necessary for limited but growing areas of the country; these DEMs can have a 10-meter grid and/or be generated at a higher resolution from LIDAR data.

1.4.1.2. Spill Paths

A spill path is a polygon chain of channels and pools across the elevation grid that follows the most direct downhill route(s). Starting at the spill location, each polygon in the chain represents the adjacent grid cell with the lowest elevation to which the product flows (see Figure 1-7).

Figure 1-7. Flow to the Lowest Adjacent Elevation Grid Cell

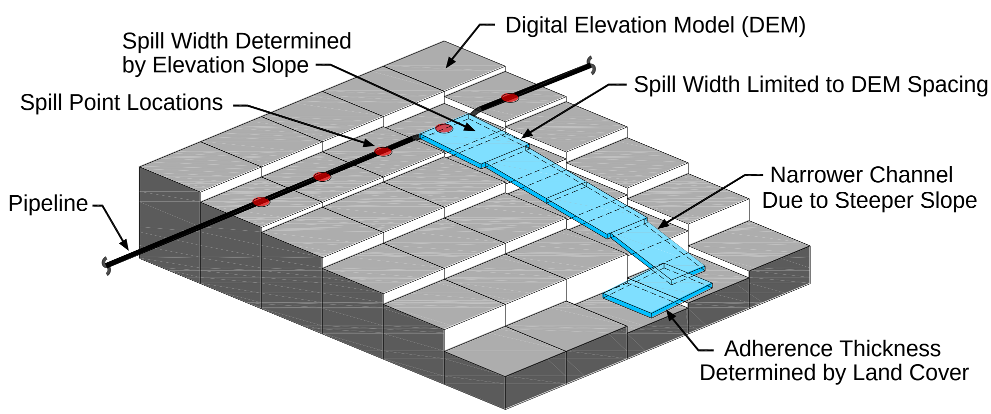


Note: An HVL may transverse short distances over land as a liquid before it completely evaporates; however, because air-dispersion buffers extend beyond such distances, they are thus more than adequate to account for the spread of an HVL over land. Water-soluble HVLs such as ammonia are of special concern because they will disperse into water if they encounter a water network (see Section 1.6.3., Drain Tiles).

Channels of linear product flow continue until the product reaches a level area or depression, where the product will spread or pool until it can again form a channel. Channel width is inversely proportionate to the degree of slope but is also based on spill rate and velocity.

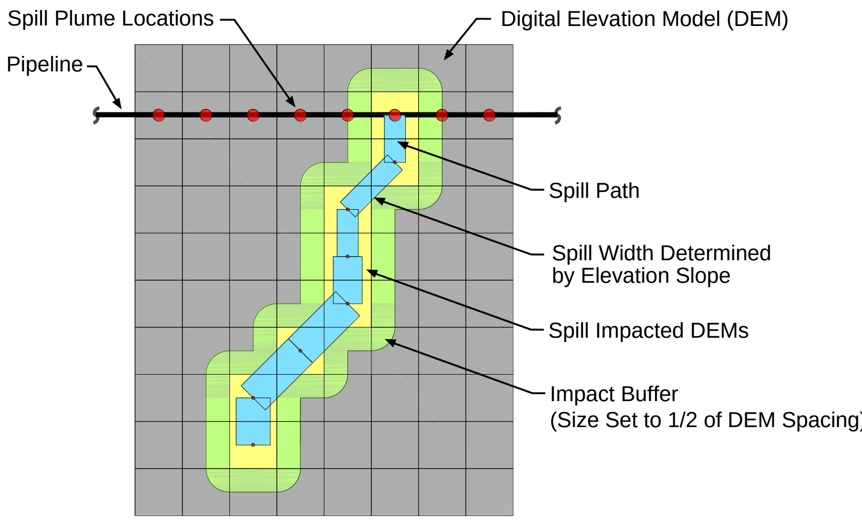
Figure 1-8 illustrates that channel width is both affected by slope and bound by elevation cell dimensions.

Figure 1-8. Channel Width in Relation to Slope



The spill modeling software applies a buffer that is half the width of the DEM resolution (e.g., 15 meters on all sides for a 30-meter grid). The buffer surrounds every grid cell to which the spill path flows as shown in Figure 1-9 to form the final impact footprint used to determine whether the path affects an HCA.

Figure 1-9. Spill Impact with Buffering

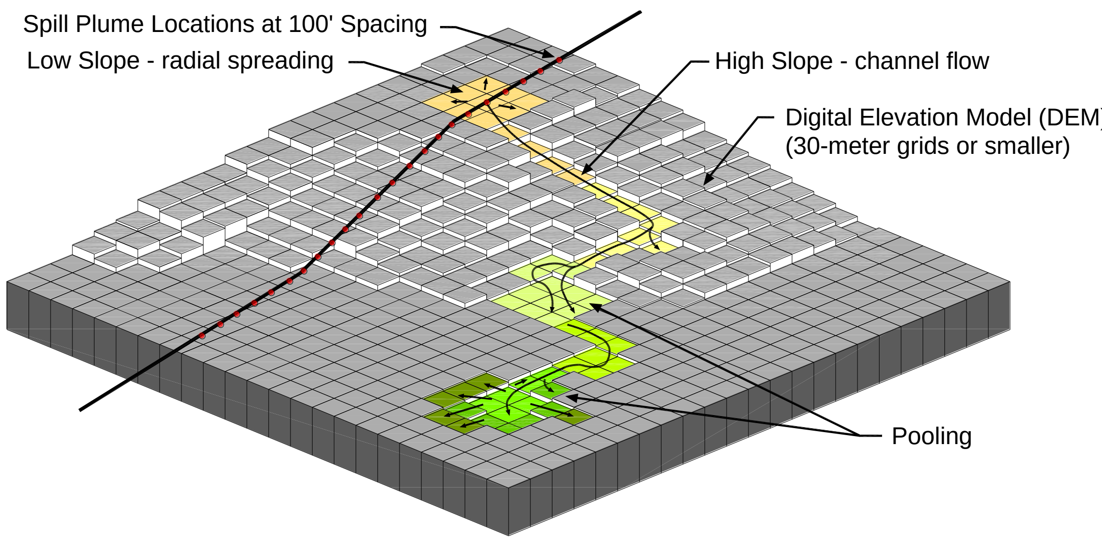


When a channel encounters a level area, the software identifies the closest lower cell beyond adjacent cells and directs the spill at it (as shown in Figure 1-10). To realistically account for the spreading of product in level areas even as it seeks out lower ground, the program randomizes the grid elevation resolution in the level area by up to 0.05 meters (the parameter is user defined with a default value of zero).

When a channel encounters a depression (any area with two or more contiguous grid cells that are lower than their surrounding grid cells), the spill fills it before continuing down slope.

A spill path continues until it reaches a stream or other surface water feature or until the total spill volume is depleted by product losses.

Figure 1-10. Spill Path Spreading, Channeling, and Pooling



1.4.1.3. Over Land Product Losses

Product losses along spill paths are calculated using the following formula:

Total product losses = (adhesion and puddling losses + pooling losses) – evaporation losses

1.4.1.3.1. Adhesion and Puddling Losses

Some product flowing along a spill path is lost as it adheres to surface vegetation, rocks, and soil and as it puddles in small depressions. These losses are calculated using the following formula:

Adhesion and puddling losses = path length × path width × the adhesion thickness constant for the land cover type

The rate of adhesion and puddling losses depends primarily on the characteristics of the spilled product and of the land surface (e.g., land cover or slope).

1.4.1.3.2. Pooling Losses

Product lost to land surface pooling is the volume retained within depressions in the land elevation grid.

1.4.1.3.3. Evaporation Losses

The spill-modeling program can calculate evaporation loss rates based on surface area, spill thickness, and vapor pressure (a function of liquid composition, wind speed, air temperature, and land temperature). Due to the unpredictability of weather variables, such as wind speed, air temperature, and land temperature, and in order to account for a worst-case scenario, NuStar does not currently include evaporation losses in its spill model analysis used in the final HCA study.

1.4.1.4. Over Land Spill Velocity

The velocity of the leading edge of an over land spill is determined by the slope of the land surface using Manning's Equation:

$V = 1/n\ R^{2/3}\ S^{1/2}$			
Where	V	=	velocity
	n	=	a dimensionless number that characterizes the flow resistance
	R	=	hydraulic radius
	S	=	slope

Example: Assuming n is 0.05 and R is 0.122 m, V = 4.92 S1/2 (meter/sec).

1.4.2. Water Transport Analysis

Released product can spill into a surface water feature such as a stream, river, or lake in one of two ways.

- Directly—product is released into water at the spill location.
- Indirectly—product first flows over land before reaching water.

In either case, product that reaches a water feature travels downstream on the surface until product is completely lost to shoreline adhesion and evaporation or the emergency response time established has been met.

1.4.2.1. Water Transport Data Sources

The National Hydrography Dataset (nhd.usgs.gov) developed by the U.S. EPA and the U.S. Geological Survey was used to define the network of streams and lakes. The Enhanced River Reach File distributed by the U.S. Geological Survey defined stream velocities for water transport of the spilled product.

1.4.2.2. Watershed Vector Calculations

1.4.2.2.1. Product

The water transport modeling program, uses the following formula to calculate the watershed vector (the furthest downstream that the spill can reach):

Distance Traveled (ft) = Flow Velocity (ft/sec) × Response Time (sec)			
Where	Velocity	=	the current flow velocities of nearby waterways per reliable sources
	Response Time	=	the time to begin response activities, as documented in NuStar's Facility Response Plan; includes notification, mobilization and travel of identified response resources to the incident location

Product that reaches lakes or similar water bodies spreads out until it either reaches the minimum thickness needed to stop its spread (the default thickness is 1000 nanometers) or covers the entire surface and continues down any out-flowing streams at their surface current velocities.

1.4.2.2.2. Water-Soluble HVLs

Because anhydrous ammonia is water soluble, product containment in streams and rivers may not be attainable. For the purposes of this rule and HCA risk modeling, NuStar assumes that all waterways impacted via the overland spread analysis, could potentially affect an HCA. (See Section 1.6.2.3.)

1.4.2.3. Additional Water Transport Factors

Using the Material Safety Data Sheets (MSDS) for specific products (maintained by the Corporate HSE Group), NuStar considers the following additional factors in its water transport analysis:

- **Changes in Commodity Properties.** The compositions of most refined products—gasoline (all grades), jet fuel, diesel (both high- and low-sulfur), propane, butane, propylene, polypropylene, crude oil (both sour and sweet), gasoil, and kerosene—do not change as a result of interaction with the environment. Ammonia, however, is chemically altered by contact with water; NuStar addresses this alteration in its water transports analysis.
- **Commodity Solubility.** Most refined products have at maximum only trace solubility in water; however, ethanol and ammonia are soluble in water, which NuStar takes into account in its water transport analysis.
- **Abnormal Stream Conditions.** NuStar accounts for storm and flood conditions by making its water transport formula velocity equal to up to 125% of the current flow velocities of nearby waterways.
- **Subsurface Water Transport.** Because subsurface water will not typically spread further than surface water, NuStar concludes that its surface spill paths are sufficient to reasonably cover subsurface migration in excess of the surface transport potential already modeled.
- **Spray Releases.** NuStar accounts for any product spray releases in its spread analysis (overland spill paths are more than adequate to encompass spray).
- **Storm Drains/Sewers.** The above ground storm drains identified in the National Hydrology Datasets are modeled with streams and rivers. The below ground storm drains are not currently available for modeling; if they become available NuStar will incorporate them into its analysis. Usually, below ground storm drains reside in either an HPA or an OPA and therefore are encompassed in other HCA analysis methods. Also as a part of the procedure 101.2.Field Identification of Potential New HCAs, field personnel can notify the HCA Specialist of any storm drains that may transport product and impact an HCA.

1.4.3. Quality Checking Spill Modeling Results

Even with the best available data, missing and erroneous data do occur in the sources used to model over land and water transport flow. (Stream segments in a surface water network may flow upstream. Elevation rasters with erroneous data may be produced as artifacts of the data generation process.)

NuStar quality checks all spill modeling results for such errors before accepting any spill modeling results. When erroneous output is identified, NuStar determines the cause(s), corrects the errors, reruns the affected spills, and confirms the accuracy of the revised results.

1.5. Air Dispersion Analysis

NuStar had qualified vendors perform air dispersion analyses of its HVL pipelines to evaluate the potential impacts on HCAs and establish buffer zones around the pipelines. These analyses are summarized in the following reports:

- Model Predictions of Hypothetical Releases from the NuStar Central East Ammonia Pipeline System. RPS Applied Science Associates, 2015.
- Release and Dispersion Calculations for the Kaneb Propane Pipelines and Terminal Storage. Quest Consultants, Inc. 2004.

If new or reconfigured pipelines require fresh analyses in the future, NuStar will again work with qualified vendors to have these analyses performed.

1.6. Identification of Segments That Could Affect HCAs

1.6.1. Could-Affects for Product

1.6.1.1. Product Pipeline Could-Affects

For every liquid pipeline spill path or watershed vector that reaches an HCA, (see Section 1.4. Spill Modeling), its spill point and a portion of pipe on either side are classified as an HCA Could Affect segment (as shown in Figure 1-11 and Figure 1-12). The width of the segment is proportionate to the distance between spill points (e.g., given 100-foot spill point spacing, the HCA segment includes 50 feet of pipe on either side of the spill point in question).

Figure 1-11. Liquid Pipeline Could-Affects

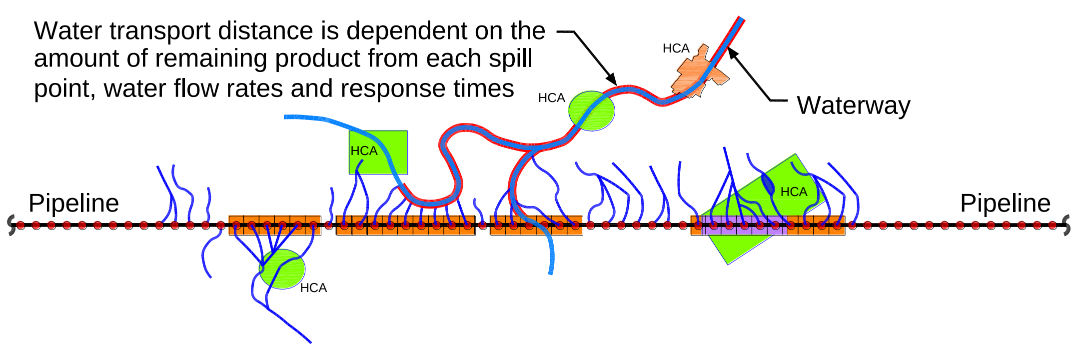
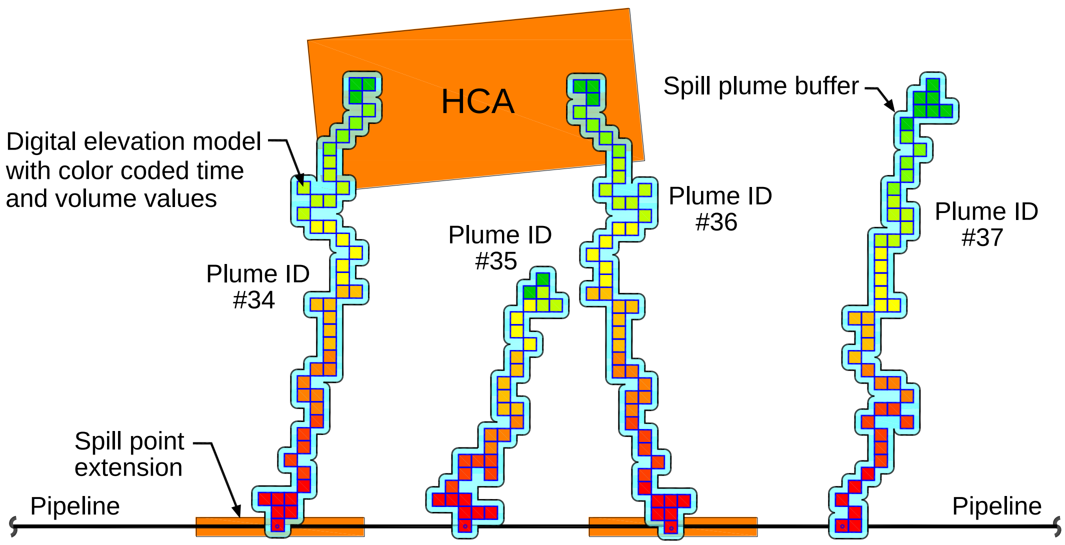


Figure 1-12. Liquid Pipeline Spill Path-HCA Intersections



1.6.1.2. Product Facility Could-Affects

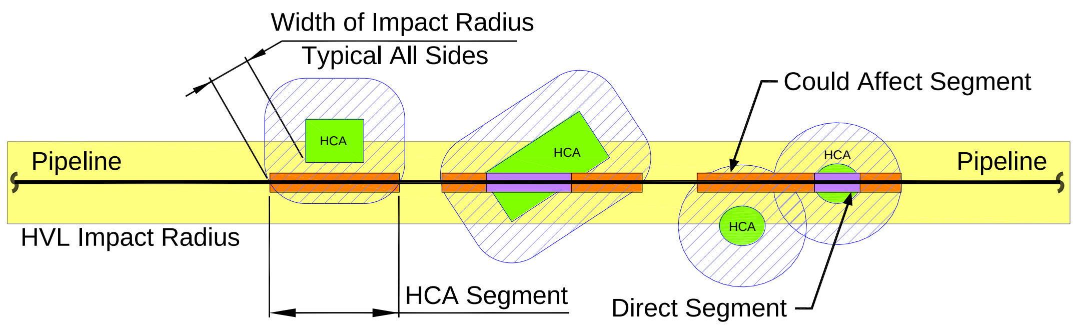
If a spill path or watershed vector from a product facility reaches an HCA, the entire facility is classified as an HCA Could Affect.

1.6.2. Could-Affects for HVLs

1.6.2.1. HVL Pipeline Could-Affects

When an HCA intersects an HVL pipeline buffer zone—as defined by the HVL Impact Radius (see Section 1.3.1. Release Locations)—the HCA itself is buffered by the defined buffer width, the intersection points with the pipeline are identified, and the resulting pipeline segment is classified as an HCA Could Affect segment (as shown in Figure 1-13).

Figure 1-13. HVL Pipeline Could-Affects



Note: For lines that transport anhydrous ammonia, the Drinking Water HCA is omitted in the HVL Impact Radius buffer analysis but is included in 1.6.2.3 Overland Spread Analysis for Anhydrous Ammonia Pipelines. For lines that transport Propane, the Drinking Water HCA is omitted.

1.6.2.2. HVL Facility Could-Affects

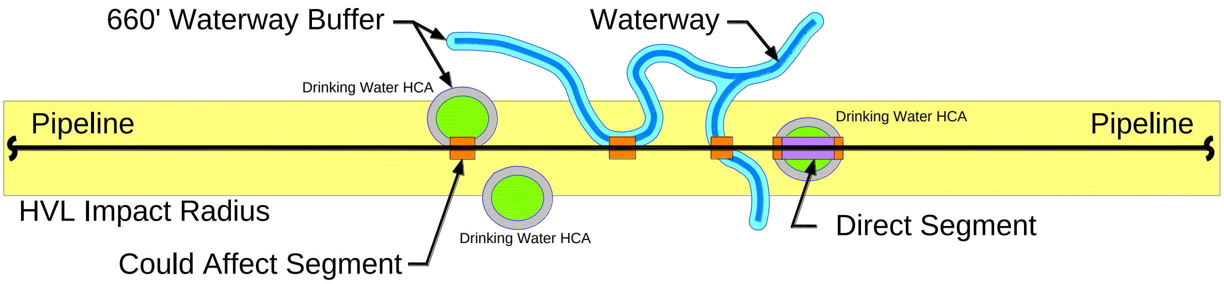
For HVL facilities, a spill radius equal to the pipeline buffer is produced at each spill release point. If any HCA intersects this buffer radius, the facility is classified as an HCA Could Affect facility.

1.6.2.3. Overland Spread Analysis for Anhydrous Ammonia Pipelines

NuStar uses a 660-ft buffer around all stream networks identified in the 1 in. = 1000 ft National Hydrology Dataset and Drinking Water HCAs. This distance is based on an historic ammonia leak, which traveled overland and through farm tiles to enter a stream.

Note: The presence of farm tiles extended the impact of this spill. On the surface, the spill would not have traveled this distance in a liquid form.

Figure 1-14. Overland Spread Analysis for Anhydrous Ammonia Pipelines

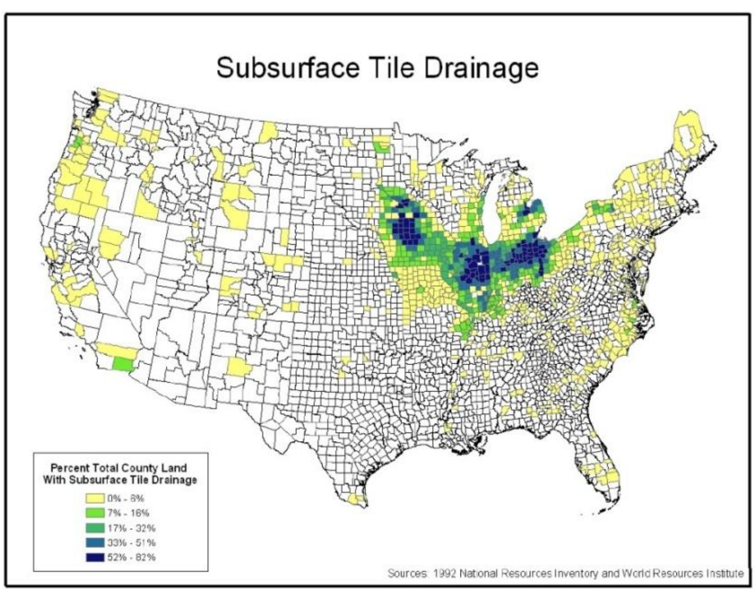


1.6.3. Drain Tiles

NuStar uses the national hydrology data sets to identify water features along the pipelines. The Company relies on its field identification process to identify new, man made drainage features along the pipeline right-of-way, which could act as a conduit to an HCA. NuStar will continue to use newer hydrology and digital elevation models to improve the accuracies of the HCA analysis process.

The overland spill spread analysis is conservative enough to cover the overland spread through farm tiles. NuStar's HCA analysis assumes that there is no evaporation or soil absorption, which could be up to 60% less volume than currently used. NuStar's use of the average flow rate of the fastest nearby river plus 25% to all identified streams and ditches is more than adequate to account for product spread through farm tiles. NuStar's pipelines in the states that have farm tiles are predominantly on the Ammonia System East Leg and Ammonia System West Leg. See Section 1.6.2.3. Overland Spread Analysis for Anhydrous Ammonia Pipelines.

Figure 1-15. Subsurface Tile Drainage Usage Map



1.7. HCA Updates and Revisions

1.7.1. Periodic HCA Reviews

1.7.1.1. Changes Requiring New HCA Analysis

At least once a year, the HCA Specialist checks for any HCA, pipeline, or technology/methodology changes to determine if any new HCA studies are required.

1.7.1.1.1. HCA Changes

The HCA Specialist checks the NPMS website (and possibly the other sources noted in Section 1.1.1., HCA Data from the National Pipeline Mapping System) for revised or updated HCA data to determine if any new or expanded HCAs now intersect or come near NuStar pipeline systems. NuStar HSE also monitors www.regulations.gov for notices of regulations, violations, advisories and other information..

The HCA Specialist also reviews any field identified HCA changes as discussed in Section 1.1.2., Field Identification of Potential New HCAs.

In accordance with the Rule, NuStar produces an assessment schedule for newly identified HCA segments within one year of their identification and completes any necessary baseline assessments within five years of identification.

1.7.1.1.2. Pipeline Changes

As major pipeline operational changes occur that can affect an HCA study—such as EFRD addition or removal, flow reversals, changes to MOP, etc.—an action item for a new HCA analysis is generated in the MOC process. The GIS department also communicates to the IMP team any major pipeline location corrections, product type conversions and operating status changes. Additionally, the HSE department notifies the IMP Team whenever pipeline jurisdictional changes affect IMP.

1.7.1.1.3. Technology/Methodology Changes

As part of its efforts to stay current with developments in IMP technology and methodology, NuStar incorporates improvements in HCA identification methods and software into its HCA analyses in order to produce the most accurate HCA segments possible.

1.7.1.2. Updated HCA Segments

The HCA Specialist performs new HCA studies as needed based on updated data and/or methods. If any study results in new or altered HCA segments, the changes are saved in NuStar's GIS system and become available for viewing via NuStar's online mapping system.

Note: NuStar will never shorten or modify any pipeline HCA segment solely to avoid making repairs.

1.7.2. Other HCA Reviews

In addition to its periodic HCA reviews, NuStar may need to perform new HCA studies on idle lines or on newly constructed or acquired lines.

1.7.2.1. Idle Lines

The Rule recognizes pipelines as either active (in operation on a regular basis) or abandoned (disconnected, purged, and sealed; no longer an asset). Active pipelines not currently in use but that could be put back into use in the future are considered idle. Idle lines are defined as either in-service idle (containing hazardous liquids but currently static or unused) or out-of-service idle (effectively isolated from active pipe and containing water or inert gas). NuStar includes out-of-service idle pipelines in its analysis of direct HCA intersects. If, however, NuStar decides to put an idle line back into service, NuStar will reanalyze both direct HCA intersections and Could Affect data for that line segment prior to placing the pipeline back into service.

1.7.2.2. New or Acquired Lines

As new pipelines are constructed, converted, or acquired, the HCA Specialist evaluates the appropriate segments in accordance with the procedures outlined in this section to determine if they could affect HCAs. The HCA Specialist will conduct this evaluation prior to the pipeline going into service.

1.7.2.3. Bio-Fuels

NuStar performs the required HCA analysis based on the specific product composition. For example, bio products which are water-soluble are evaluated differently from the non-water-soluble bio products with respect to their spill and migration characteristics.

1.7.2.4. Rural Onshore Hazardous Liquid Gathering Lines and Low-stress Lines

Per federal regulation §195.11, which covers rural gathering lines, and §195.12, which covers rural low-stress pipe, a buffer zone is applied to all USAs (¼ mile for gathering lines and ½ mile for low-stress lines). Any segment of pipe that meets the criteria outlined in Table 1-1 is considered regulated. Any pipe determined to be low-stress Category 1 or 2 pipe will be incorporated into NuStar's IMP plan.

Table 1-1. Criteria for Rural Onshore Gathering or Low-stress Pipe

Rural Onshore Pipe Type	Nominal Diameter	Proximity to USA	MOP (psig)	§195.452 Required
Gathering	6 or 8 in	<= ¼ mi	>20% SMYS, or (>125 psig, if stress level unknown)	No
Low-stress Category 1	8" or more	<= ½ mi	<=20% SMYS, or <=125 psig, if stress level unknown	Yes
Low-stress Category 2	< 8"	<= ½ mi	<=20% SMYS, or (<=125 psig, if stress level unknown)	Yes

1.8. Communication of New or Changed HCAs

NuStar communicates newly identified HCAs to employees via an annual email to regional managers with a mileage report representing the previous year's HCA changes. This report is also available on the IMP web site.

HCA analyses are preformed throughout the year and the resulting changes are available on NuStar's NuGIS Web Map Viewer within 24 hours. Additionally, the results of an HCA analysis performed in response to operational changes are part of the MOC closeout communication.

Any new HCA analysis that is required, due to software enhancements or methodology changes, will be communicated to the IMP team..

1.9. Timely Completion of Segment Identification

NuStar has met the required time limit for segment identification as required by the Rule. NuStar identified these segments for pipelines prior to the December 31, 2001, compliance date for Category 1 pipelines.

For Category 3 pipelines, NuStar completes segment identification prior to the date pipeline begins operation.

1.10. Exclusion of Identified HCA Segments

Once NuStar has identified pipeline segments and facilities that directly or indirectly affect an HCA, it does not typically attempt to exclude any pipeline or facility; that is, NuStar does not typically attempt to prove that the pipeline or facility could not affect an HCA despite its location within or near an HCA.

(Should NuStar choose to prove that a direct HCA intersect could never affect a particular HCA, it will perform a supplemental detailed analysis and document the technical justification for that conclusion. Such an analysis would include consideration of HVL properties, topographical data, and HCA properties.)

101: HCA Segment Identification

Introduction

The Department of Transportation (DOT) has specific regulations requiring an operator to identify any segment that directly intersects, or could affect a high consequence area (HCA). NuStar classifies HCAs as populated areas, unusually sensitive areas (USA), and commercially navigable waterways (CNW).

Regulation

49 CFR §195.452 (f) An operator must include, at minimum, in each written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.

49 CFR §195.452 (d) (3) Newly-identified areas. (i) When information is available from the information analysis (see paragraph (g) of this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in §195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified.

Scope

This procedure applies to all jurisdictional liquid pipeline systems and breakout tanks operated by NuStar.

Resources

National Pipeline Mapping System (NPMS) HCA data

State network ecological data

Operational and pipeline/facility data

Oilmap Land

Intrepid

LVR Model in IMP 6

AutoCAD

GIS

Air Dispersion Analysis Report

ASA software

High Consequence Area Identification and Analysis Procedure Manual

101.1. Periodic Check for Updated HCA Boundaries (NuGIS Aerials)

1A	**[HCA Specialist]** At least once a year, check HCA data sources for updated HCA boundaries, including but not limited to the sources below. **Note:** Newly identified HCAs must be incorporated into the IMP within one year of identification.	
	1	Check NPMS (and possibly also the sources below) for updated populated areas data (usually updated every 10 years). • NuGis−Bing and Google Earth source data • U.S. Census Bureau maps • Information analysis of One Call tickets and the results of Right-of-Way patrols • Aerial photography
	2	Check NPMS (and possibly also state agencies if needed) for updated USA data—drinking water and Environmentally Sensitive Areas.
	3	Check NPMS (and possibly also the sources below) for updated data regarding commercially navigable waterways. • NuGis−Bing and Google Earth source data • The Geographic Database (http://www.bts.gov) • The Bureau of Transportation Statistics database (http://www.bts.gov)
	4	Gather other data that could affect or change the pre-defined HCAs.
1B	Follow 101.2,. Field Identification of Potential New HCAs.	
1C	Continue with either: • 101.3., HCA Identification for Pipelines • 101.4., HCA Identification for Breakout Tank Facilities	

101.2. Field Identification of Potential New HCAs

2A	**[Field Personnel]** As part of daily operations, note the following indications of potential new HCAs: • New schools, hospitals, churches, malls, stadiums, parks, and other civic structures and congregation places • New or expanded housing subdivisions and/or mobile home parks • New significant drainage features (e.g., manmade lakes, drain tiles, storm drainage areas, crossings of roadways with ditches)	
2B	Email the HCA Specialist with the following information about the potential new HCAs: • Location data (e.g., nearest town/city, GPS, station numbers, mileposts, driving directions) • Description of changes that may indicate a new or expanded HCA • Reason(s) for concern Note: Field Identification may also be discussed during P&M Measures Meetings to consider new information relayed to the HCA Specialist via the P&M Coordinator.	
2C	**[HCA Specialist]** Classify the potential new HCAs, either as valid new HCAs, or as non-HCA areas of concern.	
	1	For valid new HCAs, integrate them into GIS. Refer to the High Consequence Area Identification and Analysis Procedure Manual for the current process.
	2	For non-HCA areas of concern, record the from/to stationing, and a brief explanation for the exclusion on the HCA Revision Summary.
2D	Maintain a log of field-identified potential new HCAs, with outcomes noted.	

101.3. HCA Identification for Pipelines

3A			**[HCA Specialist]** Identify EFRDs.
	1		Identify all Station Suction Valve Motorized (SSVM) and Station Discharge Valve Motorized (SDVM) in SAP equipment list for all pipelines.
		a	Add these valves as EFRDs in Intrepid using the RTV stationing for SSVMs and the LTV for SDVMs.
	2		Change all MOVs listed as isolation valves to EFRDs.
3B	1		If the pipeline transports HVL, follow 101.5., Air Dispersion Analysis and HVL Impact Radius Calculations, before skipping to Step 3F.
	2		If the pipeline transports product, continue with Step 3C.
3C			If no pipeline profile data exists, open the Oilmap Land program and select the Create Profile tab.
	1		Click on the pipeline centerline to select it.
	2		Select the digital elevation model (30m, 10m, etc.) and enter 100 ft for the Output Interval.
	3		Select the location for the output point shape file and click OK to save the pipeline profile.
3D			Perform drain down calculations.
	1		Validate that all EFRDs and profile data are populated in Intrepid.
	2		Follow 101.6., Determination of Leak Detection and Isolation Time.
	3		Run the AI export for the primary testable segment, including any secondary testable segment required because of EFRD valve locations.
	4		Run the drain down model for the primary testable segment. **Note:** The model will generate spill points with volumes along the centerline every 100 ft stationing.
	5		Generate the Intrepid import spreadsheet for only the primary testable segment.
	6		Import the spreadsheet into Intrepid and format it for the final HCA report.
3E			Follow 101.7., Spill Spread Analysis.
3F			Follow 101.8., HCA Analysis for the pipeline (HVL or product), analyzing, and correcting any errors.
3G			Follow 101.9., Final Documentation and Notification for the pipeline.

101.4. HCA Identification for Breakout Tank Facilities

4A		**[HCA Specialist]** For new breakout tank facilities—or for tanks that meets the Part 195 definition of a breakout tank but have not been previously identified as such—locate or create an AutoCAD plot plan drawing for the facility. **Note:** This drawing needs to identify the breakout tanks and all regulated piping to and from the breakout tanks.
4B		Follow 101.4. Field Identification of Potential New HCAs.
4C		Generate a breakout tank spreadsheet for the facility and record all drain down volumes and pipeline shutdown times.
	1	Gather breakout tank data (size, volumes, location, in/out flow rates etc.).
	2	Follow 101.6. Determination of Leak Detection and Isolation Time.
	3	Gather flow rates and volumes, bbls/day for all associated piping.
	4	From the plot plan, determine the pipeline drain down volumes going from/to each breakout tank.
4D		Determine the spill points around the breakout tanks and piping that could have the greatest potential to impact to an HCA and note on the plot plan drawing. **Note:** Tank dikes are considered in liquid spill analysis. If the drain down volumes are less that the capacity of the tank dikes, only piping outside of dike will have liquid spill analysis preformed. The SPCC Plan validates that the tank dikes are capable of containing the greater of the two situations: 110% of the largest tank dike or the largest tank + the largest 25-year, 24-hour rainfall.
	1	Define all drainage features, including storm drains, oil water separators, farm tiles, etc., that could act as a conduit for product transport.

4E	1	If the facility holds HVL, follow 101.5. Air Dispersion Analysis and HVL Impact Radius Calculations.
	2	If the facility holds product, follow 101.7. Spill Spread Analysis.
4F	Follow 101.8., HCA Analysis, for the facility, analyzing and correcting any errors.	
4G	Follow 101.9., Final Documentation and Notification, for the facility.	

101.5. Air Dispersion Analysis and HVL Impact Radius Calculations

5A	**[HCA Specialist]** If the HVL being shipped is “like in kind” to other HVLs currently being shipped, review the Air Dispersion analysis used for that particular HVL.	
	1	If the previously established HVL impact radius is independent of discharge volume, use the predefined HVL impact radius and skip the remaining 101.5 steps.
	2	If the previously established HVL impact radius is dependent on discharge volume, continue with Step 5B.
5B	If the predefined HVL impact radius cannot be used, provide the necessary information (either pipeline centerline and statistics or facility data) to a qualified vendor that specializes in air dispersion modeling.	
5C	**[Air Dispersion Vendor]** Complete an air dispersion analysis and submit a report to the HCA Specialist that recommends an impact radius representing the worst case scenario.	
5D	**[HCA Specialist]** Review the Air Dispersion Analysis Report, working with the vendor to resolve any issues before accepting the final report and its recommended impact radius.	

101.6. Determination of Leak Detection and Isolation Time

6A	**[Risk Specialist/Control Center Manager]** Determine the time it takes operators and/or controllers to detect a leak. • For lines with locally or centrally SCADA monitored leak detection, this is the time needed to recognize and process the status change to determine that a release has occurred. • For lines without SCADA leak detection, this is the time needed to visually recognize that a release has occurred (either time between patrols or a shorter time if the line is being continuously monitored during operation).
6B	Determine the time it takes to shut down pumps and/or valves. • For lines with remote actuated pumps and/or valves, this is the time needed for the signal to reach the equipment, and for it to be actuated. • For lines without remote actuated pumps or valves, this is the time needed to dispatch personnel to manually shut down the pump and/or actuate the valve.
6C	Add these two times together to determine the total leak detection and isolation time.

101.7. Spill Spread Analysis

7A	**[HCA Specialist]** Generate spill paths using ASA software and the digital elevation model best suited for the analysis (30m, 10m, etc.).	
7B	Correct any errors in water transport direction.	
	1	Select the Editor Tool and the stream that needs editing.
	2	With the stream selected, right click to select Attributes.
	3	Correct the COM_ID_2 property to match the correct next downstream ID and click Save Edits.
7C	In areas where drain tiles are known to be present, determine whether the spill path could reasonably be expected to encounter a nearby water network and stretch the path accordingly.	
7D	Save spill shape files and corresponding data in Intrepid.	

101.8. HCA Analysis

8A	**[Risk Specialist]** Perform a drain down analysis using the LVR model in the IMP risk software.	
8B	**[HCA Specialist]** Import drain down analysis data into the GIS database.	
8C	Export the spill point shape file from the database into the spill modeling software.	
8D	Perform the over land spill path and water transport analyses using the spill modeling software.	
	1	Validate analysis results, eliminating any errors.
8E	Export spill analysis results from the spill modeling software to Intrepid.	
8F	Perform direct/indirect HCA impact analysis in Intrepid.	
8G	Notify the IMP Team that the HCA impact analysis is completed.	
	1	As needed, generate current HCA query reports out of GIS.

101.9. Final Documentation and Notification

9A	**[HCA Specialist]** Generate the following HCA Analysis reports: • Overall HCA Summary • Direct HCA Intersections • HCA Could Affects (over land, water transport, and if applicable, air dispersion)
9B	Import HCA data to the GIS database for use in reporting and viewing via GIS mapping systems.

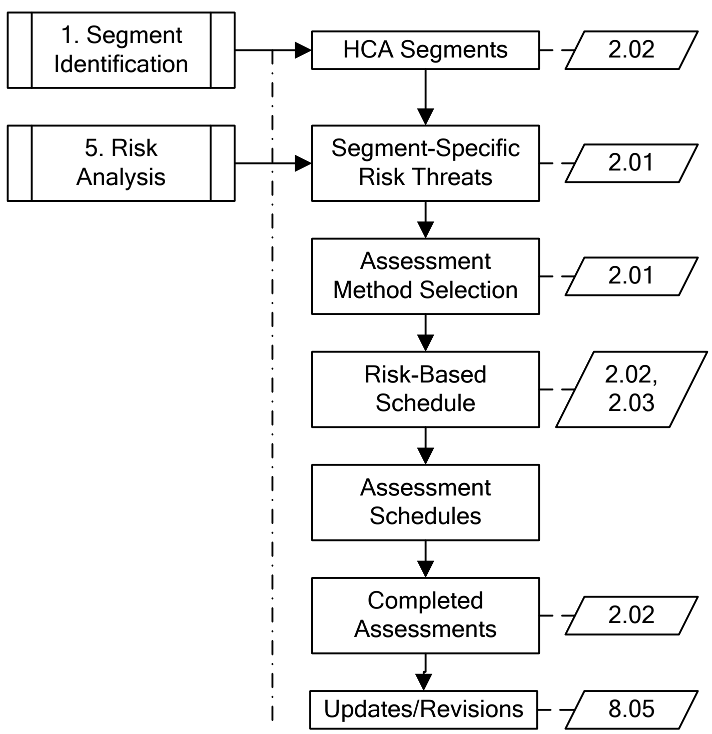
2: Baseline Assessment Plan

As illustrated in Figure 2-1, the Baseline Assessment Plan (BAP) identifies the integrity assessment method(s) for each pipeline segment that can affect a High Consequence Area (HCA). It also records the schedule of when NuStar planned each assessment. For Category 1 pipe, the BAP included all segments owned and operated between January 2, 2002 and March 31, 2008, in which operations potentially impacted an HCA. The baseline and current assessment schedules meet the following requirements:

- Includes all DOT and state jurisdictional pipeline segments that can affect an HCA
- Uses risk rankings to prioritize assessment scheduling
- Provides a risk based assessment schedule for each segment to meet regulatory deadlines
- Specifies the integrity assessment method(s) for each segment, and explains the technical basis for the integrity assessment method(s) selection

For Category 3 pipe—pipelines constructed or converted after May 29, 2001—NuStar performs a baseline assessment prior to the date the pipeline begins operation.

Figure 2-1. Baseline Assessment Plan Flowchart



2.1. HCA Segments

To create the baseline schedule, the HCA Specialist determined which HCAs could be impacted by the operation of all pipelines operated by NuStar. Section 1, Segment Identification, outlines NuStar's formalized process for identifying HCAs. A list detailing each HCA to the testable segment appears in the IMP HCA Report (on the IMP Intranet). Once NuStar identified and scheduled all HCA segments for assessment, it documented them in the Baseline Assessment Schedule.

2.2. Segment-Specific Integrity Threats

NuStar performs a risk analysis, as outlined in Section 5, Risk Analysis, to help identify specific risk threats for each HCA segment, and incorporates the results from the risk analysis with other data to determine which risk threats apply to each HCA segment. Once it completes the initial baseline, NuStar uses the risk results to re-evaluate these risk threats and their relevance to the condition of pipeline integrity.

2.2.1. Corrosion (COR) and Deformation (DEF)

NuStar recognizes corrosion and third-party damage as continual risk threats to all HCA segments. When in-line inspection (ILI) is selected as an assessment method, NuStar uses both the DEF and COR tools for each piggable segment to address these specific risk threats.

2.2.2. Stress Corrosion Cracking (SCC)

NuStar conducts an initial screening of its systems to identify segments where SCC is a potential specific risk factor (PRF), independent of whether such segments could affect an HCA. This process uses logic decisions based on pipeline conditions and environmental attributes that have been documented as being linked to SCC in industry studies, as well as a Kiefner & Associates study done specifically for NuStar.

When NuStar applies the criteria to the screening process, it uses the susceptibility levels of High, Moderate, Low, SCC Not Expected, and Not a PRF, to indicate the need for further investigation. Appendix I, SCC Management Plan, details this screening process and presents additional information for investigating areas susceptible to SCC.

2.2.3. Longitudinal Seams

IMP Procedure 201, Identifying Low-Frequency Longitudinal Seams, details NuStar's process for determining susceptibility, assessment intervals, and type of seam for pipe of unknown seam type. NuStar records susceptibility attributes for all segments identified as susceptible in the pipeline integrity database.

Currently, NuStar adheres to the information provided in the *OPS TT05—Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation* (found on the IMP Intranet) to determine how to handle Low-Frequency ERW and lap-welded pipe. This paper provided insight on the potential of time dependent seam failures on Low–Frequency ERW and longitudinal lap-welded pipe. NuStar developed a screening tool based on Section 4.3 of *OPS TT05*. This screening tool looks at the failure history, prior hydrostatic test, and operating stress to determine whether a Low–Frequency ERW or lap-welded seam pipe is susceptible to seam failure.

Note: This process considers all seam failure modes (preferential corrosion, hook cracks, etc.). If the conditions listed in Procedure 201.3.3A are satisfied, NuStar may accept a pipe as not susceptible to seam failure, without any further evaluations or tests. In all other cases, the screening analysis results in the need to perform an engineering analysis.

For pipe with longitudinal seam of unknown type or vintage, NuStar may send a sample to an independent mechanical testing laboratory for metallurgical analysis to determine the seam type

2.3. Assessment Method Selection

IMP Procedure 202, Integrity Assessment Selection, establishes the formal process for selecting assessment methods. When using an ILI assessment method, the specific ILI tool type selected is dependent on the type of threat being assessed. Descriptions of all assessment methods currently being considered, and a table of the threats each type of tool is capable of assessing, appear in Appendix D, Anomaly Types, Detection Tools, and Assessment Methods.

If in-line inspection is unreasonable or is not the preferred assessment method, NuStar may perform a pressure test, in accordance with O&M Procedure 609, Pipeline Hydrostatic Testing. If NuStar plans to use Other Technology (such as those described in IMP Procedure 304, Guided Wave Ultrasonic Testing, or IMP Procedure 305, Direct Examination), it submits notification to PHMSA at least 90 days prior to performing the assessment.

2.4. Risk Based Schedule

NuStar's current version of the Assessment Schedule includes total mileage, a comprehensive schedule, a yearly schedule, assessment scheduled dates, assessment completed dates, and assessment methods used for NuStar's pipelines. The Assessment Schedule sets the projected schedule, and annually addresses the pipeline segments needing assessment. The current Assessment Schedule appears on the IMP network drive, and in the pipeline integrity database.

2.4.1. Schedule Requirements

As required by the Rule, NuStar, a Category 1 pipeline operator, completed all baseline assessments for pipeline segments that could affect HCAs by March 31, 2008. NuStar assessed at least 50% of the line pipe affecting HCAs by September 30, 2004, beginning with the highest risk segments.

Pipelines constructed or converted after May 29, 2001, are subject to the schedule requirements of Category 3 pipelines; that is if a Category 3 pipeline segment could affect an HCA, then the rule requires a baseline assessment before the pipeline begins operation.

For Category 1 operators, the Rule also requires that any prior pipeline assessment used as a baseline assessment, must have been performed after January 1, 1996, and must meet the requirements of the Rule. Prior assessments include those in-line inspections or hydrostatic pressure tests that were conducted between January 1, 1996, and May 29, 2001. If NuStar uses a prior assessment to satisfy the baseline assessment requirement of the HCA rule, then it must reassess the pipeline within 5 years—not to exceed 68 months—of the baseline assessment, per the Rule *§(j)(3)*. Additionally, prior assessments must meet the Rule's requirements.

For example, if NuStar only ran a COR tool in the prior assessment, then it must run a DEF tool for it to consider the assessment complete, once all potential dent indications are excavated and examined. In this case, NuStar will consider the date of the earlier COR run as the effective date of the prior assessment.

If NuStar decides to declare that it will use a prior assessment as the baseline assessment for the purposes of satisfying the Rule *§(c)(1)*, then it must review the results of the prior assessment to determine if there are any anomalies meeting the criteria described in the Rule *§(h)(4)*, that NuStar has not already remediated. After NuStar has addressed any anomalies that it discovered, the time frames for remediation established in *§(h)(4)* apply. NuStar must make the determination of what anomalies need remediation no less than 180 days after it has declared the assessment as its baseline assessment.

2.4.2. Risk Application

In 2003, legacy NuStar updated the original risk analysis to assign risk to individual HCA segments, as opposed to operational segments of the original analysis. It then organized the testable segments based on the highest risk HCA contained within the testable segment, and scheduled the higher risk segments remaining in the initial baseline for earliest completion dates.

Since the establishment of NuStar's initial BAP, it acquired the former Kaneb Systems. Kaneb originally established schedules for its BAP that prioritized assessment segments identified through the identification process outlined in Section 1.4, Identification Process in the former Kaneb's *Integrity Management Plan*. The schedules for the Refined Products and Ammonia Systems are based on risk factors that reflect risk conditions for the pipeline segments, including the risk factors listed in Section 2.3, Element 3—Prioritization Risk Factors of the former Kaneb's *Integrity Management Plan*.

During its Preventative and Mitigative (P&M) Measures process, NuStar performs data integration of integrity assessments, risk analysis, and continual evaluations to determine the reassessment interval of each testable segment. Such reviews may result in a shorter interval or a change in assessment method or technology. See Section 6.2.1, Reassessment Intervals, for a list of risk factors considered. NuStar currently chooses to keep its standard reassessment interval at a maximum of five years, not to exceed 68 months.

NuStar's current risk analysis software considers the risk factors contained in *49 CFR §195 Subpart E,* and is described in detail in Section 5, Risk Analysis. NuStar will analyze all future risk analyses for the legacy

NuStar systems, the former Kaneb Systems, and any other acquired or constructed systems using this software.

2.5. Assessment Schedules

IMP Procedure 203, Assessment Scheduling, demonstrates the formal process for developing an assessment schedule. This procedure details the process of integrating input from the Assessment Engineer, the Assessment Project Manager, the Risk Engineer, the Operations Director/Maintenance Manager, and the ILI Service Provider, to create an annual quarterly schedule.

As discussed in IMP Procedure 601, P&M Meetings, NuStar determines the reassessment intervals of HCA pipeline segments during its P&M process. Currently, NuStar does not intend to exceed a five year reassessment interval.

2.6. Completed Assessments

NuStar has developed the pipeline integrity database to document both baseline assessment schedules, and reassessment schedules. NuStar has documented formal processes, as explained below, for verifying that assessments are completed for in-line inspection, hydrostatic testing, and GWUT. Communication between the Assessment Project Manager and Operations/Maintenance Personnel precedes these processes as the scheduled dates come up. NuStar documents the total pipeline mileage, and the mileage completed that could affect HCAs in the pipeline integrity database.

Note: In the event of a failed tool run, the availability of the pipeline and/or tool may prohibit the completion of the tool run within the assigned quarter. Once the pipeline and/or tool is available, the Assessment Engineer will update the Assessment Schedule, and the pipeline integrity database with the new assessment date, while ensuring that NuStar remains within all regulatory deadlines (as shown in Section 7.2.1, Engineering Justification).

2.6.1. In-Line Inspection

The date on which an assessment is considered complete, will be the date on which final field activities related to that assessment are performed, not including repair activities.

For ILI, this date is when the last in-line inspection tool run of an integrated set of tool runs is performed. NuStar considers final field activities complete when the last tool is received into the receiver.

Once these field activities are complete, the ILI Service Provider provides in-line inspection documentation to NuStar in two steps. First, the ILI Service Provider sends a periodic activity report to inform NuStar of completed assessments for tracking purposes. The Assessment Engineer compares the completion dates provided in the report, with the scheduled dates in the Assessment Schedule, and the pipeline integrity database to verify that the assessments were completed as scheduled. Lastly, NuStar checks the dates from the report with the dates provided by the ILI Service Provider in the Final Inspection Survey Report. The date recorded in the Assessment Schedule and the pipeline integrity database, is the date the assessment is complete. The ILI Service Provider presents this information to NuStar in the report.

2.6.2. Hydrostatic Testing

For hydrostatic tests, NuStar considers the date of completion as the date on which all final field activities related to that assessment are performed, not including repair activities.

The Regional Technical Services Personnel receive all hydrostatic test documentation for tracking, and final disposition, as described in O&M Procedure 609, Pipeline Hydrostatic Testing. If appropriate, the Assessment Engineer documents completion dates in the Assessment Schedule, and the pipeline integrity database with the dates provided in the hydrostatic test documentation. All hydrostatic test assessments are subject to a cathodic protection review and Close Interval Survey (CIS), as outlined in *Corrosion Control Manual,* Section 5.4.5.

2.6.3. Guided Wave Ultrasonic Testing

For GWUT, NuStar considers the date of completion as the date on which final field activities related to that assessment are performed, not including repair activities. This is the date when the last validation is performed for each GWUT Group, as defined in IMP Procedure 304.9.

The Assessment Engineer receives all GWUT test documentation for tracking and final disposition, as described in IMP Procedure 304. If appropriate, the Assessment Engineer documents completion dates in the Assessment Schedule, and the pipeline integrity database with the dates provided in the documentation.

2.7. Updates and Revisions

NuStar's pipeline integrity database captures all changes to the assessment schedule, including the following:

- Date
- Pipeline system
- Pipeline segment
- Assessment schedule modification
- Justification for modification (including removing segments from the Assessment Schedule)

The Assessment Engineer obtains and archives this information on a yearly basis, and maintains the document in the IMP network drive and Intranet. Appendix E, Documentation and References, lists the retention periods for documentation generated, as the result of the Assessment Schedule.

2.7.1. Newly Identified Areas

In accordance with the Rule, NuStar classifies new HCAs as such in the IMP Assessment Schedule within one year of their identification. NuStar also completes any necessary baseline assessments of affected pipelines within five years of identification.

201: Identifying Low Frequency Longitudinal Seams

Introduction

DOT regulations require all pipeline operators to validate the integrity of all in-service pipelines. Several threats exist that challenge the integrity of carbon steel constructed lines. One phenomenon is longitudinal seam failure caused by pressure fatigue cycles. Pipelines constructed before 1979 with low frequency electric resistance weld (ERW) are susceptible to this phenomenon.

Regulation

49 CFR §195.452 (c)(1)(i) The methods an operator selects to assess low frequency electric resistance welded pipe or lap-welded pipe susceptible to longitudinal seam failure, must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar.

Resources

Pipeline integrity database

Longitudinal Seam Susceptible Segments

OPS TTO5—Low Frequency ERW and Lap-Welded Longitudinal Seam Evaluation

Table C-5, Past Manufacturers of ERW Pipe in *History of Line Pipe Manufacturing in North America*

201.1. Gather Information on Pipeline Systems

1A	1		**[Risk Engineer]** Identify pipeline segments constructed before 1979 or at an unknown date.
		a	Review published data in NuStar's pipeline database GIS system for date in service.
		b	Consult alignment sheets or interview the appropriate personnel.
	2		Identify mill manufacturer information for pipeline segments.
		a	Review published data in NuStar's pipeline database GIS system for mill manufacturer information.
		b	Review actual mill test reports in Regional HSE permanent files.
1B	1		Cross-reference this information with *History of Line Pipe Manufacturing in North America* Table C-5: Past Manufacturers of ERW Pipe, which includes information on the mill welding process.
	2		Use pipeline manufacturer, pipe size, and manufacturer date to identify the welds as high or low frequency ERW seam type.
	3		If mill manufacturer information cannot be located or Table C-5 does not list the mill welding process, have Operations/Maintenance Personnel send samples to engineering firm for a material properties test per section 201.2 Perform Seam Analysis.
1C	Record seam attribute in the pipeline integrity database (NuPASS) for all pipeline segments identified as pre-1979 low frequency ERW seam pipe and lap welded seam pipe.		

201.2. Perform Seam Analysis

2A	**[Risk Engineer]** Contract with an independent mechanical testing laboratory to perform a seam analysis on unknown longitudinal seam pipe with an install date prior to 1979.
2B	Provide the following pipe sample background information: • Line Name and/or System Name • Nominal Outside Diameter • Nominal Wall Thickness • Pipe Grade • MOP • Pipe Seam Type • Pipe Manufacturer • Product • Year of Installation • Coating Type • Pipe Sample approximate GIS Stationing • Pipe Sample Joint Number and approximate ODO from last ILI log • Pipe Sample Latitude and Longitude
2C	Request for a material properties test that identifies all tensile properties for the pipe sample, including: • Seam type and process • Chemical Composition • Hardness Measurements • Yield Strength Tensile Strength • % Elongation • Charpy Impact Test • Microhardness Measurements
2D	Submit a Seam Analysis Report documenting the seam type and process for the pipe sample.
2E	Record seam attribute in the pipeline integrity database (NuPASS) for pipe sample.

201.3. Initial Seam Susceptibility Screening

3A	**[Risk Engineer]** Perform initial seam susceptibility screening for all pipeline segments identified as pre-1979 low frequency ERW seam pipe and lap welded seam pipe.	
	1	Per *OPS TT05—Low Frequency ERW and Lap-Welded Longitudinal Seam Evaluation*, consider low frequency ERW seam pipe as not susceptible to seam failure if the following applies: • It operates at a hoop stress with MOP less than or equal to 30% of SMYS.
	2	Per *OPS TT05—Low Frequency ERW and Lap-Welded Longitudinal Seam Evaluation*, consider lap-welded seam pipe as not susceptible to seam failure if all three of the following apply: • No prior seam failure history is known or suspected • It is hydrostatically tested to 125% or greater of MOP • It operates at a hoop stress with MOP less than or equal to 30% of SMYS.
3B	Record susceptibility attributes in the pipeline integrity database (NuPASS) for all pipeline segments identified as not susceptible to seam failure.	

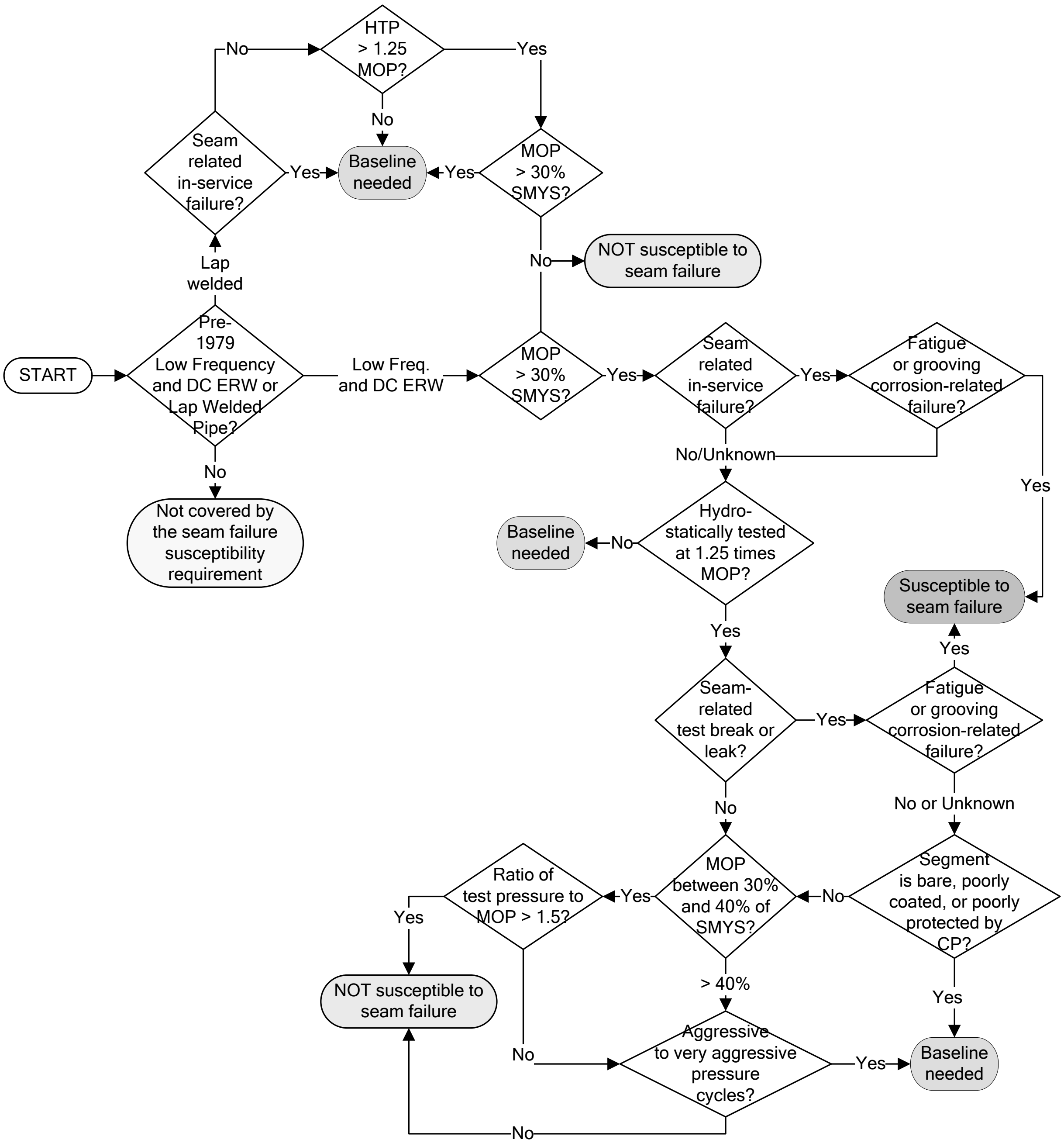
201.4. Perform Pressure Cycle Analysis

4A	**[Risk Engineer]** Use NuStar's Macro-based spreadsheet tools to estimate failure pressures for identified crack-like features (from UT ILI Inspection). Utilize the tools to establish the pressure cycling severity level for the pipeline segment. Conduct fatigue life analysis based on fracture mechanics principles for all remaining flaws. Integrate data to determine reassessment interval. (Note: from time to time, it may be necessary for the IMP Team to utilize an outside engineering contractor to perform Pressure Cycle Analysis to meet backlog or scheduling requirements. Contractor shall provide analysis that is consistent with NuStar procedures.)
4B	Collect the following information: • hydrostatic test documents that outline - date of previous hydrostatic test - test pressure throughout the test - all test failures and failure pressures • ILI seam assessment documents (if applicable) that outline - tool tolerances - any seam anomalies that did not repair criteria • comprehensive operating pressure data for a year • a detailed elevation profile with pump stations marked • pipeline product • pipeline specifications **Note:** Collect as much information on test failures as possible so the information can be included (e.g., failure on seam, failure caused from corrosion, failure pressure, etc.) in the study.
4C	Submit a Pressure Cycle Analysis Report outlining susceptibility and the remaining time-to-failure of flaws surviving pervious seam assessment.
4D	Incorporate all results into the Assessment Schedule.
	Note: Consider changes in pressure cycle severity when incorporating results into the Assessment Schedule.
4E	Archive Seam Analysis Report on IMP share drive.

201.5. Identify Seam Susceptibility

5A	**[Risk Engineer]** Follow the longitudinal seam identification process for all segments with potential seam susceptibility as illustrated in Figure 201-1 from *OPS TT05—Low Frequency ERW and Lap-Welded Longitudinal Seam Evaluation*. **Note:** This process considers all seam failure modes (preferential corrosion, hook cracks, etc.).
5B	Record susceptibility attributes per Figure 201-1 in the pipeline integrity database (NuPASS).
5C	Incorporate final results into the Longitudinal Seam Susceptible Segments List.

Figure 201-1. Determining Susceptibility of ERW and Lap Welded Pipe to Longitudinal Seam Failure



202: Integrity Assessment Selection

Introduction

DOT regulations require operators to assess the integrity of the pipeline using one or a combination of the following methods: internal inspection tools, pressure tests, and other technology. NuStar uses these methods to assess the following risk factors:

- Corrosion and deformation
- Stress corrosion cracking (SCC)
- Longitudinal seam failure
- Other pipeline risk factors

Regulation

49 CFR §195.452 (c) What must be in the baseline assessment plan? (1) An operator must include each of the following elements in its written baseline assessment plan: (i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(A) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;

(B) Pressure test conducted in accordance with subpart E of this part; or

(C) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section…

(iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar.

Resources

Section 4: Remedial Action

Appendix D: Anomaly Types, Detection Tools, and Assessment Methods

Pipeline integrity database

O&M Procedure 609: Pipeline Hydrostatic Testing

202.1. Assessment Planning

1A	1	**[Assessment Project Manager]** Determine if the pipeline segment has a launcher and/or receiver.
	2	If pipeline is not currently equipped for in-line inspection (ILI), perform a study to determine if launcher and/or receiver should be installed for future assessments.
1B		Confirm and review any previous integrity assessments with respect to tool selection, execution, and results.
1C		Gather pipeline data for tool vendor, such as outside diameter (OD), wall thickness (w.t.), pipeline length, operating pressure, and operating temperature. Other information may be needed as per vendor's specifications.
1D	1	If line has been assessed by in-line inspection, check for any complications encountered during run.
	2	Take appropriate precautions to minimize complications for upcoming inspection.
1E		**[Assessment Engineer]** Determine line-specific risk factors.

202.2. Corrosion and Deformation

2A	**[Assessment Engineer]** Evaluate for corrosion and mechanical damage for every assessment.
2B	Use the following to determine which method to use for assessment: • The preferred method for assessing for corrosion or mechanical damage is to use a combination of high-resolution corrosion detection and internal geometry in-line inspection tools to assess for corrosion and mechanical damage. • If DEF tool is unable to perform in a particular pipeline segment (i.e., experience has shown difficulty running these types of tools in ammonia lines), then NuStar will use a gauge plate capable of detecting 6% deformations in conjunction with a COR tool, which must be able to identify possible deformations. However, NuStar must investigate each deformation indication identified by the COR tool that is potentially a defect meeting the repair criteria in Section 4: Remedial Action. NuStar will excavate any dent indication that could potentially meet the repair criteria, or will conduct a subsequent assessment using a deformation tool or hydrostatic test. • The secondary method for assessing for corrosion or mechanical damage is by running a hydrostatic test in accordance with O&M Procedure 609: Pipeline Hydrostatic Testing for unpiggable pipeline segments. NuStar shall subject the hydrostatic test, used to assess for corrosion, to a corrosion control program.

202.3. SCC

3	**[Assessment Engineer]** Use one of the following methods to assess for SCC: • A hydrostatic test. Include a spike test for 15–30 minutes in this hydrostatic test. • An In-line inspection tool capable of detecting cracks.

202.4. Longitudinal Seam Failure

4	**[Assessment Engineer]** Use one of the following methods for longitudinal seam failure assessment: • A hydrostatic test. • An ILI tool capable of detecting longitudinal seam anomalies.

202.5. Other Pipeline Risk Factors

5	**[Assessment Engineer]** If other factors, identified by any parties involved with assessment, present risk to a pipeline segment, NuStar will assess them at that time.

203: Assessment Scheduling

Introduction

DOT regulations require that all pipeline operators assess the integrity of the pipeline by selecting assessment methods that detect corrosion and deformation anomalies. In addition, for pipelines determined to be susceptible to seam failure, an appropriate assessment method will be selected. NuStar addresses these requirements by scheduling in-line inspections and hydrostatic tests.

Regulation

49 CFR §195.452 (j) (5) Assessment methods: An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency, electric-resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure, must be capable of assessing seam integrity, and of detecting corrosion and deformation anomalies. (ii) Pressure test conducted in accordance with subpart E of this part.

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar.

Resources

Pipeline integrity database

ILI Service Provider Technical Questionnaire (in Appendix F, Forms)

203.1. Developing an Assessment Schedule

1A		**[Assessment Engineer]** Develop a prioritized annual assessment schedule for the upcoming year, based on previous inspections, risk rankings, and data integration results from the previous P&M Measures Meeting.
	1	**[Assessment Project Manager]** Present the annual assessment schedule to the Operations General Manager for quarterly projections.
1B		**[Assessment Project Manager]** Contact Operations/Maintenance Managers and ask them to provide feedback on possible conflicts with the proposed schedule (e.g., vacation, re-routes, refinery outages).
1C	1	**[IMP Manager]** Send the quarterly projected in-line inspection (ILI) portion of the Assessment Schedule to the ILI Service Provider.
	2	**[ILI Service Provider]** Approve projected schedule and allocate personnel and tools to accommodate the schedule.
1D		**[Assessment Project Manager]** Upon acceptance of projected annual inspection schedule by both NuStar and the ILI Service Provider, assign a Work Order for the inspection of each segment. **Note:** The Assessment Project Manager creates Work Orders for hydrostatic tests upon finalization of schedule.
1E		**[Assessment Project Manager]** Complete the ILI Service Provider Technical Questionnaire and submit it to the ILI Service Provider for tool design, prior to inspection.
1F	1	Project a tentative day and month for tools to be run.
	2	Communicate with the ILI Service Provider and Operations Maintenance Managers before date of inspection to ensure actual date is achievable. Expect slight variations in actual dates and make proper arrangements.
	3	**[ILI Service Provider]** Provide a weekly status report of inspections to the Assessment Project Manager.

203.2. Completing the Schedule

2A		**[Assessment Engineer]** ILI Analysts shall communicate regularly with the various Assessment Project Managers to ensure that a scheduled assessments have been completed. These are typically discussed in weekly staff meetings..
2B		Notification to PHMSA is required under the following conditions: • The inspection cannot be scheduled prior to the required assessment interval. • The inspection cannot be completed within eight months of the required assessment interval.
	1	**[Assessment Project Manager]** If an inspection schedule is missed, prepare the justification to PHMSA and forward to the IMP Manager.
	2	**[IMP Manager]** Review, approve, and submit the notification to PHMSA.

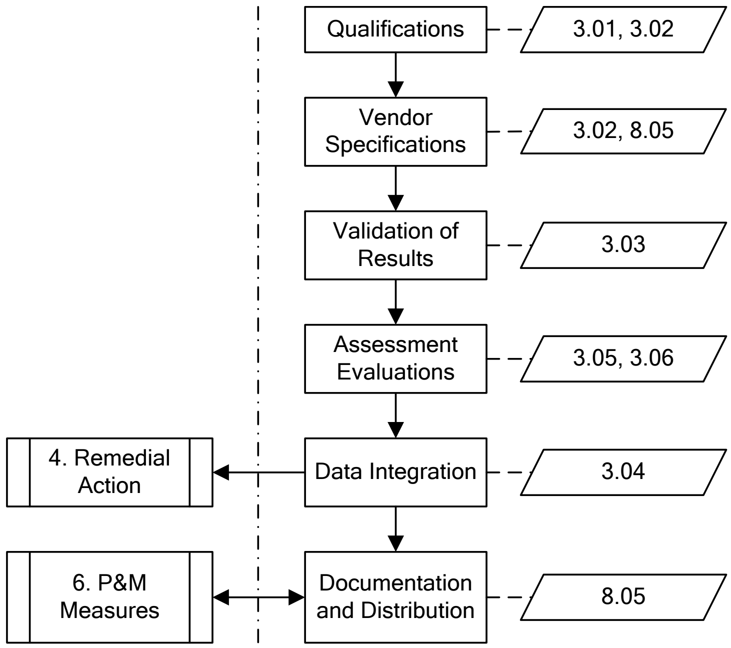
203.3. Continual Evaluation of the Schedule

3A		**[Assessment Project Manager]** Communicate any possibility of missed inspection schedules •
3B	1	**[Risk Engineer]** If an inspection may miss its deadline, review with Operations and appropriate SMEs prior to the inspection due date.
	2	**[SMEs with IMP Team]** Review the circumstances that caused the missed deadline and determine if further actions are required—such as additional repairs (as identified on the previous assessment), pressure reduction, additional patrols, etc.—to ensure the safe operation of the pipeline until the inspection can be completed. **Note:** For inspections on a shortened interval, re-evaluate to determine if a new deadline can be established.
	3	**[Assessment Project Manager]** If the 5-year regulatory deadline cannot be met, return to step 2B to notify PHMSA of the missed interval.
3C		**[Assessment Project Manager]** If the assessment schedule changes,
	1	Update the pipeline integrity database with the new tool run schedule.
	2	If the due date changes, update the pipeline integrity database with the new date and record the justification as determined by the review team.

3: Integrity Assessment

This section describes the process by which NuStar collects, integrates, categorizes, documents, and distributes the inspection data, as illustrated in Figure 3-1 (with corresponding Protocols noted).

Figure 3-1. Integrity Assessment Flowchart



Currently, NuStar uses the following four approved technologies for qualified integrity assessments:

- Hydrostatic testing—O&M Procedure 609, Pipeline Hydrostatic Testing
- In-line inspections—IMP Procedure 301, ILI Assessment, Data Evaluation, and Remediation
- Guided wave ultrasonic testing—IMP Procedure 304, Guided Wave Ultrasonic Testing
- Direct Examination—IMP Procedure 305, Direct Examination

Note: PHMSA considers guided wave ultrasonic testing and direct examination to be Other Technology as integrity assessment methods and requires notification as described in Section 2.3.

3.1. Qualifications

3.1.1. NuStar Employees

The IMP Manager ensures that personnel assigned to assessment tasks meet the employee qualifications by continually providing additional training, educational tools, and skills (documented in the Vendor/Training Log on the IMP network drive). NuStar employs an Assessment Engineer who is dedicated full time to the evaluation of inspection results and remediation processes. The Assessment Engineer's project tasks include interpreting and validating inspection logs, maintaining communications with ILI Service Provider, remediating defects, and performing other qualified assessment activities such as hydrostatic tests. Furthermore, the NuStar employee that directs and observes the hydrostatic test is qualified under NuStar OQ Task # 41, Conduct Pressure Test. A complete list of roles, responsibilities, and qualifications for NuStar employees can be found on the IMP Intranet.

3.1.2. ILI Service Providers

NuStar requires the qualifications of the ILI Service Provider's personnel to comply with the latest version of the American Society for Nondestructive Testing's *In-line Inspection Personnel Qualification and Certification* document (ANSI/ASNT ILI-PQ) and Section 5.2 of API Standard 1163: In-Line Inspection Systems Qualification

NuStar requires the following minimum qualifications for ILI Service Provider personnel:

- The ILI Tool Operator shall be qualified to Level II.
- The ILI Data Analyst shall be qualified to Level II.
- Final reports shall be reviewed and approved by an ILI Data Analyst Level III.

NuStar expects its ILI Service Providers to provide documentation that demonstrates that their project personnel are qualified to perform the tasks involved with the in-line inspection process. Each Final Inspection Survey Report will contain the latest qualifications for the ILI Service Provider's personnel responsible for the direction of any task that may directly impact the integrity of the asset being assessed. Any deviation from ASMI/ASNT ILI-PQ, API Standard 1163, or NuStar's requirements will be documented in the final report and approved by the NuStar Assessment Engineer prior to acceptance of the final report.

3.1.2.1. ILI Service Provider Vendor Service Agreement

The ILI Service Provider Vendor Service Agreement lists the minimum requirements for services, tools, and communication expectations required of the ILI Service Provider, as outlined in API Standard 1163, including at least the following provisions:

- NuStar uses deformation (DEF) and corrosion (COR) tools to ensure that both anomaly types are detected.
- NuStar may also use specialty tools to address other threats specific to a pipeline system, such as
  - an Axial Flaw Detection (AFD) tool to locate and define areas of longitudinally oriented metal loss; or
  - an Electro Magnetic Acoustic Transducer (EMAT) or an Ultrasonic Crack Detection (UTCD) tool for detecting stress corrosion cracking (SCC) colonies.
- NuStar may request that a representative of the ILI Service Provider be present for some verification digs.
- NuStar's reporting requirements include the following:
  - For standard DEF and COR tools, the ILI Service Provider submits a Final Inspection Survey Report within 60 days after completion of the inspection.
  - For a UT metal loss tool, the ILI Service Provider submits a Preliminary Inspection Survey Report within 60 days and a Final Inspection Survey Report within 90 days after completion of the inspection
  - For a UT crack detection tool, the ILI Service Provider submits a Preliminary Inspection Survey Report within 60 days and a Final Inspection Survey Report within 120 days after completion of the inspection.
  - For all types of tools, the ILI Service Provider provides notification of any immediate conditions within 30 days of completion of the inspection.

3.1.2.2. Communication with the ILI Service Provider

NuStar periodically discusses information regarding the ILI Service Provider's performance and upcoming enhancements to the inspection process with the inspection vendors. These discussions communicate issues related to tool inspection performance, inadequate assessment results, and reporting delays. relays Anomaly-sizing information from field NDE is also communicated to the tool vendor in an effort to improve the development of future tools and evaluation software.

3.1.3. GWUT Service Providers

NuStar expects its GWUT Service Providers to provide documentation that their project personnel are qualified to perform the tasks involved with guided wave ultrasonic testing (see IMP Procedure 304). Each GWUT Service Provider Report will contain the latest qualifications for the provider's personnel responsible for the direction of any task that may directly impact the integrity of the asset being assessed.

3.2. Assessment Folder Construction

For consistency in data storage, the following folder structure has been devised for collecting all assessment-related data, spreadsheets, reports, emails, etc. For each inspection effort, folders will be originated in the IMP section of the Corporate Shared Drive:

S:\Americas\SanAntonio_HQ\Integrity Management\Segment Folders

Locate the Segment Folder for the testable segment to be assessed

Under this segment folder, create a new sub-folder named only with the year of the assessment (e.g. 2017)

Under this sub-folder create three sub-folders with the following names (using the appropriate year):

- 2017 ILI
- Digs and Repairs
- 2017 Closeout Report

If applicable, another sub-folder can be created for "2017 Hydro" if the segment is assessed with a hydrostatic test. This folder would include the Test Planning form, the Hydrotest Report, the Hydrotest Pressure chart and the third-party contractor Hydrotest report

If multiple tool types are utilized in a particular year, appropriate sub-folders must be created to allow data to be stored appropriately. Change ""2017 ILI" to "2017 DEF+MFL" for example and add another folder for "2017 UT-C" as appropriate.

Underneath the "2017 ILI" sub-folder, create the following eight sub-folders:

- Communications
- Data Analysis
- Data Manager
- Final Report
- Google Files
- Prelim Report
- Site Survey

If any of these particular sub-folders are not used, the file names should be appended with "Not Applicable"

The "Digs and Repairs" sub-folder will typically contain the following types of information:

- Dig Sheets
- Dig Maps
- Pipe Tallies
- Dig Folder Checklist

Under the “2017 Closeout Report” sub-folder, the following 13 sub-folders are created:

- 01 Questionnaire
- 02 Meeting Minutes
- 03 Site Survey
- 04 Tool Failure
- 05 Prelim Report
- 06 Final Report
- 07 Data Manager
- 08 Temporary Pressure Restrictions
- 09 ILI Graphs
- 10 Mitigation Report
- 11 Third Party Analysis
- 12 PHMSA Notification
- 13 Observations and Recommendations

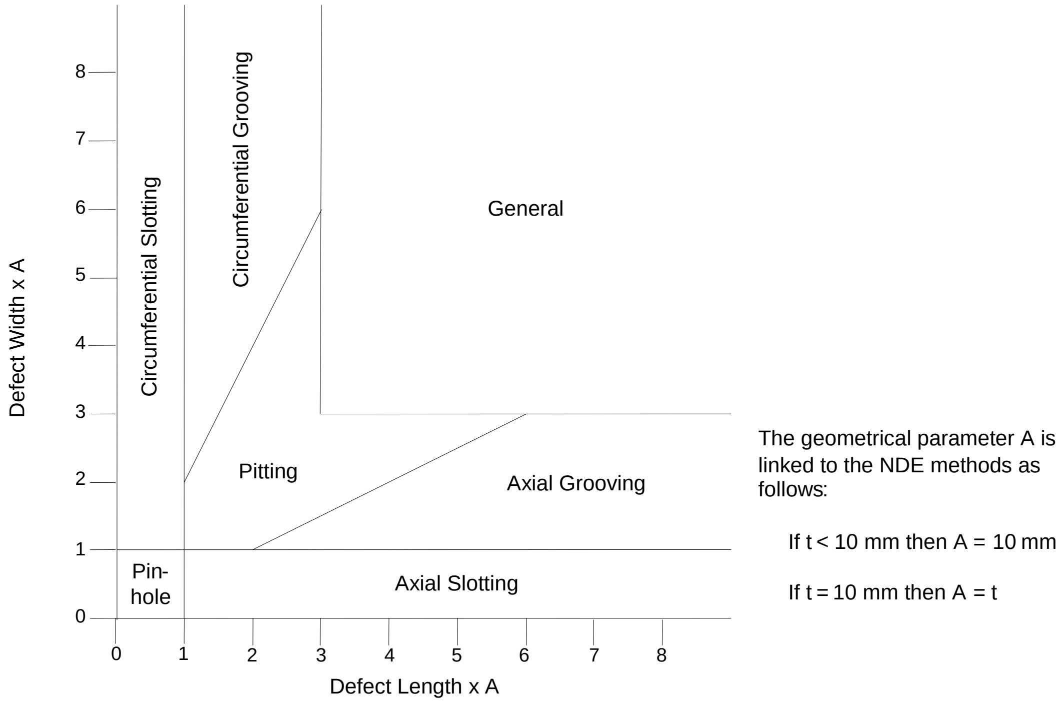
3.3. ILI Tool Tolerances

NuStar expects the ILI Service Provider to provide accurate inspection data in accordance with the published specifications and tolerances for each inspection tool. Minimum acceptable tool accuracies are specified in the service agreements with the ILI service providers. The ILI Service Provider provides NuStar with datasheets and inspection performance specifications for DEF, COR, EMAT, and AFD tools. The Final Inspection Survey Report also provides the tolerances that apply for the specific inspection.

The ILI Service Provider bases its vendor tool tolerances on historical correlations of the tool’s performance. Each inspection tool has a stated tolerance for length, depth, and width that the ILI Service Provider strives to achieve at a certain confidence level, which is usually 80%.

Because ILI measurement capabilities depend on the geometry of the metal loss anomalies, ILI service providers classify metal loss anomalies in dimension classifications based on the anomalies’ lengths and widths. Each dimension classification has a different tolerance level, as shown in Figure 3-2.

Figure 3-2. Metal Loss Anomalies per Dimension Class



NuStar accounts for tool tolerances in the evaluation of immediate conditions associated with metal loss features and the evaluation of the reassessment interval and probability of exceedance (POE) as described in Sections 7.2 and 3.5. As field data becomes available, the Assessment Engineer can plot a unity curve to validate the stated tool tolerance (see Section 3.4.3, Unity Curve).

3.4. Validation of Results

NuStar has implemented a formal process for validating the results of an ILI inspection. IMP Procedure 301, ILI Assessment, Data Evaluation, and Remediation, outlines NuStar's use of verification digs to compare the results provided in the inspection reports to actual field data.

The ILI Service Provider may also use this information to calibrate the data used in evaluation for data collected by on-site ILI personnel. The ILI Service Provider uses this calibration of data to aid in providing NuStar with a more accurate Final Inspection Survey Report.

3.4.1. Data Acceptance

NuStar has established a process for approving an inspection run before the results are sent to the ILI Service Provider Evaluation Team. After the ILI Service Provider has approved the inspection results with its data acceptance specification, it reports key inspection variables to NuStar for tool run acceptance. Table 3-1 lays out the minimum acceptance criteria for vendor tool tolerances.

Table 3-1. Vendor Data Tolerance, Validation Matrix

Accuracy of ILI Measurements of Anomalies

ID Reduction Anomalies:							
Category	**Scores for differences between measurements**			**Category**	**Scores for differences between measurements**	
Orientation [± 22º]	= ± 22.5º	= ± 45 min	**Validation** OK	**Dent Depth** [±1.5% of ID]	= 1.5%	**Validation** OK
Corrosion Anomalies:						
Category	**Scores for differences between measurements**			**Category**	**Scores for differences between measurements**	
Orientation [± 10º]	= ± 15º	= ± 30 min	**Validation** OK	**Metal Loss Depth** [± 0.15*t]	= ± 15%	**Validation** OK
Length [± 18 mm]	= ± .709		**Validation** OK	**Width** [± 23 mm]	= ± .906'	**Validation** OK
* Indicates the current validation dimensions for DEF. ** Indicates the current validation dimensions for COR.				**Weld to Feature** [± 0.1 m]	= ± .328'	**Validation** OK

This information is captured in the Preliminary Site Survey Report and sent to the Assessment Engineer. Once the vendor-accepted report is transmitted to NuStar, the IMP Team reviews and confirms the following pieces of data:

- Velocity graphs for the tool run
- Primary and Secondary Sensor coverage percentages
- Any notes added by the vendor's team

NuStar has the opportunity to request clarification from the vendor for any questionable areas of interest in order to deliver its acceptance or rejection of the inspection run. Information captured during this feedback loop is saved, typically in email conversations and is filed with the other inspection data in the appropriate segment files.

Either NuStar or the ILI Service Provider can deem the tool run unacceptable at any stage of this process. Both of them must disclose reasons why the run is unacceptable on the Preliminary Site Survey Report. The ILI Service Provider's data acceptance specification is stored on the IMP Shared Network Drive. files.

3.4.2. Validation Digs

NuStar uses validation digs to verify tool accuracy. These features may be DOT-required repairs or other features selected for validation purposes only. A minimum of two features shall be investigated for each assessment unless one of the following criteria is met:

- the reported features can be validated against a prior assessment
- no metal loss features greater than 20% are reported

API Std. 1163, In-Line Inspection Systems Qualification is the consensus industry standard for validating ILI tool performance, and NuStar's data collection tools have been developed based on the recommendations of this standard.

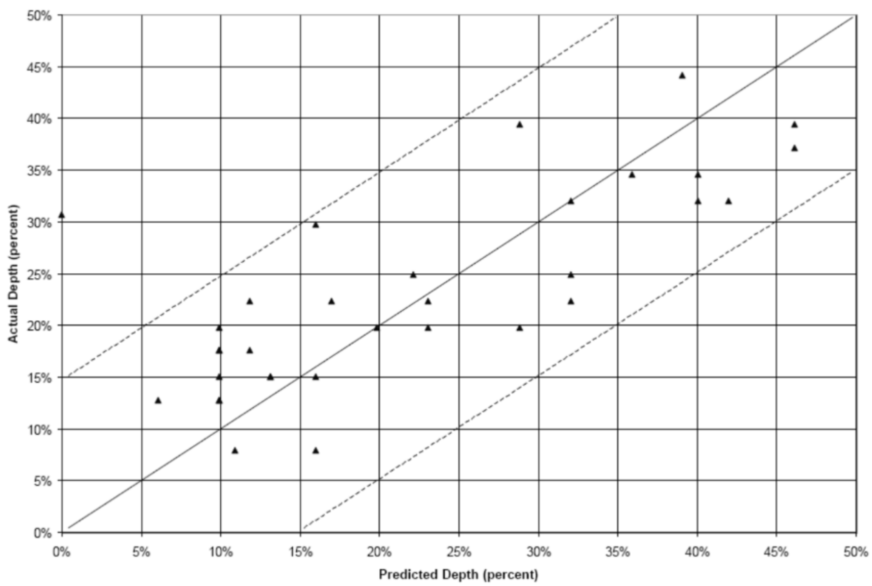
If these digs are performed based on information from a preliminary report, NuStar communicates the results to the ILI Service Provider who may then adjust its data analysis before issuing the Final Inspection Survey Report.

The ILI service contracts include provision for the ILI Service Provider to participate in two validation digs per assessment, so they may be utilized to assist in these digs. NuStar documents any inconsistencies with tool inspection data and communicates them to the ILI Service Provider for corrective action.

3.4.3. Unity Curve

To verify that the tool is working within stated tolerances, the Assessment Engineer plots a unity curve of the anomalies measured during all anomaly digs against the assessment tool measurement (see Figure 3-3).

Figure 3-3. Unity Curve Example



This data shall be provided to the Assessment Service Provider for feedback on tool performance. If the Assessment Engineer determines that the tool did not perform as specified, the Assessment Service Provider analyzes the data and provides a written response explaining the discrepancy.

Adjustments are made to the dig program if the tool performance is either not within the stated tolerances or exceeds the stated tool tolerance as shown in IMP Procedure 301.

3.5. Probabilistic Approach for Consideration of Tool Tolerances (POE Analysis)

NuStar uses POE analysis to calculate the probability that anomalies remaining in the pipeline could exceed the requirements for an Immediate condition (i.e., depth > 80% or ERF > 1.39). NuStar uses the results of a POE analysis as a tool for managing the long-term integrity of pipeline systems. POE tools are available for prioritizing anomalies, comparing sets of metal-loss data, determining the impact of a remediation program on the reduction in the likelihood of a corrosion-related release, and comparing metal-loss data from multiple pipelines.

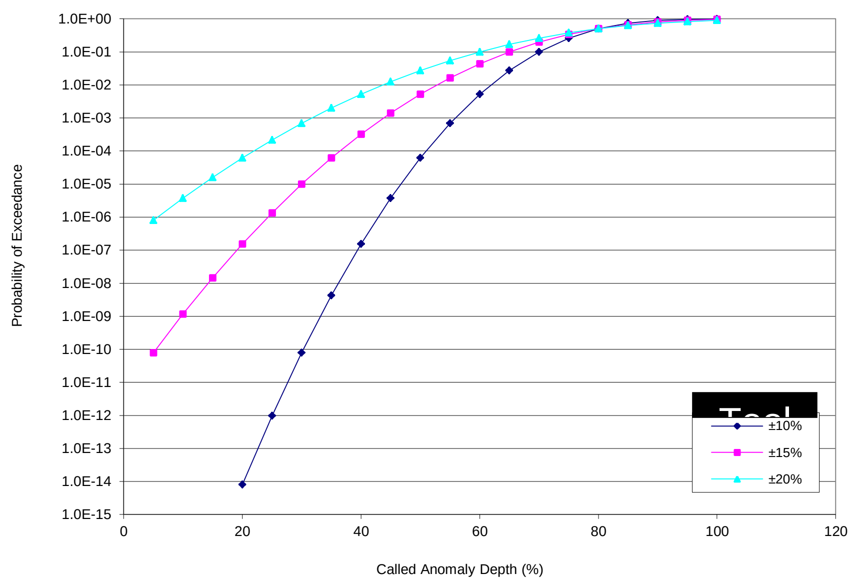
During the POE process, NuStar uses the stated vendor tool tolerances as a first step unless they are proven otherwise with field verification data and a unity curve. The POE processes take into account that an ILI tool performs within a stated tolerance based on a normal distribution. From this normal distribution, the POE process calculates the probability that an anomaly with a certain called depth will actually be ≥80% or will result in an ERF ≥ 1.39.

For example, the probability that an anomaly with a called depth of 80% will actually be 80% deep is 0.5. That is, there is a one in two chance that the actual depth of the anomaly will be greater than 80%. As the anomaly called depth decreases, the probability that that anomaly actually exceeds 80% also decreases. For example, if the tool tolerance is ±15% at an 80% confidence and the tool call is 65%, there is only a

10% probability (one in ten chance) that that anomaly is actually 80% or greater. This relationship between the called depth and POE is illustrated in Figure 3-4.

The POE process described above calculates the probability that existing anomalies at the time the ILI tool was run actually exceed the immediate condition threshold. NuStar also predicts the future POE of all anomalies by assuming that they grow in depth at a specified rate over a specified reassessment interval. This additional POE analysis determines the probability that anomalies will exceed the immediate criteria at the time of the next scheduled reassessment if they grow at a specified rate—information can be used to make repair decisions.

Figure 3-4. Probability Curves Based on Three Tool Tolerance Levels (Probability the Predicted Depth Is Greater Than 80%)



3.6. Assessment Evaluations

3.6.1. In-Line Inspection Assessments

The ILI Service Provider submits a tabular Client List, which presents the processed ILI inspection data as a tabular list of all features detected by the ILI tool(s). This list provides all the relevant data to determine anomaly type, size, and location on the pipe and is evaluated to create a remediation priority list. Figure 3-7, Figure 3-8, and Figure 3-9 (all at the end of the section) are based on the Rule *(h)* and illustrate the evaluation rules for categorizing anomalies.

The Assessment Engineer evaluates the Client List (either manually or using an integrity evaluation computer program) to categorize anomalies and develop a required remediation plan. NuStar further modifies this plan to address additional anomalies or sections of pipe based on other pertinent data obtained from other reports or known areas of concern. Calculations for determining the safe operating pressure for metal loss features are described in the following sections.

3.6.1.1. Anomaly Interaction Criteria

Several anomaly interaction rules and burst pressure calculations are available for use in assessing ILI results. The following paragraphs explain how NuStar performs anomaly interaction, calculates a safe operating pressure, and determines the date of discovery for all ILI assessments.

NuStar uses the ASME B31G interaction criteria. These interaction criteria play an important role in determining the length of the metal-loss area that NuStar uses for its metal-loss remaining strength calculation.

The ASME B31G criteria are applied until an area of sound pipe is reached. The sum length of all grouped metal-loss anomalies becomes the total length of the new interacted feature. NuStar uses the metal-loss group length and the maximum depth to calculate the predicted burst pressure for the metal-loss area. These criteria are sufficiently conservative to capture the influence of adjacent metal-loss areas.

3.6.1.2. Corrosion Assessment Criteria

The Rule *§(h)* requires evaluation and remediation of all corrosion-related anomalies having a calculated safe pressure value less than the design pressure of the pipeline in an HCA or in an area that could affect an HCA. NuStar does not permit the calculated safe pressure (P_{safe}) to be less than the established maximum operating pressure (MOP) for any line and, therefore, has further adopted the same criteria for addressing conditions within non-HCA areas.

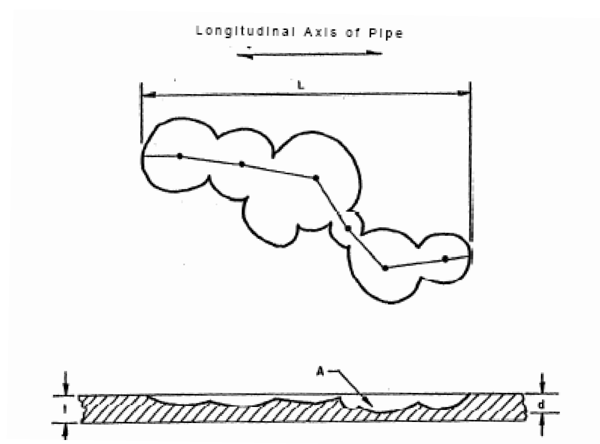
In general, NuStar does not differentiate between HCA and non-HCA pipeline segments in selecting a particular repair method. NuStar must adhere to repair timeframes for HCA segments only, but it repairs non-HCA segments in a timely manner commensurate with the type and severity of the anomaly or defect.

NuStar uses a remaining strength calculation on metal-loss anomalies measured by the following methods:

- in-line assessment results
- field measurements
- ultrasonic (UT) meter measurements

Figure 3-5 demonstrates how to determine the dimensions of the metal loss area in a corrosion feature.

Figure 3-5. Parameters of Metal Loss Used in Analysis of Remaining Strength



Suitable remaining strength calculation methods for determining remaining strength of corroded area in pipe include, but are not limited to, ASME B31G and Modified ASME B31G, including the effective area method. The *PRCI Report PR 3-805: A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe* (Kiefner and Vieth, December 22, 1989) details these three cases. They are listed as Case 1: Modified B31G Criterion—Effective Area, Case 2: Modified B31G Criterion—0.85 dL Area, and Case 3: B31G Criterion. NuStar's preferred method is Case 2. Using these equations, NuStar calculates the safe maximum pressure (P_{safe}) as follows:

3.6.1.2.1. Safe Maximum Pressure—P_{safe}

P_{safe} is more specifically defined through the following three cases:

Case 1: Modified B31G Criterion—Effective Area

$$P_{safe} = P\left(1+\frac{10{,}000}{SMYS}\right)\left[\frac{1-\left(A_{eff}/A_o\right)}{1-\left(A_{eff}/A_o\right)M_1^{-1}}\right]$$

Case 2: Modified B31G Criterion—0.85 dL Area

$$P_{safe} = P\left(1+\frac{10{,}000}{SMYS}\right)\left[\frac{1-\left(0.85\frac{d}{t}\right)}{1-\left(0.85\frac{d}{t}\right)M_2^{-1}}\right]$$

Case 3: B31G Criterion

For: $\frac{L_{Total}^2}{Dt} \le 20$

$$P_{safe} = 1.1P\left[\frac{1-\left(\frac{2}{3}\right)\left(\frac{d}{t}\right)}{1-\left(\frac{2}{3}\right)\left(\frac{d}{t}\right)M_3^{-1}}\right]$$

For: $\frac{L_{Total}^2}{Dt} > 20$

$$P_{safe} = 1.1P\left[1-\left(\frac{d}{t}\right)\right]$$

3.6.1.2.2. Predicted Burst Pressure—P_{burst}

The P_{burst} equation is as follows:

$$P_{burst} = \frac{P_{safe}}{0.72}$$

3.6.1.2.3. Folias Factor

The Folias Factor for the three cases is as follows:

Case 1: Modified B31G Criterion—Effective Area

For: $\frac{L_{eff}^{\;2}}{Dt} \le 50$

$$M_1 = \left[1+\frac{1.255}{2}\frac{L_{eff}^2}{Dt}-\frac{0.0135}{4}\frac{L_{eff}^4}{D^2t^2}\right]^{\frac{1}{2}}$$

For: $\frac{L_{eff}^{\;2}}{Dt} > 50$

$$M_1 = 0.032\frac{L_{eff}^2}{Dt}+3.3$$

Case 2: Modified B31G Criterion—0.85 dL Area

For: $\frac{L_{Total}^2}{Dt} \le 50$	$M_2 = \left[1 + \frac{1.255}{2}\frac{L_{Total}^2}{Dt} - \frac{0.0135}{4}\frac{L_{Total}^4}{D^2t^2}\right]^{\frac{1}{2}}$
For: $\frac{L_{Total}{}^2}{Dt} > 50$	$M_2 = 0.032\frac{L_{Total}^2}{Dt} + 3.3$

Case 3: B31G Criterion

For: $\frac{L_{Total}^2}{Dt} \le 20$	$M_3 = \left[1 + 0.8\frac{L_{Total}^2}{Dt}\right]^{\frac{1}{2}}$

3.6.1.2.4. Variable Definitions

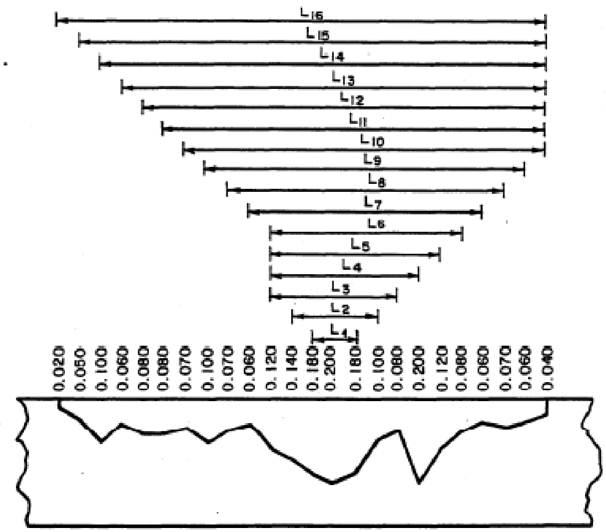
The variable definitions for the equations in the previous three subsections are as follows:

P_{safe}	=	The safe maximum pressure for the corrosion area (psi). Must be less than or equal to P.
P_{burst}	=	The calculated burst pressure for the corrosion area (psi).
P	=	The greater of either the P'design internal design pressure—determined by applying the equation in *49 CFR §195.106* (including 0.72 design factor and excluding seam joint factor) to the pipe containing the corroded area—or the established MOP (psi)—see 3.6.1.2.6. P'design Equation.
D	=	Nominal outside diameter of the pipe (inch).
SMYS	=	The specified minimum yield strength in pounds per square inch (psi). If the specified minimum yield strength is not known, the yield strength shall be determined per Section 3.6.1.2.7.1. Unknown SMYS.
d	=	Maximum depth of corroded area (inch).
A_{eff}	=	The effective area of the metal lost due to corrosion in the axial direction through-the-wall thickness based on an iterative calculation (in^2).
A_o	=	Original area prior to metal lost due to corrosion within the effective area, $L_{eff} \times t$ (in^2).
L_{eff}	=	Effective axial extent of the corrosion (inch).
L_{Total}	=	Axial extent of corrosion (inch).
t	=	Nominal wall thickness of the pipe (inch). If this is unknown, it is determined in accordance with Section 3.6.1.2.7.2. Unknown Wall Thickness.
M_1	=	Folias Factor a function of L_{eff}, D, and t for Case 1.
M_2	=	Folias Factor a function of L_{Total}, D, and t for Case 2.
M_3	=	Folias Factor a function of L_{Total}, D, and t for Case 3.

3.6.1.2.5. Determination of Effective Area

The effective area of the corrosion is determined through an iterative calculation procedure that results in a minimum predicted pressure. The iterative calculation procedure uses the corresponding lengths and corrosion pit depths to calculate an effective area of missing metal and an effective length (as shown in Figure 3-6). These effective areas and effective lengths are used to calculate a predicted pressure. The minimum predicted pressure that is the result of this iterative calculation procedure is presented as the safe maximum pressure for the corrosion area.

Figure 3-6. Profile of Pit Depths along River-Bottom Path



3.6.1.2.6. P'design Equation

The greater of MOP or P'design is used as P in the Remaining Strength Calculations. P'design is the internal design pressure determined by the equation in *49 CFR §195.106* with the exception of excluding seam joint factor E. The design factor *F* (typically 0.72) is still included in the equation. The pipe specifications (*SMYS*, *t*, and *D*) will be those properties of the pipe containing the corroded area. Specific guidelines are given below if *SMYS* or *t* is unknown.

$$P'_{design} = \left(\frac{2 \times SMYS \times t}{D} \right) F$$

Where:	*D*	=	Nominal outside diameter of the pipe in inches
	F	=	A design factor of 0.72, except that a design factor of 0.60 is used for pipe, including risers, on a platform located offshore or on a platform in inland navigable waters, and 0.54 is used for pipe that has been subjected to cold expansion to meet the specified minimum yield strength and is subsequently heated, other than by welding or stress relieving as a part of welding, to a temperature higher than 900 °F (482 °C) for any period of time or over 600 °F (316 °C) for more than 1 hour.
	t	=	Nominal wall thickness of the pipe in inches. If this is unknown, it is determined in accordance with Section 3.6.1.2.7.2: Unknown Wall Thickness.
	SMYS	=	The specified minimum yield strength in pounds per square inch (psi). If the specified minimum yield strength is not known, the yield strength to be it is to be determined per Section 3.6.1.2.7.1. Unknown SMYS.

3.6.1.2.7. Determination of Unknown Pipe Properties

3.6.1.2.7.1. Unknown SMYS

Per *49 CFR §195.106 (b)*, SMYS is the Specified Minimum Yield Strength in pounds per square inch (psi). If the SMYS is not known, NuStar uses one of the following three methods to determine the yield strength:

1) The yield strength determined by performing all of the tensile tests of API Specification 5L on randomly selected specimens with the following number of tests:

Pipe Size	No. of Tests
Less than 6.625” nominal outside diameter	One test for each 200 lengths
6.625” through 12.75” nominal outside diameter	One test for each 100 lengths
Larger than 12.75” nominal outside diameter	One test for each 50 lengths

2) If the average yield-tensile ratio exceeds 0.85, NuStar takes the yield strength as 24,000 psi. If the average yield-tensile ratio is 0.85 or less, it takes the yield strength of the pipe as the lower of
   a) 80% of the average yield strength determined by the tensile tests
   b) the lowest yield strength determined by the tensile tests
3) If the pipe is not tensile tested per earlier in this section, NuStar takes the yield strength as 24,000 psi.

3.6.1.2.7.2. Unknown Wall Thickness

Per *49 CFR §195.106 (c)*, *t* is the nominal wall thickness of the pipe in inches. If the nominal wall thickness to be used is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end. However, if the pipe is of uniform grade, size, and thickness, NuStar only needs to measure 10 individual lengths or 5% of all lengths, whichever is greater. NuStar will verify the thickness of the lengths that are not measured by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness may not be more than 1.14 times the smallest measurement taken on pipe that is less than 20 inches nominal outside diameter, nor more than 1.11 times the smallest measurement taken on pipe that is 20 inches or more in nominal outside diameter.

3.6.1.2.8. Limitations of Remaining Strength Calculations

The limitations for the remaining strength calculations are as follows:

- This criterion was developed to consider ruptures of a section of corroded pipe and does not account for the possibility that a defect may leak. This equation, therefore, is not applicable for determining fitness for services for pit depths exceeding 80% of the wall thickness due to the possibility of a leak.
- For Case 1: Modified B31G Criterion—Effective Area and Case 2: Modified B31G Criterion—0.85 dL Area, general corrosion where all of the measured pit depths are less than 20 percent of the wall thickness is permitted.
- For Case 3: B31G Criterion, there is no limit on the length of corrosion when all of the measured pit depths are less than 12.5% of the wall thickness. The reason that there is no length limit specified for depths less than 12.5% is that such cases would be expected to have the same remaining strength as a pipe which just meets the minimum wall-thickness requirement for some grades of API line pipe.

3.6.1.2.9. Summary of RSTRENG

Table 3-2 summarizes the three cases for calculating remaining strength.

Table 3-2. Comparison of the Three Remaining Strength Cases

Assessment Criterion	$\bar{\sigma}$, Flow Stress	M, Folias Factor	A, Area of Missing Metal	Ratio of Predicted-to-actual failure pressure*	
				Mean	**Std Dev**
Case 1: Modified B31G Criterion—Effective Area	SMYS + 10,000 psi	For: $\frac{L_{Total}^2}{Dt} \le 50$ $M_1 = \left[1 + \frac{1.255}{2}\frac{L_{Total}^2}{Dt} - \frac{0.0135}{4}\frac{L_{Total}^4}{D^2 t^2}\right]^{\frac{1}{2}}$	Profile of Corrosion, *(Iterative Calculation,* $L_{Total} = L_{eff}$*)*	0.935	0.168
Case 2: Modified B31G Criterion—0.85 dL Area		For: $\frac{L_{Total}^2}{Dt} > 50$ $M_1 = 0.032\frac{L_{Total}^2}{Dt} + 3.3$	A = 0.85 Ld	0.825	0.187
Case 3: B31G Criterion	1.1 x SMYS	For: $\frac{L_{Total}^2}{Dt} \le 20$ $M_3 = \left[1 + 0.8\frac{L_{Total}^2}{Dt}\right]^{\frac{1}{2}}$	A = $^2/_3$ Ld (Parabola)	0.784	0.217

* Test results from 168 samples, includes both ruptures and leaks, using actual yield if available (as shown in *PRCI Report PR28-9304: Continual Validation of RSTRENG* (Kiefner, Vieth, and Roytman, December 20, 1996, pg 68).

Whereas:

$$\sigma_{Failure} = \bar{\sigma}\left[\frac{1 - \frac{A}{A_o}}{1 - \frac{A}{A_o}M^{-1}}\right]$$

Where:

Where:	$\sigma_{Failure}$	=	predicted failure stress, psi
	SMYS	=	specified minimum yield strength, psi
	$\bar{\sigma}$	=	flow stress, psi
	A	=	area of missing metal
	A_o	=	original area prior to any metal loss
	t	=	nominal wall thickness of pipe
	L	=	axial length of the corrosion
	D	=	nominal outside diameter of the pipe
	M	=	Folias Factor

3.6.1.2.10. Applicability of ERF

NuStar may use an Estimated Repair Factor (ERF) ratio to determine if P_{safe} is less than MOP.

$$ERF = \frac{MOP}{P_{safe}}$$

3.6.1.2.11. Applicability to Classifications of Immediate Repair Conditions

NuStar calculates the ERF and P_{burst} with consideration of the tool tolerance depth and length tolerances (at an 80% confidence). NuStar will classify the anomaly as an immediate repair condition if the predicted burst pressure (P_{burst}) is less than the established MOP at the location of the anomaly.

> When ERF ≥ 1 / F, the P_{burst} is less than the MOP and thus must be considered an immediate repair condition.
>
> **Note:** When F = 0.72, the condition becomes ERF ≥ 1.39. Section 3.6.1.2.6. P'design Equation details F determination.

3.6.1.2.12. Applicability to Classification of 180-Day Repair Conditions

NuStar will classify the anomaly as a 180-day repair condition if the P_{safe} is calculated to be less than current established MOP at the location of the anomaly.

> When ERF > 1, the P_{safe} is less than the MOP and thus must be considered a 180-Day repair condition.

3.6.1.3. Discovery of a Condition

NuStar defines the discovery of a condition as the time at which it has sufficient information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. The ILI Service Provider provides inspection reports as outlined in the ILI Service Providers' Vendor Service Agreements. The following measures list some of the deadline criteria for defining discovery:

- The ILI Service Provider must submit a Preliminary Inspection Survey Report within 60 days after the completion of the inspection for all specialty tools. NuStar does not require a preliminary report for standard deformation or corrosion detection tools.
- The ILI Service Provider must submit a Final Inspection Survey Report according to the following schedule:
  - Standard deformation and corrosion tools—60 days after the completion of the inspection
  - UT metal loss tool—90 days after the completion of the inspection
  - UT crack detection tools—120 days after the completion of the inspection
- NuStar recommends discovery within 45 days of delivery of the Final Inspection Survey Report.
- The Company must define discovery within 180 days of the completed inspection.
- If data processing delays are expected, the ILI Service Provider notifies NuStar with an anticipated completion date.

The provisions listed above give NuStar personnel ample time to obtain sufficient information about a condition within 180 days of an integrity assessment. NuStar maintains contact with the ILI Service Provider throughout this process and tracks key deliverable dates in the ILI Service Provider Tracking Report. NuStar contacts the ILI Service Provider to establish an estimated date of delivery with an explanation of the delay if NuStar will not receive the Final Inspection Survey Report within 120 days of the completed assessment. NuStar notifies OPS if discovery cannot be made within 180 days from the date of the inspection.

3.6.2. Hydrostatic Test Assessments

The integrity assessment of pipelines using hydrostatic pressure testing requires a supplemental assessment of cathodic protection data integration. The Corrosion Manager verifies the corrosion control effectiveness of every hydrostatic test used as an assessment as outlined in IMP Procedure 303: Corrosion Control Effectiveness Review. The Corrosion Manager brings up any issues with the corrosion control program during the P&M measures process so that NuStar can work to prevent active corrosion and minimize the likelihood of failure.

For any failures that occur because of a hydrostatic test, NuStar sends pipe samples to a third-party metallurgical company per IMP Procedure 302: Failure Analysis to determine a cause of failure. NuStar acknowledges industry documentation which discusses failures due to a phenomenon called Pressure Reversal. These failures can occur when flaws exist in pipe that is being subjected to a hydrostatic test. If the test is at or near the failure pressue of the flaw, ductile growth of the flaw can occur. If the pressure is reduced prior to the flaw reaching its critical size, it may survive that pressurization. However, the growth that was experienced can lead the flaw to fail upon subsequent pressurization to a level less than the original hydrostatic test. Industry testing has also demonstrated that for pipelines tested to 1.25 times the MOP of the pipeline, a pressure reversal of 20%, in which the pipe would fail at MOP, is an extremely unlikely event. For pipe thought to be susceptible to axially-oriented flaws, NuStar employs ILI technology designed to detect and size these flaws. Hydrostatic tests for pipelines carrying liquids for which such axial flaw detecting tools are not available are conducted at a minimum of 1.25 times the MOP, significantly reducing the likelihood of failures due to pressure reversals.

All hydrostatic pressure tests are in accordance with O&M Procedure 609: Pipeline Hydrostatic Testing, which meets or exceeds the requirements set forth in the *§49 CFR 195 Subpart E: Pressure Testing*.

3.6.3. Guided Wave Ultrasonic Testing Assessments

Anomalies are categorized as Severe (depth ≥ 50%), Medium (50% > depth ≥ 26%) or Minor (26% > depth ≥ 10%). Metal-loss indications deemed Severe are categorized as Immediate repair conditions. Metal-loss indications deemed Medium are 180-Day repair conditions. All features that are evaluated by direct exam are categorized according to the requirements of Section 3.6.1., In-Line Inspection Assessments.

For GWUT assessments, NuStar defines the discovery of a condition as the time at which it has sufficient information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. For features deemed Severe during the GWUT assessment, the date of discovery is the date the condition is reported in the field. For all other features, the date of discovery is either the date of the direct exam (if the feature is classified during direct exam) or the date NuStar receives the final GWUT report (if it is not classified during direct exam).

3.6.4. SCC Program Evaluation

Any time NuStar personnel uncover a pipeline that may be susceptible to SCC, they examine it to gather information for SCC analysis. They record information on the Pipeline Information Report/Defect Evaluation Forms (in *O&M Manual*). NuStar then uploads this information into its GIS system and integrates this data into the integrity assessment results per NuStar’s data evaluation and integration procedures.

3.6.5. Direct Examination

NuStar may use Direct Examination (DE) on exposed steel pipe to locate and evaluate areas of metal loss or mechanical damage utilizing Procedure 305 of this manual. DE is considered Other Technology when used as a standalone IMP technology for covered segments as identified in Section 1.6, Identification of Segments That Could Affect HCAs; therefore, notification must be submitted for approval to PHMSA 90 days prior, as required by the Rule *49 CFR §195.452 (c)(1)(i)(D)* and *49 CFR §195.452 (j)(5)(iv).*

DE, in the context of this procedure, is a direct visual examination of the pipeline to assess for external corrosion or deformations. Any identified anomalies are measured, evaluated for effect on integrity, and remediated as necessary.

This procedure does not cover assessment methodologies for pipe that is susceptible to internal corrosion, SCC, or long-seam failure. NuStar does NOT use ECDA for evaluation of pipe.

3.7. Data Integration

3.7.1. Collecting and Integrating Data

NuStar has developed the P&M measures process to integrate all available integrity-related information. Relevant personnel review the results from the ILI assessment and the repair criteria required in the Rule *(h)(4)*. The ILI areas of concern are reviewed graphically as needed—using Pipeline Integrity Profile Sheets for localized areas of concern or GIS-based interactive maps for global review—along with the following data:

- cathodic protection history
- maintenance and repair records
- One-Call data
- leak history
- previous assessment results
- information on how a failure would affect a high consequence area
- metallurgical analyses
- tool accuracies or tolerances
- other data pertinent to the pipeline segment

Attendees use the pipeline integrity data along with their inherent knowledge of the pipeline segment to propose additional remediation locations. They may also review any new information such as industry reports, incident reports, or conference presentation materials for consideration during this meeting.

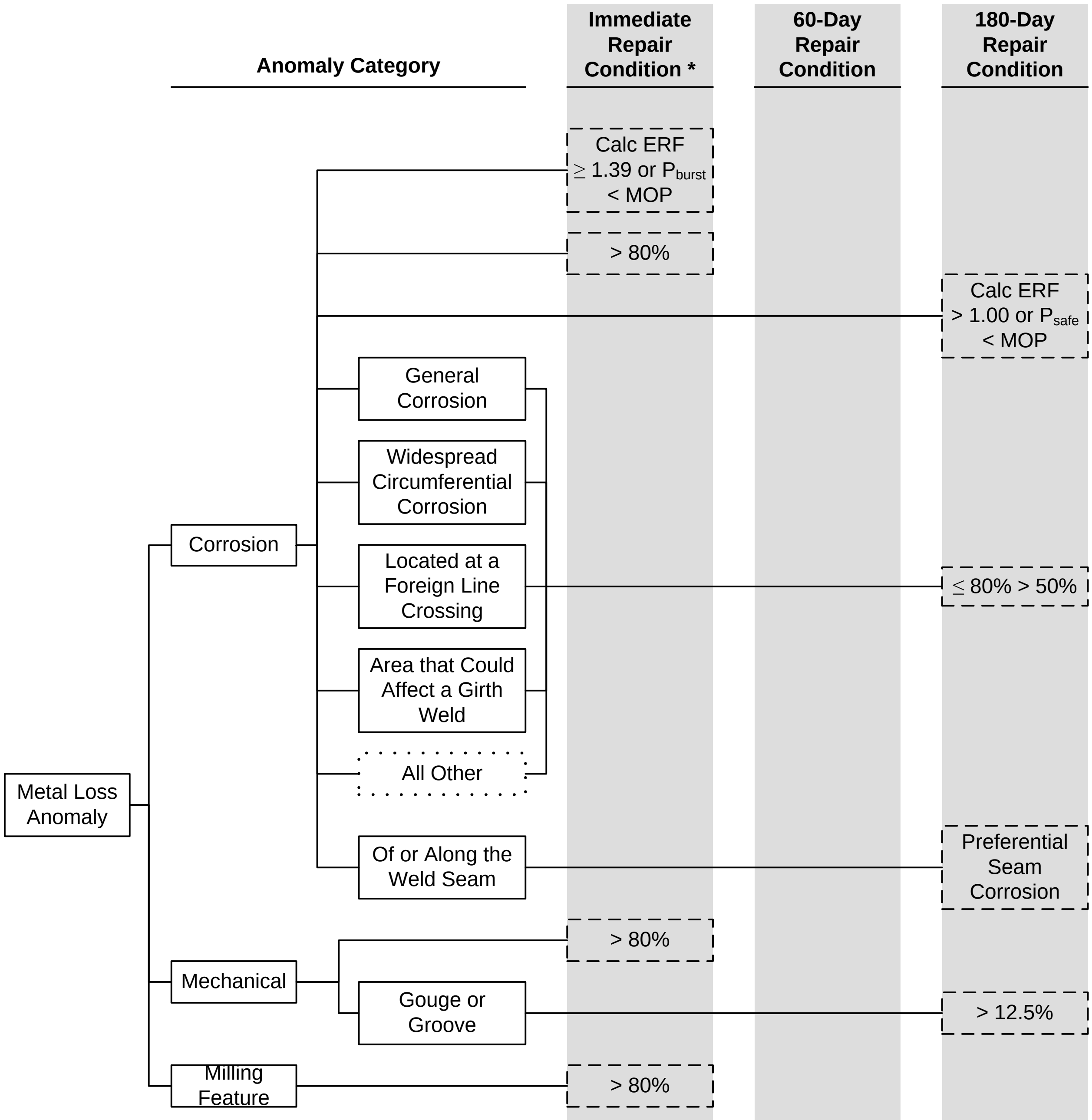
3.7.2. GIS Database

NuStar continues to improve its data integration through enhancements to the Risk Model and GIS databases. Improvements to these databases continually allow the Assessment Engineer to electronically correlate other sources of information with assessment results to determine integrity trends and areas of concern more efficiently.

3.8. Documentation and Distribution

Assessment records document the assessment results, assessment evaluation, repair information, and conclusions; and are archived in the pipeline integrity database on the Corporate IMP sever. IMP Procedure 301 outlines how the Assessment Engineer generates and maintains these records.

Figure 3-7. Categories for Anomalies and Repair Priority Conditions with Pressure Reduction Guidelines (Part 1 of 2)

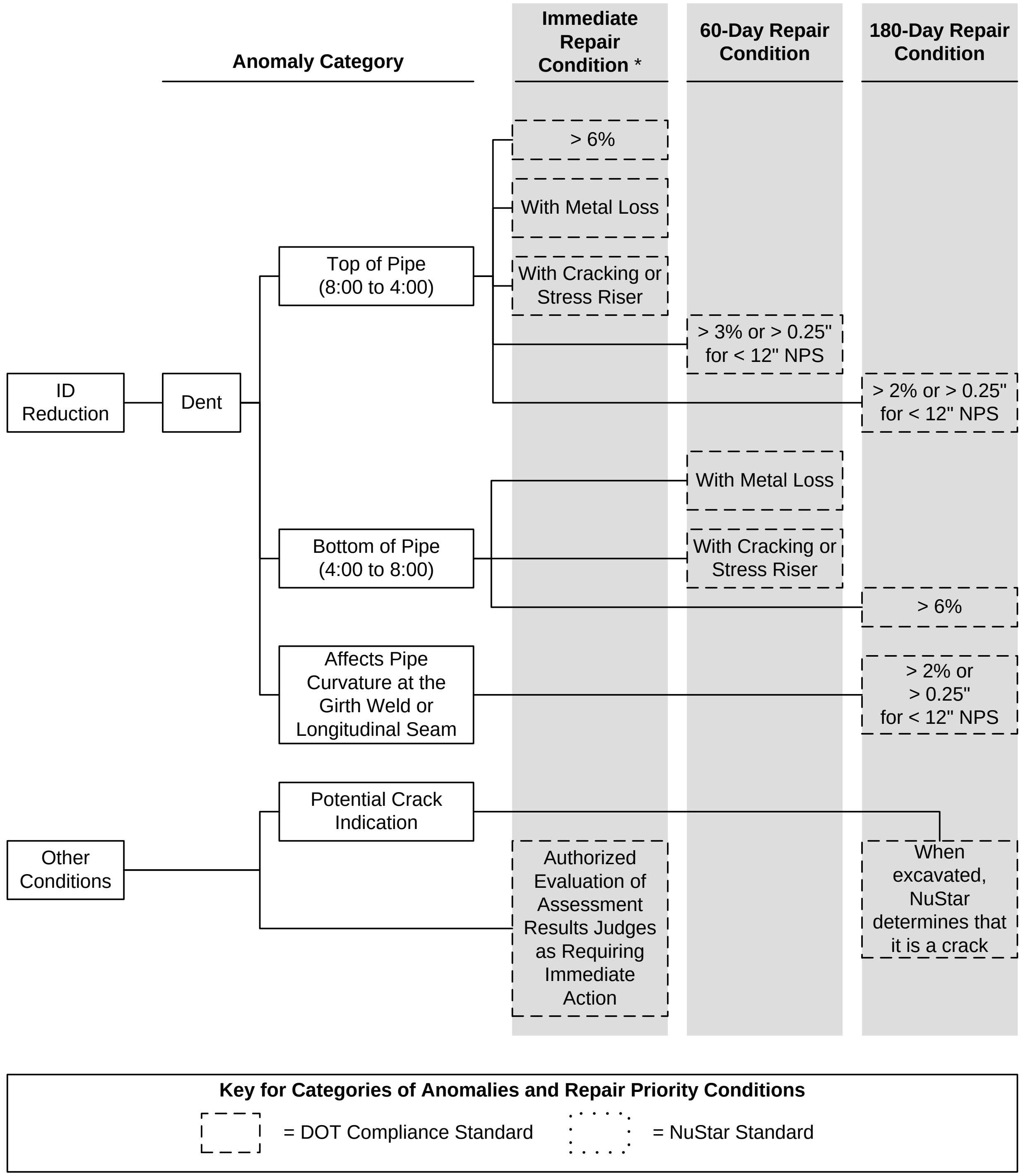


Key for Categories of Anomalies and Repair Priority Conditions

(dashed box) = DOT Compliance Standard (dotted box) = NuStar Standard

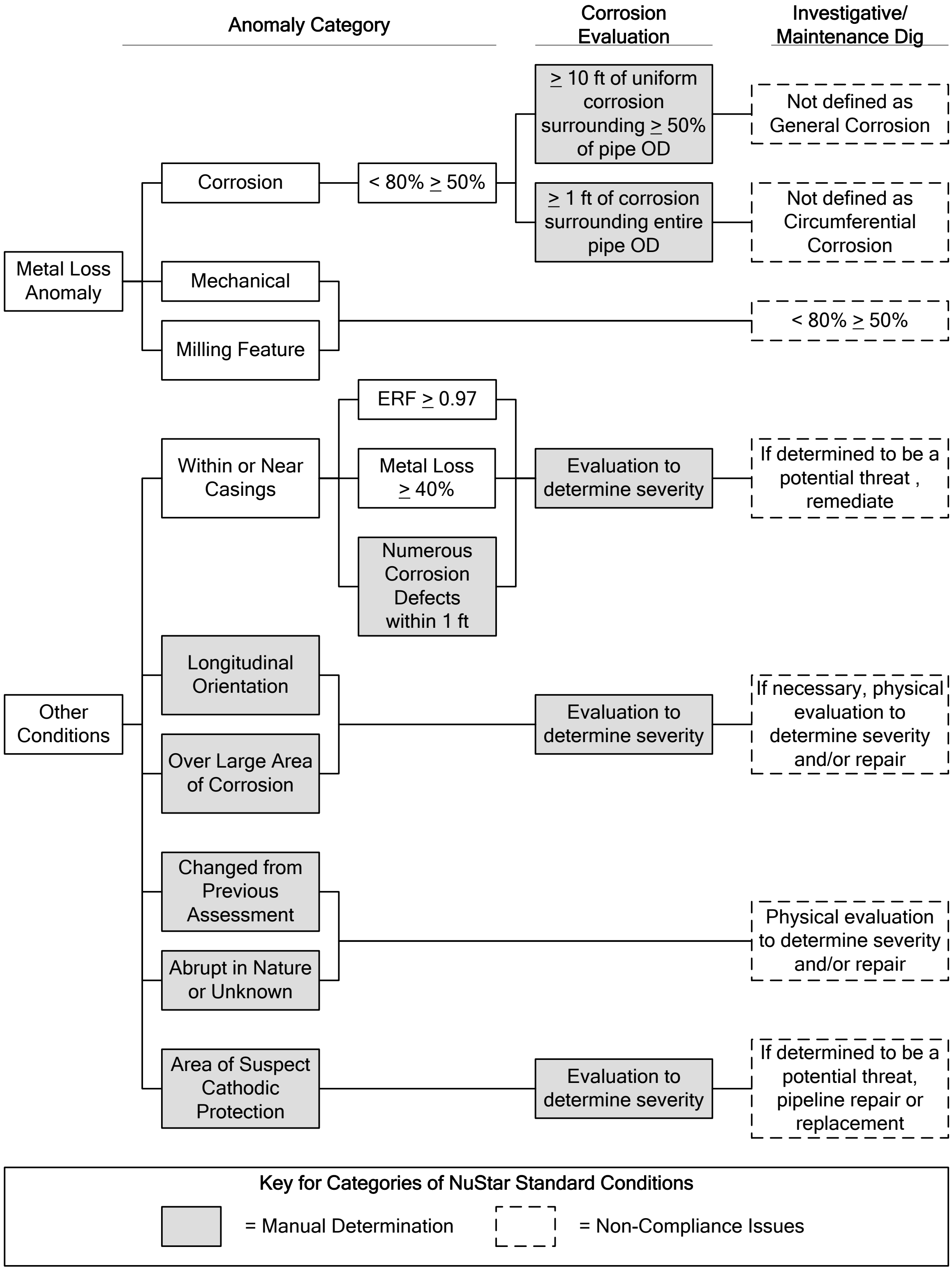
* Tool tolerances for depth and length shall be included when evaluating whether a repair condition is Immediate.

Figure 3-8. Categories for Anomalies and Repair Priority Conditions with Pressure Reduction Guidelines (Part 2 of 2)



* Tool tolerances for depth and length shall be included when evaluating whether a repair condition is Immediate.

Figure 3-9. Categories of NuStar Standard Remediation Conditions



301: ILI Assessment, Data Evaluation, and Remediation

Introduction

DOT regulations require all pipeline operators to assess the integrity of the pipeline, address all anomalous conditions, review the integrity assessment results and information analysis by a qualified person, and take prompt action to address all anomalous conditions that the operators discover, and remediate the ones that could reduce pipeline integrity. This procedure demonstrates how NuStar works closely with the ILI Service Provider to ensure that it meets these conditions, provides qualified personnel to review the in-line inspection (ILI) data, and compiles the completed repair documentation and findings to create the ILI Assessment Closeout Report.

Regulation

49 CFR §195.452 (f) …An operator must include, at minimum, each of the following elements in its written integrity management program:…(8) A process for review of integrity assessment results, and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).

(g) What is an information analysis? In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:

(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.

(2) Data gathered through the integrity assessment required under this section.

(3) Data gathered in conjunction with other inspections, tests, surveillance, and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys.

(4) Information about how a failure would affect the high consequence area, such as, location of the water intake.

(h) What actions must an operator take to address integrity issues? (1) General requirements: An operator must take prompt action to address all anomalous conditions that the operator discovers through integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long term integrity of the pipeline. An operator must comply with §195.422 when making a repair. (i) Temporary pressure reduction. An operator must notify PHMSA, in accordance with paragraph (m) of this section, if the operator cannot meet the schedule for evaluation and remediation required under paragraph (h)(3) of this section, and cannot provide safety through a temporary reduction in operating pressure. (ii) Long term pressure reduction. When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section, and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.

(2) Discovery of a condition: Discovery of a condition occurs when an operator has adequate information about the condition, to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

(3) Schedule for evaluation and remediation: An operator must complete remediation of a condition, according to a schedule prioritizing the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety or environmental protection.

(4) Special requirements for scheduling remediation: (i) Immediate repair conditions. An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure, using the formula in section 451.7 of ASME/ANSI B31.4 (incorporated by reference, see Sec. 195.3), if applicable. If the formula is not applicable to the type of anomaly or would produce a higher operating pressure, an operator must use an alternative acceptable method to calculate a reduced operating pressure.

§49 CFR 195.452 (j)(5) Assessment methods:. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric-resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure, must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.…

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar and inspected utilizing in-line inspection technology.

Resources

NACE 35100

NACE SP0102-2012

API Std. 1163 In-Line Inspection Systems Qualification

NuStar *Operations & Maintenance Manual (O&M Manual)*

NuStar AGM Summary Sheet

Final Survey Inspection Report

Dig/Remediation Records:

- ILI Data Manager Output
- Mitigation Spreadsheet
- Dig Worksheets
- Other documents (OQ, Material Reports, etc.)
- Photos/etchings
- Pipeline Information Report/Defect Evaluation (PIR) Forms

ILI Service Provider Technical Questionnaire (blank)

ILI Assessment Closeout Report (in Appendix F: Forms):

- GIS-generated HCA maps or ranged event reports
- ILI Data Manager Output (copy)
- Mitigation Spreadsheet (copy)
- Temporary Pressure Reduction Forms
- Supplemental reports/analyses (e.g., PCA Reports, Baker Study, and Industry Reports)
- Unity curves
- Final Inspection Survey Report
- ILI Assessment Analysis Checklist
- ILI Assessment Observations and Recommendations

301.1. Initiating the ILI Assessment Closeout Report

1A		**[Assessment Engineer]** Download a blank copy of the ILI Assessment Closeout Checklist from the intranet.
	1	Complete the Assessment Information section.
	2	Save an electronic copy of the completed form to the assessment documentation folder.

301.2. Preparing the Technical Questionnaire

2A		**[Assessment Project Manager]** Gather the data needed to complete the Technical Questionnaire.
	1	Identify and confirm the pipeline segment's maximum operating pressure (MOP).
	2	Contact Operations/Maintenance Personnel to identify trap dimensions and appurtenances.
	3	Review current pipeline data (GIS, pending PIR Forms, etc.) to identify pipe specifications.
2B		Complete (or update for reassessments) the Technical Questionnaire.
	1	Confirm data on the questionnaire with Operations/Maintenance Personnel.
	2	Sign off on the questionnaire.
	3	Fax or email the completed questionnaire to the ILI Service Provider, preferably 30 days prior to the scheduled inspection date.
2C	1	Save an electronic copy of the completed file to the assessment documentation folder.
	2	Mark this document as "archived" on the ILI Assessment Closeout Checklist.

301.3. Identifying Aboveground Marker Locations

3A		**[Operations/Maintenance Personnel]** For baseline assessments, or if aboveground markers (AGMs) were not previously identified—e.g., Category 3 pipe—perform the following steps:
	1	Prior to the in-line inspection, select and mark AGM locations—approximately 1 mile apart, where feasible, within the pipeline right-of-way (ROW).
	2	For each AGM, record the following location data on an AGM summary sheet: • AGM number • Location description • Alignment station number (optional) • GPS coordinates
	3	**[Assessment Project Manager]** Distribute completed AGM summary sheets to the ILI Service Provider.
3B		**[Assessment Project Manager]** For reassessments, perform the following steps:
	1	Discuss AGM tracking during the pre-launch meeting.
	2	Provide the AGM summary sheet from the previous inspection.

301.4. Employing Gauge Pigs

4A		**[ILI Service Provider]** Ship gauge tools to Operations/Maintenance Personnel, at least 10 days prior to the inspection.
4B	1	**[Operations/Maintenance Personnel]** Run gauge tools and report results to Assessment Project Manager.
	2	**[Assessment Project Manager]** Report findings to the ILI Service Provider as soon as the information is available but at least two to three days prior to inspection.
Note: The gauge plate tool run can take place either before or after the ILI pre-launch meeting described in Step 5.		

301.5. Conducting the Pre-Launch Meeting

5A	**[Assessment Project Manager]** As soon as practicable (preferably within one week of the scheduled launch date), coordinate ILI run with Schedulers, Control Center, Operations Personnel, and ILI Service Provider.	
5B	**[Attendees]** Topics for discussion (including, but not limited to): • Product schedule • Run conditions • Launching and receiving logistics • PPE requirements • Gauge plate results or schedule • AGM boxes • Intelligent pig type and configuration • Equipment and manpower to load and unload the tool • Manpower to track the tool • Vendor and Operator contacts	
5C	**[Assessment Project Manager]** Document meeting minutes.	
	1	Distribute minutes to Attendees.
	2	Save an electronic copy of the completed form to the assessment documentation folder.
	3	Mark this document as "archived" on the ILI Assessment Closeout Checklist.

301.6. Preparing for the In-Line Inspection

6A	**[Operations/Maintenance Personnel, ILI Service Provider]** Mobilize to the inspection site.	
6B	**[Operations/Maintenance Personnel]** Place the appropriate AGMs at the marked locations, as discussed in the pre-launch conference call.	
6C	1	**[ILI Service Provider]** Perform pre-assessment system check to ensure that the ILI tool is operating correctly, according to the vendor specifications.
	2	If requested, assist Operations/Maintenance Personnel with loading the tool.

301.7. Running the In-Line Inspection Tool

7A	**[Operations/Maintenance Personnel]** Run the ILI tool.	
	1	Launch the tool into the process flow.
	2	Track the progress of the tool run.
	3	**[ILI Service Provider]** Assist in tool tracking, when required.
7B	**[Operations/Maintenance Personnel]** When the tool completes the run, unload the tool and secure the segment for normal operation conditions	
7C	**[ILI Service Provider]** Perform quality assurance checks on the ILI data to ensure the validity of the ILI results.	

301.8. Processing the Preliminary Site Survey Report

8A	**[ILI Service Provider]** Document the validated ILI findings on the Preliminary Site Survey Report and email or fax it to the Assessment Project Manager and the Assessment Engineer.	
8B	**[Assessment Project Manager]** Conduct a data acceptance evaluation of the submitted report, according to Section 3.3., Validation of Results.	
8C	**[Assessment Project Manager]** Update the assessment record in the pipeline integrity database.	
	1	Update the completion date as follows: • For the completion date of in-line inspections, use the date the pig was removed from the receiver. • For the completion date of hydrostatic tests, use the date of the completed hydrostatic test.
	2	Update the tool run record(s) with the following: • Receive Date • Status • Assessed Length Site Survey completion Date

	3	• If full run, Enter the Current HCA length • If partial run, enter the assessed HCA length
8D	1	Save an electronic copy of the completed form to the assessment documentation folder.
	2	**[Assessment Engineer]** Mark this document as "archived" on the ILI Assessment Closeout Checklist.

301.9. Initiating the ILI Assessment Analysis Checklist

9A	**[Assessment Engineer]** Download a blank copy of the ILI Assessment Analysis Checklist from the intranet.	
	1	Complete the Assessment Information section.
	2	Save an electronic copy of the form to the assessment documentation folder.
9C	Mark each step as complete and record comments at each stage of the assessment analysis processes.	
9B	Refer to the Guidance for ILI Data Validation, Data Integration, and Engineering Criticality Assessment for direction on how to perform a complete end-to-end assessment analysis.	
	1	Prior to receiving the Vendor Inspection Survey Report, gather all available information on the assessed segment that may be used for data validation or integration, as described in the guidance document.

301.10. Processing the Vendor Inspection Survey Report(s)

10A	**[ILI Service Provider]** Following a successful in-line inspection, provide the Inspection Survey Report(s) to the Assessment Engineer via email or FedEx according to the schedule outlined in Section 3.1.2., ILI Service Provider Vendor Service Agreement.	
10B	**[Assessment Engineer]** Upon receipt of the ILI data (client list), perform the following steps:	
	1	Validate pipe specifications and segment features, as outlined in the Guidance for ILI Data Validation, Data Integration, and Engineering Criticality Assessment.
	2	Evaluate the client list in the ILI Data Manager application—or manually, if applicable—to determine discovery of prescriptive remediation conditions. **Note:** Discovery of a condition begins when the Assessment Engineer has sufficient information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline.
	3	Generate the following: • ILI Assessment Summary • Casing Corrosion Summary • Anomaly Distribution Summary • XML file (from ILI Data Manager) • DOT regulatory repair list
	4	If applicable, request a temporary pressure reduction, per IMP Procedure 401, Implementation of Temporary Pressure Reduction.
10C	**[Assessment Engineer or Assessment Project Manager]** Issue a summary report (may be from ILI Data Manager) to at least the following SMEs: • IMP Team • Regional Engineering Manager • Pipeline Area Manager • Operations/Maintenance Personnel • Regional Corrosion Manager	
	1	If the data indicates the presence of significant and/or concentrated third-party damage (i.e., topside dents), also forward findings to the Regional HSE Manager.
	2	**[Regional Corrosion Manager]** Review summary of ILI assessment data to identify areas of concern.
10D	1	Save all electronic files to the assessment documentation folder.
	2	**[Assessment Engineer]** Mark document(s) as "archived" on the ILI Assessment Closeout Checklist.

301.11. Initiating the Mitigation Completion Report

11A		**[Assessment Engineer]** Download from the intranet a blank copy of the Mitigation Completion Report, which includes the following information:
		• Dig ID • Work Order (WO) number • Predicted and measured anomaly geometry • Repair due date (remediate by date) • Repair date (actual date of repair) • Repair type • ERF calculation • HCA identification • Comments
	1	Complete the assessment information section.
	2	Enter the list of prescriptive repairs identified in Step 10B.2.
	3	Save an electronic copy of the completed form to the assessment documentation folder.
11B		**[Assessment Engineer]** Upload the XML file to the pipeline integrity database.
	1	Flag DOT regulatory (prescriptive) remediation conditions and add them to the repair tracker.

301.12. Initiating Dig/Remediation Records

12A		**[Assessment Project Manager]** Initiate PIR/DE Forms for each proposed repair or group of repairs.
	1	Review and update the forms according to the requirements of this procedure.
	2	Print hard copies for inclusion with Dig/Remediation Records, if necessary.
	3	Forward the electronic forms to the Operations/Maintenance Personnel via the O&M Forms dashboard.
12B		Create a Dig Worksheet for each anomaly flagged for repair using the uploaded anomaly location diagram from the ILI Service Provider.
12C		Create dig SAP Work Orders as needed.
12D		Assemble the Dig/Remediation Records, which include the Dig Worksheets, PIR Forms, and Dig Checklist.
12E		Send the Dig/Remediation Records and Mitigation Spreadsheet to the Operations/Maintenance Personnel.
	1	If necessary, coordinate Corrosion Personnel to be present during ILI digs to make further observations regarding the corrosion.

301.13. Conducting the Post-ILI Review

13A		**[Assessment Engineer]** Review the in-depth data analysis of the ILI results with SMEs as appropriate.
	1	**[Attendees]** Discuss recommended confirmatory digs.
	2	Review possible corrosion issues, as warranted.
13B		**[Assessment Engineer]** Communicate a summary of the ILI Analysis to the asset stakeholders. Summary should include the following: • A review of prescriptive repairs • Recommendations for additional digs (confirmatory or scheduled repairs) • Recommendations of anomalies for monitoring • Preliminary reassessment interval discussions, if warranted
13C		**[Assessment Engineer]** Update ILI closeout report with outcomes
13D	1	**[Assessment Project Manager]** Update the Mitigation Spreadsheet with the list of discretionary repairs, as needed. Include confirmatory digs and scheduled repairs.
	2	Update the pipeline integrity database repair tracker, as needed.
	3	Initiate dig/remediation records—as described in Step 12—for discretionary repairs.

301.14. Completing Digs and Repairs

14A	**[Assessment Project Manager]** Prioritize repair schedule according to the DOT repair classification.	
	1	If applicable, request temporary pressure reduction per IMP Procedure 401.
	2	Generate the Dig/Remediation Records according to Section 301.12.
14B	**[Assessment Project Manager]** Assist Operations/Maintenance with any issue related to the reported inspection data, provided by the ILI Service Provider.	
	1	Liaise between Operations/Maintenance and the ILI Service Provider regarding inspection data issues.
14C	**[Operations/Maintenance Personnel]** Locate each feature listed in the Mitigation Spreadsheet, and capture all required information for verification and ILI Service Provider data performance evaluations.	
	1	If necessary, repair any defect considered hazardous, or having the potential of becoming a hazardous condition in the near future. See *O&M Manual* Procedure 614, Detailed Pipeline Repair Procedures.

14D	1	Measure and record at least the following information:
		• Defect depth (inches)
		• Defect length (inches)
		• UT wall thickness (inches)
		• Defect orientation (o'clock position)
		• Defect distance from girth weld (feet)
		• Longitudinal seam orientation (o'clock position)
		• Joint length (feet)
		• Defect log distance (feet)
		• Additional observations, as required by
		  • *IMP Manual*, Appendix K, Examination of Exposed Portions of Buried Pipe
		  • *IMP Manual,* Procedure 306, Magnetic Particle Inspection for Defect Investigation, under the direction of the Assessment Engineer

	2	Record all findings on the PIR/Defect Evaluation Forms, including miscellaneous notes, etchings, and other pertinent documentation.
14E	Address all repairs per pipeline segment.	
	1	Approve and submit all PIR/Defect Evaluation Forms to GIS for electronic archive (via O&M system).
	2	Archive PIR/Defect Evaluation Form hard copies in the Regional permanent filing system.
	3	Send the completed Dig/Remediation Records back to the Assessment Project Manager.
14F	**[Operations/Maintenance Personnel]** Periodically email or fax the Mitigation Spreadsheet, or verbally update the Regional Assessment Project Manager on the progress of the repairs.	
14G	**[Assessment Project Manager]** Enter the repair data into the electronic copy of the Mitigation Spreadsheet.	
	1	Generate unity curves from the predicted verses measured data.
	2	Review the dig records for areas of concern.
14H	Track pressure reduction deadlines, repair compliance dates, and methods of repair.	
14I	**[Assessment Project Manager]** File the hard copy Dig/Remediation Records in the Regional permanent filing system and the electronic copies in the assessment documentation folder.	

301.15. Validating Inspection

15A	**[Assessment Engineer]** Compare the actual measured defect data to the ILI to confirm that the ILI data dimensions are within the specified tolerances of the actual measured dimensions.	
	1	Report all findings back to the ILI vendor.
	2	If ILI data are not within specified tolerances, complete step 15B; otherwise, continue with Section 301.16.
15B	1	If any data points are not within tolerances,
	2	**[ILI Service Provider]** reanalyze data to determine why it was out of specification.
	3	**[Assessment Engineer]** If reanalysis cannot validate vendor data, determine if additional digs are required.
	4	If additional digs or data reanalysis cannot validate the ILI results, reject log and re-inspect. **Note:** Section 3, Figure 3-2, In-Line Inspection and Data Evaluation, shows the data verification process.

301.16. Verifying Dig/Remediation Records after Completed Repairs

16A	**[Assessment Engineer]** After the completion of DOT repairs, verify that the required repairs on the Mitigation Spreadsheet are complete and within the required timeframe.	
16B	1	**[Assessment Project Manager]** Verify that each anomaly has the following repair documentation: • PIR/Defect Evaluation Form • Dig Worksheet • Photos/etchings • Additional observations, as required by *Appendix* K • Other documents (OQ, Material Reports, etc.)
	2	Append any additional non-regulatory repairs to the back of the Dig/Remediation Records.
16C	**[Assessment Engineer]** If field measurements of an anomaly are significantly different from those reported by the ILI tool, note the changes in the Mitigation Spreadsheet.	
	1	Note any changes to the repair schedule based on this reclassification.
16D	**[Assessment Project Manager]** File Dig/Remediation Records in the Regional permanent filing system.	

301.17. Compiling the ILI Assessment Closeout Report

17A	1	**[Assessment Engineer]** After the completion of DOT repairs, update the following sections of the ILI Assessment Closeout Checklist: • Dig Observation Highlights • Unity Curves and Tool Accuracy Comments • Preliminary P&M Recommendations • Preliminary Reassessment Interval Recommendations • ILI Supplemental Reports/Analyses
	2	Complete the Observations and Recommendations portion of the report prior to the P&M Meeting.
	3	Use the title page checklist to ensure nothing was omitted from the report.
17E	Archive the ILI Assessment Closeout Report once it receives final approval.	
	1	Create a PDF of the final closeout report and save it to the proper folder on the IMP network drive. **Note:** If the assessment has outstanding correlation digs, save the master files for potential revisions, when correlation digs are complete.

301.18. Revising a Completed ILI Assessment Closeout Report

18A	**[Assessment Engineer]** Update the Mitigation Spreadsheet and append to include data from any correlation digs that were concluded after the ILI Assessment Closeout Report was originally completed.	
	1	If needed, update appropriate recommendations based on information gained from additional digs, adding the heading, “Updated Information [DATE]”, before the new information to differentiate it from the original.
18B	Add “Revised [DATE]” under the original report date on the title page.	
18C	Replace the bound, hard copy in the Regional filing system, and the electronic PDF and master files on the IMP network drive, discarding the originals.	

302: Failure Analysis

Introduction

DOT regulations require all pipeline operators to address integrity issues on their pipelines. This procedure demonstrates the actions NuStar will follow when a hydrostatic test failure or in-service failure occurs.

Regulation

Not applicable

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar.

Resources

Hydrostatic Test Leak Report (see *O&M Manual* Procedure 609, Pipeline Hydrostatic Testing)

Pipeline Information Report/Defect Evaluation Forms (PIR Forms)

Pipe Specimen Analysis Report

Appendix C: Pipe Sample Handling and Analysis Processes

O&M Manual Procedure 610: Failure Analysis

302.1. Failure Excavation

1	**[Operations/Maintenance Personnel]** Locate and excavate the failure per O&M Procedure 610.

302.2. Failure Documentation

2A	**[Operations/Maintenance Personnel]** Take pictures of excavated failure and fill out the following forms: • PIR Forms • Hydrostatic Test Leak Report (if applicable) **Note:** Pay special attention to seam location and document if failure occurred in seam.
2B	Send pictures and PIR Forms to the Technical Services Director/Manager and send a copy to the IMP Department.

302.3. Failure Analysis

3A	**[Operations/Maintenance Personnel]** Remove the failed portion of pipe (including at least 1 foot of sound pipe on each side of the failure).
3B	**[Assessment Project Manager]** Send the pipe sample to an independent mechanical testing laboratory for a failure analysis, which may include the specific tests listed in Table 302-1.
3C	**[Assessment Engineer]** Determine the specific tests to perform on the specimen from those listed in Table 302-1.
3D	Distribute the laboratory's Pipe Specimen Analysis Report internally to proper departments for further action, as identified in the distribution list on the form.

Table 302-1: Pipe Testing Protocol

Test	Description
Pipe Body Tensile Test	Specimen orientation as specified in API 5L (transverse for > 8⅝-inch OD, longitudinal for < 8⅝-inch OD). Test results include yield strength, tensile strength, and elongation. Results indicate mechanical strength level of the pipe, which can be compared to the minimum requirements for various pipe grades given in API 5L (the edition in effect at the time the pipe was manufactured, if known).
Chemical Analysis	The content in weight percent of the following elements: C, Mn, P, S, Si, Al, Cu, Ni, Cr, Mo, V, Ti, Cb, Ca, and B. Results can be compared to the minimum requirements for various pipe grades given in API 5L (the edition in effect at the time the pipe was manufactured, if known).
Hardness Tests	Specimens (often the tensile test tab) are subjected to hardness tests (either Brinell or Rockwell). For hot rolled carbon steel, there is a relationship between hardness and tensile strength (not yield strength). Hardness and tensile test results are compared to assure consistency.
Charpy V-Notch Impact Tests	Specimens are broken over a range of temperatures representing the full ductile-to-brittle transition. For each specimen, results include test temperature, absorbed energy (ft-lbs), percent shear area, lateral expansion, transition temperature (taken at 85% shear appearance), and upper-shelf impact energy (taken at 100% shear appearance).
Metallography	To identify the longitudinal seam type, the microstructure of specimens of the pipe body and the weld area are examined. Pipe body specimens can reveal the type of material (e.g., cast iron, wrought iron) and sometimes the type of steelmaking (e.g., Bessemer, Open Hearth, or BOF). Weld specimens indicate type of welding process (especially differentiating between D.C. and low-frequency or high-frequency ERW) and whether a post-weld heat treatment was performed. (The Pre-Investigation Pipe Failure Handling Procedure in Appendix C, Vendor Procedures details the process to follow when selecting material to submit for seam type determination.)
Visual Examination	To evaluate pipe condition, the pipe surface (OD and ID) is examined for evidence of anomalies and defects using non-destructive examination (MT is preferred) of the pipe OD surfaces. Any evidence of cracks or other anomalies and photograph anomalies is noted.

303: Corrosion Control Effectiveness Review

Introduction

This procedure validates the corrosion control program effectiveness for line segments and outlines the process for integrating cathodic protection data with hydrostatic test integrity assessments.

Regulation

49 CFR §195.452(g) (2) Data gathered through the integrity assessment required under this section; (3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys.

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar.

Resources

Corrosion Control Manual

Corrosion Control Effectiveness Review Form (in Appendix F: Forms)

303.1. Completing and Documenting the Review

1A	**[Corrosion Manager]** Whenever NuStar performs a hydrostatic test as part of an integrity assessment, perform the following sub-steps:		
	1	Gather corrosion control data per *Corrosion Control Manual,* Section 5.3.3., Pipelines Not Designed for In-Line Inspection.	
	2	Complete the Corrosion Control Effectiveness Review Form.	
		a	If there are any deficiencies, create action plans and enter them into the Cathodic Protection Data Manager (CPDM) for tracking and completion.
	3	Submit the completed form to the Assessment Engineer.	
1B	**[Assessment Engineer]** Append the completed form to the hydrostatic test records and transmit to Assessment Project Manager.		
1C	**[Assessment Project Manager]** Collect all required documentation, digitize, and file in the appropriate segment folder in the pipeline integrity database.		

304: Guided Wave Ultrasonic Testing

Introduction

NuStar may use Guided Wave Ultrasonic Testing (GWUT) on cased, buried, or above-ground steel pipe to locate and evaluate areas of metal loss. When GWUT is used as Other Technology, PHMSA must be notified 90 days prior as required by the Rule *§(c)(1)(i)(D)* and *§(j)(5)(iv).*

GWUT uses a transducer collar that is temporarily or permanently installed on a section of the pipe to impress ultrasonic energy on the pipe, and detect the ultrasonic energy reflected back from features, such as, weld joints, bends, flanges, and metal-loss anomalies. Because ultrasonic energy is transmitted and detected in both directions, testing must be performed on both sides of the transducer collar location. For buried pipe, inspection distances are usually 40–150 ft on either side. The type of coating, coating thickness, annular fill in a casing, and presence of bends or fittings, typically affect the range of the GWUT.

GWUT cannot distinguish between internal and external corrosion, so pipe that is directly examined (per *Corrosion Control Manual* Section 4.2., Examination of Exposed Portions of Buried Pipe and *IMP Manual* Appendix K) must be tested at the anomaly with an ultrasonic pipe thickness tester to identify internal corrosion.

Regulation

49 CFR §195.452 (c)(1)(i)(D) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

49 CFR §195.452 (j)(4)(i) Engineering basis: An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation, combined with the use of other technology, such as external monitoring technology that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j)(5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval, and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section.

49 CFR §195.452 (j)(5)(iv) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conducting the assessment by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

FAQ 6.23 If Guided Wave UT is used as part of the ECDA process, is it considered other technology requiring notification? Use of guided wave technology, alone, as an examination method or an alternative to excavating pipeline to conduct a direct examination would be considered other technology, and would require notification prior to use. If guided wave UT is used as one of the complementary tools for indirect inspections as part of ECDA, however, it would not be considered other technology. NACE RP0502-2002 lists some indirect inspection tools, but notes that they are not the only tools that can be used. Rather, they are representative examples. "Other indirect inspection methods can and should be used as required by the unique situations along a pipeline, or as new technologies are developed. [The operator must] assess the capabilities of any method independently before using it in an ECDA program" (3.4.3.1.).

Scope

This procedure applies to all pipelines and station piping operated by NuStar. Per the Rule, it may be used as a qualified IMP assessment when GWUT is part of the External Corrosion Direct Assessment (ECDA) process, or if PHMSA approves GWUT as a standalone tool to assess 100% of the HCA segment.

304.1. PHMSA Notification

1A	**[Assessment Engineer]** Determine if GWUT will be performed either: • As standalone technology to evaluate 100% of an HCA segment • In conjunction with an approved assessment method, such as ECDA, to evaluate pipe within a HCA	
1B	If GWUT will be performed as a standalone assessment, fill out the OPS Integrity Management Notification Form (see Appendix F, Forms) and submit it to the IMP Manager for approval.	
	1	**[IMP Manager]** Review/approve the notification form.
	2	**[Assessment Engineer]** Submit the approved notification form to PHMSA by one of the following methods: • Online: http://primis.phmsa.dot.gov • Fax: 202-366-7128 • Mail: Information Resources Manager Pipeline Safety Pipeline and Hazardous Materials Safety Administration U.S. Department of Transportation Room 7128 400 Seventh Street SW Washington DC 20590
1C	If GWUT will be performed in conjunction with ECDA, follow NACE RP 0502. **Note:** Per FAQ 6.23, PHMSA notification is not necessary in this case.	

304.2. GWUT Service Provider Qualifications

2A	**[Assessment Engineer or Operations/Maintenance Managers]** Require the potential GWUT Service Provider(s) to provide all necessary qualifications/requirements during the contractor selection process, in order to ensure that a qualified GWUT Service Provider will perform all GWUT assessments.	
2B	**[GWUT Service Provider]** Use a qualification program that is modeled after American Society for Nondestructive Training (ASNT), or another recognized training accreditation society and meet the following qualifications/requirements.	
	1	Provide qualified personnel with the following equipment-specific training and experience in equipment operation, field data collection, and data interpretation: • At least one week of classroom training and successful completion of coursework testing • At least one week of documented field training specifically related to buried steel pipelines and buried cased steel pipelines • Prior experience testing similar pipe with the equipment • To perform the testing, either a Senior Level GWUT Equipment Operator (one who has additional training and experience using the equipment with cased and buried pipe), or a First Level Operator whose data will be analyzed by a Senior Level Operator • To analyze the data for the final GWUT Service Provider Report, a Senior Level GWUT Equipment Operator (analysis includes data interpretation for filter screening, the conversion of wave signals, and the interpretation of metal loss)
	2	Provide documented test and data analysis procedures for the following aspects: • Method for converting the area of metal loss into length and depth determinations • Inspection parameters (e.g., frequencies, modes, amplitudes, signal-to-noise ratios)
	3	Provide documented GWUT quality assurances that include the following measures: • Training/qualification program for personnel • Safety precautions • Verification of equipment operating conditions prior to the assessment • Proper equipment calibration

304.3. Equipment Specifications

3	**[GWUT Service Provider]** Use the following equipment during the assessment: • GUL (G3 or newer) or Teletest (Rev 3 or newer) equipment and software, which are specifically developed to operate the instrument transducer • A GWUT test instrument transducer collar with signal output capabilities, specifically suited for the relevant pipe installation conditions (e.g., cased coal tar-coated pipe, direct buried Fusion Bonded Epoxy [FBE]) • An analysis product that is part of the hardware/software tool, referenced above, that provides preliminary on-site data analysis of each test conducted • Filters (if required to remove noise from the reflected waveform) that do not detract from the tool's accuracy

304.4. Equipment Documentation

4A	**[GWUT Service Provider]** Prior to the assessment, provide the Assessment Engineer or Operations/Maintenance Managers with a calibration certificate, or similar proof of equipment calibration from the manufacturer that includes the following documentation: • Date of last calibration* • Name/qualification level of the technician who performed the calibration* • Method of calibration (specify self-calibrating if using GUL or any other self-calibrating tool) • Due date for next calibration* • Tool tolerance specifications with confirmation that the tool is performing within those tolerances • Serial number, version number, or other identification of the equipment being used (collars, computer hardware and software, B-Scan tool, etc.), indicating that it is the latest version (unless noted and justified) * For equipment that is self-calibrating in the field (e.g., GUL), original factory calibration information is still needed	
4B	1	Document the use of noise elimination filters and confirmation that such filters will not detract from the tool's accuracy.
	2	Provide this documentation in the GWUT Service Provider Report.
4C	1	Document the type of sensors being used (e.g., single or dual) and the spacing of those sensors.
	2	Provide this documentation in the GWUT report.
4D	1	Document the status of the algorithm used to determine the extent of metal loss, including the following information: • Software revision number • Algorithm age • Algorithm updating • Algorithm validation • Algorithm tolerance and accuracy
	2	Provide this documentation in the GWUT report.

304.5. Pre-Assessment Information

5A	**[Assessment Engineer]** Identify the locations where GWUT will be performed based on estimated signal attenuation provided by the vendor.
5B	**[Assessment Project Manager]** Gather the following pre-assessment data pertaining to the pipe segment(s) to be assessed: • Location and identification information* • Length intended for assessment* • Pipe depth** • Pipe diameter* • Wall thickness** • Pipe grade • Maximum Operating Pressure (MOP) • Operating stress level (% Specified Minimum Yield Strength [SMYS])

	• Joint type • Year of installation • Coating type** • Locations of valves and fittings • Locations of bends • As-built drawings/alignment sheets • Repair history • Any adjacent metal objects * Required ** If not obtained during pre-assessment, gathered once exposed per 7B (consult the vendor regarding tool performance with concrete-coated pipe).
5C	For cased pipeline locations, also compile the following information: • Length of casing • Construction practices at casing (e.g., spacers) • Medium with which annular space is filled (e.g., water, dirt, wax, air) • Whether the casing is shorted to the carrier pipe • Whether one end of the casing is lower than the other
5D	Provide the GWUT Service Provider and Operations/Maintenance Managers with the completed form and related information prior to performing the assessment.

304.6. Assessment Preparation

304.6.1. Dig Planning Requirements

6A	**[Assessment Project Manager]** Prior to performing excavations, develop a dig plan according to the following requirements. Consult with the GWUT Service Provider for specific limitations for the given tool to be used. • Buried pipe will require a full-encirclement excavation. • The tool vendor will provide the minimum required clearance for the particular collar being used. The clearance between the bottom of the pipe and the floor of the excavation can be as small as 3 in. in some cases, but the preferred minimum clearance is 6 in. If there is standing water in the excavation, clearance is measured from the top of the water. • For buried pipe in a casing, the transducer collar should be placed on the carrier pipe approximately 5 ft outside the casing on both sides. See Figure 304-1. • The collar locations should be spaced to ensure that the shot meets the 5% minimum overlap, 2:1 minimum sound-to-noise (S/N) ratio, and 5% maximum CSA (Cross Sectional Area) sensitivity requirements. See Figure 304-2. If the end of the casing is not accessible, the transducer should be placed in a location that allows the collar to be moved to multiple locations within the excavation in order to maximize the length of pipe inspected, and ensure that no area intended for inspection falls within the Dead Zone or the Near Field. See Figure 304-3. • For buried pipe not in a casing, the transducer collar should be placed approximately 5 ft outside the area to be assessed. This distance will vary with the given pipe condition and with the tool and tool frequency used. See Figure 304-1. As an alternative, the transducer collar may be placed in the middle of the pipe segment to be assessed, and the collar moved to multiple locations to ensure that the entire pipe is assessed and that no part of the pipe is missed because of the Dead Zone, or the Near Field. See Figure 304-3.
6B	Apply for the appropriate permits, taking into account that certain permits may require several months for processing.

Figure 304-1: Properly Placing the Transducer in Relation to the Region of Concern (ROC)

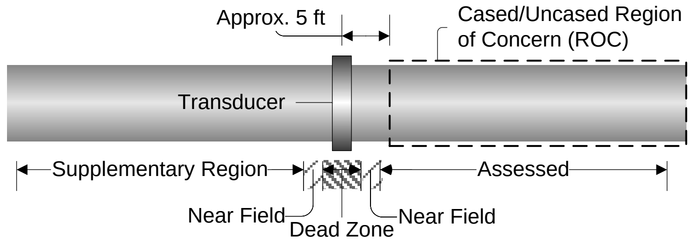


Figure 304-2: Overlapping Shots and Using a Complementary Nondestructive Evaluation (NDE) Tool for Dead Zones and Near Fields

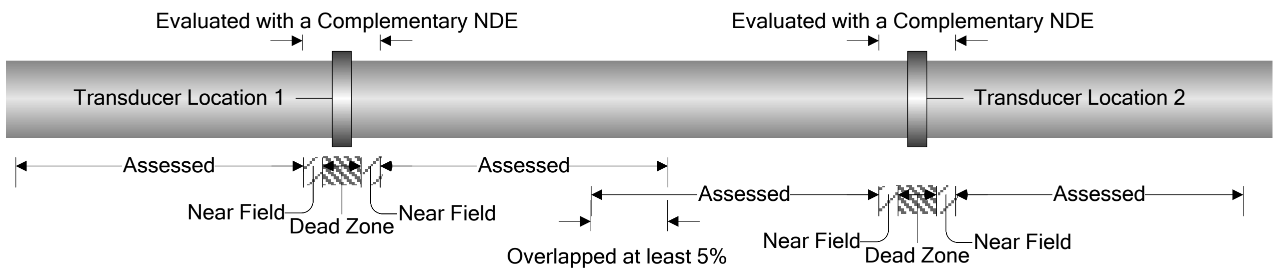
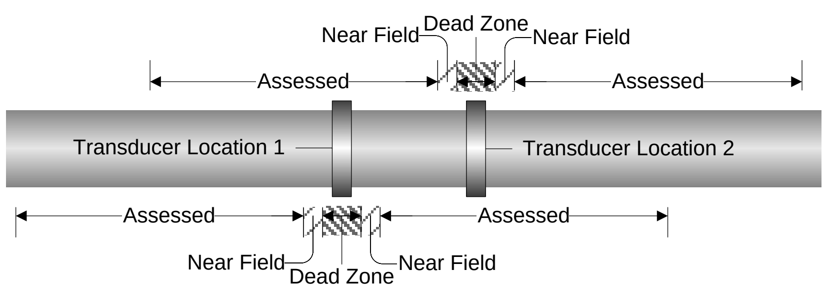


Figure 304-3: Moving the Transducer to Assess Dead Zones and Near Fields



304.6.2. Dig Planning Recommended Logistics

6C	**[Operations/Maintenance Managers]** To ensure the most efficient use of tool time, the preferred method is to pre-dig several of the locations selected for transducer placement, based on the estimated signal range given by the GWUT Service Provider.	
	1	Ensure that these sites are fully prepared so the GWUT Technician can enter the excavated trench and connect the transducer collar without having to wait for the pipe to be exposed and/or the coating removed.
	2	Once the first few pre-dug locations are assessed and the distance per shot is known, have the remaining sites excavated ahead of the assessment, using the actual signal distance from the pre-dug locations. **Note:** Consider employing multiple excavators to stay ahead of the GWUT Technician.

304.6.3. Dig Planning Notifications

6D		**[Operations/Maintenance Personnel]** Apply for appropriate locates of buried facilities prior to performing the excavations.
	1	Notify the applicable state One-Call systems, noting the following considerations: • A lead time of two working days is required. • Locates generally expire after two weeks.
	2	Contact other non-participating utilities to locate their facilities near the proposed excavations.
	3	Ensure that all NuStar facilities involved in the assessment, as well as any nearby facilities that may not be covered, are properly located and marked prior to excavation.

304.7. Excavation and Direct Examination

7A			**[Operations/Maintenance Managers]** Ensure that a qualified dig technician is on-site to examine the pipe during excavation, preparation for the GWUT inspection, and coating repair after the collar is removed, per Appendix K, Examination of Exposed Portions of Buried Pipelines.
7B	1		**[Operations/Maintenance Personnel]** Using the Pipeline Information Report/Defect Evaluation (PIR) Form, evaluate the condition of the coating and note if any corrosion is present.
	2		Ensure that the Excavation Crew removes an approximately 6-ft full-encirclement area of coating for collar placement. **Note:** It may not be necessary to remove the coating from FBE-coated pipe, or from painted or bare pipe; such might be found in above-ground applications. Consult the tool vendor for specific guidance on each application.
	3		If the coating is removed, verify that the pipe is cleaned to smooth, bare metal.
	4		If the coating is removed, examine the pipe and perform the testing necessary to complete the PIR Form.
		a	If any of the required data elements from 5B need to be gathered when the pipe is exposed, record them with the inspection.
	5		Notify the Operations/Maintenance Managers and the IMP Manager as soon as possible of any adverse condition (e.g., mechanical damage, deep pitting, Stress Corrosion Cracking [SCC] evidence) found during the examination and complete the defect evaluation portion of the PIR Form.
	6		If GWUT will be performed on cased pipe and if the end of the casing is exposed, remove the casing end seals and visually inspect the first 2–5 ft of the pipe. Record results on the PIR Form. **Note:** If the casing is shorted and it must remain shorted for the assessment, the assessment may not be considered a qualified integrity assessment, per the Rule, unless justification for not clearing the short is provided along with the notification for approval of Other Technology.
		a	If the casing is intentionally filled with wax or another electrolyte, do not remove the casing end seals.
		b	If the end seal does not have to be removed (such as clearances with the road surfaces or railroad tracks), justification must be provided and documented.

304.8. GWUT Inspection

8A	1	**[GWUT Service Provider]** Once the pipe has been examined, perform the GWUT according to the requirements of this procedure.
	2	Perform a diagnostic check of the equipment to ensure that it is operating within its acceptable limits. (The GUL tool does this automatically and will not allow the user to operate it if it is not performing within its allowable limits.)
	3	Perform a minimum of two shots at each location for each direction using the torsional wave configuration as a minimum. If longitudinal waves are used in conjunction with the torsional wave, distinguish the data obtained, using the torsional wave from that obtained using longitudinal waves.
	4	Attach the collar and take a shot in both directions (if applicable) using 5% or better CSA sensitivity settings on the tool. Use a lower setting whenever possible; use a higher setting only when background noise is too great in order to meet the overlap requirements of 8A.5. The CSA sensitivity setting in the final shot may not exceed 5%.

	5		Determine the collar location for the next shot based on the length obtained by the initial shot, while ensuring that a 5% minimum overlap, a 2:1 minimum S/N ratio, and a 5% maximum CSA sensitivity are present throughout the shot distance. Refer back to Figure 304-2.
	6		If the tool is capable (e.g., GUL), use a pitch-catch configuration to confirm mirror echoes without having to move the collar. Otherwise, complete the following steps to confirm mirror echoes:
		a	Move the collar a distance of at least 1 ft from the original location, or change the transducer spacing and leave the collar in the original location. Take another shot in each direction to validate the results of the initial shots. **Note:** A minimum of 5% overlap that meets the 2:1 minimum S/N ratio and 5% maximum CSA requirements, must be maintained.
		b	Review the results of the shots and verify that both shots detect the same anomalies/features.
		c	If the shots do not indicate the same features/anomalies, identify the reason(s) for the discrepancy and ensure that the tool is functioning properly.
		d	Perform additional shots as needed to ensure two consecutive shots with the same features/anomalies.
	7		Use a GWUT frequency that both maximizes the range of the inspection and minimizes the Dead Zone. Change the transducer spacing as necessary to achieve this goal.
	8		Take multiple shots as necessary using varying frequencies to achieve optimal results. After the optimum frequency has been determined, check at least three frequencies—the optimum, one greater than the optimum, and one less than the optimum. **Note:** This step is automatically done by the GUL G3 tool.
	9		For cased pipe locations, determine if the shot assessed the entire length of the cased pipe.
		a	Even if the entire length of cased pipe was assessed, perform an inspection from the opposite end of the casing and compare the overlap to ensure that the same anomalies are called out from both directions.
	10		If the pipeline is cased and the entire segment cannot be assessed using GWUT technology (i.e., for long cased pipeline segments), determine if the casing must be modified to allow for complete inspection by the GWUT tool. or if an alternative assessment method must be selected.
	11		Provide preliminary results to the Operations/Maintenance Personnel with metal-loss anomalies broken down into the following categories set by the GWUT tool: • **Indications Above the 5% Cross-Sectional Area Threshold:** These are locations for which indications are evident on the data attenuation curves but the CSA sensitivity exceeds the 5% maximum. At locations where GWUT is used as an other technology standalone IMP assessment under the Rule, such as, at cased crossings, this procedure must be used as a Go/No-Go procedure. No matter what the category of the estimated corrosion, all indications greater than 5% CSA must be directly examined. • **Minor or Non-reportable Corrosion:** This corrosion has caused 10% to less than 26% cross-sectional area loss; the defect is usually identified on pipe in good general condition. • **Medium Corrosion:** This corrosion has caused 26% to less than 50% cross-sectional area loss; the defect is oriented in such a way that it will not likely become a through-wall defect. • **Severe Corrosion:** This corrosion has caused cross-sectional loss equal to or greater than 50%; the defect has the possibility of being a through-wall or virtually through-wall defect. **Note:** The Minor, Medium, and Severe Corrosion evaluation categories above are allowed only when GWUT is *not* being used as an other technology standalone IMP assessment, or as a Go/No-Go assessment.
	12	a	Recommend appropriate locations for validation examinations based on a preliminary evaluation of the Distance Amplitude Correction (DAC) curves from the shots. **Note:** The DAC curve takes into account attenuations caused by coating, pipe diameter, pipe wall thickness, and environmental conditions for the given test site.
		b	Indicate all locations that could be considered severe metal loss.
	13		For each validation location, provide Operations/Maintenance Personnel with the distance of the validation locations in reference to the collar location or another feature.
	14	a	If this procedure is used as a standalone qualified IMP assessment under the Rule, achieve 100% assessment for the Region of Concern (ROC) by performing shots that meet the requirements of a minimum of 5% overlap with a 2:1 minimum S/N ratio and a 5% maximum CSA. Refer to Figure 304-2. **Note:** If 100% inspection (with the required overlap) of the full pipe length cannot be performed, then GWUT is not considered a qualified other technology standalone IMP assessment under the Rule, and an alternative assessment method must be used for that section of pipeline.
		b	If any section of pipe in the ROC does not meet this requirement, perform a 360° B-Scan (or use a comparable handheld manual ultrasonic Nondestructive Evaluation [NDE] tool). See Figure 304-1.

		c	If the Dead Zone is located in an area that cannot be accessed, such as inside a casing, relocate the collar further away to enable the GWUT tool to assess the section.
8B	**[Operations/Maintenance Personnel]** Ensure that the GWUT Service Provider is performing the assessment, per the contract and procedural requirements.		
8C	Complete the PIR Form during the inspection.		
8D	Review the initial results provided by the GWUT Service Provider.		
8E	Review the recommendations of the GWUT Service Provider regarding the locations of validation examinations.		

304.9. Validation Locations

304.9.1. Determining the Number of Validation Locations

9A	**[Operations/Maintenance Personnel, Operations/Maintenance Managers, and Assessment Engineer]** To determine the required number of validation examinations, first categorize the examinations into GWUT Groups that meet all of the following requirements: • Assessments conducted using equipment with the same serial number • Assessments conducted and analyzed by the same GWUT Technician • Assessments conducted within the same timeframe (i.e., the same mobilization) • Assessments conducted on pipe with the same pipe characteristics (e.g., same vintage of pipe, construction practices, coating type, and diameter)
9B	Identify the number of validation examinations according to the following guidelines: • Perform at least one validation dig per GWUT Group. • A metal loss indication deemed Severe is an Immediate repair condition; excavate and verify the extent of the metal loss through a company approved measurement device (e.g., Pit Gauge, B-Scan). • A metal loss location deemed Medium is a 180-Day repair condition; estimated remaining strength calculations cannot be performed on them using IMP 3.6.1.2, Corrosion Assessment Criteria. • For metal loss locations deemed Minor, excavate at least two such locations per group to determine the extent of the metal loss. • See 11A and B of this procedure for specific details on determining anomaly classification and 12 for determining the remediation schedule. • For features with a CSA greater than 5%, follow the schedule in Table 304-1.

Table 304-1. Preventative Measures Schedule for Features with a CSA Greater than 5%

	< 30% SMYS	**30–50% SMYS**	**> 50% SMYS**
Direct Examination	within 12 months	within 6 months	within 6 months
Leak Survey	one/month	one/month	one/month
MOP Reduction	—	less than psi at discovery	80% of psi at discovery

304.9.2. Selecting the Validation Examination Locations

9C	**[Operations/Maintenance Personnel]** For GWUT applications at cased pipeline locations, perform validation examinations in the Supplementary Region. Refer back to Figure 304-1.	
9D	For GWUT applications at non-cased pipe locations, perform any required validation examination in the ROC.	
	1	If the ROC lies in a “difficult area” (e.g., a stream bed, a major roadway), perform validation examinations in the Supplementary Region.

9E	Choose validation examination locations in the following order of preference: 1) Corrosion anomalies 2) Anomalies in areas not meeting the 5% maximum CSA sensitivity setting requirement* 3) Known features (i.e., girth welds)** 4) No-feature locations *Such anomalies must have a direct examination or be replaced. **In all other cases, at least one weld must be excavated and measured to validate the equipment and aid in constructing the DAC; if validation cannot be accomplished, the GWUT assessment is not considered feasible.
9F	Ensure that the GWUT Service Provider provides the distance from a physical reference point, as well as the sizing (for metal loss anomalies) of the feature to be used for validation. **Note:** It may be possible to extend the length of an existing excavation to use for the validation examination.
9G	Attempt all validation examinations while the GWUT Technician is still on site. **Note:** Results from the validation digs will help the GWUT Service Provider analyze the inspection data.

304.9.3. Performing the Validation Examination Locations

9H	1	**[Operations/Maintenance Personnel]** Perform the validation examination in accordance with Appendix K.	
	2	Complete all applicable sections of the PIR Form.	
	3	For examinations at a corrosion anomaly, complete the following tasks:	
		a	Locate the approximate anomaly location based on guidance from the GWUT Service Provider, or GWUT report references.
		b	Remove a full-encirclement area of coating at the area of the anomaly, making note of the coating condition prior to removal.
		c	If external corrosion is found, verify the corrosion anomaly dimension from the reference point, as given by the GWUT Service Provider or GWUT report references.
		d	Measure the defect pit depth, if applicable.
		e	Measure the maximum defect length, if applicable.
		f	Send the results to the Assessment Engineer to evaluate the remaining strength of the pipe using IMP 3.6.1.2, Corrosion Assessment Criteria for each metal loss anomaly, if applicable.
		g	Take ultrasonic thickness measurements around the circumference of the pipe at the four different o'clock positions (e.g., 12:00, 3:00, 6:00, 9:00).
		h	If no external corrosion is evident, perform a 360° B-Scan of the pipeline at the location where the metal loss anomaly was identified by the GWUT Technician, as well as 18 in. to either side of the location.
		i	Document the results on the PIR Form.
		j	Take photographs documenting the pipe condition.
		k	Use a paint pen or chalk to write pertinent information on the pipe—pit depth, station number, etc.
		l	Verify that the size of the corrosion anomaly reasonably agrees with the sizing provided by the GWUT Service Provider.
	4	For validation examinations at a known feature (i.e., weld), perform and document the following steps:	
		a	Verify the feature location dimension from the reference point, as given by the GWUT Service Provider or GWUT report references.
		b	Expose the girth weld/feature.
		c	Remove enough coating to positively identify the existence of the girth weld/feature.
		d	Take photographs of the girth weld/feature.
		e	As deemed necessary, remove additional coating to allow additional inspection.
		f	Take photographs documenting the pipe condition.
	5	For validation examinations at a no-feature location, perform and document the following tasks:	
		a	Verify the dimension location from the reference point, as indicated by the GWUT Service Provider or GWUT report references.
		b	If GWUT is being used as part of the ECDA process, remove an approximate 3 ft width of coating around the circumference of the pipe, regardless of the coating condition.

		c	Verify that no external corrosion anomalies exist.
		d	Evaluate the condition of the pipe.
		e	Take ultrasonic thickness measurements around the circumference of the pipe at the four different o'clock positions (e.g., 12:00, 3:00, 6:00, 9:00).
		f	Compare the ultrasonic thickness measurements with the as-built wall thickness to evaluate for internal wall loss.
		g	If wall loss is found, perform a 360° B-scan on the pipe over a 3 ft section of the pipe where the wall thickness did not correspond to the expected value.
		h	Document the pipe examination on the PIR Form.
	6	Make repairs in accordance with O&M Procedure 614, Detailed Pipeline Repairs.	
9I	**[Operations/Maintenance Personnel]** Review the results of each validation examination.		
9J	Determine if the results of the examination reasonably agree with the information provided by the GWUT Service Provider or GWUT report.		
	1	If the results of one or more validation examinations do not agree with the GWUT assessment results, perform a validation examination for the remaining locations in the GWUT Group.	
	2	Re-perform the GWUT assessment at each location where the results of the validation examination do not correlate with the original GWUT results.	
		a	Perform an additional validation examination for each location, or use the results from the previous validation examination.
	3	If the results of the GWUT assessment still do not agree with the results of the validation examination, determine the appropriate response from among the following options: • Recalibration of the equipment and reassessment of all locations • Dismissal of the GWUT Service Provider • Assessment, via an alternate technology	
	4	Request assistance/feedback from the Assessment Engineer or Operations/Maintenance Managers, as deemed appropriate.	
	5	Resolve discrepancies with the GWUT Service Provider, as necessary.	
9K	1	**[Operations/Maintenance Personnel]** Upon completion of the inspection, ensure that the pipe is recoated per *Corrosion Control Manual* Section 4, Coating Inspection.	
	2	Using a submeter GPS Unit (or equivalent means of accuracy and repeatability for determining spatial location), mark each location where the transducer collar was placed on the pipe and place a black zip tie on the pipe at that location, as well after the pipe has been recoated.	
	3	As needed, reattach/install new test leads per *Corrosion Control Manual* Section 5.9.1, Test Station Installations.	
	4	As needed, replace casing end seals.	
	5	As needed, repair or replace casing vents.	
	6	If a shorted casing is encountered, attempt to clear the short.	
	7	Backfill and restore the excavation site.	

304.10. GWUT Service Provider Report

10A	**[GWUT Service Provider]** Within 30 days of completing the field inspection, provide the Assessment Engineer or Operations/Maintenance Managers with two printed copies and one electronic PDF copy of the GWUT Service Provider Report, including the Reflected Wave Plots.
10B	Submit a copy of the invoice to the Assessment Engineer.
10C	Ensure that the GWUT report is reviewed and signed by both: • The person analyzing the results • A second qualified person designated by the GWUT Service Provider

10D	Use the GWUT Service Provider Report Checklist (in Appendix F, Forms) to ensure that the following components are included:
	• A cover page that includes the full customer name, pipeline name, inspected section location, date of inspection and date of report
	• A project scope description
	• Color photographs of, at minimum, the following features:
	  • Excavation opening from grade, including ditch shoring and support
	  • Exposed pipe
	  • Transducer collar attached to the pipe
	  • Transducer collar drive electronics showing the manufacturer and model
	  • Casing end seal, if applicable
	  • Exposed weld joints, if available
	• A color analysis plot for the entire length of inspected pipe, including marked locations of weld joints, bends, casing seals, casing spacers, collar locations, dead zone/near field lengths, and anomalies
	• Anomaly data, including the following information:
	  • Estimated CSA sensitivity per anomaly
	  • Location dimension from the zero reference point
	  • Wall loss estimate
	  • Defect length estimate
	• Documentation of the method used to convert the area of metal loss into length and depth determinations
	• Specifications on test equipment, including the transducer manufacturer/model number, the transducer drive unit, and other significant test equipment information
	• Test procedure—including frequencies and wave type used for each shot
	• Overall assessment of pipe inspected
	• Summary of unusual conditions, if found
	• GWUT quality assurances, including the following information:
	  • The training/qualification program for personnel
	  • Safety precautions
	  • Verification of the operating condition of the equipment prior to performing the inspection
	  • Equipment calibration
	  • Summary of compliance with GWUT quality assurances
	  • Summary tutorial of the GWUT test process with a specific overview on reflected response data analysis methodology
	  • Tool tolerances and signal attenuation at each inspection location
	  • Single line diagram showing that 100% of pipe was assessed by GWUT, or direct exam that the overlap requirements of 307.8 were met
	  • Validation examination documentation including: locations, measurement techniques, and comparison of as called versus as measured
	  • Items listed in Steps 4B, 4C, and 4D

10E	**[Assessment Engineer]** Review the GWUT Service Provider Report.
10F	Review the GWUT color analysis plot(s).
10G	Verify that the plots/report meets the following requirements: • Each of the required items from 10D are included • The GWUT shot(s) cover(s) the entire length of pipe intended for inspection • Feature locations (e.g., weld joints, casing seals, pipe supports) marked on the color plots agree with known information about the pipeline
10H	Contact the GWUT Service Provider to obtain any missing information; or resolve any discrepancies.
10I	**[Assessment Project Manager]** Once all contract requirements have been met, notify the Operations/Maintenance Managers that the invoice can be paid.
10J	Pay the invoice as soon as contract requirements have been met.

304.11. Anomaly Classification

11A		**[Assessment Engineer]** Within 30 days of receiving the GWUT Service Provider Report, calculate the estimated remaining strength using IMP 3.6.1.2. Corrosion Assessment Criteria, for each metal loss anomaly provided in the GWUT report if such calculations were not included. **Note 1:** At locations where GWUT is used as an other technology standalone IMP assessment under PHMSA, such as at cased crossings, this procedure must be used as a Go/No-Go procedure. No matter what the category of the estimated corrosion, all indications greater than 5% CSA must be directly examined. **Note 2:** The GUL G3 line can produce the estimated anomaly dimensions of axial length and depth required for remaining strength calculations, such as, B31.G or RSTRENG. Currently, Teletest equipment cannot sufficiently discriminate between the axial and circumferential length of a metal loss anomaly to be used in remaining strength calculations; therefore, dig priority must be based on cross sectional area loss as described in Section 304.8. GWUT Inspection for Go/No-Go assessments.
11B		When calculating the estimated remaining strength for a particular anomaly, adjust the values used in the calculation (i.e., depth and defect length) by a vendor-specified tolerance, typically 5–10%, to account for any error that may be inherent in the tool.
	1	It is possible to increase the variables used in the estimated remaining strength calculation by a value less than vendor-specified tolerances, provided the direct examination results support lesser values.
	2	Document a complete technical justification for any values used below vendor-specified tolerances and submit it to the IMP Manager for review and final approval.
	3	Upon direct examination, it is possible to revise estimated remaining strength calculations based on the direct measurements of the axial length and depth dimensions. If necessary, the anomalies may be reclassified for remediation accordingly. **Note:** In order to meet the Rule *§(h)* requirements for using GWUT as an other technology standalone IMP assessment, all anomaly locations identified by the Go/No-Go procedure, must be directly examined within 6 months of the GWUT assessment.

304.12. Remediation

12A	**[Assessment Project Manager]** Respond to repair conditions per Section 4, Remedial Action.
12B	**[Operations/Maintenance Managers]** For all anomalies that meet remediation requirements, remediate per O&M Procedure 614.

304.13. Reassessment Intervals

13A		**[Assessment Engineer]** When GWUT technology is used as an IMP integrity assessment method, determine an appropriate reassessment interval.
13B		For each assessment location, identify the most severe anomaly remaining in the ROC.
13C	1	Determine the corrosion growth rate for the anomaly using the soil resistivity chart from ASME B31.8S, per IMP 3.4.1, Corrosion Rates for Determination of Reassessment Intervals.
	2	Assume 12 mpy if the soil resistivity data is unavailable and another engineering-based estimation for growth rate is unavailable.
13D		Calculate the estimated time for remaining defects to grow to critical size, using the POE Analysis described in IMP 3.5, Probabilistic Approach for Consideration of Tool Tolerances (POE Analysis).
13E		If no anomalies were detected or if all anomalies were remediated in the ROC of the assessed pipe, then set the reassessment interval at 5 years, based on the maximum interval allowed per the Rule. **Note:** The Assessment Engineer will document the reassessment interval on the Assessment Schedule worksheets; the reassessment interval will also be evident on the POE spreadsheet.

304.14. Post Assessment

14A	**[Assessment Engineer]** Evaluate the results of the GWUT inspections.
14B	**[Corrosion Manager]** Determine if active corrosion was found during the integrity assessments; and take steps to mitigate it per *Corrosion Control Manual* Section 5.3., Cathodic Protection Criteria.

305: Direct Examination

Introduction

NuStar may use Direct Examination (DE) on exposed steel pipe to locate and evaluate areas of metal loss or mechanical damage. DE is considered Other Technology when used as a standalone IMP technology for covered segments as identified in Section 1.6, Identification of Segments That Could Affect HCAs; therefore, notification must be submitted for approval to PHMSA 90 days prior, as required by the Rule *49 CFR §195.452 (c)(1)(i)(D)* and *49 CFR §195.452 (j)(5)(iv).*

DE, in the context of this procedure, is a direct visual examination of the pipeline to assess for external corrosion or deformations. Any identified anomalies are measured, evaluated for effect on integrity, and remediated as necessary.

This procedure does not cover assessment methodologies for pipe that is susceptible to internal corrosion, SCC, or long-seam failure.

Regulation

49 CFR §195.452 (c)(1)(i)(D) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

49 CFR §195.452 (j)(5)(iv) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

Scope

This procedure applies to DOT jurisdictional pipelines operated by NuStar that meet the following criteria:

- 100% accessible for direct visual examination
- No threat of internal corrosion—as in the case of anhydrous ammonia pipelines
- Not susceptible to long-seam crack threat—per Section 2.2.3, Longitudinal Seams—or stress corrosion cracking (SCC)—per Section, 2.2.2 Stress Corrosion Cracking

305.1. PHMSA Notification

1A		**[Assessment Engineer]** Determine if DE will be performed as standalone technology to evaluate an HCA segment
1B		If DE will be performed as a standalone IMP assessment, fill out the OPS Integrity Management Notification Form (see Appendix F, Forms) and submit it to the IMP Manager for approval.
	1	**[IMP Manager]** Review/approve the notification form.
	2	Submit the approved notification form to PHMSA by one of the following methods: • Online: http://primis.phmsa.dot.gov • Fax: 202-366-7128 • Mail: Information Resources Manager Pipeline Safety Pipeline and Hazardous Materials Safety Administration U.S. Department of Transportation Room 7128 400 Seventh Street SW Washington, DC 20590

305.2. DE Technician Qualifications

2	**[Assessment Project Manager]** Require the potential DE Technician(s) to provide all necessary qualifications/requirements during the technician selection process, in order to ensure that a qualified DE Technician will perform all DE assessments. The DE Technician must be qualified under the following NuStar OQ tasks: • 7.1 Visual Inspection of Atmospheric Coating • 8.1 Measure Pit Depth With Pit Gauge • 8.2 Measure Wall Thickness With Handheld Ultrasonic Meter • 8.3 Measure Corroded Area

305.3. Pre-Assessment Information

3A	**[Assessment Engineer]** Identify the locations where DE will be performed based on a minimum of 100% of the pipe surface area for sections designated as HCA pipe.
3B	**[Assessment Project Manager]** Gather the following pre-assessment data pertaining to the pipe segment(s) to be assessed: Pipe Related: • Material (steel, cast iron, etc.) and grade • Pipe diameter • Pipe depth (Pipe must be visually exposed for DE process.) • Length intended for assessment • Wall thickness • Year manufactured • Seam type (Another technology must be used to assess pipe susceptible to seam failure such as lap-weld or LF-ERW.) • Bare pipe • Location and identification information Construction Related: • Year installed • Route changes/modifications • Route maps/aerial photos • Construction practices

	• Locations of valves, clamps, supports, taps, mechanical couplings, expansion joints, cast iron components, tie-ins, and insulating joints, and locations of construction methods used at casings (Another technology must be used to assess cased pipeline sections.) • Locations of bends, including miter bends and wrinkle bends • Depth of cover • Underwater sections; river crossings • Locations of river weights and anchors • Location of pipe supports or pipe hangers (Pipe supports or hangers must be repositioned such that pipe surface can be evaluated.) • Proximity to other pipelines, structures, high voltage electric transmission lines, and rail crossings • As-built drawings/alignment sheets Soils/Environmental: • Soil characteristics/types • Drainage • Topography • Land use (current/past) • Frozen ground Corrosion Control: • CP system type (anodes, rectifiers, and locations) • Stray current sources/locations • Test point locations (or pipe access points) • CP evaluation criteria • CP maintenance history • Years without CP applied • Coating type—pipe (All coatings other than FBE or thin film paint must be removed.) • Coating type—joints (All coatings other than FBE or thin film paint must be removed.) • Coating condition • Current demand • CP survey data/history Operational Data: • Pipe operating temperature • Maximum Operating Pressure (MOP) • Operating stress levels (% Specified Minimum Yield Strength [SMYS]) and fluctuations • Product (Another technology must be used to assess pipe susceptible to internal corrosion.) • Monitoring programs – (coupons, patrol, leak surveys, etc.) • Pipe inspection reports—excavation • Repair history/records, such as steel/composite repair sleeves, repair locations, etc. • Leak/rupture history (external corrosion) • Evidence of external microbiologically influenced corrosion (MIC) • Third party damage type/frequency • Data from previous over-the-ground or from-the-surface surveys • Hydrotest dates/pressures • Other prior integrity-related activities- (close interval survey (CIS), ILI runs, etc.)
3C	Provide the DE Technician and Operations/Maintenance Managers with the completed form and related information prior to performing the assessment.

305.4. Performing the Direct Examination Locations

4A	**[DE Technician]** Perform the direct examination in accordance with Appendix K, making note of any metal loss and/or deformation features.	
4B	Complete the defect evaluation sections of the PIR Form.	
4C	Using absolute GIS stationing as a linear reference, document the location of all girth welds, pipe supports and pipe hangers, and fittings.	
4D	For examinations at a metal loss or deformation anomaly, complete the following tasks:	
	1	Make note of the linear location of the anomaly (GIS absolute stationing).
	2	Make note of the orientation of the anomaly.
	3	Measure the metal loss depth or deformation depth, if applicable. For dents, grooves, or gouges, perform Magnetic Particle Inspection (MPI) on 100% of the affected area to ensure cracking has not initiated due to stress risers. (See IMP Procedure 306, Magnetic Particle Inspection.)
	4	Measure the maximum defect length and width, if applicable. (Submit all documentation to the Project Engineer.)
	5	• **[Assessment Project Manager]** Send the results to the Assessment Engineer to evaluate the remaining strength of the pipe using IMP 3.6.1.2, Corrosion Assessment Criteria for each metal loss anomaly, if applicable. • **[Assessment Engineer]** Determine if the anomaly is a required repair.
	6	**[DE Technician]** Take ultrasonic thickness measurements around the circumference of the pipe at the 3 o'clock, 6 o'clock, 9 o'clock, and 12 o'clock positions. Be sure to take measurements at every joint to verify pre-assumption of no internal corrosion threat. (Refer to Appendix K, Section K.5.2.1.2.2.)
	7	Use a paint pen or chalk to write pertinent information on the pipe (pit depth, station number, etc.).
	8	Take photographs documenting the pipe condition.
	9	**[Assessment Project Manager]** When using the Direct Examination procedure as a qualified IMP assessment, discovery occurs in the field when the technician takes a direct measurement of the anomaly. Therefore, contact the Assessment Engineer immediately to determine anomaly classification and remediation requirements for potentially injurious features—i.e., those that potentially meet the definition of immediate or 60-day repair, per *49 CFR §195.452 (h)(4)(i)*. Possible injurious features include: • Metal loss greater than 80% (immediate condition) • Metal loss depth and length, such that the remaining strength of the pipe shows a P_{burst} less than MOP (immediate condition). Contact the Assessment Engineer prior to assessment to determine metal loss depth and length thresholds for the given pipe specification. • Any dent with metal loss, cracking, or stress riser (top of pipe is immediate, bottom of pipe is 60-day) • A dent located on the top of the pipe (above the 4 and 8 o'clock positions) with a depth greater than 6% is an immediate condition. • A dent located on the top of the pipe (above the 4 and 8 o'clock positions) with a depth greater than 3% of the pipeline diameter (greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12) is a 60-day condition. Also, contact the Assessment Engineer for the following concerns (not necessarily immediate or 60-day repairs): • Grooves or gouges greater than 12.5% • Corrosion, dents, cracks, grooves, gouges, or stress risers that affect girth weld or long-seam See step 305.6 and 305.7 for response and repair procedures to classified anomalies. **Note:** The Assessment Engineer will analyze all other features during step 305, 6c to determine if any of the remaining features fall under the 180-day repair classification.

305.5. DE Technician Report

5A	**[Assessment Project Manager]** Within 30 days of completing the field inspection, provide the Assessment Engineer or Operations/Maintenance Managers with copies of the DE Technician Report, including the PIR with defect examination sections completed and photographs.

5B	The DE Technician Report should include the following components (listed in this procedure):
	• A cover page that includes:
	  • Operator and owner name
	  • System name
	  • SAP name
	  • Testable segment name
	  • Technician name
	  • Inspected section location
	  • Date of inspection
	  • Date of report
	• A project scope description
	• Color photographs of, at minimum, the following features:
	  • Overall site
	  • Each anomaly
	  • Pipe exposed at supports
	• Use a tabular station report and a single line diagram to document the following:
	  • Location dimension using absolute GIS stationing (making note of the zero reference point)
	  • Wall loss measurement
	  • Defect length measurement
	• Specifications on all NDE equipment used (e.g., mag-particle, pit gauge, ultrasonic thickness, etc.)
	• Mag-particle inspection results
	• Ultrasonic thickness results
	• The version of this procedure
	• Overall assessment of pipe inspected
	• Summary of unusual conditions, if found
	• DE quality assurances, including the following information:
	  • Operator qualification documentation
	  • Verification of the operating condition of the equipment prior to performing the inspection
	  • Equipment calibration
	• Attach any recorded supplementary information to the PIR form.

5C	Review the DE Technician Report.
5D	Verify that the diagrams and report meets the following requirements: • Each of the required items from 5B are included • The DE was performed on the entire length of the covered pipe intended for inspection • Feature locations (e.g., weld joints, valves, pipe supports) marked on the tabular station report, and a single line diagram agree with known information about the pipeline
5E	Contact the DE Technician to obtain any missing information or to resolve any discrepancies.
5F	Once all contract requirements have are met, notify the Operations/Maintenance Managers that the invoice can be paid. (Not applicable if the DE technicians are company personnel.)
5G	Pay the invoice as soon as contract requirements have are met. (Not applicable if the DE technicians are company personnel.)

305.6. Anomaly Classification

6A	**[Assessment Engineer]** For this procedure, discovery occurs in the field when the DE technician records the direct exam measurement, as outlined in step 305.4. Record this date and use it to determine response times for immediate, 60-day and 180-day repairs.
6B	The Assessment Engineer calculates the estimated remaining strength using IMP Manual, Section 3.6.1.2, Corrosion Assessment Criteria, for each metal loss anomaly identified in the DE report.
6C	For all anomaly types, determine the remediation time frame categories—immediate, 60-day, and 180-day, as defined in *49 CFR §195.452 (h)(4)(i)*—based on the evaluation rules found in IMP Manual, Section 4.2, Remediation Timeframe, and Figures 3-9, 3-10, and 3-11.

305.7. Remediation

7A	**[Assessment Project Manager]** Respond to repair conditions, per Section 4, Remedial Action.
7B	**[Operations/Maintenance Managers]**For all anomalies that meet remediation requirements, remediate per O&M Procedure 614.
7C	**[Corrosion Manager]** Determine if the technician found active corrosion during the integrity assessments and take steps to mitigate, per the *Corrosion Control Manual.*

305.8. Reassessment Intervals

8A	**[Assessment Engineer]** When DE technology is used as a standalone IMP assessment technology for covered segments, determine an appropriate reassessment interval.
8B	For each assessment location, identify the most severe anomaly remaining.
8C	Determine the corrosion growth rate for the anomaly, using section 6 of NACE RP 0502-2002. In no case may the reassessment interval exceed 5 years, per the Rule.
8D	If no anomalies were detected or if all anomalies were remediated, then set the reassessment interval at 5 years, based on the maximum interval allowed, per the Rule. **Note:** The Assessment Engineer will document the reassessment interval on the Assessment Schedule worksheets.

305.9. Post Assessment

9A	**[Assessment Engineer]** Evaluate the results of the DE inspections and notify the P&M Coordinator of assessment completion.
9B	**[P&M Coordinator]** Perform a specific P&M review and prescribe P&M measures, per NuStar's P&M process, outlined in section 6 of the IMP manual.

306: Magnetic Particle Inspection of Defects

Introduction

This procedure establishes a standardized magnetic particle inspection (MPI) technique of defects for NuStar facilities and pipelines.

Scope

This procedure is required where NuStar retains qualified technicians to carry out MPI during the inspection for cracks, crack-like features, and stress corrosion cracking anomalies.

This procedure does not apply to MPI of welds.

Resources

ASNT SNT-TC-1A-2006

NuStar *Operations and Maintenance Manual (O&M Manual)*

Magnetic Particle Testing Report for Defect Investigation (in Appendix F: Forms)

306.1. MPI Technician Qualifications

1	Except as noted below, NuStar requires that the technician performing and interpreting MPI meet one of the following qualifications: • Be certified as ASNT NDT Level II or III, or hold ASNT Central Certification Program (ACCP) certificates as ACCP Level II or ACCP Professional Level III, or Canadian General Standards Board (CGSB) Level II or III. • Be certified in accordance with ASNT Recommended Practice No. SNT-TC-1A-2006 as SNT Level II or SNT Level III for MPI and UT. The minimum examination level for NDT interpretation is Level II. • Satisfy a NuStar agreed equivalent qualification.

306.2. Clean and Prepare Pipe Surface

2	**[Operations Personnel]** Prior to inspection, make sure the pipe is properly cleaned and prepared. Consult with the Assessment Engineer to determine the preferred method of coating removal and surface preparation for MPI.

306.3. Perform MPI

3A	**[MPI Technician]** Conduct MPI at the site of each defect.	
3B	1	Clean steel surfaces of all oil, dirt, or spurious weld spatter.
	2	Coat the prepared steel surfaces with white contrast paint prior to inspection.
	3	Perform the MPI with an oil-based or water-based black magnetic particle suspension using an AC yoke and the continuous magnetization method.
	4	Maintain the magnetic field for several seconds after application of the black magnetic particle suspension.
	5	Perform MPI sequentially in two perpendicular directions per ASME V, Art 7 – T770, as described in the American Society for Nondestructive Testing (ASNT) Recommended Practice No. SNT-TC-1A.
	6	For potentially injurious features, contact the Assessment Engineer to determine anomaly classification and remediation requirements.
	7	For all anomalies that meet remediation requirements, remediate per *O&M Procedure 614*.

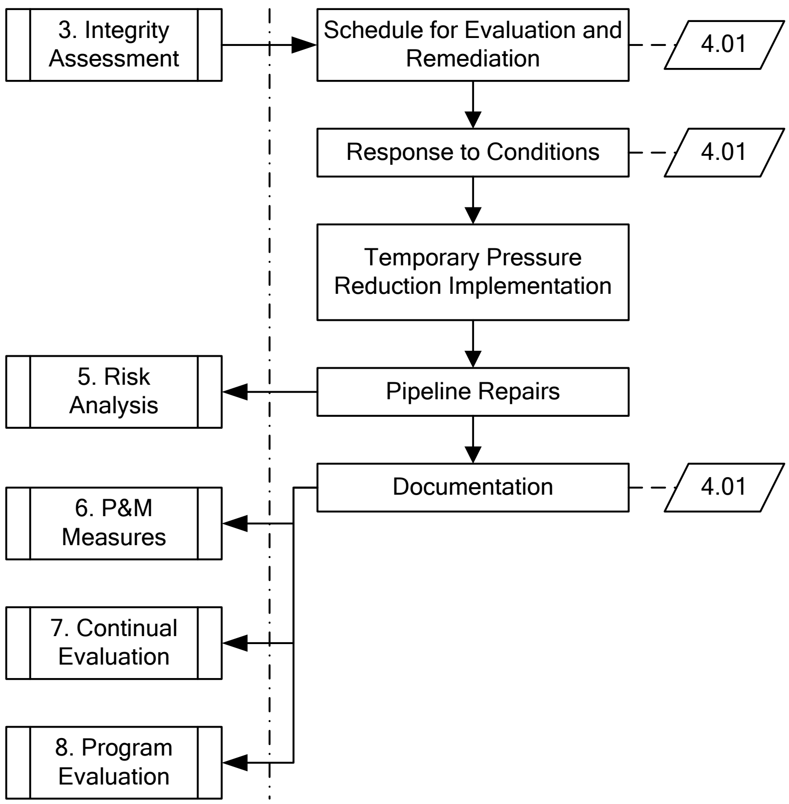
306.4. Documentation

4	**[Operations Personnel]** Complete the Magnetic Particle Testing for SCC Report and file with the repair documentation.

4: Remedial Action

This section describes the process for remediation of integrity threats identified by integrity assessment and data analysis. The *Operations and Maintenance Manual* covers remedial procedures, including emergency response, pipeline repair methods, leak repair, required repair records, and welding. Figure 4-1 outlines the NuStar Remediation Plan.

Figure 4-1. Remedial Action Flowchart



4.1. General

4.1.1. Process for Changes to Schedule Introduction and Purpose

The Rule requires NuStar to take prompt action to address anomalous conditions discovered by the baseline and continual assessments, as well as the information analysis on pipeline segments that could affect an HCA. The rule requires the Assessment Engineer to evaluate all anomalous conditions and remediate those that could reduce a pipeline segment's integrity. This section lists NuStar's responsibilities under this rule, as well as which anomalies it must remediate, the timeframe for remediation, and suggested remediation strategies.

4.1.2. Scope

This section applies to those pipeline segments identified in Section 1, Segment Identification, which could affect an HCA. Although pipeline segments, not subject to the Rule, are not required to follow these guidelines, the Assessment Engineer should consider these repair strategies when making repairs.

The Assessment Engineer should consult this section for guidance in directing repairs to pipeline segments subject to the Rule. In addition, the Assessment Engineer should consult O&M Procedure 614, Detailed Pipeline Repair Procedures, for guidelines on gathering information and remediating anomalies.

In general, NuStar will not differentiate between HCA and non-HCA pipeline segments in selecting a particular repair method. Although NuStar must adhere to the repair timeframes listed later in this section for only the HCA pipeline segments; it should make non-HCA pipeline segment repairs in a timely manner commensurate with the type and severity of the anomaly or defect.

4.2. Remediation Timeframes

PHMSA defined evaluation and remediation timeframes for certain anomalies. Depending on the specific anomaly, the evaluation and remediation must occur immediately within 60 days, within 180 days, or in a timeframe as defined by the Assessment Engineer. Subsequent subsections list the conditions for each of these evaluation and remediation timeframes. Extenuating circumstances that may prevent evaluation and remediation of anomalies within the prescribed timeframes include, but are not limited to, the following:

- Floods
- Earthquakes
- Stormy or tornadic activity
- Fires
- Landslides
- Terrorist acts, criminal acts, and/or acts of war
- Acquisition of appropriate permits or rights of access

The Assessment Engineer appropriately documents the cause of the delay in evaluating and remediating the anomaly and, where practicable, considers a reduction in maximum operating pressure until it can complete the remediation. As stated in the Rule *§(h)(1)*, a temporary reduction in operating pressure cannot normally exceed 365 days (see Section 4.3.2., Requirements After a 365-Day Temporary Pressure Reduction).

4.3. Response to Conditions

The Rule requires NuStar to remediate certain anomalies and/or defects (conditions), according to a schedule that prioritizes the conditions for evaluation and remediation. In addition, NuStar must evaluate and remediate other conditions not explicitly listed in the pipeline integrity rule, if that condition could impair the integrity of the pipeline. The prioritized schedule is based on the Immediate, 60-day, and 180-day classifications as described in the Rule.

As stipulated in the Rule *§(h)(2)*, a discovery of a condition occurs when NuStar has adequate information about an anomalous condition, to determine that the condition presents a potential threat to the integrity of the pipeline segment. Section 3.6.1.3., Discovery of a Condition, and Section 3.6.4., SCC Program Evaluation, provide a detailed discussion and guidelines concerning date of discovery of a condition. The evaluation and remediation schedules listed below start from the date of discovery.

4.3.1. Determination of Temporary Reduction in Maximum Operating Pressure

To ensure the continued safe operation of a pipeline segment, NuStar must temporarily reduce operating pressure, or shut down the pipeline segment until the anomalies and/or defects, classified as immediate repair conditions, are rectified. As stated in the Rule *§(h)(1)*, a temporary reduction in operating pressure cannot normally exceed 365 days (see Section 4.3.2).

49 CFR Part 195 Paragraph 452(h)(4)(i)(B) allows operators to assess the remaining strength of the pipe using suitable calculation methods identified in, but not limited to, ASME/ANSI B31G and PRCI PR-3-805 (R-STRENG). These calculation methods are detailed in § 3.6.1.2 of this manual.

For dents, corrosion which could affect a girth weld, a longitudinal seam, or other anomalies which cannot be specifically assessed for corrosion, the Assessment Engineer will reduce the operating pressure of the pipeline pumping segment where the anomaly is located to 80% of the pressures that the pipe has actually experienced with the defect present (i.e., pressures for which safety has been demonstrated). This pressure reduction should be no more than 80% of the highest operating pressure within the 60 days preceding inspection. In addition, NuStar may shut down a pipeline pumping segment to satisfy the temporary pressure reduction requirement, which is an alternative that is appropriate for all types of anomalies. When taking a temporary pressure reduction, the Assessment Engineer should communicate it to the appropriate personnel for the affected pumping segment, per IMP Procedure 401, Implementation of Temporary Pressure Reduction. NuStar should enact reasonable measures to limit the pressure of a pumping segment to below the temporary reduced operating pressure.

NuStar may revert to the original maximum operating pressure after investigation, or repair has rendered the anomalous condition to be safe, and after there are no other conditions requiring a pressure reduction on that pump segment. The Assessment Project Manager should communicate to appropriate personnel when NuStar can reinstate the prior MOP on the affected pumping segment.

In Section 3, Integrity Assessment, Figures 3-9 and 3-10, Categories for Anomalies and Repair Priority Conditions with Pressure Reduction Guidelines (Parts 1 and 2), show which categories of anomalies receive pressure reductions, and how NuStar determines the reductions upon discovery (immediate conditions), or after repair condition deadlines have passed (60- or 180-day conditions).

4.3.2. Requirements After a 365-Day Temporary Pressure Reduction

For any conditional defect under a temporary pressure reduction that is not repaired within 270 days of the date the pressure reduction was initiated, The Assessment Project Manager evaluates whether it can complete the repair by the end of the 365-day temporary pressure reduction period. If NuStar determines that it cannot repair the defect in time, it takes the following actions:

1) At least 90 days prior to the end of the designated temporary pressure reduction period (immediately if within 90 days due to unforeseen circumstances), the Assessment Project Manager notifies the Assessment Engineer that the defect cannot be repaired or remediated within 365 days.
2) The Assessment Engineer
   a) Determines what further remedial action(s) may be implemented, including (but not limited to):
      - Making an additional pressure reduction for another 365 days
      - Performing additional analysis to determine that the defect is non-injurious
      - Presenting an alternative remediation method to PHMSA for review
   b) Enacts the chosen further remedial action(s) to ensure the safety of the pipeline segment.
   c) Verifies that the change in schedule does not jeopardize public safety or environmental protection.
   d) Provides the IMP Manager with information, such as the following for submission to PHMSA:
      - Original deadline
      - Proposed new repair date
      - Safe pressure calculation
      - Current pressure reduction
      - Any new pressure reduction
      - Any other further remedial action
      - A full explanation for not meeting the original deadline
3) The IMP Manager notifies PHMSA online, by phone, or by fax, that NuStar cannot meet the remediation schedule, explaining why it cannot meet the schedule, and how the changed schedule will not jeopardize public safety or environmental protection.

4.4. Temporary Pressure Reduction Implementation

NuStar has designated a 48-hour window as a reasonable response time to implement any pressure reduction, after it determines that such pressure reduction is necessary to remediate a defect that is discovered. To the extent a defect is an immediate, 60-day, or 180-day condition, NuStar will implement any pressure reduction used to remediate that condition within the applicable remedial time frame. IMP Procedure 401 provides a formalized process for taking pressure reductions.

Note: For all immediate conditions, NuStar will initiate this pressure reduction procedure immediately upon discovery.

Figure 4-2 illustrates the remediation process of taking a pressure reduction. After NuStar implements a temporary pressure reduction, it assigns Operations/Maintenance Personnel to repair or replace the area of concern. Figure 4-3 outlines the process of repairing or replacing pipe segments that are an integrity threat.

Figure 4-2. Remediation Procedure Flowchart (Part 1 of 2)

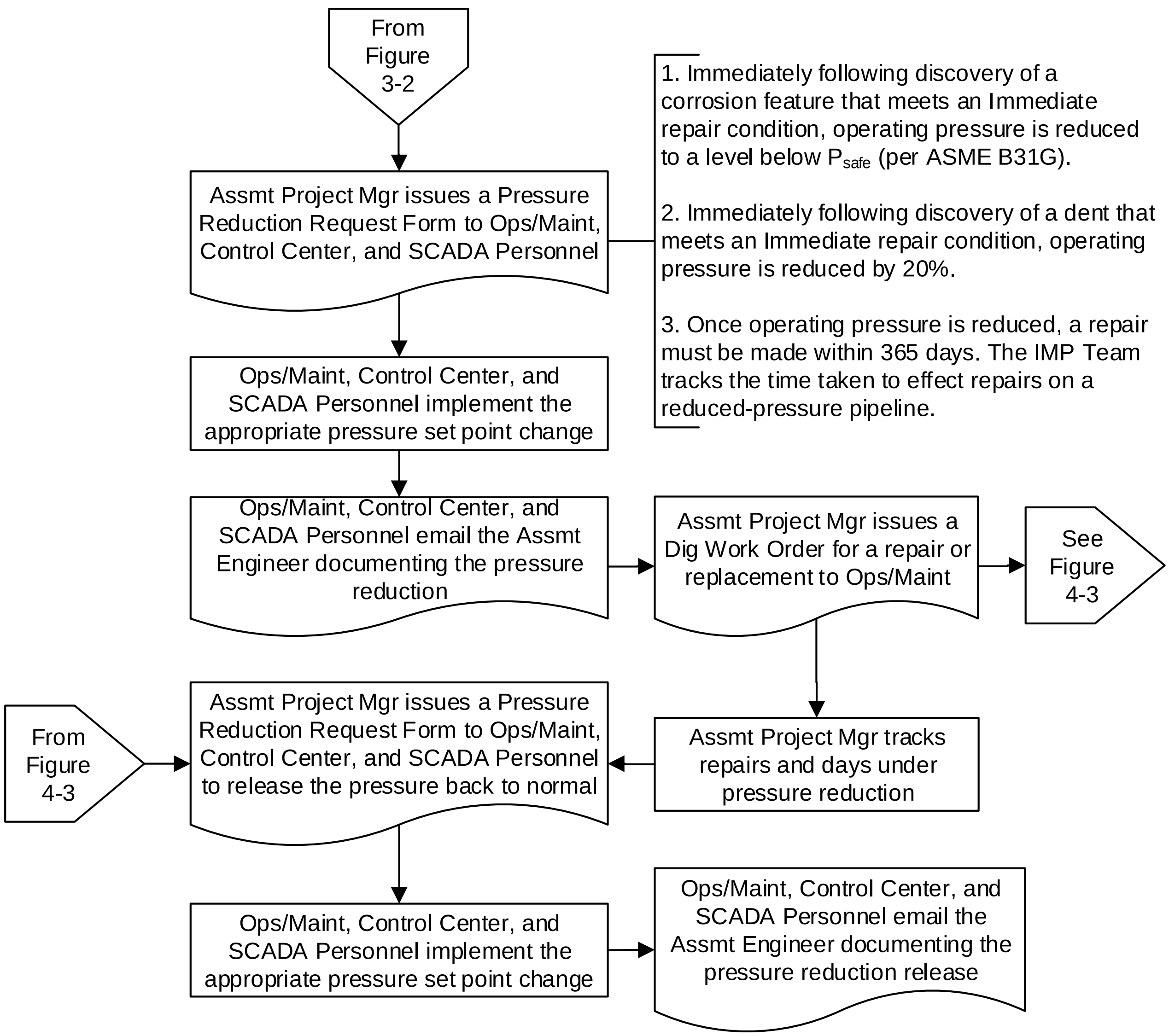
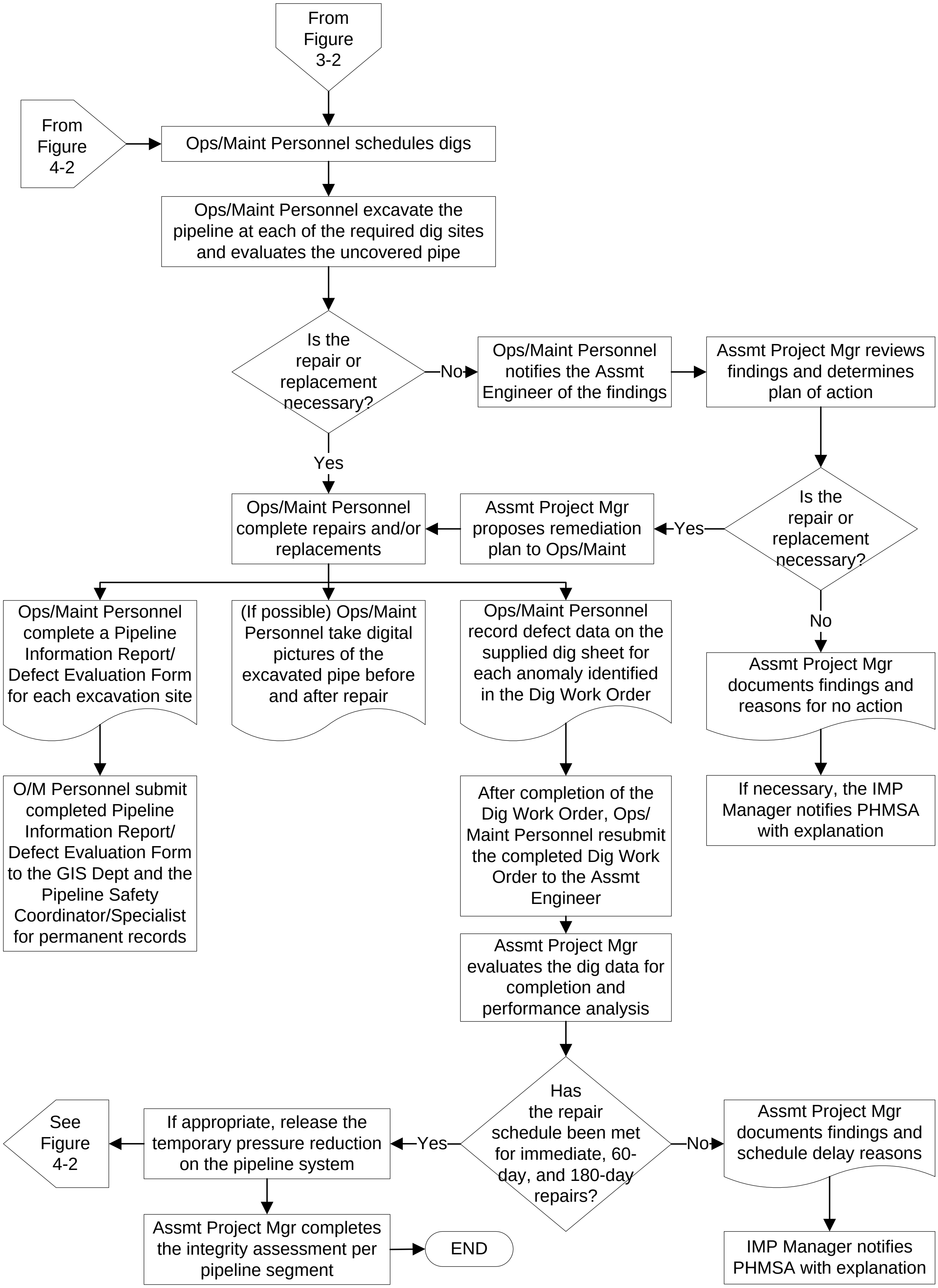


Figure 4-3. Remediation Procedure Flowchart (Part 2 of 2)



4.5. Pipeline Repairs

NuStar's Operations and Maintenance Department performs pipeline repairs by using one of the repair methods listed in O&M Procedure 614.

4.6. Documentation for Pipeline Excavations

Operations/Maintenance Personnel use the Pipeline Information Report/Defect Evaluation (PIR) Forms to record all required information whenever they excavate and examine a segment of a pipeline for repair or replacement. The forms and instructional guides for completing these forms appear in Appendix F, Forms. Operations/Maintenance Personnel complete all dig/remediation documentation and submit it to the Assessment Engineer for permanent filing and further evaluation. The Assessment Engineer compiles an assessment closeout report based on a review of the dig/remediation documentation, a comparison of the predicted versus actual measurements, and their conclusions regarding the assessment and remediation. This process is described in Procedure 301, ILI Assessment, Data Evaluation, and Remediation.

Implementation of Temporary Pressure Reduction

Introduction

DOT regulations require all pipeline operators to promptly evaluate all conditions, and remediate those conditions which could affect a pipeline's integrity. Timelines for implementing pressure reductions depend on the level of the condition being addressed:

- **Imminent threats** (e.g., immediate conditions)—whether the pipeline is operated by a remote or local Control Center, or by manual controls, the pressure is reduced a soon as practicable. Secondary controls such as SCADA set point limits, "hi-hi" alarms, and field settings (e.g., discharge pressure switch) are completed within 48 hours of notification.
- **Other conditions** (e.g., an additional remedial action)—the pressure reduction, including secondary controls, is implemented in the time specified on the Temporary Pressure Reduction Form.

Regulation

49 CFR §195.452 (h) (1) General requirements. An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long term integrity of the pipeline. An operator must comply with Sec. 195.422 when making a repair.

(i) Temporary pressure reduction. An operator must notify PHMSA, in accordance with paragraph (m) of this section, if the operator cannot meet the schedule for evaluation and remediation required under paragraph (h)(3) of this section, and cannot provide safety through a temporary reduction in operating pressure.

(ii) Long-term pressure reduction. When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section, and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar.

Resources

Temporary Pressure Reduction Form (in Appendix F, Forms)

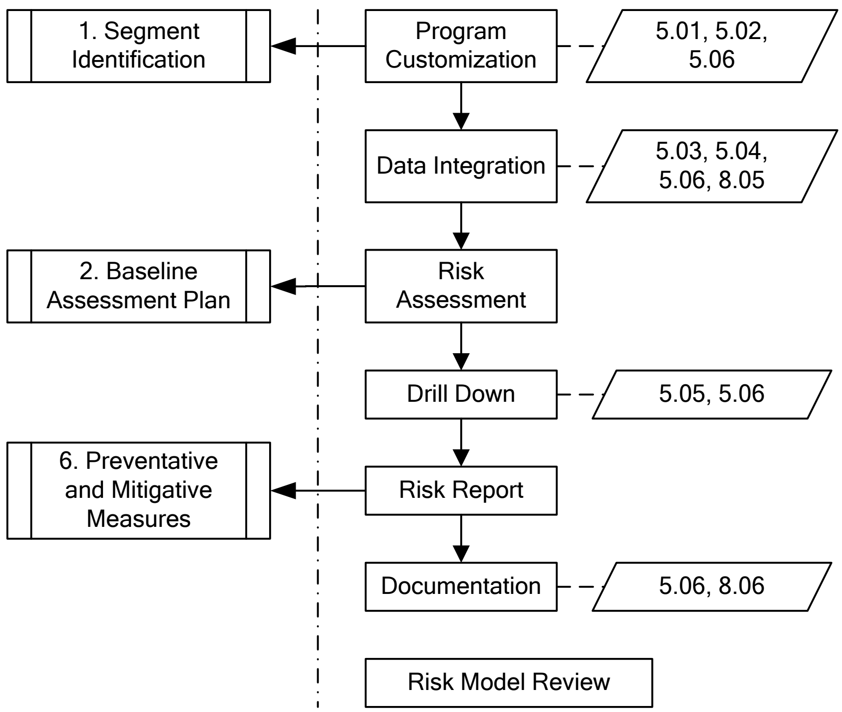
401.1. Implementing a Temporary Pressure Reduction

1A	1		**[Assessment Project Manager]** Request calculation of pressure reduction.
		a	Fill in the General Information and Anomaly Description sections of the Temporary Pressure Reduction Form (found in appendix F, Forms).
		b	Forward request to Assessment Engineer.
	2		**[Assessment Engineer]** Determine the appropriate pressure reduction by conferring with the Operations/Maintenance and the Control Center Manager/Supervisor, to determine the operational impact and appropriate field pressure switch and review historical control/operational set points to determine required adjustments (discharge pressure set point and/or hi-hi pressure alarm).
	3		Record the findings on the Temporary Pressure Reduction Form and return to Assessment Project Manager. **Note:** For imminent threats, pressure reductions shall be implemented as soon as practicable.
	4		**[Assessment Project Manager]** Email the completed form with receipt confirmation to the Operations/Maintenance Manager and the Control Center Manager/Supervisor, and carbon copy the IMP Team. **Note:** The form instructs each discipline to reduce the pipeline pressure and/or set points as specified.
1B	**[Operations/Maintenance Manager and Control Center Manager/Supervisor]** As soon as possible, but no more than 48 hours after receiving the emailed Temporary Pressure Reduction Form, implement the pressure switch and set point adjustments, according to O&M and General Systems Manual procedures.		
	1		Email the Assessment Project Manager and Assessment Engineer, documenting the date and time that the temporary pressure reduction was implemented to confirm that the 48-hour deadline was met.
1C	**[Assessment Project Manager]** If the pressure reduction is related to more than one anomaly, and if the most severe limiting anomaly is repaired, continue with Step 1C. Otherwise, skip to Step 1D.		
	1		Follow Step 1A to issue a revised Temporary Pressure Reduction Form with the following information: • Note in the anomaly description field that the repair of the most severe anomaly was made. • New temporary MOP based on the next most severe anomaly • Date ordered • Temporary MOP basis • Set points • Description of changes in the Revision History section
	2		Mark the original reduction order as obsolete and permanently file.
	3		**[Operations/Maintenance Manager and Control Center Manager/Supervisor]** On receiving the revised form, destroy the original version and implement the reduction, according to Step 1B.
1D	**[Assessment Project Manager]** After receiving confirmation of completed repairs or data, indicating that the condition is safe to return to normal operations, issue a request to return to the original MOP by emailing a Temporary Pressure Reduction Form with receipt confirmation to the Operations General Manager, and the Control Center Manager/Supervisor, with a carbon copy to the Corporate Assessment Engineer. **Note:** The form instructs each discipline to release the temporary pressure reduction and return the operating pressure and pressure set points back to normal.		
1E	1		**[Operations/Maintenance Manager and Control Center Training Coordinator]** After releasing the temporary pressure reduction, email the Assessment Project Manager and Control Center Manager/Supervisor, documenting the date and time that the pressure switch and Control Center settings were returned to normal.
	2		**[Assessment Project Manager]** Submit all pressure reduction documentation to the Assessment Engineer.
1F	**[Assessment Engineer]** File all Temporary Pressure Reduction Forms, and their associated documentation in the Regional permanent filing system.		

5: Risk Analysis

NuStar uses a formalized risk analysis program (see Figure 5-1) to evaluate the integrity of each pipeline segment as part of the continual evaluation process. The risk model applies to all jurisdictional hazardous liquid pipelines in an HCA—or could affect an HCA—associated with these pipelines. This program ensures that NuStar analyzes all available information about the integrity of the entire pipeline, as well as facilities and the consequences of a failure. The ongoing development of the process, detailed in IMP Procedure 501, Risk Model Analysis, is the responsibility of NuStar's Risk Engineer.

Figure 5-1. Risk Analysis Flowchart



5.1. Risk Model Software

NuStar uses a software solution to evaluate the relative risk between pipeline segments. The Risk Model uses dynamic segmentation, contains over 200 standard variables, and has the ability to incorporate an unlimited number of user-defined variables. Dynamic segmentation allows NuStar to input and evaluate all the risk factors independently of each other. This technique collects all the risk data and creates a risk score every time a risk variable changes, thus creating many segments within a segment. This technology prevents the user from having to use the worst-case value for variables uniformly across the HCA segment and allows for the identification of individual risk drivers for each unique section of the pipe.

With this technology, the Risk Engineer can place a greatly refined emphasis on the risk factors used to analyze the HCA pipelines. This emphasis allows NuStar to more effectively

- pinpoint pipeline locations having the highest estimated risk,
- identify most important risk drivers for the highest risk locations,
- underlying causes of primary risk drivers, which will lead to possible mitigative/preventive actions, and
- track the reduction of risk with time.

The scenario features of the program give NuStar a formalized tool to determine economically feasible preventive and mitigative actions that result in the highest reduction of risk.

5.2. Program Customization

An algorithm is an equation used to measure the magnitude of risk for attributes within the threat and consequence indexes to a pipeline system. An algorithm is the foundation of a pipeline's risk analysis; however, before an algorithm can be defined, a variable template needs to be created.

5.2.1. Customizing the Algorithm

The goal for the algorithm development process is to ensure that the threat and consequence assessment models reflect NuStar's views of risk and pipeline systems. NuStar developed its algorithm for the Risk Model based on failure frequency history, input from subject matter experts (SMEs), and company operating philosophies. When justifying the magnitude of any numerical weight used to estimate measures of risk, the Assessment Engineer, Risk Engineer, and SMEs met to determine the weights for each variable within the threat index and the consequences index, based on their knowledge (see Table 5-1).

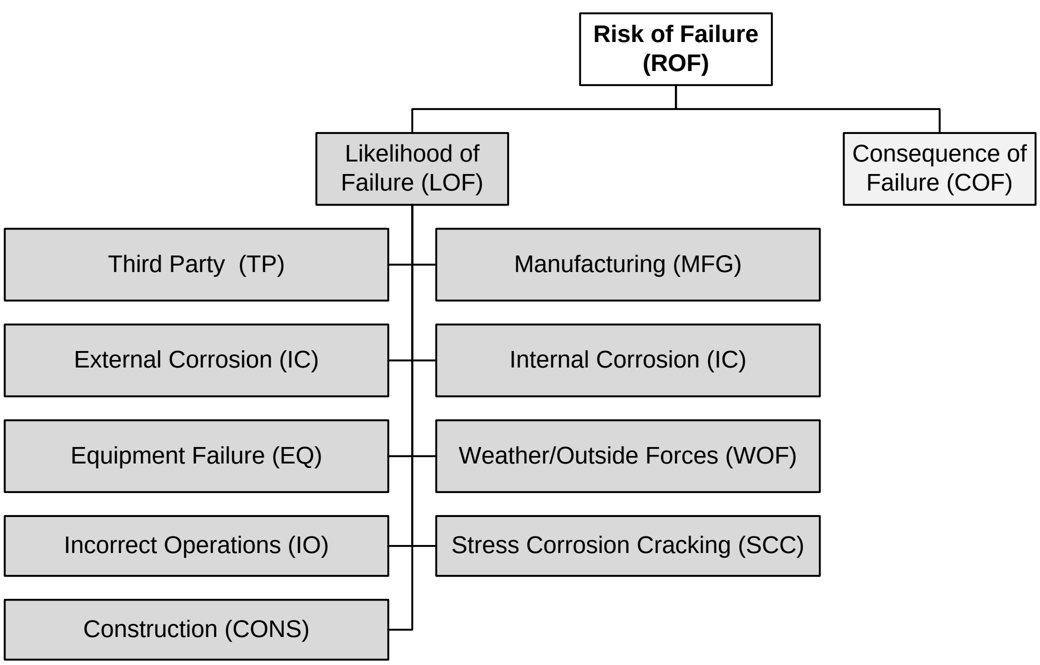
Table 5-1: SME Areas of Expertise

SMEs	Areas of Expertise			
Corrosion	External Corrosion	Internal Corrosion	Outside Forces	SCC
Regional HSE	Third Party			
Engineering	Manufacturing	Equipment	Construction	
Operations/Maintenance	Incorrect Operations			
Control Center	Leak Detection			

5.2.2. Likelihood of Failure (LOF)

When assigning threat variable weights, the Assessment Engineer, Risk Engineer, and SMEs examine all threat types and consider the environment and past failures (including causes) of NuStar's pipeline systems. Figure 5-2 and **Error! Reference source not found.**show the Likelihood of Failure (LOF) threats for pipelines and facilities.

Figure 5-2. Pipeline Risk of Failure Diagram



5.2.3. Consequence of Failure (COF)

When assigning consequence variable weights to NuStar's pipeline segment, the Assessment Engineer, Risk Engineer, and SMEs consider the following factors:

- Pipeline segment surroundings
- Product characteristics
- Pipeline segment operating conditions
- Property damage
- Health and safety impact
- Environment damages

5.2.4. Variables

Each LOF and COF is made up of assorted variables that are pertinent to likelihood of failure and consequence. The variable template is a list of variables that potentially could cause risk to an HCA pipeline system. The variable template serves as a starting point from which key variables are selected from a likelihood of failure or consequence standpoint to perform a risk analysis. These variables are listed per index (threat and consequences) in V:\Integrity Management\5_Risk\Risk Scores\Model Diagram and in the Risk Scores folder V:\Integrity Management\5_Risk\Risk Scores on the IMP Shared Drive.

The Risk Model allows the use of one variable for multiple threat types; however, the key to proper risk analysis is to be sure that the meaning of a variable is unique each time it is used.

5.2.5. Attributes

Attributes are the specific characteristics of a variable and have a direct connection to its class type.

Example: The variable Soil Corrosivity has attributes such as High, Moderate, or Low.

After assigning each variable a weighting, the Risk Engineer assigns a score to each attribute for that variable. Attributes reflect the environmental characteristics of the pipeline that are difficult or impossible to change. There are characteristics over which the Risk Engineer usually has little or no control. The attribute is scored based on a scale such as that shown in Table 5-2.

Table 5-2: Attribute Weights for Conditions/Threats

Weighting	Conditions/Threats
100 or 90	Attribute easily can independently contribute to threat. (Highest Weight)
80 or 70	Attribute possibly can independently contribute to threat.
60 or 50	Attribute is a significant contributor to threat.
40 or 30	Attribute, in concert with others, could contribute to threat.
20 or 10	Attribute plays minor role in contributing to threat.
0	Attribute plays no role in contributing to threat. (Lowest Weight)

In this table, a weight of zero (0) represents the lowest risk and a weight of 100 represents the highest risk. The data collected—in conjunction with the knowledge and experience of NuStar SMEs scoring these attributes—determines the score given to each attribute. A Risk Model report containing current scores for all LOF and COF attributes can be found on the IMP Shared Drive V:\IntegrityManagement\5_Risk\Risk Scores\Model Diagram.

Unknown attributes are scored using the best-estimate scenario instead of worst-case scenario. Using the best-estimate scenario for unknown attributes helps to avoid masking areas of concern.

5.2.6. Re-evaluation

As discussed in Section 5.8., Continuous Improvement of the Risk Model, NuStar re-evaluates variable weights as part of its P&M measures process and adjusts the weights as needed.

5.3. Data Integration

The Risk Engineer extracts adequate and appropriate data from NuStar's pipeline database GIS system, a centralized storage location for the following information:

- HCAs and Could Affects
- Pipeline design
- Internal corrosion inspections
- One call data
- Assessment results
- Soil data
- Natural force data

The Risk Engineer integrates information from the GIS system and NuStar's Intranet, into the Risk Model to perform an effective risk analysis.

NuStar bases the data collected on the requirements identified in the Risk Assessment Algorithm and extracts most of the data requirements from the GIS system, which provides completeness and quality of input information through a customized import wizard. The *NuStar GIS Data Governance Program* outlines NuStar's requirements for data quality and data accuracy, the application of which ensures that high quality data is fed into the risk model. The data auditing function within the Risk Model software reports the quality of data for missing or incomplete information (informational), data gaps, or overlaps (locational), and time-sensitive (temporal) data.

5.3.1.1. Report Data

During the P&M review process, NuStar integrates the risk analysis results with numerous reports to collect data and ensure that the Risk Model receives consistent information for different pipeline segments. These reports may include, but are not limited to, the following:

- Pipeline Information Reports/Defect Evaluations (PIR) Forms
- Inspection Survey Reports/GWUT Service Provider Reports
- Hydrostatic Test Reports
- HSE Incident Reports
- Aerial/Surface Patrol Reports
- Internal Corrosion Coupon Reports
- API-653 Inspection Reports
-

NuStar supplements the Risk Model with the subjective information provided by NuStar SME's and industry's collective operating experience data during the P&M Measures Meetings process to both compliment and verify the risk analysis results (see Section 6.6.2.).

5.3.1.2. Design and Physical Data

Most design and physical data originate from the following sources:

- Alignment sheets
- SAP
- Internal corrosion inspections
- One-call records
- HCA identification
- U.S. General Soil Map (SSURGO)
- NPMS-Natural Disaster Study [National Pipeline Risk Index]
- USGS GAP Analysis Program Land Cover Viewer

Once the GIS Department implements data into the system, the Risk Engineer imports this data from the system into the Risk Model. The Risk Engineer performs data audits for quality assurance and an analysis of the data in conjunction with the calculations and algorithm criteria. The Risk Engineer assesses this information to generate risk values.

5.3.1.3. Updating Data Prior to Re-evaluation of Risk

Along with performing a risk analysis, NuStar keeps its data and analysis up to date with respect to the evaluated pipelines. The Risk Engineer notifies the GIS Department that he/she will perform a re-evaluation of the pipeline segment to ensure that the most current data are imported into the GIS system and then verifies quality assurance of that data using the data auditing function in the Risk Model.

5.3.1.3.1. Risk Model Import Wizard

Importing this data ensures that the Risk Engineer has the most current and accurate data to perform a risk analysis. The Risk Engineer performs a risk analysis on all of NuStar's pipelines within or affecting HCAs.

To ensure that the risk analysis reflects the current pipeline material conditions and maintenance/surveillance program activities, NuStar updates the data in the GIS system from, but not limited to, the following:

- One Call Records
- Internal Corrosion Coupon Reports
- Hydrostatic Test Reports
- Inspection Survey Reports/GWUT Service Provider Reports

Most design and physical data will be updated in the GIS system before the Risk Engineer performs an annual risk analysis. Sources include, but are not limited to, the following:

- SAP
- Alignment sheets
- NPMS-Natural Disaster Study [National Pipeline Risk Index]
- U.S. General Soil Map (SSURGO)

5.3.1.3.2. HCA Updates

NuStar identifies new HCAs within one calendar year from discovery, and the HCA Specialist submits this information to the GIS system before the Risk Engineer performs the risk analysis. This process (shown in Section 1.1, HCA Identification) ensures that the risk analysis reflects up-to-date consequence characteristics near the pipeline.

5.3.1.3.3. Periodic Review

NuStar places importance on continuously revisiting and modifying the risk analysis tools and methods to determine the need for any updates whenever evidence shows that adjustments are appropriate. NuStar receives periodic feedback during P&M meetings to re-evaluate the needs of the pipeline systems and to ensure that all information is covered. Agreed-upon changes will be made by the Risk Engineer to the risk analysis tools and documented in the Algorithm Index Manual Revision Log on the IMP Intranet.

5.3.2. Pipeline Subdividing for Risk Analysis

NuStar subdivides the pipeline for risk assessment and assessment schedules uniformly along the operational segment from the launcher trap to the receiver trap and defines these segments as the testable segments shown in the GIS Web report and the pipeline integrity database (trap to trap for ILI assessments or assessment start to end for hydrostatic or guided wave ultrasonic testing). For pipelines to maintain a consistency within risk assessment and assessment schedules, NuStar sets the components within the Risk Model to mirror these testable segments, organizes the testable segments based on its requirements, and configures the testable segments during the setup of the software.

5.4. Performing Risk Assessment

5.4.1. Comprehensiveness of Approach

The Risk Model takes in consideration all relevant risk categories (shown in the *Risk Model Algorithm Index Manual V;|Integrity Management\5_Risk\Risk Scores\Model Diagram)* when the Risk Engineer evaluates pipeline segments and facilities. The Risk Model expresses the Risk of Failure (ROF), which integrates results from the analysis of how pipeline failures could affect HCAs, as the product of the Likelihood of Failure (LOF) and the Consequences of Failure (COF).

5.4.1.1. Threats to Pipeline Integrity

NuStar bases the LOF on the probability that an event or condition will result in failure, tempered by confidence in the gathered data. The LOF constitutes the standard threats shown in Figure 5-2.

5.4.1.2. Consequences of Failure

NuStar evaluates the COF resulting from the threats in the areas listed in Section 5.2.3.

5.4.1.3. Integration of Results

The Risk Model calculates the ROF by multiplying the LOF times the COF, integrating the results from the analysis of how pipeline failures could affect HCAs from the segment identification process.

The Risk Engineer processes the results from the integrity assessment and determines which risk factors influence the integrity of the pipeline system, pipe segment, or even a particular section of pipe. This process of refinement is crucial in the customization of the working algorithm.

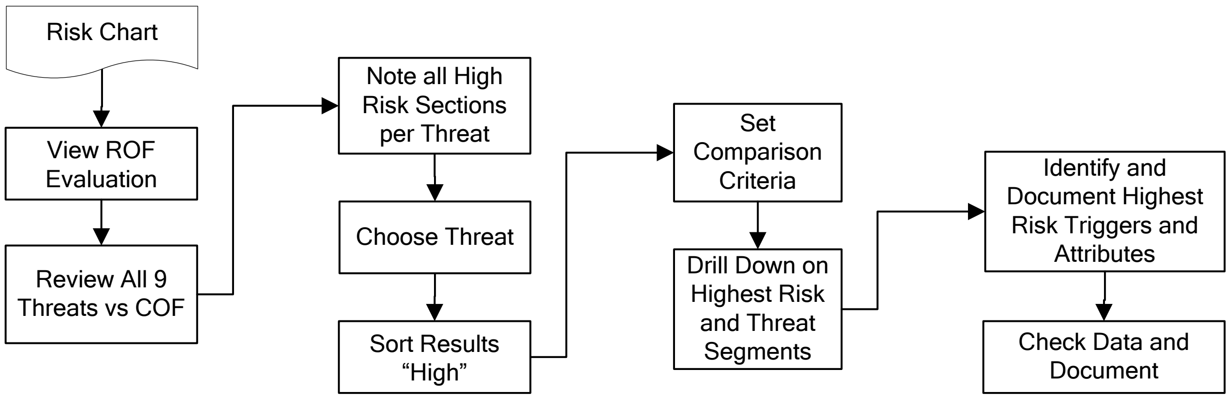
5.5. Performing a Drill Down

The Risk Model assesses risk using a relative risk or decision tree algorithm, which when applied to pipeline segment data, results in the identification of high-risk segments, and high-risk sections within segments.

Overall characteristics of risk results identify the pipeline locations having the highest estimated risk. The Risk Model also identifies the most important risk drivers for the highest risk locations and the underlying causes of that risk.

As shown in Figure 5-3, the Risk Engineer uses all results from the analyses using the evaluation models to generate a risk-ranked list of components, which NuStar uses in the development of the baseline assessment plan. The ranked list identifies components in the order of ROF and identifies which of the threats are drivers in the ROF of each component.

Figure 5-3. Risk Drill Down Flowchart



5.5.1. Identification of Highest Risk

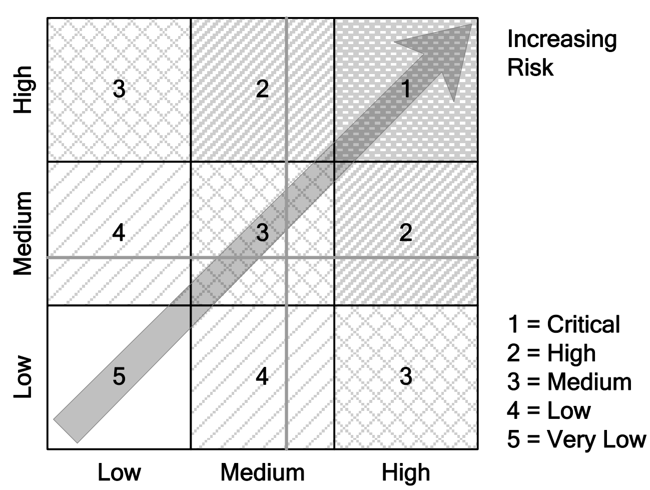
The Risk Engineer performs a risk analysis using all pertinent information available at the time then annually identifies the highest risk-ranked segments by ROF. Throughout the year in preparation for P&M meetings, the Risk Engineer may perform drill-downs to identify the risk drivers on pipeline segments being reviewed.

5.5.2. Identification of Risk Drivers

The Risk Engineer identifies the most important risk threat drivers for the highest risk location by reviewing all threats versus COF, taking note of all high-risk sections per threat.

The Risk Matrix Report Format (Figure 5-4) is divided into nine risk sections. These sections are represented on a 3 × 3 grid, and the axis limits are based on the maximum calculated algorithm potential threat score and potential COF scores. The risk increases up and to the right in the risk matrix. Each column and row represents an increasing threat from low to high, with the threat increasing from left to right for COF scores and bottom to top for scores of each individual threat. The actual pipeline data defines the dynamic segmentation (i.e., the risk evaluation interval). The gray lines indicate the comparison criteria—the highest risk-ranked sections and facilities within or affecting an HCA.

Figure 5-4. Risk Matrix Report Format



Each threat analysis summarizes the variables and associated triggers having the most significant influence on the increased threat scores. The Risk Engineer investigates each of the nine threats against COF and IOP and examines in detail any threat that is identified as being a medium or high threat score.

Example: For investigation into the Equipment (EQ) Threat, the Risk Engineer uses a ranking matrix for EQ versus COF to identify the threat's condition. Figure 5-5 illustrates that for this sample segment the EQ threat is high based on the ranking matrix.

5.5.3. Underlying Cause

The Risk Engineer further analyzes the conditions contributing to this elevated risk score by performing a drill down on each threat. The Variable Sensitivity Graph illustrates this further by showing the tendencies of the triggers. Figure 5-6 presents an example of this graph.

Figure 5-5. EQ Ranking Matrix

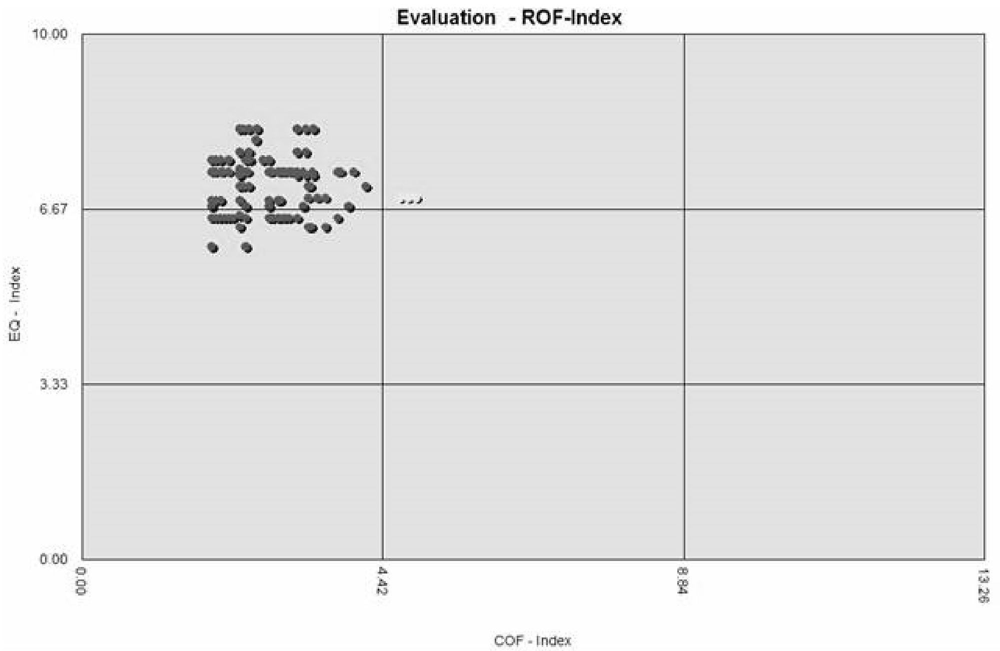
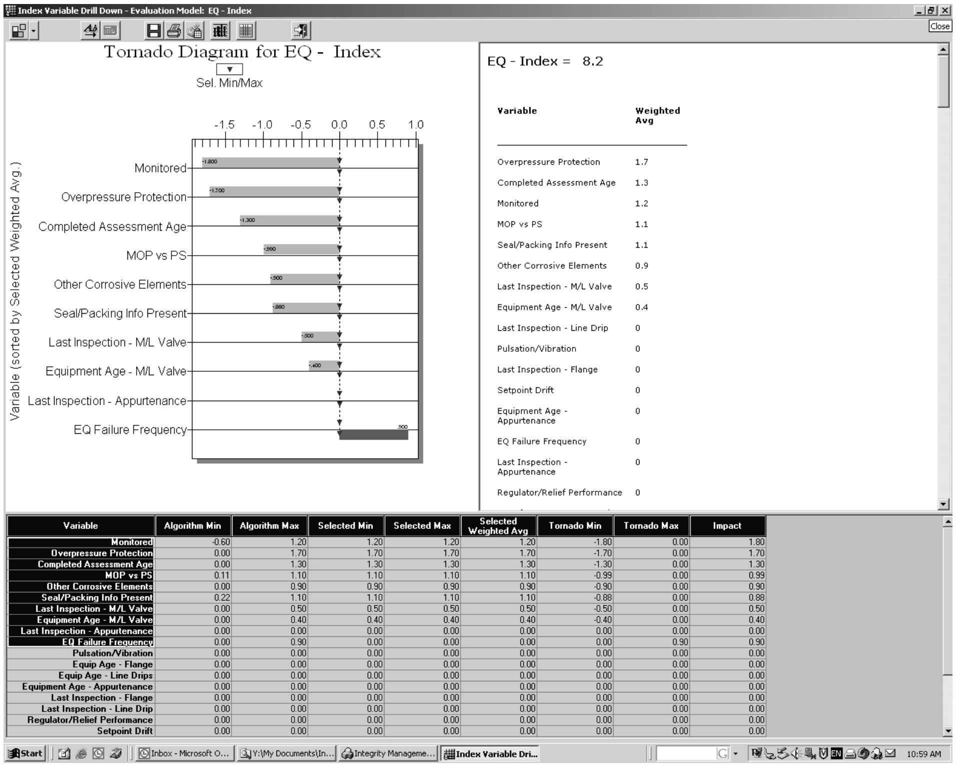


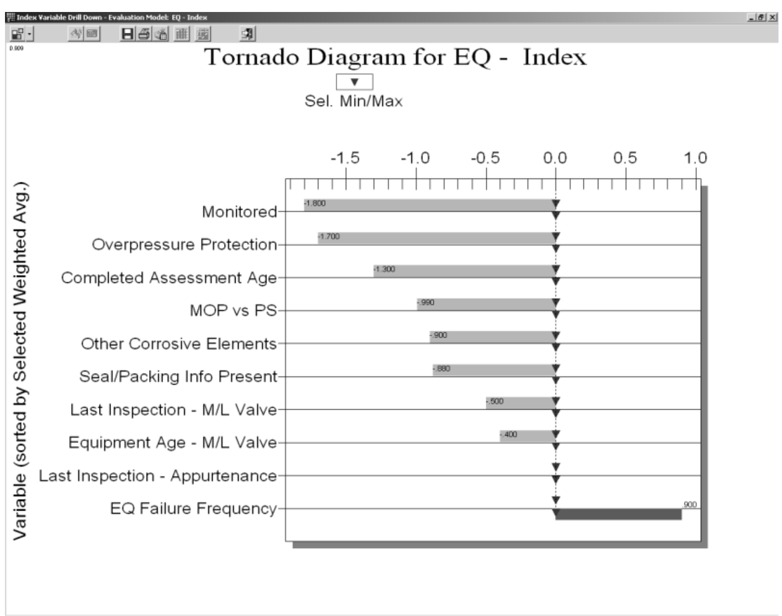
Figure 5-6. Variable Sensitivity Graph



5.5.4. Tornado Diagram

Tornado Diagrams (see Figure 5-7) illustrate the influence of risk variables on index threat scores. Green Values indicate opportunities for risk reduction, and dark green values indicate opportunities for risk increases. This one diagram reveals the influences of risk on the pipeline segment.

Figure 5-7. Tornado Diagrams

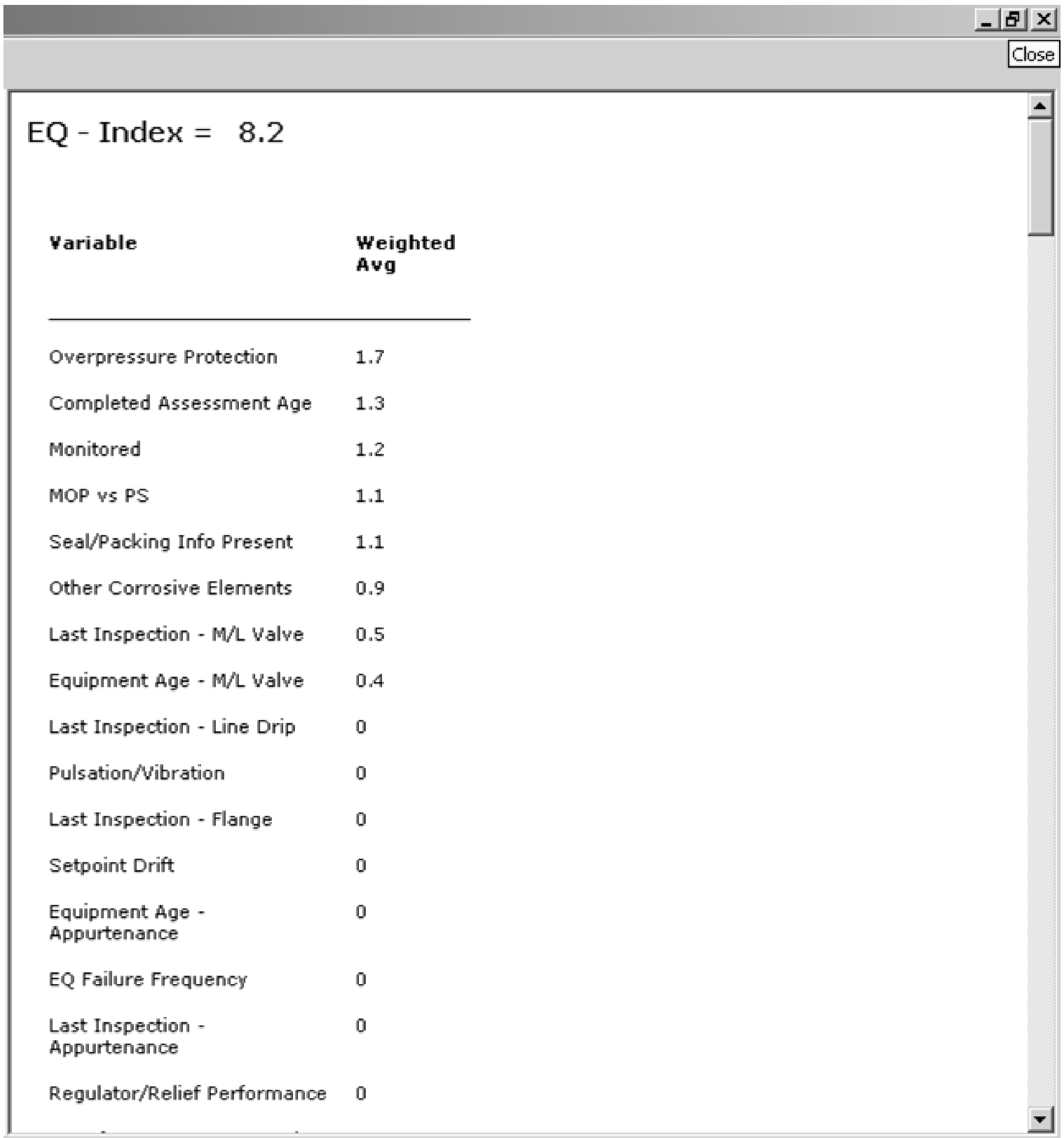


5.5.5. Index Variable

To determine which variable is driving an increased score, additional examination of the raw data becomes necessary. The Index Variable gives a list of the variable and its weighted average, which is causing the high index score.

Example: Figure 5-8 shows that Overpressure Protection, Completed Assessment Age, and Monitoring are some of the variables causing the Pipeline Equipment index to have a score of 8.2.

Figure 5-8. Index Variable


Close

EQ - Index = 8.2

Variable	Weighted Avg
Overpressure Protection	1.7
Completed Assessment Age	1.3
Monitored	1.2
MOP vs PS	1.1
Seal/Packing Info Present	1.1
Other Corrosive Elements	0.9
Last Inspection - M/L Valve	0.5
Equipment Age - M/L Valve	0.4
Last Inspection - Line Drip	0
Pulsation/Vibration	0
Last Inspection - Flange	0
Setpoint Drift	0
Equipment Age - Appurtenance	0
EQ Failure Frequency	0
Last Inspection - Appurtenance	0
Regulator/Relief Performance	0

5.5.6. Evaluating Risk

Risk results are reviewed by SMEs during the IMP Review and the P&M Measures process.

5.6. Integrity Risk Analysis Report

NuStar may produce an Integrity Risk Analysis Report for the segments and facilities to provide an interpretation of the significant risk contributors or data issues responsible for the increased risk scores in the highest risk areas of the system.

5.7. Document Distribution and Archiving

5.7.1. Document Distribution

The Risk Engineer distributes the Integrity Risk Analysis Report in a PDF file to the Regional HSE, Operations/Maintenance, SCADA, and Project Engineering Departments and archives the report on the IMP network drive, V:\Integrity Management\5_Risk\Risk Scores.

5.7.2. Database Archiving

The Risk Model database is archived on a server periodically (approximately once per year) to preserve the algorithm settings and data imports for historical purposes.

5.7.3. Documented Procedures

The *Risk Model User Reference Manual* and the *Risk Model Training Manual* (On the IMP Shared Network Drive, V:\Integrity Management\5_Risk\Risk Scores\RIPL User Manual) describe the steps required in performing an evaluation of risk.

5.8. Continuous Improvement of the Risk Model

NuStar places importance on continuously revisiting and modifying all information that is pertinent to producing a reliable risk assessment of its pipeline systems and facilities, including the use of operator's and industry's collective operating experience data, as shown in IMP Procedure 501. NuStar receives continuous feedback during the P&M measures process on the algorithm’s ability to predict as-found conditions for the pipeline systems. In doing this periodic review, the Risk Engineer will adjust the weights within the algorithm appropriately whenever evidence shows the need. It will also either add or delete any threats, variables, or attributes within the algorithm when needed.

501: Risk Model Analysis

Introduction

American Innovations developed the initial model configuration and architecture for the Risk Model, and NuStar customized it to provide a relative risk ranking for both pipelines and facilities. NuStar continuously improves and customizes this Risk Model through continuous feedback from Subject Matter Experts (SMEs), risk results, industry standards, industry and company experiences, and comparisons to performance data. The process of running the annual risk analysis is best illustrated through the flow chart in Figure 501-1, which illustrates the risk analysis process run annually through the Risk Model.

Regulation

49 CFR §195.452(e) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?

49 CFR §195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

49 CFR §195.452(g) What is an information analysis? In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure.

49 CFR §195.452(i)(2) Risk analysis criteria. In identifying the need for additional preventive and mitigative measures, 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:

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar.

Resources

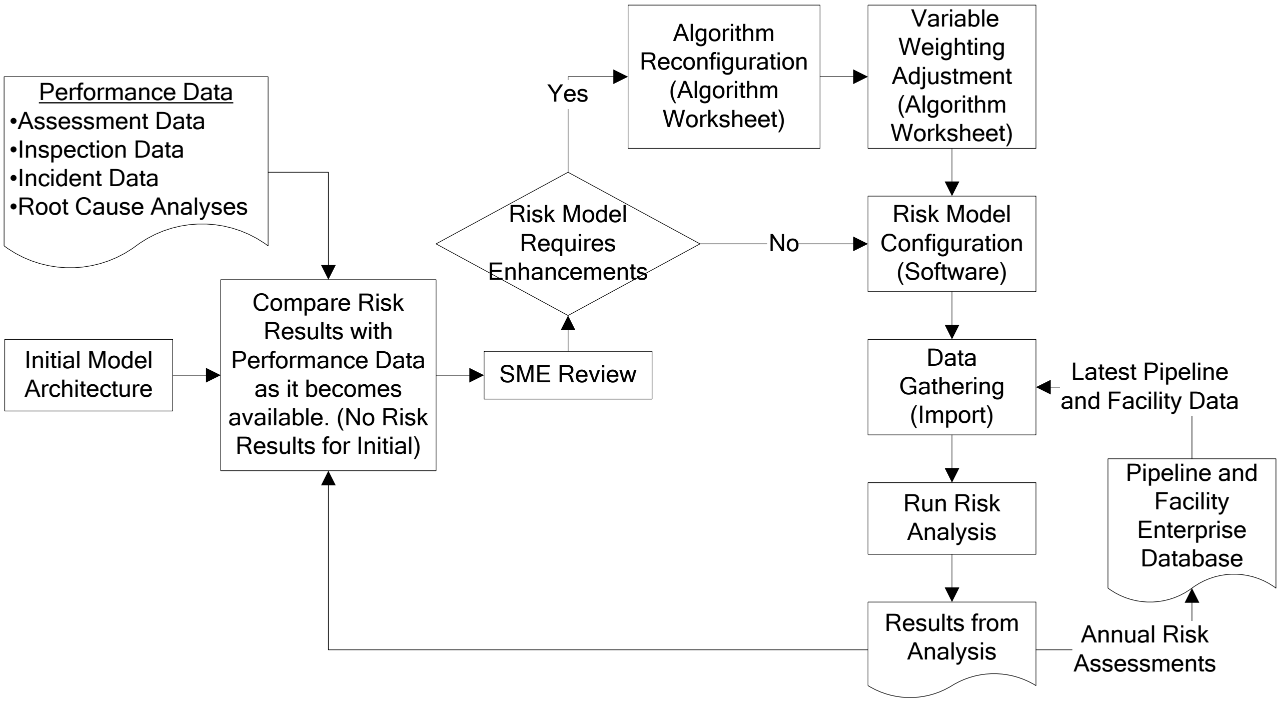
American Innovations IMP software

Risk Model Algorithm Index Manual

Risk Model User Reference Manual

Risk Model Training Manual

Figure 501-1. Risk Model Analysis Flowchart



501.1. Risk Model Comparison

1A	**[P&M Measure Meeting Attendees]** Review risk analysis results during P&M meetings.	
	1	Review the risk analysis results with other reports to collect data and ensure that the Risk Model receives consistent information for different pipeline segments and facilities.
	2	Use subjective information provided by SME's and industry's collective operating experience data to both compliment and verify the risk analysis results.
1B	**[Risk Engineer]** Incorporate agreed-upon changes as risk analysis tools and document changes in the Algorithm Index Manual Revision Log.	

501.2. Subject Matter Expert Review

NuStar has identified SMEs who give council and validation regarding the configuration and preventive and mitigative (P&M) measures of the Risk Model algorithm. This review includes consideration for threat indexes, consequence indexes, contributing variables, and their attributes.

2A	**[Risk Engineer]** Use Table 5-1., SME Areas of Expertise, in Section 5 to determine which SMEs to consult.
2B	Prior to the meeting date, direct the appropriate SMEs to review the Risk Model Variables Diagrams and Risk Model Attributes Report posted on the IMP Intranet.
2C	**[SMEs]** Review the current variables and decide if variables need to be added or removed and whether variable and/or attribute weights need to be adjusted to model more accurately NuStar's system.
2D	**[Risk Specialist]** Document the following: • The type of segments under discussion • A summary of recommended modifications to the model and subsequent discussion • All accepted changes to the algorithm

501.3. Risk Model Configuration

3A	**[Risk Engineer]** Reconfigure the Risk Model algorithms to reflect all accepted changes. **Note:** The Risk Model changes may occur either at the index, variable, or attribute levels.
3B	Update the Risk Model Variables Diagrams and Risk Model Attributes Report on the Intranet to reflect changes.

501.4. Data Gathering (Import)

4A	**[Risk Engineer]** If needed, consult guidance for actually running the Risk Model software by consulting the *Risk Model User Reference Manual* and the *Risk Model Training Manual* provided.
4B	Import data from the pipeline and facility enterprise database for use in the Risk Model program. **Note:** Section 5, Risk Analysis, illustrates the type of data gathered to run the Risk Model algorithm.

501.5. Run Risk Analysis

5A	1	**[Risk Engineer]** If needed, consult guidance for actually running the Risk Model software by consulting the *Risk Model User Reference Manual* and the *Risk Model Training Manual* provided.
	2	Perform a quality check on all of the variable changes and data input.
	3	Use the auditing feature within the Risk Model that checks the variables and data for irregularities and notifies the user of these irregularities.
	4	Run the data auditing function within Risk Model software. This report evaluates the quality of data for missing or incomplete information (informational), data gaps or overlaps (locational), and time-sensitive (temporal) data.
5B	Once the quality check is complete, run the Risk Model and place the results on the intranet.	

501.6. Export Results into Pipeline and Facilities Database

6	**[Risk Engineer]** After the final Risk analysis for the year, export the results into the NuStar GIS system or use in future risk analyses, assessments, inspections, and root cause analyses.

6: Preventive and Mitigative Measures

The Rule states that an operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect an HCA. These preventive and mitigative (P&M) measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Although *§(i)* of the Rule only requires operators to enhance P&M measures on pipelines and facilities within HCAs, NuStar may choose to apply these measures to address the likelihood and consequence of failure in defined non-HCA areas as well.

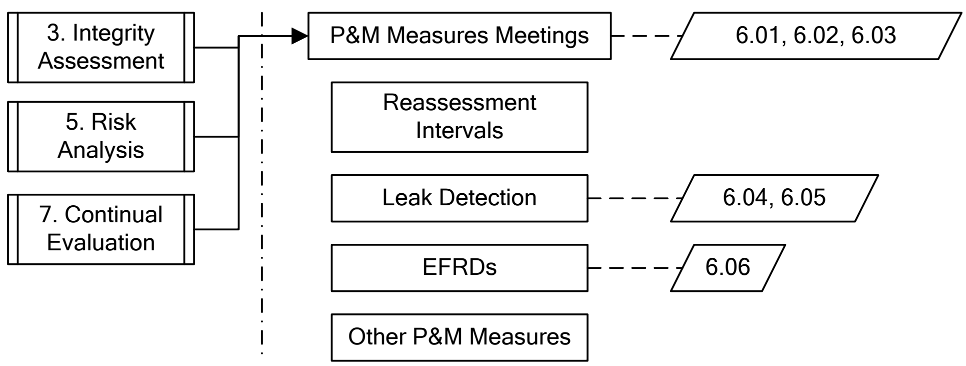
Preventive and mitigative measures are defined as follows:

- Preventive—practices that reduce the likelihood of failure
- Mitigative—practices that reduce the consequences of failure

To help ensure the safe operation of its pipelines and facilities, NuStar enacts four categories of P&M measures (shown in Figure 6-1 with corresponding protocols). NuStar also reviews the effectiveness of current P&M measures for enhancements or upgrades, evaluating existing measures in comparison with the latest risk analyses, integrity assessments, and improvements in technology.

Based on the results of integrity assessments, risk analysis, and continual evaluations, NuStar may need to explore additional measures or enhance existing measures to prevent and mitigate the likelihood or consequence of a pipeline failure that could affect an HCA.

Figure 6-1. P&M Measures



IMP Procedure 601, Preventive and Mitigative Measures Process, documents NuStar's formalized process for proposing and evaluating P&M measures. As P&M measures meetings are held and enhancements or additions to existing P&M Measures are proposed, NuStar follows processes for evaluating these candidate proposals, documenting and communicating updated information, and following up in all areas as needed.

At any time, Field and Regional Personnel may identify actions that prevent and/or mitigate the consequence of failure on an asset and send the suggestion to the P&M Coordinator. The P&M Coordinator who determines whether the action is an Accepted P&M Measure (ready for implementation or already being implemented) or needs to be considered as a Candidate P&M Measure as part of a P&M Measures Meeting. The P&M Measure Suggestion Form (in Appendix F, Forms) has been provided as a guide for submitting ideas.

6.1. Types of P&M Measures

P&M measures are one of two types.

- Conventional measures are company-wide requirements or prescriptive requirements under the Rule.
- Risk-specific measures are risk-driven, asset-specific, and based on results from the most current risk analysis, integrity assessments, and continual evaluations performed on NuStar's pipelines and facilities.

6.1.1. Conventional P&M Measures

Certain P&M measures are intrinsic to the organization and applied to its entire pipeline systems and facilities. Although the Rule and/or other federal regulations may require these conventional P&M measures, NuStar considers each one as an important aspect of its IMP. Examples of conventional measures include, but are not limited to, the following:

- Pump Station Design, Construction, and Testing
- Monitoring of Critical Bonds
- Internal Corrosion Monitoring and Control
- Right-of-Way Inspection and Maintenance
- Pipeline Signs and Markers
- Hydrostatic Testing of New Pipeline Components
- Security of Facilities (Signs and Markers, Fire-Fighting Equipment
- Public Awareness Program
- Training

6.1.2. Risk-Specific P&M Measures

Risk-specific P&M measures are risk-driven and asset-specific. Such measures are based on data from the Risk Model, integrity assessments, and continual evaluations performed on the pipeline systems and facilities.

NuStar currently implements a number of risk-specific P&M measures to protect the operation of its pipelines and facilities. Some of these initiatives either exceed the requirements of the Rule or are not required by it. Examples of risk-specific measures include, but are not limited to, the following:

- NuStar has a trailer-mounted pipeline monitor, manufactured by Dynamic Monitoring Systems, for collecting and analyzing fluid samples from pipelines and for examining trends of internal corrosion.
- NuStar may evaluate cased crossings for rehabilitation or removal, where practicable, to address the possibility of external corrosion on cased pipe.
- NuStar may increase depth of cover at locations vulnerable to third party damage—such as stream and river crossings, railroad crossings, and highway crossings—through directional boring, traditional excavation, or pipe lowering.

6.2. P&M Measure Categories and Evaluation Criteria

NuStar classifies P&M measures into four categories. The following subsections describe these categories, along with details about evaluating P&M measures for each.

6.2.1. Reassessment Intervals

NuStar continually reevaluates existing reassessment intervals in its Pipeline P&M Measures Meetings to determine if current intervals remain adequate in relation to updated risk information (see Section 7.2). Such reviews may result in a shorter interval or a change in assessment method or technology.

In evaluating the reassessment interval for each pipeline segment, attendees consider all risk factors relevant to that segment, including at least the following:

- Results from current and previous inspections
- Information from repairs
- POE conclusions
- Risk results
- Leak history
- Information on how a failure would affect an HCA
- Tool accuracies or intolerances
- One-Call data
- Current/previous integrity assessment results
- Defect type and size that the assessment method can detect (tool tolerances)
- Defect growth rate (POE analysis, corrosion rate)
- Inspection Tool Technology
- Repair results (when applicable)
- Pipeline Integrity Profile Sheets or GIS-based interactive maps (when applicable)
- Cathodic Protection (CP) Analysis and corrosion control monitoring
- Pipeline specs (size, material, manufacturing data, coating type and condition, seam type)
- Cathodic protection history
- Surveillance and patrol
- Consequence of failure
- Prior and pending decisions about preventive and mitigative actions
- Any other information relevant to the integrity of the pipeline
- Metallurgical analyses
- Maintenance records
- Leak, repair, and cathodic protection history characteristics of the product transported
- Local environmental factors that could affect a pipeline (soil corrosivity, subsidence, climatic)
- Operating stress level, % SMYS
- Geo-technical hazards
- Physical supports (a cable suspension bridge)
- Overall risk ranking and contributing threats
- Third party damage threat (existing/projected area activities, ROW surveillance, patrol reports)
- Updated risk analysis

6.2.2. Leak Detection

In addition to consideration of the factors listed for all candidate P&M measures and in conjunction with updated risk assessment results, attendees consider the following when evaluating the effectiveness of NuStar's leak detection. NuStar's current leak detection systems are described in Section 6.5.

- Prior incidents and/or leak history
- Pipeline specifications (e.g., length and size, age, product carried characteristics)
- Proximity to HCA; type of HCA
- Swiftness of leak detection and current leak detection methods (aerial/surface patrols, SCADA usage, CPM system availability, manual tabulation over/short and pressure monitoring)
- Evaluation of all operating modes, including slack line, idled line, and static conditions
- Frequency of transients and/or mode changes
- Leak detection thresholds
- Leak detection validation and testing
- Accuracy of locating the leak (e.g., distance between pressure transducers, flow meters)
- Frequency of false alarms; system reliability
- Frequency of manual tabulation and monitoring
- Leak detection response time
- Location of nearest response personnel
- Location of pipeline for detection and response (deep underground or other locations increase leak detection difficulty and/or significantly impede spill response access)
- Hydraulic gradient
- Operator response procedures and training
- Recent enhancements to the leak detection system
- Additional leak detection means for areas in close proximity to sole source water supplies
- Specific procedures for lines that are idle but still under pressure
- Product transported

6.2.3. Emergency Flow Restriction Devices (EFRDs)

For existing in-service pipelines, the Risk Engineer uses the Risk Model to investigate how including or modifying an EFRD might prevent or mitigate the effects of an unintentional release on an HCA (see Section 6.6).

The Risk Engineer configures, analyzes, and reports EFRD scenarios, considering at least the following factors:

- Swiftness of leak detection
- Type of commodity carried
- Volume that can be released
- Potential for ignition
- Location of the nearest response personnel
- Swiftness of pipeline shutdown capabilities
- Rate of potential leakage
- Pipeline topography
- Proximity to power sources (as applicable)
- Specific terrain between pipeline and HCA

For new construction, the Engineering Department consults with the IMP Team during the design phase to determine the need for EFRDs.

6.2.4. Other Measures

NuStar administers other categories of P&M measures essential to the overall preventive and mitigative effort. These include both conventional and risk-specific measure types and are continually evaluated to confirm viability and effectiveness. Examples of other categories of P&M Measures include

- implementing damage prevention best practices,
- better monitoring of cathodic protection where corrosion is a concern,
- providing additional training to personnel on response procedures, and
- conducting drills with local emergency responders and adopting other management controls.

See Appendix G, Preventive and Mitigative Measures—Risk Threats Matrices for examples of measures.

6.3. Considering Candidate P&M Measures

Candidate P&M measures can include new measures being considered for implementation, as well as upgrades or enhancements to existing P&M measures that do not seem adequate or optimal in comparison with current risks and the most recent data. Persons responsible for evaluating P&M measures investigate justifications for a variety of incremental or significant modifications to—among other things—processes, EFRDs, reassessment intervals, and leak detection. Factors that may trigger a modification to an existing P&M measure include the following:

- Alternate modes of operation (startup, shutdown, pressure cycling, etc.)
- Adjustments to other work processes, including leak detection and reassessment intervals
- Physical changes to pipeline systems or facilities, including EFRDs
- Improved technology
- Learnings from industry incidents

In evaluating all existing or candidate P&M measures, subject matter experts (SMEs) consider the following factors (along with other topics detailed in Table 6-1and Procedure 601):

- Completed assessment and repair results
- Leak detection reliability, including additional response personnel training
- POE Analysis results
- Corrosion assessment results
- High risk HCA pipeline segments, facilities
- Weather and outside forces
- Detected/undetected leaks by the leak detection system
- P&M measures from the Risk Matrix (See Appendix G)
- Candidate P&M measures submitted by field and regional personnel
- Other candidate P&M measures, including drills with local emergency responders
- Tank Information Spreadsheets

6.3.1. Risk Drivers

During the evaluation of existing or candidate measures, SMEs consider the specific threats present in the area of the asset under review, as well as how effectively current P&M measures are handling these threats. The tables in Appendix G, Preventative and Mitigative Measures–Risk Threats Matrices, illustrate the threats that pipelines and facilities may encounter (listed below), and the corresponding P&M measures that counteract these threats. These matrices allow NuStar to select appropriate P&M measures from a risk-driven standpoint, which are applicable to both pipelines and facilities.

- Third Party Damage (3PD)
- Incorrect Operations (IO)
- Internal Corrosion (IC)
- External Corrosion (EC)
- Construction (CONS)
- Weather/Outside Forces (WOF)

- Equipment Failure (EQ)
- Manufacturing (MFG)
- Stress Corrosion Cracking (SCC)
- Other asset-specific threats

6.3.2. Classifying P&M Measures as Potential or Accepted

SMEs review the effectiveness of all candidate P&M measures in order to determine which measures need further investigation and which to implement. Chosen measures are classified as one of the following:

- Potential P&M Measures—possible measures that require further review or drill down in order to determine applicability, feasibility, and rationality (these may be later rejected, or they may either become or lead to Accepted P&M Measures)
- Accepted P&M Measures—risk-specific measures identified as ready for implementation, in order to reduce the likelihood and/or consequence of a failure (these are prioritized for implementation by attendees based on risk results and any other determining factors)

6.4. P&M Measures Meetings

NuStar conducts reviews of performance metrics on pipelines and facilities that could affect an HCA in order to monitor the effectiveness of current P&M Measures and address any risk-related developments. NuStar considers implementing new P&M Measures for pipelines or facilities that meet any of the following conditions:

- One on which an IMP assessment/remediation has been completed recently
- One experiencing an incident
- One identified by Field Personnel as needing analysis
- One with high Risk of Failure (ROF) scores
- One with similar characteristics to another pipeline experiencing an incident

6.4.1. Initial P&M Measures Meetings

6.4.1.1. Preparing for the Initial P&M Measures Meeting

Procedure 601, Preventive and Mitigative Measures Meetings, outlines NuStar's formalized process for proposing and evaluating P&M Measures. Prior to the initial meeting, the Risk Engineer performs drill downs to identify the risk drivers on pipeline segments being reviewed (See Section 5.5.1).

Topics for the initial P&M Measure Meeting are listed in Table 6-1 along with the corresponding Subject Matter Expert(s) and the data to be collected as it is applicable and available for that particular meeting. Additional topics and related data may be relevant. (Table 6-2 lists the topics by Subject Matter Expert.)

Table 6-1. Topics for the P&M Measure Meeting and Related Data

Topic	Subject Matter Expert(s) [Source]	Related Data (as Applicable/Available)
Risk Analysis	Risk Engineer	• Risk Model—regional/area risk rankings, drill down reports, threat drivers, and pipe specs • Red flags and LOF/COF risk scores
Assessments and Repairs	• Assessment Engineer • Assessment Project Manager • Corrosion Manager	• Client List—completed assessments/repairs, repair results/findings • Current reassessment intervals and scheduled assessments • External/internal anomalies (density, repair classes, percent depths, percent near girth welds) • Dents (density, percent ID reduction) • Seam susceptibility studies • Dig Records—completed repairs, results/findings, possible causes • CP system effectiveness and enhancements • Pipeline Information Reports/Defect Evaluation (PIR) Forms

Topic	Subject Matter Expert(s) [Source]	Related Data (as Applicable/Available)
POE Analysis	Assessment Engineer	• Internal/external corrosion rates • Inspection intervals • Dig intervals
Corrosion	Corrosion Manager	• Test leads (number, density, below criteria, shorted casings, critical bonds) • Rectifiers (number, density, average amps, amps per mile) • Internal coupons (date installed/removed, corrosion rating/rate/type) • Inhibition program (type, usage) • Close Interval Surveys data • Corrosion Control Effectiveness Review Forms • SCC technology information
Weather and Outside Forces	• Risk Engineer • Corrosion Manager • Regional HSE • Area P&T Manager	• Environmental factors—soil type, soil corrosivity, subsidence, settlement, slope, erosion • Climatic conditions—temperature range, rainfall • Adverse weather—floods, hurricanes, earthquakes, high winds, lightning • Crossing types—railroad, bridge, high-voltage, water
HCAs	• HCA Specialist • Risk Engineer	• Pipeline Integrity Profile Sheets or GIS-based interactive maps (if needed) • HCA information (types, spill paths, drain tiles, aerial overlays, buffer zones, evaluation profiles, newly populated areas, crossings of roadways with ditches)
Incidents	Regional HSE [Control Center]	• IMPACT Incident Reports—description, findings, root cause, status • Near Miss Reports • AOCs—descriptions, findings, recommendations • 7000-1 Release Reports
Emergency Response and Public Awareness	• Regional HSE • Area P&T Manager	• Public Awareness Meetings/Seminars—total number, locations, attendance; attendee types • Mail-outs (total number, recipient types) • Emergency Response Drills/Training—total number of each, drill types
One-Call Tickets	GIS Manager	One-Call metrics—area vs. region average per mile
Leak Detection Capabilities	• Risk Engineer • Maintenance Manager • Area P&T Manager • Regional HSE	• SCADA Configuration—system specs (including system types, methods, thresholds, and response times), leak detection testing results, leak detection/monitoring of line operations including slack line, idled line, and static conditions, false alarm frequency/rate • Procedures and training (operator knowledge of leak detection system and emergency response plans) • System enhancements • Aerial/Surface Patrol Reports—methods, intervals, findings/trends, ROW conditions, unintentionally exposed pipe, encroachments • Inspection reports for pipelines with physical supports (such as cable suspension bridges)
EFRD Analysis	Risk Engineer	• Drain down studies and first scenarios • EFRD valve locations • EFRD information sheets
Pressure Cycling and Surge Analysis	• Assessment Engineer • Energy Optimization Manager	• Pressure spikes • Surge analysis results • Trends • Alternate modes of operation
Candidate P&M Measures	P&M Coordinator [SMEs]	P&M measures (from form or otherwise) to be considered

6.4.1.2. Conducting the Initial P&M Meeting

Representatives of at least the following groups attend the initial P&M meeting:

- Operations/Maintenance/Corrosion
- Engineering
- IMP
- Regional HSE

Table 6-2 lists the potential meeting attendees by area of expertise.

Table 6-2. SME Area of Expertise

Subject Matter Expert	Area of Expertise	
P&M Coordinator	• Previous P&M Measure updates	• Potential P&M Measures
Risk Engineer	• Risk Analysis • HCAs • Leak Detection Capabilities	• EFRD Analysis • Weather and Outside Forces
Assessment Engineer	• Assessments and Repairs • POE Analysis	• Pressure Cycling and Surge Analysis
Assessment Project Manager	• Assessments and Repairs	
Corrosion Manager	• Assessments and Repairs • Corrosion (Internal and External)	• Weather and Outside Forces • SCC
HCA Specialist	• HCAs	
Regional HSE	• Incidents • Emergency Response/Public Awareness • Third Party Damage	• Leak Detection Capabilities • Weather and Outside Forces
Area P&T Manager	• Weather and Outside Forces • Emergency Response/Public Awareness	• Leak Detection Capabilities • Facilities
GIS Manager	• One-Call Tickets	
Maintenance Manager	• Leak Detection Capabilities • Incorrect Operations	• Facilities
Rotating Equipment Manager	• Facilities	
Energy Optimization Manager	• Pressure Cycling and Surge Analysis	
Engineering	• Manufacturing • Equipment	• Construction
Control Center	• Leak Detection	

6.4.1.3. Following Up on the Initial P&M Meeting

6.4.1.3.1. Meeting Outcomes

The P&M Coordinator notifies attendees of any outcomes of the initial P&M Meeting.

- Action items—specific tasks assigned to attendees (these may or may not relate to a particular P&M measure)
- Potential P&M Measures—possible measures that require further review or drill down in order to determine applicability, feasibility, and rationality (these may later become or lead to Accepted P&M Measures)
- Accepted P&M Measures—risk-specific measures identified as ready for implementation, pending expenditure approval, in order to reduce the likelihood and/or consequence of a failure (i.e., measures identified as beneficial)

6.4.1.3.2. P&M Measures Tracking Report

The P&M Coordinator adds the potential and accepted P&M measures to the P&M Measures Tracking Report and keeps the entries updated as related tasks are completed.

6.4.1.3.3. Remediation Digs

If an accepted P&M measure requires remediation because conditions identified during the integrity assessment could impair the integrity of the pipeline, the Assessment Project Manager creates a work order (see IMP Procedure 301, ILI Assessment, Data Evaluation, and Remediation).

6.4.2. Additional P&M Measures Meetings

The P&M Coordinator, or any other interested party, may choose to call additional meetings as needed to follow up on the outcomes of the initial P&M Measures Meeting. For example,

- progress on action items,
- applicability, feasibility, and rationality of potential P&M measures (including EFRD scenarios), and/or
- implementation status of accepted P&M measures.

Depending on the specific topic(s) to be covered, only the applicable representatives of the following groups will attend:

- Operations/Maintenance/Corrosion
- Engineering
- IMP
- Regional HSE
- Regional General Managers
- Area Managers

6.4.2.1. Preparing for Additional P&M Meetings

To help determine if a potential P&M measure identified in the initial P&M measures meeting will reduce the likelihood and/or consequence of a failure, attendees perform their assigned tasks to gather and analyze the necessary data.

6.4.2.2. Conducting Additional P&M Meetings

Attendees present the findings of their data gathering and analysis, and reevaluate the applicability, feasibility, and rationality of potential P&M measures from the initial meeting. Information considered in this reevaluation includes

- the results of all further data collection and risk analysis,
- the most significant causes/drivers from the initial P&M meeting,
- the relative risk ranking in comparison to other pipeline segments and/or facilities, and/or
- the benefits of risk reductions in the likelihood and/or consequences of failure.

This reevaluation activity may occur in subsequent P&M measures meetings, annual risk evaluations, and/or annual program reviews.

After reevaluating each potential P&M measure, attendees decide whether it is

- rejected,
- in need of more research, or
- ready for implementation as an Accepted P&M Measure.

6.4.2.3. Following Up on Additional P&M Measures Meetings

The P&M Coordinator summarizes for attendees any action items, continued potential P&M measures, and newly accepted P&M measures and updates the P&M Measures Tracking Report, noting decision criteria for rejected and continuing potential P&M measures, and changing the status of potential P&M measures that have been accepted.

6.4.3. Documenting P&M Measures

Table 6-3 indicates which personnel are responsible for the documentation of which information relating to the P&M Measures process and where that documentation is kept.

Table 6-3. P&M Measures Documentation

Personnel	Information	Document	Location
P&M Coordinators	Meeting(s) results	Outcomes communication	IMP drive
	Status of potential and accepted P&M measures	P&M Measures Tracking Report	IMP drive
Risk Engineer	EFRD analysis	EFRD Analysis Report	IMP drive
Assessment Engineer	Updated reassessment intervals for pipelines	Reassessment interval determination form	Pipeline integrity database (Intranet)
Tank Integrity Engineer	Updated reassessment intervals for facilities	Tank Inspection Schedule	Tank Integrity Database (Intranet)

6.5. Leak Detection Systems Summary

NuStar's leak detection systems are described in its Remote Operation Manual, specifically the *Control Room Procedure Manual, Console Eight, General Systems*.

6.5.1. Leak Detection on Control Center Monitored Pipelines

The NuStar Control Center in San Antonio uses data and analysis information from the SCADA (Supervisory Control and Data Acquisition) System in accordance with Nustar’s Remote Operation Manual for leak detection on most NuStar pipelines. NuStar employs multiple layers of leak detection methodologies. These systems are both complimentary and overlapping to ensure that leak detection, in one form or another, is available at all times. The primary methodologies include the following:

- Gain/Loss calculations incorporated into Console Log Sheets.
- Deviation and Rate of Change alarms, established on pressure and flow data points
- Telvent PRESMON, Pressure Monitoring System, pressure based leak detection module
- Telvent PLM, Pipeline Monitoring System , Steady State leak detection system
- Telvent ALD, Advanced Leak Detection System, Transient Model Leak Detection

6.5.1.1. Computational Pipeline Monitoring Tool

The Telvent package integrates the data, alarms, and logs generated by SCADA with the output from its Computational Pipeline Monitoring (CPM) tool to give the Control Center a seamless view of pipeline status.

This CPM tool—which uses over/short data, line pack calculations, and flow and pressure deviations to determine if a leak has occurred—complies with API 1130 for the testing, training, and maintenance of monitoring systems.

6.5.1.2. Alarm Processing/Transient Effect Reduction

Because many pipeline operations (such as those caused by pump startups or valve swings) create transient effects and can affect the accuracy and effectiveness of computational pipeline monitoring, the Control Center uses manual tabulation by constantly monitoring flow and pressure until the transient effect has passed. The alarm limits are set accordingly to anticipate pipeline line pack and meter over/short occurrences.

6.5.1.3. Minimizing Emergency Response Time

Operations/Maintenance Personnel can receive information about pipeline leaks through pipeline system operations alarms, third party observations, emergency response organizations, aerial/surface patrols, and other means. Immediate response is imperative to any given situation involving an actual or suspected pipeline leak. The Control Center has established response procedures for responding to pipeline emergencies. Those procedures define an action plan that includes the following:

- Organizational lines of responsibility and notification for release response
- Training of all release response personnel
- Immediate verification of unintended releases (if necessary)
- Isolation/control of unintended release source
- Control of released product according to procedures developed for specific environmental impacts and unintended release volumes

6.5.1.4. Evaluating the Leak Detection System

Using a risk-based approach, NuStar periodically evaluates the need for enhancements to its leak detection systems on individual pipelines during P&M Measures Meetings. In addition to factors listed in Section 6.2.2, performance measures reviewed for the leak detection system report include at least the following:

- Results of alarm tests
- Remote data point additions or deletions
- Industry trends
- Technological advances in leak detection
- Inadequate/poor response to actual leak conditions
- Changes to product composition

NuStar has implemented a companywide program to upgrade its leak detection systems to ALD and updates the implementation schedule continually using a combination of calculated risk and table top discussions with operations, IMP, control center, and leak detection SMEs.

6.5.2. Leak Detection on Pipelines Not Monitored by the Control Center

NuStar has incorporated other means of leak detection for pipelines not covered by the Control Center. For these pipelines, NuStar may employ, but are not limited to, the following methods or combination of following methods:

- Local pressure monitoring
- Local measure-in vs. measure-out monitoring
- Periodic foot patrols
- Periodic aerial patrols

NuStar employs methods that are site-specific as applicable to that particular pipeline's operating conditions.

6.5.3. Other Leak Detection and Response Measures

6.5.3.1. Isolation and Control of Suspected Leaks

As soon as operators have reason to believe an emergency event has occurred, they shut down the pumping units that feed the line section, close the first valve at the nearest upstream station from the leak location, and keep the line down until NuStar has made an on-the-ground investigation. If NuStar knows the exact location of a break, stations downstream of the leak continue to operate for as long as possible to empty the line or reduce pressure on the line to a minimum.

Whenever a hazardous liquids leak or vapor cloud is reported, Control Center Operators immediately implement the emergency plans in *O&M Manual* Section 200.

6.5.3.2. Preparedness and Response Plans

NuStar has developed a variety of preparedness and response plans for use by Pipelines and Terminals employees in the event of a spill or other emergency, as required by the U.S. EPA, U.S. Coast Guard, U.S. Department of Transportation, and various state agencies. NuStar designed these plans to provide the information needed to respond quickly and correctly to an event and to make the required notifications. NuStar requires all employees to become familiar with the location and contents of the plans for their facility.

Each facility has at least one of the following plans (some plans are not applicable for all facilities), which are described in the sections below:

- Spill Prevention Control and Countermeasure (SPCC) Plan
- Storm Water Pollution Prevention (SWPP) Plan
- Facility Response Plan (FRP)
- Oil Spill Response Plan
- Waste Analysis Plan
- Resource Conservation Recovery Act (RCRA) Contingency Plan and Emergency Response Procedures
- Integrated Contingency Plan (ICP)
- Liquid Pipeline Emergency Response Plan (see *O&M Manual* Section 200)

6.5.3.2.1. Spill Prevention Control and Countermeasure Plan

NuStar requires a SPCC for all non-transportation-related facilities of 1,320 gallons or more engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, or consuming oil. This plan requires a listing of all above- and below-ground tanks along with the following information:

- Identification of their contents
- Containment measurements used
- Security measurement in place
- Possible causes of a spill
- Where a spill might flow

A Professional Engineer must certify the SPCC and must review the plan at least every five years.

6.5.3.2.2. Storm Water Pollution Prevention Plan

NuStar requires the SWPP Plan at most products terminals with discharge permits. This plan identifies potential pollutant sources along with the routine inspections and controls that are employed to minimize the possibility of the discharge of a pollutant from the facility as storm water runoff.

6.5.3.2.3. Facility Response Plan

The FRP applies to non-transportation-related facilities consisting of one or more above-ground tanks with a total storage capacity of at least 1,000,000 gallons and engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, or consuming oil. This plan includes the following information:

- Identification of the Qualified Individual, local response team, and the Oil Spill Response Organization (OSRO) for the facility
- Names and phone numbers of various other emergency response contacts inside and outside the company
- Facility diagrams
- Evacuation plans
- Drainage diagrams
- Initial response actions
- Incident response checklists
- Critical areas to protect
- Lists of emergency response equipment
- Spill trajectory analysis
- Explanations of safety awareness
- Processes for air monitoring, decontamination, and personal protective equipment

6.5.3.2.4. Oil Spill Response Plan

This plan applies to Texas coastal facilities and identifies spill response personnel and associated resources along with general spill response scenarios and technical response and information guidelines.

6.5.3.2.5. Waste Analysis Plan

This plan is required at all facilities designated as a large quantity generator (LQG) of hazardous waste. This plan lists all hazardous and non-hazardous wastes at the facility and characterizes the wastes generated on site and contains descriptions and locations of waste management areas at the facility.

6.5.3.2.6. Resource Conservation Recovery Act (RCRA) Contingency Plan and Emergency Response Procedures

NuStar distributes this document to the Local Emergency Planning Committee (LEPC), local sheriff's office, police department, fire department, ambulance service, and appropriate hospitals. This plan includes the following information:

- Identification of the potential sources of hazardous waste spills
- Initial spill response actions and notification requirements
- List of local response equipment and spill response contractors
- Facility evacuation plan

6.5.3.2.7. Integrated Contingency Plan

The ICP combines the Facility Response Plan, Spill Prevention Control and Countermeasures Plan, and if applicable, the Storm Water Pollution Prevention Plan.

6.6. EFRD Analysis Process

The Risk Model's drain down modeling uses elevation, flow rate, design information, and valve isolation points to calculate the volume of an unintentional release, which is then used to determine how the product might migrate to an HCA. The Risk Engineer uses the Risk Model (and the HCA Model as necessary) to investigate the effect of changes to the current pipeline configuration, and operational information of the segment(s) being studied.

As necessary, the Risk Engineer runs the EFRD scenarios being considered in the Risk Model

- to evaluate the risks associated with an LOF increase versus a COF decrease,
- to analyze how these scenarios impact HCA Could Affects, and
- to compare them against the base condition.

(The HCA Specialist may be asked to perform a spill analysis on one or more of the scenarios in order to determine which of them could provide the more significant reduction in HCA Could Affects.)

The Risk Engineer compiles a report with the final EFRD results, and then researches and documents on the necessary criteria, as listed in Section 6.2.3, on the EFRD Evaluation Form.

6.6.1. EFRD Decisions

When evaluating potential P&M measures that call for new or upgraded EFRDs, SMEs also review any additional EFRD Analysis results and any EFRD Evaluation Form data. Their evaluation should include at least the following line-specific factors:

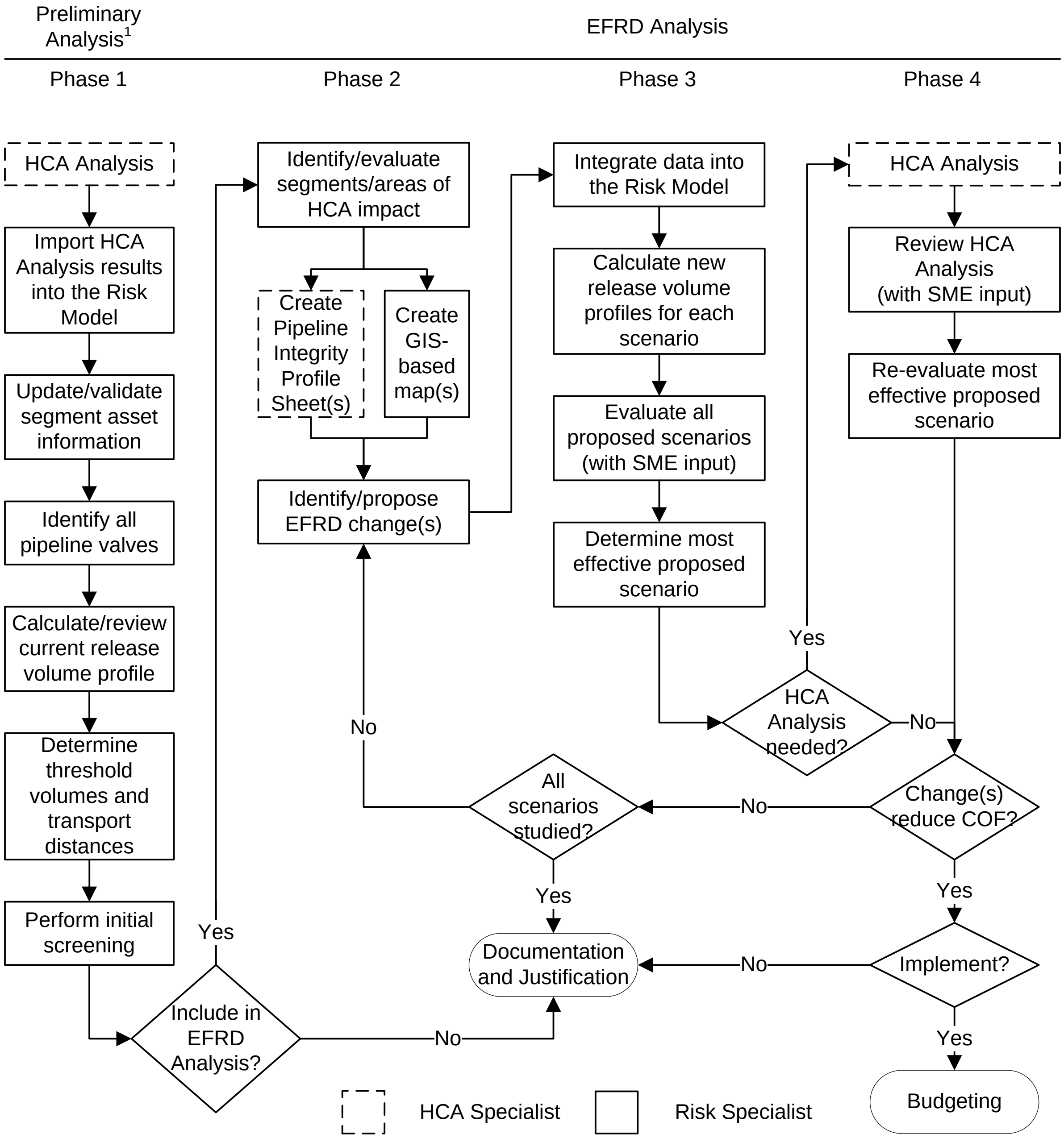
- Risk-reduction benefits, including reducing spill size
- What-if scenarios changing valve characteristics to determine the effects on potential ruptures
- Relative reliability of existing/proposed EFRDs
- Improving existing asset valve closure rates
- Any relevant operating modes beyond nominal full flow conditions
- Location of nearest response personnel
- Improved training for leak detection and emergency response personnel
- Relative risk ranking, in comparison to other pipeline segments
- Increased likelihood of a leak because of the addition of a valve
- Benefit to cost effectiveness
- Implementation logistics
- Cumulative effect of multiple factors

EFRD Scenarios that are accepted for implementation are reported to the P&M Coordinator and tracked as Accepted P&M Measures.

6.6.2. EFRD Evaluation Form

The Risk Engineer documents recommendations from P&M measures meetings or SMEs, including, factors, comments, and justifications. (The completed form may be included in an EFRD Analysis Report.)

Figure 6-2. EFRD Analysis on Existing In-Service Pipelineines Flowchart



[1]NuStar uses its 2008 comprehensive EFRD analysis to satisfy the Preliminary Analysis portion of this workflow.

601: Preventive and Mitigative Measures Meetings

Introduction

DOT regulations require operators to identify P&M measures to protect HCAs. Section 6 of this manual describes NuStar's P&M Measure methodology, including the use of P&M Measures Meetings to evaluate the effectiveness of current and propose new measures, where applicable. This procedure documents how NuStar prepares for and conducts P&M Measure Meetings. NuStar has established this procedure to evaluate the following items:

- EFRDs
- Reassessment intervals
- Leak detection
- Other risk-based P&M measures

See Section 6 for additional details including the criteria and timeframes for holding P&M Measures Meetings, the required attendees for each discussion topic, and the overall P&M Measure process.

Regulation

49 CFR §195.452 (f)(6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section)

49 CFR §195.452 (i) What preventive and mitigative measures must an operator take to protect the high consequence area? An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but not be limited to, implementing damage prevention best practices, better monitoring cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders, and adopting other management controls.

(4) Emergency Flow Restricting Devices (EFRD). If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors: the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of the nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar.

Resources

- Data sources listed in 601.1.2
- P&M Measure Suggestion Form
- EFRD Evaluation Form
- P&M Measures Meeting Outcomes Report
- P&M Measures Tracking Report
- Reassessment Interval Form
- Pipeline, tank, and/or facility assessment history
- P&M Measures Data Integration Checklist
- P&M Measures Meeting Presentation Templates

601.1. Preparing for the Initial Meeting

601.1.1. Schedule the Meeting

1A	**[P&M Coordinator]** Schedule the meeting according to the timeline outlined in Section 6.4.	
	1	Determine the scope of the meeting.
	2	Invite appropriate attendees, per Section 6.4.1.2.
	3	Send a list of data required for collection and analysis to each attendee, per 601.1.2.

601.1.2. Data Collection and Analysis

This section outlines the data that NuStar personnel typically collect prior to each P&M Measures Meeting.

The P&M Coordinator works with the following personnel, as needed, to gather the data and to assure the most accurate and current data are used. All SMEs and resources listed below are responsible for information regarding recent and current conditions in their area that may affect pipelines and/or facilities.

Note: Not all the data listed may be available for and/or applicable to the pipeline system(s), or facilities being considered; conversely, additional data not listed here may also be relevant for a particular meeting. If a discussion topic is required by the Rule, yet is inapplicable to the asset under discussion, then justification for exclusion is documented in the P&M Meeting Outcomes Report.

1B	**[P&M Coordinator]** Collect the following information: • A list of all pipeline segments and pipeline-related facilities to be considered • P&M Measure Suggestion Forms (from SMEs) • P&M Measures Tracking Report • Company overview information • Industry benchmarking data
1C	**[GIS Manager]** Verify the following data are up-to-date : • Total pipeline mileage • Product list • Miles operated by others • Miles purged and idled • HCA mileage total and percentage HPA mileage • Age of pipe • Diameter of pipe • One Call metrics (e.g., One Calls per mile for the area vs. the regional average) • GIS-based interactive maps (when applicable)

1D	**[Risk Engineer]** Collect the following information and forward to the P&M Coordinator:
	• Updated Risk Model
	  • Regional/area risk rankings
	  • Red flags
	  • LOF/COF risk scores
	  • Drill down reports
	  • Asset-specific threat drivers (top three)
	  • Leak detection types
	• Pipeline specifications:
	  • Age of pipe
	  • Pipe coating type
	  • Joint coating type
	  • Seam type
	  • Segment length
	  • % HCA
	  • Potential release volume (LVR)
	  • History of third-party damage
	  • Product type
	  • MOP
	  • Nominal pipe size (NPS)
	  • Pipe wall thickness
	  • SMYS or pipe spec
	  • %SMYS
	• SCC susceptibility report
	• Low Frequency ERW screening report
	• EFRD information sheets, drain down studies and first scenarios (see 601.1.3.)
	• Work with the Energy Optimization Manager to collect surge analysis results

1E	**[HCA Specialist]** Collect the following information and forward to the P&M Coordinator: • System maps for pipelines under review • HCA information (types, impact, spill paths, drain tiles, aerial overlays, buffer zones, elevation profiles, newly populated areas, crossings of roadways with ditches, pump stations, and break out tanks) • Pipeline Integrity Profile Sheets or GIS-based interactive maps (when applicable and available) • Distribution of internal and external corrosion vs. location of entry points, pipe casings, foreign line crossings, extra metal calls, weld plus ends, CP test leads, and other pipeline features • Distribution of dents vs. populated areas, farm areas, high activity areas, etc. • Foreign line crossings, extra metal calls, weld plus ends, surface-to-ground transitions (atmospheric corrosion) • Close Interval Survey Data (coordinating with Corrosion Manager)
1F	**[Assessment Engineer]** Collect the following information and forward to the P&M Coordinator: • Client List—completed assessment results • List of repairs required for five-year assessment (including Scheduled repairs) • List of casings • Analysis of metal loss growth in casings • Mitigation Completion Reports—Unity curves • ILI Closeout Report Observations and Recommendations • Any other information required to evaluate reassessment intervals • External/internal anomalies (density, repair classes, percent depths, percent near girth welds) • Dents (density, percent ID reduction) • POE Analysis
1G	**[Assessment Project Manager]** Collect the following information and forward to the P&M Coordinator: • Assessment history—Current reassessment intervals and scheduled assessments • Dig Records—completed repairs, results/findings, possible causes, observations • Pipeline Information Reports/Defect Evaluation (PIR) Forms • Hydrotest records and results
1H	**[Corrosion Manager]** Collect the following information and forward to the P&M Coordinator: • CP system effectiveness and enhancements • Test leads (number, density, below criteria, shorted casings, critical bonds) • Rectifiers (number, density, average amps, amps per mile) • Internal coupons (date installed/removed, corrosion rating/rate/type) • Inhibition program (type, usage) • Close Interval Surveys data • Corrosion Control Effectiveness Review Forms • SCC technology information • Soil type, soil corrosivity, subsidence, settlement, slope, erosion
1I	**[Region HSE Manager]** Collect the following information and forward to the P&M Coordinator: • Public Awareness Meetings/Seminars—total number, locations, attendance, attendee types • Mail-outs (total number, recipient types) • Emergency Response Drills/Training—total number of each, drill type • Adverse weather (including floods, hurricanes, earthquakes, high winds, lightning) and outside forces • Climatic conditions—temperature range, rainfall • IMPACT Incident Reports—description, findings, root cause, status, results, learnings, and program enhancements • Incorrect Operations • 7000-1 Release Reports • AOCs—descriptions, findings, recommendations • Aerial/Surface Patrol Reports—findings/trends, encroachments
1J	**[Maintenance Manager]** Collect the following information and forward to the P&M Coordinator: Aerial/Surface Patrol Reports—methods, intervals, ROW conditions, unintentionally exposed pipe

1K	**[Area P&T Manager]** Collect the following information and forward to the P&M Coordinator: • Details of pipeline river and water crossings, overhead and exposed spans, nearby high voltage, and other span issues • Mainline block valve security, including guards, signs, security, third party damage threats • MOP protection data (pressure reduction procedures, pressure protection devices, control valves) • Inspection reports for pipelines with physical supports (such as cable suspension bridges)
1L	**[Facility Integrity Specialist]** Collect the following information and forward to the P&M Coordinator: • Pump station information including specs, inspections, leak detection, security, safety, vibration analysis • Facility piping information
1M	**[Tank Integrity Engineer]** Collect the following information on breakout tanks and forward to the P&M Coordinator: • Specs, overfill protection • Dike capacity • Safety • Security • Tank settling • API 653 inspections
1N	**[Dynamic Flow Measurement Senior Engineer]** Collect Meter station inspection results and forward to the P&M Coordinator.
1O	**[Control Center]** Collect the following information and forward to the P&M Coordinator: • SCADA configuration—system specs (including system types, methods, thresholds, and response times), leak detection testing results, leak detection/monitoring of line operations, including slack line, idled line, and static conditions, false alarm frequency/rate • Procedures and training (operator knowledge of leak detection system and emergency response plans) • System enhancements • EFRD valve locations

601.1.3. EFRD Analysis of Existing In-Service Pipelines

If necessary, run additional EFRD analyses for pipelines under review. See Figure 6-2 in Section 6.6. for a visual overview of the full EFRD Analysis process.

1P	**[Risk Engineer]** For at least the highest risk-ranked segments within an HCA, perform an EFRD Analysis that considers at least the following factors: • Swiftness of leak detection • Swiftness of pipeline shutdown capabilities • Type of commodity carried • Rate of potential leakage • Topography or pipeline profile • Potential for ignition • Proximity to power sources (as applicable) • Location of the nearest response personnel • Specific terrain between the pipeline segment and the HCA • Volume that can be released • Relative reliability of existing proposed EFRDs • Any relevant operating modes beyond nominal full flow conditions • Surge analysis results
1Q	Create EFRD scenarios that compare the effects of a proposed EFRD, potential impact to HCAs, and subsequent risk reductions.

601.1.4. Prepare the Initial Meeting Materials

The P&M Coordinator is responsible for presentation of required data in a manner that allows ready review and evaluation of P&M measures versus risk factors and current information. The P&M Measures Data Integration Checklist assists the P&M Coordinator in assembling and presenting all relevant data. P&M presentations may include PowerPoint files, Excel spreadsheets, hardcopy handouts, and/or other materials as appropriate.

Note: Not all the topics listed are applicable to a given P&M Measures Meeting. If a discussion topic is required by the Rule, yet is inapplicable to the asset under discussion, then justification for exclusion is documented in the P&M Meeting Outcomes Report.

1R	**[P&M Coordinator]** Confer with data sources and SMEs as needed. • To confirm that any modeling or assumptions are based on best current knowledge and practices. • To perform analyses or create charts, tables, maps, etc.
1S	**[IMP Technical Writer]** Prepare presentation slides and other supporting materials using the appropriate template(s).
1T	**[P&M Coordinator]** Distribute documents to attendees for pre-meeting review. These documents may include, but are not limited to: • Initial ILI assessment and repair conclusions, including proposed reassessment interval • New EFRD scenarios, if any • Previously accepted P&M measures requiring updates • Candidate measures collected from field/regional personnel • Presentation slides and other supporting materials

601.2. Conducting the Initial Meeting

2A	**[Attendees]** Discuss the topics of Table 6-1 by reviewing, as applicable and available, the data collected according to Section 601.1.2. and the materials distributed in step 1S.	
	1	Evaluate current leak detection systems.
	2	Accept or reject any EFRD scenarios.
	3	Review recent incidents and discuss root cause, ancillary factors, and lessons learned.
	4	Evaluate existing P&M measures in light of current information and risks, and determine what is needed to close or complete them.
	5	For each candidate P&M measure—whether identified prior to the meeting or brought up in discussion—determine whether it is: • Rejected • A Potential P&M Measure (in need for further research) • An Accepted P&M Measure (ready for implementation)
	6	Prioritize Accepted P&M Measures for follow-up and implementation by risk
	7	Note any indications that conditions identified during the integrity assessment could impair the integrity of the pipeline.
2B	After the meeting, complete the steps in 601.5, Follow-up on the Meeting, 601.6, Documentation	

601.3. Preparing for Additional Meetings

3A	**[P&M Coordinator]** As needed, call additional P&M meetings to follow up on the initial meeting outcomes.	
	1	Invite only the applicable representatives from the Operations/Corrosion, Engineering, IMP, and Regional HSE groups.
	2	Report on the following: • Progress on action items • Applicability, feasibility, and rationality of Potential P&M Measures (including EFRD scenarios) • Implementation status of Accepted P&M Measures

	3	Extract and summarize key information from the initial P&M Measures Meeting, including the following: • Significant corrosion or dent findings (charts, tables) • Significant dig observations and photos • Special circumstances or operations, if any • Details of leak incidents, if any • Newly proposed P&M Measures (Rejected, Potential, and Accepted), with results of additional analysis for any Potential P&M Measures • Status of all open P&M Measures • Reassessment interval justifications
	4	**[Risk Engineer]** If applicable, prepare and present final EFRD scenarios for Potential P&M Measures involving EFRDs.
3B	**[Attendees]** Collect and present the data needed to either accept or reject Potential P&M Measures.	

601.4. Conducting Additional Meetings

4A	**[Attendees]** Review, discuss, and evaluate−subjects/topics of this meeting, as applicable, including:	

	1	• Significant findings and information from the initial meeting
		• Any new topics and/or data to be reviewed
		• Progress on open action items, as necessary
		• Status of P&M Measures from the initial meeting:
		  • Rejected P&M Measures
		  • Progress of any Potential P&M Measures
		  • Progress of any Accepted P&M Measures

	2	Propose additional Candidate P&M Measures, as necessary.
	3	For each Potential P&M Measure from the initial meeting (along with the results of follow-up data collection and risk analysis) and each new Candidate P&M measure, consider its applicability, feasibility, and rationality and determine whether it is • rejected, • potential (new or continued) and in need for further research, or • accepted P&M Measure.
	4	Prioritize Accepted P&M Measures by risk for follow-up and implementation.
	5	Finalize Reassessment intervals for each segment under review.
4F	After the meeting, complete the steps in 601.5, Follow-up on the Meeting, 601.6, Documentation	

601.5. Follow-Up on the Meeting

5A	**[P&M Coordinator]** • Acquire any needed data that was not available at time of the meeting. • Complete all documentation as described in **Error! Reference source not found.**. • Follow through on action items from the initial meeting, as needed, including obtaining results/information/analyses from action items assigned to SMEs. • Finalize any outstanding presentation or analysis materials.
5B	**[IMP Technical Writer]** Update as necessary the presentation materials based on feedback from the initial meeting.
5C	**[Appropriate Attendee/SME]** Follow through on action items from the meeting, as needed, and report status to the P&M Coordinator.

601.6. Documentation

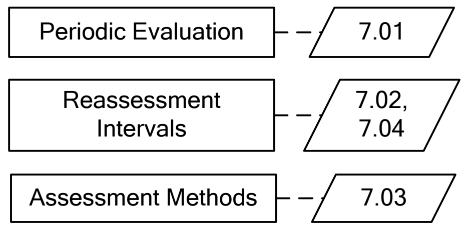
6A	**[Risk Engineer]** If applicable, document all EFRD scenario decisions on the EFRD Evaluation Form(s).
6B	**[P&M Coordinator]** Document the following on the P&M Measures Meeting Outcomes Report:

		• List of meeting attendees • List of assets reviewed • Action items • Potential P&M Measures (in need of further research) • Accepted P&M Measures (ready for implementation)
	1	Include action items related to any • features identified for remediation, • evidence of potential new HCAs (HCA Specialist), or • altered reassessment intervals (Assessment Engineer).
	2	• E-mail the completed report to all meeting attendees and IMP Team members.
	3	• Archive the report in the appropriate folder on the IMP network drive.
6C	Update the P&M Measures Tracking Report on the IMP network drive.	
	1	Enter any new Potential or Accepted P&M Measures.
	2	Change the status of Potential P&M Measures deemed ready for implementation to “Accepted”.
	3	Update entries for existing Potential or Accepted P&M Measures with any new information discussed (including the rejection of a Potential P&M Measure with justification).
6D	**[Assessment Project Manager]** For any feature identified for remediation, create an SAP Work Order per IMP Procedure 301: ILI Assessment, Data Evaluation, and Remediation.	
6E	**[HCA Specialist]** Follow the field identification steps of IMP Procedure 101, Segment Identification regarding any noted evidence of potential new HCAs.	
6F	**[Assessment Engineer]** When finalized for each pipeline segment, update the reassessment interval data in the pipeline integrity database, noting justifications for changes to the schedule in the justification log.	

7: Continual Evaluation

This section describes how NuStar performs periodic evaluations, determines reassessment intervals, and chooses reassessment methods, as illustrated in Figure 7-1 (with corresponding Protocols noted).

Figure 7-1. Continual Evaluation Overview



7.1. Periodic Evaluation

As detailed in the sections and procedures referenced in this section, NuStar periodically evaluates its pipelines' condition and line-specific risk factors using specialized software and data from key forms and reports. Appendix E, Documentation and References includes the retention periods for the resulting documentation.

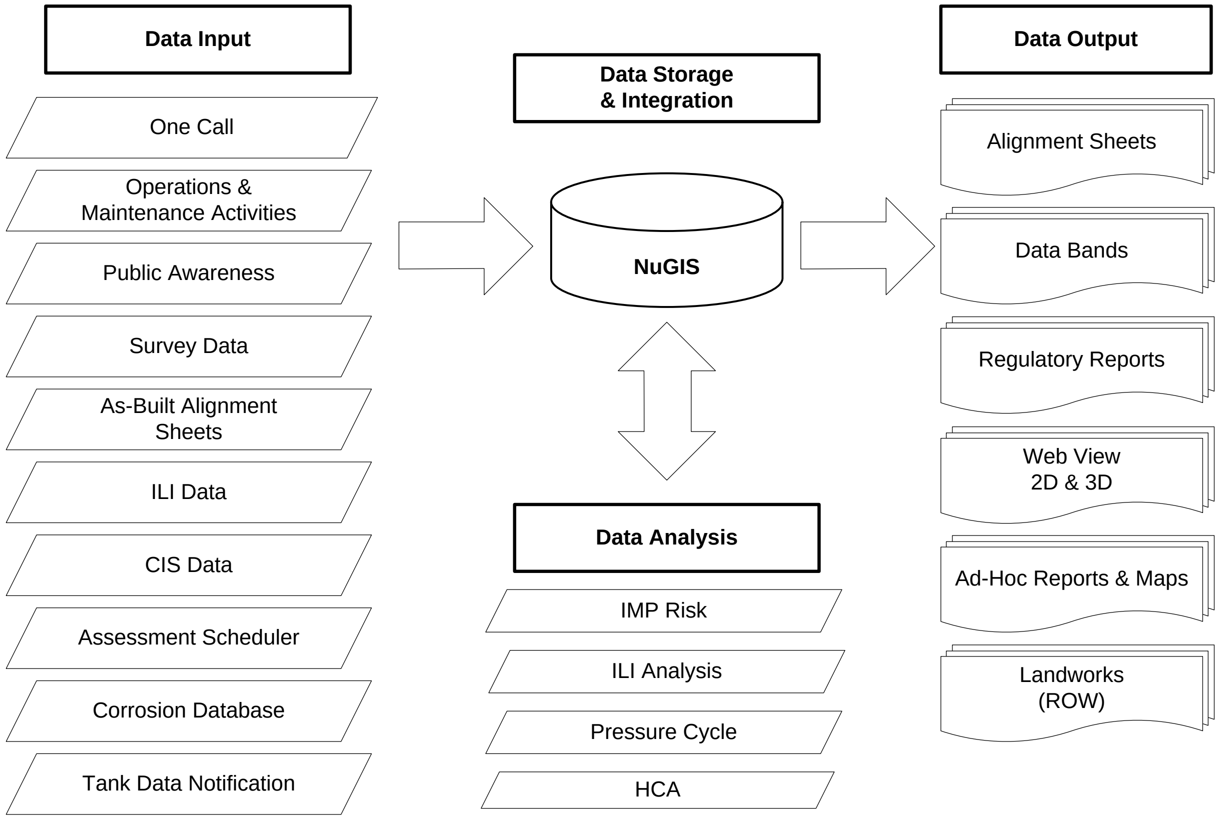
7.1.1. Geographic Information System

NuStar's GIS database is essential for the data integration, information analysis, and continual evaluation processes. To analyze pipeline integrity data and evaluate the consequences of failure, database users capture and organize pipeline information that is

- critical to determining the potential for, and prevention of, excavation damage,
- gathered through integrity assessments,
- gathered in conjunction with other inspections, tests, surveillance, and patrols, including corrosion control monitoring and cathodic protection surveys, and
- pertains to how a failure would affect HCAs.

NuStar outlines its program for ensuring and maintaining traceable, verifiable, and complete data in its *NuStar GIS Data Governance Program*. Once all information is formatted and available in the GIS database, various reports and plots can be generated. Figure 7-2, Data Integration and Evaluation Map, illustrates this process.

Figure 7-2. Data Integration and Evaluation Map



7.1.2. Spill Path Modeling Program

NuStar's spill path modeling program calculates actual drain down volume, generates spill path based on the elevation contours, and identifies all affected HCAs by station number (see Section 1, Segment Identification).

7.1.3. Risk Model Program

The Risk Specialist annually extracts the latest pipeline system data from the GIS database and performs an updated risk analysis using NuStar's risk model program. The results of this analysis help NuStar identify the location-specific integrity threats for segments that could affect HCAs (see Section 5, Risk Analysis).

7.1.4. Pipeline Information Report/Defect Evaluation Form

NuStar's Pipeline Information Report/Defect Evaluation (PIR) Form (in *Operations and Maintenance Manual [O&M Manual]*) captures several key pieces of information available only when a pipeline is excavated. This data is uploaded into the GIS database to help with the information analysis process.

NuStar may send a pipe sample to an independent mechanical testing laboratory for an analysis of pipe manufacturing properties consisting of such tests and analyses as the following:

- Pipe Body Tensile Test
- Chemical Analysis
- Hardness Test
- Charpy V-notch Impact Test
- Metallography Test
- Seam Type Analysis

These tests and analyses identify the mechanical properties and provide a chemical analysis of the pipe samples. Other program areas use the results from these tests to aid in drawing conclusions and making decisions.

If NuStar identifies an electric resistance welded (ERW) seam as being low frequency, it incorporates that pipe segment into the ERW seam assessment process and archives all results from this process. (IMP Procedure 201, Identifying Low Frequency Longitudinal Seams, along with the Longitudinal ERW Seam Classification Process in Appendix C, Pipe Sample Handling and Analysis Processes, outline how low frequency longitudinally welded pipeline segments are identified and assessment intervals are set.)

7.1.5. Pipeline Failure Analysis Report

NuStar removes a pipeline sample of any failure caused from hydrostatic testing or in-service operations and sends it to an independent mechanical testing laboratory, for a failure analysis per IMP Procedure 302, Failure Analysis. Once NuStar identifies the cause of failure, it determines the proper corrective actions to take to help prevent any future failures.

7.1.6. Aerial/Surface Patrol Form

At a minimum, NuStar requires ROW pipeline patrols at least 26 times per calendar year at intervals not to exceed three weeks. Reported events include, but are not limited to, the following items:

- Leaks
- Encroachments
- Exposed pipe
- Excessive/dead vegetation
- Construction activity

The Aerial/Surface Patrol Form (in *O&M Manual*) is designed to help streamline the data integration process. Inspection personnel now electronically fill out this report and submit it for uploading into the GIS database. Also, NuStar sends this standardized report out to all aerial patrol companies that it uses so it can achieve consistency between companies.

O&M Procedure 611, HVL and Liquid Pipeline Movement, also gives guidance on how to lower pipe with insufficient cover. NuStar modifies ROW patrol reports to have information imported into the GIS database for use in the risk analysis. The *O&M Manual* provides a detailed explanation of the pipeline patrol requirements.

7.1.7. Industry Reports

NuStar participates in annual industry reporting—including the DOT 7000.1-1 Annual Report and the API Pipeline Performance Tracking System (PPTS) Infrastructure Survey. It also reports incidents through PPTS and participates in other reporting opportunities such as the periodic API Pipeline Benchmarking Surveys and the *Worldwide Liquid Pipeline Performance Analysis*, administered by Solomon Associates. This participation allows NuStar to better understand its performance in an industry-wide context and to make decisions in keeping with industry trends and common practices.

7.2. Reassessment Intervals

Assessment data can be used to determine the maximum reassessment interval based on the predicted growth of metal loss and crack-like features. The final reassessment interval is determined as part of the P&M measures process by calculating the lifetime remaining for each feature until it becomes a DOT Immediate condition. Tool tolerances are considered in these calculations. For metal loss features, ERF calculations are based on Modified B31G and grown in depth only (see 3.4.1). For crack-like features, reassessment intervals are determined through crack propagation calculations per DOT report TTO5.

7.2.1. Corrosion Rates for Determination of Reassessment Intervals

Internal corrosion rates are calculated based on information gained from the coupon testing program. For a line with no evidence of internal active corrosion, NuStar will apply 1-mil/year to internal corrosion pits.

External corrosion rates are determined either by the anomaly depth divided by half the life of pipe or based on the soil characteristics and the values in Table 7-1.

Table 7-1. ASME B31.8S—Corrosion Rates Related to Soil Resistivity

Corrosion Rate, mils/year	Soil Resistivity, ohm-cm
3	> 15,000 and no active corrosion
6	1,000–15,000 and/or active corrosion
12	< 1,000 (worst case)

The presence of active modes of deterioration from some conditions, such as external and internal corrosion and the growth of defects because of pressure cycle fatigue, necessitate repeated inspection. NuStar used the risk factors listed in the Rule *(e)* to determine the initial BAP schedule. Although Probability of Exceedance (POE) calculations can predict a reassessment interval of greater than five years (68 months), NuStar currently chooses to keep its standard reassessment interval at a maximum of five years.

If the risk factors and/or POE Analysis indicate a potential need for reducing that interval for HCA pipeline segments, NuStar reviews these factors and makes recommendations, per Section 6.2.1, Reassessment Intervals, and IMP Procedure 601, Preventative and Mitigative Measures Meetings. Any Conclusions and recommendations from this meeting are documented in the P&M Measures Tracking Report. NuStar evaluates in-service failures on a case-by-case basis to determine if it needs to reduce the inspection interval.

If NuStar justifiably decides in the future to extend a pipeline's reassessment interval beyond five years, NuStar will submit notification to PHMSA for approval before that 5-year maximum is reached. (PHMSA has extended the notification window eight months to allow an operator to resolve unforeseen issues that prevented the completion of a reassessment by its scheduled date—which must have been within five years.) NuStar documents all changes to the inspection schedule in the Assessment Schedule Revision Log (as shown in the Assessment Schedule on the IMP Intranet).

7.2.2. Engineering Justification

NuStar has the option to extend the reassessment interval if it can provide the proper engineering justification to PHMSA and bases the new reassessment interval on the engineering analysis. NuStar will determine individual justification on a case-by-case basis. In the event a variance is necessary, NuStar will send PHMSA notification of an assessment interval variance 270 days before the end of the 5-year (68-month) reassessment deadline. If NuStar elects an extension, it will employ other technology, such as external monitoring, to prevent pipe degradation from the time of the justification. NuStar will submit any notification for variance to PHMSA.

7.2.3. Unavailable Technology

NuStar can request a variance from the minimum 5-year (68-month) reassessment interval if current technology does not adequately address the line-specific risk factors. NuStar will send PHMSA notification on reassessment interval variance 180 days before the end of the 5-year (68-month) reassessment interval deadline. It will perform interim actions used to evaluate the integrity of the pipe segment and provide the results to PHMSA for approval. NuStar will provide an estimate on when it can complete the assessment within the notification request. NuStar will submit any notification for variance to PHMSA.

7.3. Reassessment Methods

NuStar performs reassessments using the methods outlined in Appendix D, Anomaly Types, Detection Tools, and Assessment Methods. As NuStar develops the inspection schedule, it considers results from the risk analysis, previous inspection results, and other information from the informational analysis when determining the line-specific risk factors. The criteria set in IMP Procedure 202, Integrity Assessment Selection, determine NuStar's reassessments methods. NuStar uses the process described in Section 2.2.3., Longitudinal Seams to address longitudinal seam failure. If NuStar suspects a pipeline is susceptible to cracks or the pipeline exhibited crack-like features, it uses the screening process described in Section 2.2.2., Stress Corrosion Cracking.

If NuStar plans to use technology other than pressure testing or in-line inspection, it will submit notification to PHMSA at least 90 days before conducting the reassessment.

NuStar subjects all hydrostatic tests performed for the purpose of an integrity inspection to a corrosion control effectiveness program, as described in IMP Procedure 303, Corrosion Control Effectiveness Review. NuStar documents any changes in assessment methods from the initial BAP in the Assessment Schedule and its Revision Log.

NuStar's IMP Team reviews vendor information and industry documentation regarding new or enhanced inspection technology. When this new technology offers both accurate inspection results and specific applicability to NuStar's pipeline systems, consideration is given to performing an evaluation inspection with the vendor. If deemed appropriate, Procedure 202 is updated to include the new technology and appropriate documentation, processes and procedures are developed for incorporation into NuStar's IMP.

7.3.1. Completed Assessments

NuStar has developed a process to verify that assessments were performed and documented as shown in Section 2.6, Completed Assessments.

8: Program Evaluation

The eighth required IMP element is to define methods to measure the IMP's effectiveness (see Figure 8-1). This section describes the methods used to confirm adherence to the IMP processes, procedures, and schedules, and to determine whether the IMP processes are effective in addressing pipeline system integrity issues. To facilitate these activities requires data collection using a combination of program evaluations, performance metrics, and periodic analysis of such information, to ensure IMP effectiveness and promote continual performance improvement. Discussion includes, but is not limited to, the following:

- Program evaluation—establish systematic performance evaluations
- Selected activity, deterioration, and failure performance metrics—establish measurable performance objectives
- Internal and external audits and assessments
- Root cause analyses—lessons learned; understand and integrate identified root causes of leaks, spills, and other operational upsets into the IMP
- Review procedures
- Planned improvements

Figure 8-1. Program Evaluation Overview

Program Evaluation	8.01, 8.02
Performance Measures	8.01, 8.02
Interval vs External Comparisons	8.01, 8.02, 8.06
Root Cause Analysis	8.02, 8.04
Annual IMP Review	8.01-8.06
Communication	8.01, 8.03, 8.06
Pipeline Acquisitions	8.05
Quality Assurance/Control	8.02, 8.04-8.06
Records Retention	8.05

8.1. Program Evaluation

NuStar conducts program evaluations on an ongoing basis with information accumulated and documented over time. In addition, the NuStar IMP undergoes a formal annual review, as described in IMP Procedure 801, Annual IMP Review. The IMP Department documents the results from the annual review in the Annual IMP Review Report. Using the information gathered for this report, the IMP Manager or a designee presents recommendations for IMP improvements to those responsible for NuStar pipeline integrity and operations.

When appropriate, NuStar integrates evaluation and measurement results into future risk assessments, and adjusts performance metrics to ensure achievement of IMP goals or changes/improvements in current processes.

NuStar documents and communicates performance metrics to all appropriate personnel

- through line management for the entire organization,
- by posting the Annual IMP Review Report to the IMP website , or
- by notifying all applicable Operations/Maintenance Personnel via email.

IMP Procedure 801 identifies and documents the responsibilities and accountability for system wide, pipe-specific, and threat-specific performance metrics.

8.2. Performance Metrics

Performance metrics provide objective evidence for evaluating system effectiveness and performance trends. These metrics verify that processes and procedures are functioning as intended through system outputs, or other measurable results. Measurement confirms the achievement of objectives or expected results, and provides an indication of future potential. NuStar annually captures overarching performance metrics in the Annual IMP Review Report.

NuStar aims all of the risk assessment and mitigation methods described in this IMP at reducing the likelihood and consequences of a product release. The primary performance metric of this IMP is the degree to which NuStar eliminates unintended releases. This section describes the approach to monitoring performance of the components of the IMP, with the expectation that component progress correlates with overall program success.

As shown in Table 8-1, NuStar uses performance metrics relevant to the particular IMP aspect under evaluation. It bases these metrics on an understanding of the failure mechanisms or threats to integrity for each pipeline system.

Table 8-1. Annual Performance Goals and Metrics

	Performance Metric	Measurement Process	Ultimate Goal	Responsible for Tracking
1	Reduce total volume from unintended releases of pipelines and pump stations/terminals.	Track volume of releases of pipelines and pump stations/terminals by pipeline system and compare to previous years' total.	Zero releases	Regional HSE
2	Reduce total number of unintended releases of pipelines (based on 5-gallon threshold).	Track number of unintended releases by pipeline system, and compare to previous years' number (HCA vs. non-HCA).	Zero releases	Regional HSE
3	Reduce total number of unintended releases at Pump Stations and Terminals (based on 5-gallon threshold).	Track number of unintended releases in Pump Stations and Terminals by pipeline system, and compare to previous years' number.	Zero releases	Regional HSE
4	Reduce average release volume to < industry average.	Compare NuStar's reported volume against industry data obtained from PHMSA.	Below average number	Regional HSE
5	Percentage of IMP Activities Completed during the Year	Track completion of planned activities on the previous year's IMP Activities List.	100%	IMP Team
6	Immediate Repair Conditions	Compare with previous inspections to see if there were increases or decreases.	Total anomalies reduction	Assessment Engineer
7	60-Day Repair Conditions	Compare with previous inspections to see if there were increases or decreases.	Total anomalies reduction	Assessment Engineer
8	180-Repair Conditions	Compare with previous inspections to see if there were increases or decreases.	Total anomalies reduction	Assessment Engineer
9	Number of metal loss anomalies found in ILI tool run with ERF >1	Track number of anomalies with ERF >1 by class (internal/external) per pigged mile by segment; compare with previous cycle.	Reduction in number of ERFs >1	Assessment Engineer
10	Evaluate the effectiveness of outreach activities.	Track number of third-party damage incidents; compare to previous year.	Zero third party damage	Regional HSE

	Performance Metric	Measurement Process	Ultimate Goal	Responsible for Tracking
11	Integrity Assessment Schedule Maintained	Track number of assessments completed vs. number scheduled.	100%	Risk Specialist
12	Miles Scheduled for Assessment vs Actual Miles Assessed	Track miles of pipeline assessed vs amount scheduled.	100%	Risk Specialist
13	Completed Required Surveillance Activities	Track number of Surveillance Flights in last 12 months; compared with 3 previous 12-month periods.	26 per year, no more than 3 weeks apart	Regional HSE
		Track number of ROW encroachments without One-Call notification	Zero	
14	Annual Training Requirements Met	Track number of training/vendor activities.		IMP Manager
15	Annual Risk Analysis Completed	Complete annual Risk Analysis.	Completed	Risk Specialist
16	P&M Measures Analysis Completed	Complete required meetings; complete subsequent Work Orders and AFEs.	100% completion of all meetings and subsequent Work Orders and AFEs	IMP Team
17	Summary of Performance Improvements	Provide qualitative and quantitative description of pipeline system integrity.		IMP Manager (or designee)

8.2.1. Other Monitoring

In developing IMP performance metrics, NuStar also considers the potential metrics identified in the Annual IMP Review Report (see Table 8-2). Although not official IMP performance metrics, the Company may monitor these data to ensure pipeline system integrity.

Table 8-2. Other Monitoring Activities

Leading →			Lagging
Failure Mechanism	**Selected Process Metrics** ←	**Deterioration Metrics**	**Failure Metrics**
Corrosion			
External corrosion	Rectifier readings, annual pipe to soil surveys, close-interval surveys, bond reading		Release due to external corrosion
	Cathodic protection (CP) system inspections		
Internal corrosion	Corrosion coupon monitoring, NACE spindle test and analysis of fluids	Corrosion coupon test results	Release due to internal corrosion
		ILI data indicating internal corrosion	Release due to internal corrosion
Equipment Failure			
Equipment malfunction or failure of non-pipe component	Near-miss root cause analysis	Function test results	Release due to gasket, packing, or mechanical seal failure
	Preventive maintenance	Inspection results	Release due to equipment failure

Leading			Lagging
Failure Mechanism	**Selected Process Metrics**	**Deterioration Metrics**	**Failure Metrics**
Operation Error			
Valve left or placed in wrong position	Near miss root cause analysis	Relief valve released	Release due to erroneous valve position
Pipeline or equipment over pressured	Near miss root cause analysis	Relief valve released	Release due to over pressure
Other			
Leak Detection System	Leak Detection System testing		Undetected leak greater than program thresholds.

8.3. Internal and External Comparisons

Internal and external comparisons show how NuStar's annual performance measures against previous years and current industry benchmarks. These comparisons also show how the Company complies with federal and state regulations.

8.3.1. Internal Comparisons

NuStar annually reviews its HCA segments by pipeline system to compare system wide performance metrics (shown in Annual IMP Review Report, Section 3, System-Wide Performance Metrics) among pipeline systems, to determine if HCA segments in a particular pipeline system demonstrate any trends that need further review and analysis. The IMP Department evaluates current performance against past performance, to identify any developing trends using information from previous Annual IMP Review Reports, and the ILI Service Provider's comparisons of previous ILI runs to current runs. They then report these trends in Annual IMP Review Report, Section 6, Pipeline-Specific Performance Metrics.

8.3.2. External Comparisons to Benchmark NuStar Performance

The IMP Department performs annual comparisons of IMP performance using applicable industry-wide benchmarking and data initiatives. NuStar ensures that it conducts benchmarking in a manner that provides comparable data among the various systems. The IMP Department commuicates how NuStar compares with the industry at large to various internal stakeholders.

By June 15 of each year, NuStar submits the previous year's applicable 7000-1.1 Annual Reports (crude oil, HVL, petroleum products, and/or carbon dioxide) as part of the PHMSA Pipeline Safety Program.

8.3.3. Periodic Program Self-Assessments

NuStar currently has a process in place to evaluate the elements of the IMP program and ensure that the framework of the program stays compliant with federal and state regulations.

The *IMP Manual* undergoes an internal or external audit on a regular alternating cycle, normally every three years. The internal auditors and the external auditors perform a gap analysis on the program using the current state and federal regulations, inspection protocols, and FAQs.

8.3.3.1. Internal Audits

Periodically, NuStar performs an internal audit of the IMP program performed as a quality control measure.

8.3.3.2. External Audits

NuStar periodically uses industry consultants for external audits on the IMP program. Experienced with the federal and state liquid/natural gas pipeline integrity management regulations, these consultants provide an objective evaluation of NuStar's IMP documentation. A record of these reviews is kept in the IMP Audit Log on the IMP drive.

In support of these types of audits, the IMP Technical Writer I, in consultation with the IMP Manager, will perform the following tasks once the auditors send the results of the audit to the IMP Team:

- Create a task list based on the gap analysis results.
- Communicate this list to the IMP Team and NuStar Senior Management.
- Assign the items within the task list to individual subject matter experts (SMEs).
- Receive the projected dates of completion from the SMEs.
- Update and maintain the task list on a monthly basis and forward this list to members of the IMP Team.

The appropriate IMP Team members review completed items before adding them into a draft revision of the manual. NuStar annually reviews and incorporates major changes, if any, to its documentation. However, NuStar will integrate minor changes to the IMP documentation as needed. Once NuStar completes revisions, it provides an electronic version on the IMP intranet and emails the appropriate personnel when updates are available.

8.4. Root Cause Analysis

Identification of root causes from incidents, releases, near misses, or other situations, provides NuStar with a direct indication of items that require attention within the NuStar system. When pipeline failure or damage occurs, the NuStar HSE Group uses O&M Procedure 206, Incident Investigation, to identify both direct and contributing causes of incidents. NuStar then determines and implements appropriate corrective actions to prevent a recurrence at the specific location of the incident, as well as other areas where similar incidents could occur. NuStar also uses an internal incident management system to track incidents; this computer-based program also allows personnel, company-wide, to input data and generate reports based on incidents that have occurred.

8.4.1. Lessons Learned

Identifying lessons learned from incidents, near misses, releases, or other situations, both within and outside of the NuStar organization, is a key element in the continuous improvement of the IMP. Lessons learned come primarily from action items in the Incident Investigation Reports. Lessons Learned are communicated per O&M Procedure 206. Safety Bulletins are also posted on the HSE Intranet site.

If the report indicates that a similar action and/or reaction could occur in the NuStar system, the Operations General Manager communicates the lesson learned throughout the organization to those levels of management that have the direct responsibility for implementing appropriate actions.

The IMP Department presents a list of approved corrective actions applicable to pipeline operations as candidate P&M measures, per IMP Procedure 601, Preventive and Mitigative Measures Meetings.

8.4.2. Trending of “Near Misses” and Equipment Failures

The IMP Manager reviews all incident reports in the NuStar’s incident management system related to pipeline operations for trends, and compares current reports to those of previous years. If NuStar identifies a trend, it discusses the trend at a roundtable discussion between IMP and Operations/Maintenance Management to determine the appropriate corrective action. NuStar records any additional trends that it identifies in the minutes and adds them to a list of possible P&M measures for further review during the P&M Measures Process. The applicable lessons learned are included in the Annual IMP Review.

8.5. IMP Review

NuStar collects and evaluates data annually, not to exceed 15 months for its IM Program evaluation during the first quarter of each year, and prepares the Annual IMP Review Report as delineated in IMP Procedure 801. The IMP Team meets with Operations and other NuStar personnel to review the program evaluation results. Program evaluation results to upper management, via the Annual IMP Review Report.

8.5.1.1. IMP Review Topics

Topics covered at the Annual IMP Review include, but are not limited to, the following:

- Overall assessment of the IMP's effectiveness
    - Summary of IMP performance for the reporting year
    - IMP activities completed for the reporting year
    - Comparison to previous years' performance
    - System wide performance metrics
- Benchmarking of NuStar IMP performance
- Threat-specific performance metrics
- Pipeline-specific performance metrics
- IMP process summaries
    - New HCAs identified
    - Integrity assessments completed for the reporting year
    - Assessment results and repair/remediation work completed in the reporting year
    - P&M measures implemented in the reporting year
    - Process improvements identified and implemented in the reporting year

After review, the Annual IMP Review Report is posted on the IMP Intranet. E-mail notifications are sent to all Operations/Maintenance Personnel that these documents are available for review.

8.6. Communication

The IMP Team communicates its activities to its senior management through the following information:

- Weekly reports
- Monthly performance metric reports
- Monthly executive reports that progress through upper management to the President and CEO of NuStar and denote all activities occurring during the previous month for all of the departments
- Results from the Annual IMP Review Report

Regular and periodic communication between the IMP Team and Operations/Maintenance Personnel occurs through the following activities:

- Conference calls
- IMP Team meetings
- PM06 reviews
- CP calls
- Email of relevant reports and results
- Intranet posting of IMP information with notification e-mail
- Pressure reduction e-mails

Operations/Maintenance Personnel maintain communication with the public as part of Health, Safety and Environment's Public Awareness Program, which seeks to make third parties, such as landowners, public agencies, local businesses, emergency responders, and excavators better aware of our pipelines and how to work around them safely. Forms HSE 6201, Public Awareness Documentation Form and HSE 6202: Pipeline Encroachment Violation Form, are used to document this communication.

8.7. Pipeline Acquisitions

If NuStar acquires new pipeline assets, it shall ensure that the previous owner transfers all documentation (records, manuals, and procedures) as part of the acquisition.

8.8. Quality Assurance/Quality Control

It is NuStar's goal to assure that the Integrity Management Program remains a strong and viable tool for maintaining compliance with regulatory requirements and protecting its employees, the public, and the environment. NuStar maintains a number of programs and policies to ensure quality assurance/control. These programs and policies include, at a minimum, the following:

- Internal and external audits (see Section 8.3.3., Periodic Program Self-Assessments)
- Annual IMP Review (see Section 8.5, IMP Review).
- Assessment schedule review
- Participation in various industry programs such as:
    - The Geospatial Information and Technology Association (GITA)
    - The API Integrity Committee (NuStar's IMP Manager serves on the committee)
    - Industry conferences and seminars (at every opportunity, NuStar sends employees to applicable conferences and seminars)
- Reviews with the ILI Service Provider (goal of quarterly, but not exceeding annually)
- Field verification of maps
- Field testing of leak detection
- Risk validation during the P&M Measures Process
- GIS system data validation
- SME review of P&M measures during the P&M Measures Process
- Receipt of daily emails from the Government Printing Office with PHMSA updates
- Periodic check of the PHMSA Website for "What's New"

8.9. Records Retention

The IMP Department maintains all its electronic files in a designated directory of the IMP network drive. The NuStar IT Department manages the backup and maintenance of these files on its server system. NuStar maintains these archived files for the life of the pipeline.

IMP Procedure 802, Document and Revision Control, describes its process for documentation and revision control. A list of these documents and their respective retention dates appear in Appendix B, Compliance Dates.

801: Annual IMP Review

Introduction

The Annual IMP Review process is a component of the NuStar IMP as described in Section 7, Continual Evaluation, and Section 8, Program Evaluation. Members of the IMP Team, Management, and Operations/Maintenance Personnel, review the elements of the program to determine the effectiveness of the IMP and to recommend program improvements.

These annual reviews are consistent with the federal regulatory requirements to have a review process of integrity assessment results, and information analysis. NuStar uses this review process to advance the safe operation of company owned and/or operated pipeline systems, and to reduce the risk for future unintended pipeline releases.

The IMP Technical Writer works with corporate and regional SMEs to collect data and create a company wide Annual IMP Review Report that is the framework for the regional review meeting presentations.

Regulation

49 CFR §195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar.

Resources

Annual IMP Review Report template

801.1. Data Collection

1A	Gather the following needed records, data, and reports for all identified reporting areas: • Assessment annual plan • Assessment logs and repair records • Completed versus pending IMP activities for the year • Cathodic Protection Data Manager (CPDM) data • Documentation of process improvements (IMP Revision Logs and software updates) • 7000-1 Release Reports • PHMSA 7000-1.1 Annual Report • IMPACT Incident Reports • Inspection records for valves and rectifiers • Pipeline Information Report/Defect Evaluation (PIR) Forms • P&M Measures Tracking Report • One-Call data (as available) • Pipeline Encroachment/Damage Education Report • Record of new and/or altered HCAs • Risk results • Aerial/Surface Patrol Forms • Tank inspection data • Training and vendor documentation
1B	Update Annual IMP Review Report Section 6, Pipeline-Specific Performance Measures with any changes in jurisdictional pipelines (e.g., added or removed pipelines).

801.2. Pipeline-Specific Performance Measures

2		Complete Annual IMP Review Report Section 6, using the Comments column for explanatory or summary notes regarding each performance measure shortfall, if any. **Note:** If a goal is not applicable to a pipeline for the reporting year, enter NA under Performance Achieved, and note in the Comments column why it is not applicable (i.e., no assessment performed).
	1	Use 7000-1 Release Reports and IMPACT Incident Reports to record the appropriate leak information, including any equipment failures by pipeline system.
	2	Use IMPACT Incident Reports to record any near misses.
	3	Use IMPACT Incident Reports, PIR Forms, and 7000-1 Release Reports to record if any system(s) experienced any third party damage or encroachments.
	4	Use CPDM data to record the number of critical bonds, shorted casings, test points below criteria, and confirmed stress corrosion cracking (SCC) areas.
	5	Use valve and rectifier inspection data to record whether NuStar completed the required inspections within the required timeframe.
	6	Use assessment logs and repair records to record • Number of internal and external corrosion metal loss features • Number of immediate, 60-day, and 180-day repair conditions
	7	Use assessment logs and repair records to record whether NuStar completed all repairs according to regulatory guidelines.

801.3. NuStar IMP Performance Benchmarking

3		Complete Annual IMP Review Report Section 4, Benchmarking of NuStar's IMP Performance.
	1	Use 7000-1 Release Reports and IMPACT Incident Reports to record each cause of failure on NuStar pipelines, the barrels lost, and barrels recovered.
	2	Record, for each NuStar pipeline, the number of each failure type and the percentage of total failures each type represents (i.e., 2 of 4 failures resulting from external corrosion = 50% of total failures).
	3	Use DOT failure statistics to record the Industry's number of accidents for each corresponding type of failure, barrels lost, and barrels recovered, and then calculate the percentage of total failures, those failure types represent for the industry at large (i.e., 35 of 125 resulting from external corrosion = 28% of industry reported failures).
	4	Include PHMSA totals for the reporting year as notes below the table.

801.4. Threat-Specific Performance Metrics

4	Complete Annual IMP Review Report Section 5, Threat-Specific Performance Metrics, providing summary comments for any item with a result greater than zero.

801.5. System Wide Performance Measures

5	Complete Annual IMP Review Report Section 3, System-Wide Performance Measures, using the Comments column for explanatory notes regarding performance shortfalls, or as indicated in the Step.		
	1	Use 7000-1 Release Reports, IMPACT Incident Reports, and previous Annual IMP Review Report to record: • Total volume released for pipelines and for pump stations/terminals (based on 5-gallon reporting threshold) • Total number of pipeline releases for each year • Total number of releases for each year at pump stations/terminals	
	2	Determine the number of releases per pipeline mile in the current and previous years for NuStar and the industry (based on PHMSA statistics).	
		a	Record whether NuStar's average is less than or greater than the industry average.
	3	Use the list of IMP Activities scheduled for the reporting year to record the percentage of activities completed.	
	4	Record the number of Immediate, 60-day, and 180-day repair conditions in the current and previous years.	
	5	Evaluate assessment results to record the number of metal loss anomalies with ERF ≥ 1.0. **Note:** Compare the current and previous years under Comments.	
	6	Record the Community Outreach Activities completed for the year.	
		a	For annual awareness mailings to and/or meeting with local community, record the following: • Number of mass mailings sent to general businesses, residential, emergency officials, excavators, public officials, and schools • Number of newspaper and magazine ads with the number of states covered
		b	For annual meetings with local emergency agencies, record the following: • Number of attendees at emergency responder meetings (list number of cities and states and total attendees under Performance Achieved and each meeting's attendee number under Comments) • Number of attendees at contractor awareness meetings (list number of cities and states and total attendees under Performance Achieved and each meeting's attendee number under Comments) • Number of states in which NuStar participated in Damage Prevention Councils (list specific states under Comments) • Number of cities in which NuStar participated in monthly Local Emergency Planning Committees (list specific cities under Comments)
		c	For contacts made by Operations/Maintenance Personnel along the Right-of-Way (ROW), record the total number of contacts (list number for each affected pipeline under Comments).
	7	Use the Assessment Schedule to record the following: • Number of scheduled in-line inspections and hydrostatic tests under Performance Goal • Number of these completed under Performance Achieved	
	8	Use the Assessment Schedule to record the following: • Number of pipeline miles scheduled for assessment under Performance Goal • Number of miles actually assessed under Performance Achieved	
	9	Use patrol records to record whether NuStar completed 100% of its scheduled aerial and surface patrols under Performance Achieved (list total number of aerial and surface patrols completed under Comments).	
	10	Use the Training/Vendor Log to record the total number of training/vendor activities attended by relevant IMP personnel (include details of each activity under Comments).	
	11	Use risk analysis results to record any areas of increased risk highlighted by updated risk analyses.	
	12	Use P&M documentation to record whether NuStar completed its requisite P&M analyses under Performance Achieved (list number of P&M measures proposed, implemented, and in process under Comments).	

801.6. Review of Specified IMP Activities

6	Complete Annual IMP Review Report, Section 2, IMP Process Summaries.		
	1	Summarize HCA changes, including: • Any pipelines changes • A list of changed or added HCAs by pipeline	
	2	Provide an overview of integrity assessments completed in covered year, including a summary table of completed inspections.	
	3	Summarize in-line and hydrostatic testing results, including: • Total anomalies • Total immediate, 60-day, and 180-day, and "other" conditions • Any notes relevant to large numbers of conditions on specific pipelines • Any findings that help identify trends and actions/activities this information may initiate	
	4	Summarize the number and types of P&M measures implemented during the year.	
		a	Discuss any high profile activities that resulted from comprehensive P&M analyses.
	5	Summarize any process improvements identified and implemented during the year.	
		a	For measures identified but not implemented, include the implementation plan for the coming year.

801.7. Recommendations

7	Complete Annual IMP Review Report, Section 7, Recommendations.	
	1	Recap the status of the previous year's recommendations for all aspects of the program, including: • HCA Analysis • Risk Analysis • Assessment • P&M Measures • Performance Metrics • Program Administration
	2	Summarize the IMP Department's goals for the next calendar year.

801.8. Overall Assessment of IMP Effectiveness

8	Complete Annual IMP Review Report, Section 1, Overall Assessment of IMP Effectiveness.		
	1	Summarize the year in review, including: • Significant accomplishments and results • Any trends resulting from data analysis	
	2	Identify percentage of scheduled IMP activities completed.	
		a	Provide explanations for any activities not completed.
	3	Include the activities scheduled for the coming year in the IMP Activities by Quarter table.	
	4	Summarize how NuStar's performance compared to last year's performance, including: • Any areas of increased and/or decreased performance • plans for improving performance in the coming year	
	5	• Summarize the overall effectiveness of the program, including any issues/processes needing improvement.	

801.9. Publication and Distribution

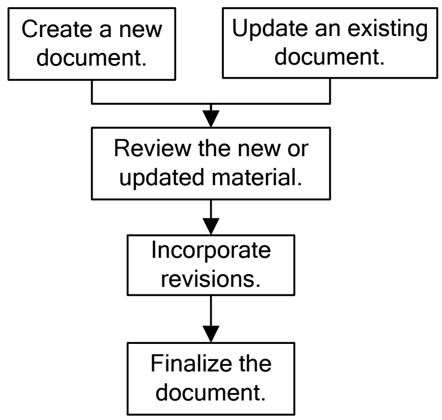
9A	Once the sections of the report are complete, perform a final edit for clarity and completeness.	
9B	Send final draft to appropriate management personnel for review and final approval.	
9C	Provide requisite copies for personnel identified in the distribution list.	
	1	Send reports to those personnel.
9D	Create PDF of final approved report and post to IMP website.	
	1	Send e-mail notification to those designated for e-mail notification in the distribution list.

802: Document and Revision Control

Introduction

The purpose of this procedure is to describe how NuStar creates and updates its IMP documentation while ensuring that all employees have access to the final version. Figure 802-1 describes the documentation revision and control process.

Figure 802-1. Documentation Revision and Control Flowchart



Regulation

49 CFR §195.452 (l) (1) (ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations, and determinations made, and actions taken to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.

Scope

This procedure applies to IMP documentation for all jurisdictional liquid pipeline systems operated by NuStar.

802.1. Drafting a New or Updated IMP Document

1A	**[IMP Team]** Determine that a new section, procedure, appendices, or other IMP document is needed or that an existing document needs to be updated.	
	1	Assign the appropriate SME(s) to work with the IMP Technical Writer on the new or updated document.
1B	**[IMP Technical Writer]** Meet with assigned SME(s) as needed to gather the required information.	
1C	1	When the necessary information is gathered, open either: • The correct template (for any new document or for an existing document based on an outdated template) • The previously final version (for an existing document already based on the current template)
	2	Enter the current version number and month/year in the footers.
	3	Save a new draft of the document with the title, date, and preparer's initials in the filename.
1D	Incorporate the gathered information into the document, using styles to correctly format the material.	
	1	If updating an existing document, use Track Changes to indicate all substantive additions, deletions, and edits to the previous version. (Proofreading corrections and formatting do not need to be tracked.)
1E	Use Comments to address any comments or questions to the reviewer(s).	

802.2. Reviewing the Draft

Reviewing is the process of using SME expertise and policy-making authority to examine a new document or updates to an existing document. A complex new document or an extensive set of changes could require multiple review cycles.

2A	**[Lead SME and IMP Technical Writer]** Based on the nature of the material to be reviewed, select the best method for reviewing the new or updated draft. (For all but the last method, continue with Step 2B.) • **Single Review−**Only the Lead SME reviews the draft and returns it to the IMP Technical Writer. • **Serial Review−**The Lead SME reviews the draft, then forwards it to the next reviewer; this handoff continues, with reviewer comments and edits, accumulating on a single forwarded version of the draft until the last reviewer gives the reviewed draft back to the Lead SME, who then performs a final check before returning the draft to the IMP Technical Writer. • **Parallel Review−**All reviewers work on the initial draft simultaneously; the IMP Technical Writer gathers the separate review versions. • **Writer Meeting−**Reviewers meet with the IMP Technical Writer to go through the draft together, noting changes to be made either during or after the meeting. (Skip to Step 3A.)	
2B	**[IMP Technical Writer]** Submit the draft file to the Lead SME (Single or Serial Review) or to all reviewers (Parallel Review), noting the timeline for the review.	
2C	**[Reviewer(s)]** Confirm the review timeline and save a copy of the draft with the current date and reviewer initials added to the filename.	
2D	Review the draft using the following methods to indicate the results of the review: • To approve the draft as submitted or with a few global changes, add a Comment at the beginning noting this. • To indicate individual edits that need to be made, use either Track Changes to make exact additions/deletions, or comments to note the edits that need to be made.	
	1	If reviewing an updated draft that was submitted with Track Changes edits, use these additional methods: • To approve individual edits, right-click on them and select Approve Addition/Deletion. • To reject individual edits, leave them as is and add a Comment noting the reason for the rejection.
2E	**[IMP Technical Writer]** Receive the reviewed draft(s) from the Lead SME (Single or Serial Review) or from all reviewers (Parallel Review).	

802.3. Revising the Document

3A	**[IMP Technical Writer]** Consult with the Lead SME to address any questions concerning the draft review (and to resolve any issues resulting from the multiple reviews of a Parallel Review).	
3B	Open the submitted draft (not a review draft) and immediately save a version with the new date in the filename. **Note:** Always work on one's own file to lessen the chances for inadvertent formatting changes and corrupted documents.	
3C	With Track Changes on, make any edits noted in the review and follow-up consultation.	
	1	To safely incorporate large chunks of new or edited text, copy/paste the text into the Notebook program first, then copy/paste it from there into the revised draft.
3D	Consult with the Lead SME to determine of an additional round of reviews is needed.	
	1	If necessary, follow Steps 2A through 3D again.

802.4. Finalizing the Revised Document

4A	**[IMP Technical Writer]** Make sure that the correct version number (1.0 for new documents) and month/year are in the footer, and that the filename indicates the final revision date. **Note:** Minor revisions to a stand-alone document or to a portion of a larger document (such as to a procedure in the IMP Manual) designate a minor version change (e.g., 1.0 to 1.1). Only significant revisions to a stand-alone document or to the majority of sections in a larger document designate a major version upgrade (e.g., 1.0 to 2.0).	
4B	If the revised document is part of the IMP Manual*,* update Appendix I, Version and Revision Logs by: • Changing the version number and month/year in Current Section, Procedure, and Appendix Versions • Adding a row at the top of Revision Log that contains the type of revision; the section, procedure, or appendix number/letter; a summary of the revisions (for updates); the version number; and the month/year	
4C	Archive all draft files to the appropriate folder on the personal drive.	
4D	1	Save a copy of the final revised Word file—with the date and initials removed from the filename—in the proper folder on the IMP network.
	2	Print this Word document to PDF and save the PDF to both: • The proper folder on the IMP network • The IMP Documents folder on the IMP Intranet
4E	Archive a copy of the new or updated document on the IMP share drive.	
4F	Notify the appropriate personnel about the new or updated document and where it can be found on the IMP Intranet. **Note:** The Manual Distribution List on the IMP network drive lists the appropriate personnel to notify when certain new or updated versions of key documents are available.	
	1	If updating an existing document, include a reminder to replace obsolete hard copies with the new version.

802.5. Updating Vendor Manuals and Documents

5A	**[Vendor]** Send updated reference material to IMP/GIS Department.
5B	**[IMP Team]** Update the office copy of the vendor material.
5C	Archive the updated version in the IMP High Density area (along with the old version).
5D	If applicable, place an updated version in the IMP Documents folder in the IMP Intranet.

A: NuStar Pipeline Systems

The three tables that follow list the DOT jurisdictional pipelines belonging to each of NuStar's functional regions as of April 2015.

- All Central East Region pipelines belong to PHMSA ID 10012
- All East Coast, Gulf Coast and West Coast pipelines belong to PHMSA ID 26094
- All Central West Region pipelines belong to PHMSA ID 31454, except SIN (ID 10012

Table A-1. Central East Region Pipelines (PHMSA ID 10012)

Code	Pipeline Name	Inter- or Intrastate	Jurisdictional Agency
Refined Product			
CSF ETH NMM NMR	Council Bluffs–Sioux Falls Pipeline Magellan 6" Ethanol Line North System: Mandan–Moorhead North System: Moorhead–Roseville	Interstate	PHMSA PHMSA PHMSA* MinnOPS (for PHMSA)
Refined Product/HVL (Propane)			
SCS	South Central System	Interstate	PHMSA
HVL (Ammonia)			
ASM ASE ASW	Ammonia Main Line Ammonia System East Leg Ammonia System West Leg	Interstate	PHMSA

* MinnOPS has jurisdiction over the 2.73 miles of NMM pipe between the ND/MN border and Moorhead

Table A-2. Coast Regions Pipelines (PHMSA ID 26094)

Code	Pipeline Name	Inter- or Intrastate	Jurisdictional Agency
East Coast Refined Products			
AND	Andrews AFB (Maryland)	Interstate	PHMSA
LIN VIR	Linden Terminal (New Jersey) Virginia Beach NAS (Virginia)	INTRAstate	PHMSA (as state agency) VA Corporation Comm.
Gulf Coast Crude			
STJ	St James (Louisiana)	INTRAstate	LA Dept. of Natural Resources (DNR)
West Coast Refined Products			
POR SEL	Portland Terminal (Oregon) Selby Terminal (California)	INTRAstate	PHMSA (as state agency) CA Liquid, St. Fire Marshall

Table A-3. Central West Region Pipelines (PHMSA ID 31454*)

Code	Pipeline Name	Inter- or Intrastate	Jurisdictional Agency
Crude			
ADJ CLW RGG WAS	37P - Wasson ADJ Crude Pipeline 23P - Clawson - McKee Pipeline 31P - Ringgold - Wasson Pipeline 32P - Wasson - Ardmore Pipeline	Interstate	PHMSA
CHC DIL DIX GAR OAK PAW TRO TUL PTS WIF	70P - Choke Canyon Crude Pipeline System 69P - Dilley Pipeline System 17P - Borger McKee Pipeline 68P - Gardendale Pipeline System 45P - Oakville Pipeline 42P - Pawnee Pipeline & Terminal System 44P - Three Rivers to Origin Crude Oil Pipeline 43P - Tule to Three Rivers 55P - Pettus South 16P - Wichita Falls - McKee 14 inch	INTRAstate	RRC (RR Comm. of TX)
Refined Product			
ALB BRN BUR DNV ELP KM8 KML LAR SLK	08P - Amarillo - Albuquerque Pipeline 62P - Brownsville Pipeline 61P - Burgos Pipeline 04P - McKee - Denver Pipeline 03P - El Paso Pipeline 14P - El Paso Kinder Morgan 8in Pipeline 15P - El Paso Kinder Morgan 16in Pipeline 50P - Laredo Pipeline 05P - Southlake Pipeline	Interstate	PHMSA
SIN	65P - Sinclair WY - Rawlings WY [PHMSA ID 10012]	INTRAstate	PHMSA (as state agency)
AM6 AM8 CCP GRV HOU LUB NLS ORI SAE SAS TRL VAL	06P - Amarillo 6in Pipeline 11P - Amarillo 8in Pipeline 48P - Corpus Christi Chemical Pipeline 58P - Tribble Lane - Grove Junction Pipeline** 46P - Houston Pipeline** 09P - Amarillo - Lubbock Pipeline 59P - CC Refinery East - Lone Star Pipeline** 60P - Citgo Booster - Origin Pipeline 52P - Three Rivers to San Antonio (East) Pipeline 53P - Three Rivers to San Antonio (South) Pipeline 54P – Three Rivers to Lone Star Junction** 51P - Valley Pipeline	INTRAstate	RRC (RR Comm. of TX)

* Except where noted

** Purged-Out of Service Idle

B: IMP Event Frequency

Event	Frequency or Due Date
PHMSA 7000-1.1 Annual Reports	annually by June 15
IMP Review - NuStar Internal	annually
Baseline Assessment on new HCA segment	within 5 years of new HCA segment identification
Baseline Assessment on new construction (Category 3 pipelines)	prior to in-service date
Discovery of a condition	Date of Client List processing in Data Manager
EFRD necessity determination	annually (as part of the P&M Measures process)
External audit of IMP documentation	Every 3 years
HCA review/analysis for new/changed HCAs (including check of NPMS and possibly other sources for updated HCA data)	at least annually
Inspection Survey Report, Preliminary	within 30 days of a successful DEF/MFL in-line inspection within 60 days of a successful crack tool inspection
Inspection Survey Report, Final	within 60 days of a successful DEF/MFL in-line inspection within 120 days of a successful crack tool inspection within 90 days of a successful AFD inspection
New HCA segment identification	within 1 year of discovery
New HCA segment in the Assessment Schedule	within 1 year of new HCA segment identification
P&M Measures Meetings	at least annually
PHMSA notification for using Other Technology	90 days before conducting the assessment
PHMSA notification to extend the reassessment interval past 68 months	270 days before the end of the reassessment interval
PHMSA notification to extend the reassessment interval because of unavailable technology	180 days before the end of the reassessment interval
API PPTS Infrastructure Reports	annually by last day of February
Preliminary Site Survey Report	within 5 days of a successful in-line inspection
Reassessment interval	within 5 years, not to exceed 68 months
Risk analysis update for pipeline segments	annually
Risk assessment algorithm reevaluation	periodically

C: Pipe Sample Handling and Analysis Processes

C.1 Classification of Longitudinal ERW Weld Seams

NuStar's pipeline systems have a varied history of ownership and construction. Recognizing that some portion of the line pipe in the system can be classified as "vintage," when appropriate, NuStar uses the following process to classify the long seam of ERW line pipe which has been removed from active segments due to failures or repairs. This process is provided to the mechanical testing laboratory selected to perform the required destructive testing and analysis.

C.3.1 Scope

This process uses visual examination, non-destructive testing, destructive testing and metallography to locate, examine and to classify the longitudinal ERW seam weld type into one of the following groups:

- Low-Frequency electric-resistance weld (non-post-weld heat treated)
- Low-frequency electric-resistance weld (post-weld heat treated)
- Low-frequency electric-resistance weld (full body normalized)
- DC electric-resistance weld (non-post-weld heat treated pre 1948)
- DC electric-resistance weld (post-weld heat treated)
- High frequency electric resistance weld (non-post-weld heat treated)
- High frequency electric resistance weld (post-weld heat treated)
- High frequency electric resistance weld (full body normalized)
- Undetermined

Low-frequency electric-resistance welded (LF ERW) line pipe is of particular concern to the industry because of demonstrated issues with long seam integrity. Typically, the long seam of LF ERW line pipe exhibits one or all of the following characteristics:

- A coarse-grained heat affected zone
- A decarburized bond line
- A rectangular-shaped heat affected zone

Direct current electric-resistance welded (DC ERW) line pipe was produced by a single manufacturer, Youngstown Sheet and tube. It is often recognized by contact marks and a coarse-grained heat affected zone.

C.3.2 References

- Code of Federal Regulations, Part 192 (49 CFR 192)
- Code of Federal Regulations, Part 195 (49 CFR 195)
- ASME B31.4
- ASME B31.8
- History of Line Pipe Manufacturing in North America
- Vintage pipe Report - Eiber
- Proprietary databases

C.3.3 Procedures

C.3.6.3 Pipe Background Documentation

If available, the following information should be provided to the testing laboratory with the pipe sample.

Manufacturer - Mill name, Facility name, City and State
Year manufactured
Year installed
Pipe outside diameter
Pipe wall thickness
Pipe grade
Nominal joint length

C.3.6.4 Visual Examination of Pipe

Visually examine both the outside surface and the inside surface of the pipe for evidence of a longitudinal weld seam, including weld trim marks and contact marks (if present). Obviously cleaning and proper lighting will be beneficial to this examination.

C.3.6.5 Non-Destructive Examination

Wall Thickness measurements
Measure and record the wall thickness (to the nearest 0.001 inch) at a minimum of four locations around the pipe circumference using either a micrometer or a calibrated ultrasonic thickness gauge.

Magnetic Particle Testing
Magnetic Particle Testing (MT) can be used to highlight features commonly associated with longitudinal welds, including those listed below:

- Trim marks
- Flash
- Seam Flaws

C.3.6.6 Metallographic Examination

Evidence that can be gained through a **<u>macroscopic examination</u>** of a metallurgical section through the seam weld includes the following:

- What is the size and shape of the weld heat affected zone?
- Did a post-weld heat treatment occur? (presence of a wide heat affected zone)
- Are there any signs of contact marks?
- Are there any weld or parent metal imperfections or defects?
- Are the ID and OD surfaces trimmed?

Evidence that can be gained through a **<u>microscopic examination of a metallurgical section</u>** through the seam weld including the following:

- What is the size and shape of the weld heat affected zone?
- Does the weld have a wide heat affected zone, often associated with DC or LF?
- Does the weld contain coarse-grained areas of the HAZ which could indicate DC or LF welding?
- Does the weld contain fine-grain areas of the HAZ which can indicate post-weld heat treatment?
- Does the weld have a prominent fusion line?
- Does the weld appear to have been post-weld heat treated?
- Are flow lines visible which may be a sign of segregation?
- Does the weld have an hour-glass shape which is more typical of high frequency welds?

- Does the weld have a grain structure similar to the base material which could indicate a full-body normalizing process?
- Are numerous contact marks present, a sign of DC welding?
- Are stringers present?

Evidence that can be gained through a **microscopic examination of the base metal** includes the following:

- Is the grain structure uniform?
- Is there a banded grain structure?
- What is the shape and distribution of inclusions?
- Are there any signs of decarburization?
- Are there signs of burned steel?
- Are there signs of numerous contact marks (indication of DC welding)?
- Are there other signs of unique steel processing methods?

C.3.4 Data Integration

The data collected during the examination will be integrated (evaluated as a whole) to verify that the manufacturing method was ERW and to classify the ERW seam weld type as being 1 of the 9 groups listed at the beginning of this appendix. The following information will be used to classify the ERW seam:

- Verify that the welding process used was ERW
- If the manufacturer, mill and date are known, verify that the weld microstructure and shape are consistent with the known information about the welding process and heat treatment methods used
- For those pipe where the manufacturer is not known, the following steps may be used to determine the seam type:
    - Verify whether the ERW weld received a post-weld heat treatment
    - Verify whether the pipe received a full body normalizing heat treatment
    - Verify whether a coarse grained heat affected zone is present (this would indicate that the seam was not post weld heat treated)
    - Verify whether the weld heat affected zone is shaped like an hour-glass (this is an indication of a high frequency welding process?
    - Compare the unknown weld cross-section to photographs or samples of weld cross-sections from known manufactur5eres to see if a match exists
    - If the approximate year of manufacture or installation is known, verify what ERW welding methods were available.
- Fort those welds where there is not enough evidence to conclusively determine whether they are low-frequency, DC or high frequency welded, the weld will be classified as undetermined.

C.2 ERW Line Pipe Manufacturers

Table 1 - Past ERW Manufacturers and Associated Facilities

Manufacturer	Location	Mill	ERW Process	Years	Diameters	Seam Anneal?	Seam Stress Relief	Full Body Normalizing?
Aceron Alta	Monterrey, Mexico		?	1962 - 1973	6.625			
Armco Steel	Ambridge		LF	1964 - 1967	0.5 to 4			Yes
Beall Pipe & Tank	Portland, OR		?	1956 - 1982	3 to 16			
Bethlehem Steel	Sparrows Point, MD	Small OD	HFC	1963 - 1982	2.375 to 6.625	Yes		
Bethlehem Steel	Sparrows Point, MD	Large OD	LF	1957 - 1970	5.625 to 16		Yes	
Bethlehem Steel	Sparrows Point, MD	Large OD	HFC	1970 - 1983	5.625 to 16	Yes		
Big Inch Pipe	Calgary, Alberta		HFC	1960 - 1970	18 to 36	Yes		
Brooks Tube	Brooks, Alberta		?	1975 - 1983				
Bull Moose Tube	Gerald, MO		HFC	1975 - ?				
Cal-Metal	Torrance, CA		HFC	1963 - 1983	2.625 to 16	Yes		
Canadial Pheanix	Edmonton, Alberta		?	1960 - ?				
Canadial Pheanix	Calgary, Alberta		HFC	1960 - 1970	18 to 36	Yes		
Canadial Pheanix	Port Moody, B.C.		?	1960 - ?				
Central Steel Tube	Clinton, IA		?	?	4.5 to 8.5			
Consolidated Western	Provo, UT		LF	1956 - ?	4 to 12.75			
Cooperweld Steel	Shelby, OH		LF	1937 - 1986				
Cooperweld Steel	Shelby, OH		HFC	1986 - ?				
Cooperweld Steel	Chicago, IL		?	1985 - 1987	1 to 6			
Fort Collins Pipe	Fort Collins, CO		?	1963 - ?	2.375 to 8.625			
Fox Steel Pipe	Jacksonville, FL		HFC	1962 - 1963				
Geneva Tube	Geneva, NE			1984 - 1987				
J&L Steel	Aliquippa, PA		LF	1957 - 1965	6.625 to 12.75		Yes	
J&L Steel	Aliquippa, PA		HFC	1965 - 1980	4.5 to 12.75	Yes		

Kaiser	Fontana, CA		LF	?				
Kaiser	Napa, CA			1954 to ?	6.625 to 20			
Kaiser	Fontana, CA		HFC	1965 - 1984	4.5 to 16			
Lone Star	Lone Star, TX	Mill 1	LF	1953 - ?	6.625 to 16			Yes
Lone Star	Lone Star, TX	Mill 2	LF	1953 - 1963	1.9 to 6.625			Yes
Mobile Pipe Corp	San Francisco, CA		HFI	1962 - 1975	6.625 to 10.75			
National Pipe and Tube	Liberty, TX		HFC	1976 - 1990	2.375 to 10.75			Yes
Newport Steel	Newport, KY		LF	1951 - 1980	4.5 to 8.625	Yes		
Page-Hersey Tubes	Welland, Ontario		LF	1950 - ?	4.5 to 16			
Page-Hersey Tubes	Welland, Ontario		HFC	? - ?				
Produtors Tubulares	Fontera, Mexico			1970 - ?	5.5 to 16			
Republic Steel	Youngstown, OH	Mill 1	LF	1929 - ?	2.375 to 6.625			
Republic Steel	Youngstown, OH	Mill 2	LF	1930 - 1961	4.5 to 8.625			
Republic Steel	Youngstown, OH	Mill 3	LF	1930 - 1961	8.625 to 16			
Republic Steel	Youngstown, OH	Mill 5	HFC	1963 - ?	6.625 to 16	Yes		
Southern Pipe and Casing			?	1945 - 1969	4 to 14			
Southwestern Pipe	Houston, TX		?	1957 - 1973	0.5 to 4.5			
Standard Tube			?	1958 - 1985	6.625 to ?			
Standard Tube Canada	Woodstock, Ontario		?	1970 - 1975				
Valmont Industries	Valley, NE		?	?	6.626 to 10.75			
Youngstown Sheet and Tube	Youngstown, OH	Large OD	DC	1930 - 1948	16 to 26			
Youngstown Sheet and Tube	Youngstown, OH	Small OD	DC	1935 - 1948	6.625 to 12.75			
Youngstown Sheet and Tube	Youngstown, OH	Final Mill	DC	1948 - 1980	6.625 to 22		Yes	

Table 2 - Current ERW Manufacturers and Associated Facilities								
Manufacturer	**Location**	**Mill**	**ERW Process**	**Years**	**Diameters**	**Seam Anneal?**	**Seam Stress Relief**	**Full Body Normalizing?**
American Steel Pipe	Birmingham, AL	Mill 1	HFC	1963 to present	10.75 to 20	Yes		
American Steel Pipe	Birmingham, AL	Mill 2	HFC	1989 to present	16 to 24	Yes		
Bellville Tube	Bellville, TX		HFC	1980 to present	2.375 to 4.5			Yes
California Steel	Fontana, CA		HFC	1988 to present	4.5 to 16	Yes		
Camp Hill	McKeesport, PA		HFC	1964 to present	8.625 to 20	Yes		
Camrose Pipe	Camrose, Alberta		HFC	1963 to present	4.5 to 16	Yes		
Geneva Steel	Vineyard, UT		HFC	? To 2004	6.625 to 16			
Hysla SA	Garza, Mexico		HFC		2.375 to 4.5			Yes
Ipsco	Calgary, Alberta		HF600 VT	1982 to present	4.5 to 10.75	Yes		
Ipsco	Edmonton, Alberta		HF280 VT		4.5 to 16	Yes		
Ipsco	Red Deer		HF300 VT		2.875 to 12.75	Yes		
Ipsco	Regina		160 VT	1992 to present	1.5 to 2.375	Yes		
Ipsco	Regina		600 VT	1994 to present	14 to 24	Yes		
Ipsco	Camanche		HV 300 VT		2.375 to 8.625	Yes		
Lone Star	Lone Star, TX	Mill 1	HFC	1968 to present	8.625 to 16			Yes
Lone Star	Lone Star, TX	Mill 2	HFC	1968 to present	2.375 to 6.625			Yes
Lone Star	Lone Star, TX		HFC	1992 to present	4.5 to 8.625	Yes		
LTV	Cleveland, OH		HFC	?	3.5 to 8.625			
LTV	Counce, TN		HFC	late 1960's to present	2.375 to 8.625	Yes		
LTV	Youngstown, OH		HFC	1992 to present	4.5 to 8.625	Yes		

Maverick Tube	Conroe, TX				2.375 to 8.625			
Newport Steel	Newport, KY	8" Mill	HFC	1983 to present	4.5 to 8.625	Yes		
Newport Steel	Newport, KY	16" Mill	HFC	1983 to present	8.625 to 16	Yes		
Northwest Pipe and Casing	Atchison, KS		HFC		3 to 16			
Pittsburgh Tube	Darlinton, PA		HFI		0.625 to 5			
Procarsa SA	Frontera, Mexico				2.375 to 4.5			
Procarsa SA	Frontera, Mexico				5.5675 to 16			
Prudential Steel	Calgary, Alberta	Mill 1		1966 to present	2.375 to 4.5			
Prudential Steel	Calgary, Alberta	Mill 2	HFI	1975 to present	5.625 to 12.75		Yes	
Prudential Steel	Calgary, Alberta	Mill 3	HFI	1994 to present	2.375 to 4.5		Yes	
Sawhill Tubular	Sharon, PA		HFC	1960 to present	2 to 12.75			
Stelpipe Ltd	Welland, Ontario	Page-Henry	HFC	?	2.375 to 16	Yes		
Stelpipe Ltd	Welland, Ontario	Page-Henry	HFI	1993 to present	0.5 to 4.5			Yes
Stupp	Baton Rouge, LA		HFC	1970 to present	8.625 to 24	Yes		
Tex-Tube	Houston, TX	1 Mill	HFC	1956 to present	3.5 to 8.625	Yes		
Tex-Tube	Houston, TX	2 Mill	HFC	1968 to present	2.375 to 4.5	Yes		
Tubacero SA	Monterrey, Mexico	Mill 2		1943 to present	18 to 24			
Tubacero SA	Monterrey, Mexico	Mill 3		1943 to present	6.625 to 16			
Tuberla Laguna SA	Palaclo, Mexico		HFI		6.625 to 24			
U.S. Steel	Lorain, OH		HFC	1967 to present	4.5 to 6.625	Yes		
Villacero Tuberla	Leon, Mexico		HFI		0.405 to 6.625			Yes

C.3 Handling Pipe Samples Prior to Examination

Getting the materials to the investigator in a preserved, undamaged condition is an important first step in a successful failure examination. For failures involving small components or short lengths of pipe, e.g. 40 feet, consider sending all the components involved. For larger failures, it may be necessary to identify the origin and remove sufficient adjacent material to perform a full analysis. The following steps should be followed when selecting material to submit for analysis:

C.3.1 Photography

A photograph should be taken or a sketch made of the specimen in place before disturbing it. Photographs should also be taken after the pipe is removed from the ditch. It is a good idea to mark each photograph with the test section and failure number, as well as the date and time the photograph was taken.

C.3.2 Excavation Cautions

Extreme care should be exercised during excavation to prevent digging tool contact with the pipe in the vicinity of the failure surface. In handling the pipe, no hooks, chains, slings or similar metal devices are to contact the pipe at a fracture location. Sometimes, the origins of pipe ruptures are on a flap that protrudes from the pipe body, making it prone to being damaged during handling. Damage to the origin can obscure or destroy important information that may be critical to the examination.

C.3.3 Surface Protection

Steel surfaces can flash rust quickly when exposed to the atmosphere and moisture (within 155 minutes). As soon as it practical after excavation or exposure of the failure segment, the fracture surfaces should be coated with a light, water dispersing oil, such as WD-40, motor oil or Vaseline.

It is essential to avoid damaging the fracture surfaces. Do not clean the fracture surfaces, other than to remove mud with water. The surfaces should not be rubbed, brushed, sandblasted or otherwise contacted. Avoid damaging the fracture surfaces during handling.

C.3.4 Marking

Small leaks or flaws should be indicated by paint marker with care being taken to get paint or ink on the failure. Mark all materials to indicate their position/orientation in the pipeline prior to failure. On all failures requiring cutout, mark the top of the pipe (12 o'clock position), direction of flow (arrow pointing downstream) and a "North" arrow with a paint marker or other indelible marker.

Hydrostatic test failures should be identified sequentially by test section, failure number, milepost and/or station number. The name of the person and company gathering the pipe specimen, the station number, test section and failure numbers should be written on the pipe.

C.3.5 Shipping Preparation

After the failed segment of pipe has been removed from the line and treated as described above, the segment should be wrapped and taped in a water-resistant film such as polyethylene to prevent contamination during transport and storage. The plastic film should be positioned on the failure segment to permit access to the failure surfaces for examination or reapplication of the oil coating.

Prepare the materials for shipment by a method that will immobilize the samples and prevent damage due to rolling into other objects. If the materials need to be cut to accommodate shipment, avoid cutting within 6 inches of the failure origin or and other fracture surface if possible. When handling the materials avoid using metal tie-down straps, chains or hooks near the origin. Most items can be strapped onto a wood pallet with banding straps. If bands must be located near the origin, first cover the origin with several layers of cardboard and secure them to assure they will not move during transit. Smaller pieces may fall off a pallet and become lost, so use a box or crate to ship them.

C.3.6 Pipeline Incident Background Data

Data below should be captured and provided to the investigator by the NuStar personnel for each leak or rupture-type failure being analyzed. Not all fields may be applicable or may be known, but the greater the detail provided, the more precise and thorough the evaluation and report will be.

C.3.6.1 Basic Information

- Operating Company
- Product
- Line Name and Number and/or System Name
- Survey Station and Mile Post
- Date of Failure/Incident/Anomaly
- How was the Failure/Incident/Anomaly found
- State, county and closes city or town
- Pipe nominal outside diameter
- Pipe nominal wall thickness
- Pipe grade
- Pipe seam type and joint length (if not 40 feet)
- Pipe manufacturer
- Year of installation
- Coating type

C.3.6.2 Cathodic Protection and Soil Conditions

- Cathodic protection type and year installed
- Distance to nearest rectifier or anode bed
- Terrain and soil conditions, including pH if possible
- Pipe to soil potential readings

C.3.6.3 Failure or Anomaly Location and Orientation

- Distance to upstream and downstream pump stations
- Distance to upstream and downstream girth welds
- Position of failure or anomaly on pipe circumference

C.3.6.4 Operational Information

- Pressure at the time and location of the failure/incident/anomaly
  The pressure to be reported is the calculated failure pressure at the location of the failure considering elevation. Under "description of failure," it should be reported whether the failure was a leak or a rupture and whether it was in the longitudinal weld, girth weld or pipe body. A short written description of the event is very helpful in adding completeness to the final investigation report.
- Normal operating pressure at location of failure/incident/anomaly
- MOP, MAOP, Design Factor, and/or Location Class
- Date, Test Pressure and Duration of most recent hydrostatic test
- Hydrostatic test pressure at location of failure/incident/anomaly
- Other comments and/or observations
- Contact information for further information

C.3.6.5 Post-Evaluation Requirements

- Identify disposal requirements (asbestos present?)
- Preservation requirements
- Storage or shipping requirements following assessment

D: Anomaly Types, Detection Tools, and Assessment Methods

Assessment method selection is dependent on many factors, including pipeline characteristics, the likelihood of manufacturing defects, susceptibility to internal and external corrosion, the possibility of third-party or construction damage, and exposure to pressurization above the maximum operating pressure. Each of these factors can cause or influence pipe anomalies and should be considered when selecting an assessment method(s) for a particular pipeline segment, in order to obtain the most representative information on the condition and serviceability of the pipeline. This appendix provides an overview of the types of anomalies and defects typically found on pipelines, the available tool technologies and their capabilities, and current assessment method options, as referenced in NACE 35100, NACE SP0102-2012 and API Std. 1163.

D.1. Anomaly Types

An anomaly is a possible deviation from sound pipe material or weld. Many anomalies are natural consequences of installing metal pipe underground. Generally, anomalies can be separated into two categories: metal loss (corrosion) and construction or third-party damage.

A defect is an anomaly for which an analysis indicates the pipe is approaching failure as the nominal hoop stress approaches the specified minimum yield stress (SMYS) of the pipe. Defects include such mill-related anomalies as hook cracks, incomplete fusion, burnt pipe, and hard spots.

D.1.1. Metal Loss (Corrosion) Anomalies

External Corrosion is typically a natural consequence of burying metal pipe in soil. It is sometimes referred to as “local pitting” or “general corrosion” but also includes a specific type of corrosion.

- **Local Pitting** is normally confined to a small area or several interconnected small areas. It is either individual or multiple pits surrounded by pipe that is at or near full wall thickness. Bacteria, differential oxygen concentrations, or simply interaction between galvanic cells can cause localized pitting. Because the pipe area being attacked can be very small and the corrosion rate, in some situations, can be extremely high, local pitting must be dealt with.
- **General Corrosion** typically consists of a larger area of corrosion than local pitting. It can consist of an area covering at least three quadrants of pipe and several feet in length, where the wall thickness is reduced on the whole area. General corrosion is typically evaluated by determining the remaining wall thickness as if the whole pipe were that thickness and calculating the strength accordingly.
- **Narrow Axial External Corrosion (NAEC)** is typically found at double-submerged, arc-welded pipeline seams coated with polyethylene tape. The tenting of the tape coating, created by raised longitudinal seam welds, provides an environment that can shield the external surface of the pipe from cathodic protection. This shielded area is axially oriented and limited to the area immediately adjacent to the seam weld.
- **Selective ERW (Preferential) Seam Corrosion** is created when corrosion is caused by internal or external metal loss that is across or adjacent to an ERW seam. It often causes a V-shaped crevice or groove within the seam line.

Internal Corrosion also typically includes local pitting and general corrosion. Because cathodic protection is ineffective in mitigating internal corrosion, corrosion treatment chemicals such as inhibitors and bactericides are often used to treat it. Frequent pigging is useful in conjunction with chemical treatment to remove water and debris from the pipeline and prevent internal corrosion.

D.1.2. Cracks and Crack-like Defects

Stress Corrosion Cracking (SCC) is a form of environmentally assisted cracking, wherein small cracks lengthen and deepen slowly over a period of years. The individual cracks, which may occur in colonies, may eventually join together to form larger cracks that can compromise pipe integrity.

Longitudinal Seam Weld Imperfections are primarily mill-related defects, which include defects associated with the longitudinal seam, including burnt pipe and hook cracks.

Incomplete Fusion is a mill-related defect, which results from a lack of complete coalescence of some portion of the metal in the weld joint.

D.1.3. Dents

Plain Dents are local changes in surface contour by mechanical impact but without loss of metal.

Dents with a Stress Concentrator are dents with gouges, pits, notches, arc burns, or weld cracks located within them.

Gouges are elongated grooves or cavities caused by mechanical removal of metal. They can typically be recognized by the sharpness of their edges.

Wrinkle Bends and Buckles are collapses of the pipe wall, normally found in the crotch of a bend. Typical wrinkle bends can be recognized as ripples on the inside of a bend.

D.1.4. Other Anomalies

Laminations or Inclusions are internal metal separations creating layers generally parallel to the surface. Laminations are caused by a shrinkage cavity in the upper part of an ingot. If oxides form on the surface of this cavity, the surfaces will not weld together during subsequent rolling operations. Since the shrinkage cavity starts in the center of an ingot, it remains in the center of the resulting slab, plate, and pipe. Laminations that break the surface and may behave much like cracks.

Previous Repair usually consists of a steel sleeve or patch that has been applied to the pipeline to strengthen the pipe in the area surrounding an anomaly.

Mill-Related Anomalies are pipe defects that occur during the manufacturing process.

Ovalities are pipes that are oval or egg-shaped, and on which the major and/or minor axes are respectively in excess or less than the tolerances permitted in the pipe standard designated in the purchase order specifications.

D.2. Detection Tools

Modern assessment tools are capable of providing significant information on the condition of the pipeline, including the size, type, and orientation of an anomaly. In most instances, in-line tools are the preferred assessment method because of the higher level of information obtained, as compared to pressure testing, which merely indicates whether a segment is capable of operating at a certain pressure at a specific point in time. There are specific in-line tools capable of detecting different corrosion anomalies and mechanical damage, such as dents and gouges, as well as mill defects. When using an in-line assessment method to ascertain the serviceability of a pipeline segment, it is important to select an appropriate tool capable of detecting various anomalies on a particular segment.

The primary tools used to assess integrity on NuStar’s pipelines are in-line inspection (ILI) tools—specifically deformation (DEF) and corrosion (COR) tools. Some circumstances, such as ERW seam and SCC susceptible lines, may require the use of other types of tools or methods, such as hydrostatic testing or Axial Flaw Detection (AFD) ILI tools. Other technologies such as GWUT may be used in circumstances when it is impracticable to use preferred methods.

A notification to PHMSA for approval of these technologies must be submitted per the Rule. Otherwise, all assessment tools must be used in accordance with the acceptable methods specified in *§(c)(1)(i)* of the Rule.

D.2.1. Metal Loss (Corrosion) Tools

Standard Resolution (SR) Magnetic Flux Leakage (MFL) Tools are typically considered first generation tools used as permanent magnets or electromagnets to induce a magnetic field in the pipe wall as it travels down the pipeline. Sensors measure the MFL in the pipe and record any deviation in flux density. Such deviations are an indirect indicator of a change in wall thickness or other anomaly that causes a disturbance of the magnetic field, such as metal in proximity to the pipeline. This type of tool is limited in its detection of longitudinally oriented metal loss. This tool typically reports corrosion anomalies as light, moderate, or severe based on estimated depth of the anomaly (e.g., light as being 10–30% of wall thickness, moderate as being 30–50%, and severe as being over 50%).

High Resolution (HR) MFL Tools work on the same principles as the SR MFL tools, but have more sensors with closer spacing to measure deviations in the magnetic field. This configuration allows the tool to collect more data around each anomaly. Using ASME B31G, Modified B31G, RSTRENG, or other suitable remaining strength calculations, MFL data can be used to determine the approximate remaining strength of the pipe. HR MFL tools can also determine if a corrosion anomaly is internal or external to the pipe wall. As with SR MFL tools, there are limitations to the ability to detect longitudinally oriented metal loss. The advantage of HR MFL tools is a better definition of corrosion anomalies, which usually results in fewer unwarranted excavations and repairs, because only those anomalies that are determined to be injurious to the pipe are excavated.

Ultrasonic Corrosion Tools work by using transmit and receive transducers to transmit an ultrasonic pulse into the inside diameter (ID) wall of the pipe. It also records the time it takes the signal to be reflected back to the transducer, and are therefore capable of detecting and differentiating ID and outside diameter (OD) metal loss. These tools provide data that is theoretically more precise compared to HR MFL tools because it is a direct and linear measurement of wall thickness. Like the HR MFL tools, the remaining strength of pipe calculations can be performed using ASME B31G, Modified B31G, RSTRENG, or other suitable remaining strength calculations. These tools typically provide a more direct description of an anomaly, as compared to the HR MFL tool, which is an inferred measurement of an anomaly. With an ultrasonic tool, it is critical that the signal be acoustically coupled to the ID of the pipe.

D.2.2. Crack Detection Tools

Axial Flaw Detection (AFD) Tools detect narrow longitudinal shaped defects, which are generally too narrow for traditional MFL tools to detect. Several vendors have specific tools designed to inspect for narrow longitudinal shaped defects using either ultrasonic or MFL technology. These tools can detect and size narrow longitudinal features, such as notches, cracks, gouges, seam weld flaws, and SCC.

Ultrasonic Crack Detection Tools operate by introducing an ultrasonic signal into the pipe wall at an angle. This tool generates a shear wave traveling circumferentially through the pipe wall as it is reflected off the pipe's ID and OD surfaces. If the pulse encounters a crack, it is reflected back along the same path and is received at the transducer. The ultrasonic tool is capable of detecting defects such as lack of fusion, hook cracks, SCC, and voids, as well as narrow axial corrosion. The level of detection, discrimination, and sizing achieved by these tools, is superior to hydrostatic pressure testing because they can detect flaws smaller than those that would fail a hydro test. The tools are also capable of detecting circumferential cracks and crack-like features by rotating the transducer 90º.

Transverse MFL Tools magnetize the pipe wall circumferentially and use transverse magnetic flux leakage to detect cracks and lack of fusion. These tools can also detect longitudinally oriented seam corrosion.

Like the Ultrasonic Crack Detection Tools, the level of detection, discrimination, and sizing that has been achieved by these tools, is superior to hydrostatic pressure testing as the tool is capable of detecting flaws that are smaller than those that would fail a hydro test.

D.2.3. Geometry Tools

Caliper Tools measure deviations in the geometry of a pipeline's diameter. They use a set of mechanical fingers or arms that ride against the ID of the pipe, or use electromagnetic methods to sense its ovality. Any movement of these arms relative to each other is recorded mechanically or electronically. Any change in the geometry of the diameter of the pipe will cause relative movement. Changes in pipe geometry can be due to pipe bends, dents, buckles, gate or check valves, or changes in wall thickness. Caliper tools are used to verify that pipelines are capable of passing other tools, (e.g., corrosion tools) and to detect potentially injurious buckles or dents in the pipe.

Pipe Deformation Tools provide the same information as caliper tools with the addition of the clock position of the dent, or other anomaly that is changing the geometry of the diameter.

Mapping Tools are based on inertial navigation using built-in gyroscopes and accelerometers, and are useful for creating pipeline alignment maps, populating GIS information systems, and determining pipeline ground movement.

D.2.4. Other Tools

D.2.4.1. Optional ILI Tools

Cleaning and Gauging Pigs (CLP) are run on the pipeline before running Corrosion or Deformation tools, if necessary. CLPs clean the pipeline segment by using spring-loaded radial brushes, and cups to scrape debris from the pipeline walls. They also gauge the internal diameter of the pipeline segment by using a deformable plate. This plate is interpreted by analyzing any and all deflections in the plate's outer edges. A successful run of a CLP ensures that subsequent ILI tool runs will go through without interruption.

Gauge Tools use a set of rings to gauge the overall diameter of the pipeline. Gauge tools can be sized to determine whether deformations exist on the pipeline and used to size bends to determine if a smart tool is capable of passing these bends. These tools can also determine whether there are significant obstructions that may prohibit the passing of an ILI tool.

D.2.4.2. Other Technology Tools

As allowed for in the Rule *§(c)(1)(i)(D)*, newer technologies that have not been specifically named in the Rule may be used with proper notice. When NuStar determines that the use of such technology is needed for a particular pipeline, NuStar notifies OPS 90 days before conducting the test.

Guided Wave Ultrasonic Testing (GWUT) Tools are external transducer collars temporarily installed on a section of the pipe. The transducer impresses ultrasonic energy on the pipe and detects the ultrasonic energy that is reflected back from piping features, such as weld joints, bends, flanges, and metal loss anomalies. For buried pipe, inspection distances usually range from 40 to 150 ft on either side. The type of coating, coating thickness, annular fill in a casing, and presence of bends or fittings, typically affect the range of the GWUT. Because GWUT cannot distinguish between internal and external corrosion, pipe that is directly examined will need to be tested with an ultrasonic pipe thickness tester at the anomaly location to identify internal corrosion.

D.3. Assessment Methods

D.3.1. ILI Assessments

The preferred method of testing pipeline integrity is with ILI assessments. Table D-1 shows how the different ILI tools do at addressing the various threats.

Table D-1. Threat-Based Assessment Tool Selection

ILI Purpose	Metal Loss (Corrosion) Tools			Crack (Axial Flaw) Detection Tools		Geometry (Deformation) Tools	
	Magnetic Flux Leakage (MFL)		Ultrasonic (Compres-sion Wave)	Ultrasonic (Shear Wave)	Transverse MFL	Caliper	Mapping
	Standard Res (SR)	High Res (HR)					
Internal and External Metal Loss (Corrosion)	D[1], S[2, 3, 4]	D[5], S[2]				—	
Narrow Axial External Corrosion (NAEC)	—	D[6]	D[5], S[2]			—	
Cracks and Crack-Like (Axial) Defects[7]	—			D[5], S[2]		—	
Circumferential Cracking	—	D[8], S[8]	—	D[5], S[2, 9]	—		
Dents	D[10], S[10]					D[3, 11], S	—
Wrinkle Bends or Buckles	if D, circumferential position provided						
Gouges	D[1, 5] but no discrimination as gouges						—
Lamination or Inclusion	limited D		D, S[2]	D, S[2]	limited D	—	
Previous Repairs	D[12]		D[13]		D[12]	—	
Mill-Related Anomalies	limited D		D		limited D	—	
Bends	—					D, S[2]	D, S[2]
Ovalities	—					D, S[2, 14]	D, S[2, 15]
Pipeline Coordinates	—						D, S[2]

D = Detection
S = Sizing
[1] limited by minimum detectable metal loss
[2] defined by tool's specified sizing accuracy
[3] available in tethered tool
[4] no ID/OD discrimination
[5] limited by minimum detectable depth, length, and width of defects
[6] if width is smaller than tool's minimum detectable defect width
[7] SCC, fatigue cracks, longitudinal seam welds, imperfections, incomplete (lack of) fusion, toe-cracks
[8] reduced Probability of Detection (POD) for tight cracks
[9] if modified with transducers rotated 90º
[10] reduced reliability depending on dent size and shape
[11] depends on tool configuration and circumferential position
[12] steel sleeves and patches; only others with ferrous markers
[13] only steel sleeves and patches welded to pipe
[14] if equipped for bend measurements
[15] if equipped for ovality measurement

D.3.2. Hydrostatic Testing

Pipe segments that are not piggable can be assessed by a hydrostatic test or other technology. NuStar will hydrostatically test a pipe segment if the segment is too short, lacks a launcher and receiver, or requires a hydrostatic test to assess the line specific risk factors.

O&M Procedure 609, Pipeline Hydrostatic Testing, describes NuStar's hydrostatic test procedure, which exceeds the requirements of Subpart E for the purpose of increasing the integrity of the line.

All NuStar pipe segments that are regularly hydrostatically tested, as part of an integrity assessment, are subject to a corrosion control program as outlined in the *Corrosion Control Manual*.

D.3.3. Guided Wave Ultrasonic Testing

When NuStar uses other technologies such as GWUT because preferred methods are impracticable, it must notify PHMSA for approval. GWUT is performed using IMP Procedure 304, Guided Wave Ultrasonic Testing, which outlines the actual steps that must be followed in performing the GWUT inspection, its validation examinations, and in classifying and reporting the anomalies discovered. The procedure also addresses PHMSA notification regarding the use of this Other Technology; service provider qualifications; equipment specifications and documentation; the pre-assessment information that must be gathered; dig planning and transducer placement requirements; and guidelines for excavation and direct examination. Careful attention to all portions of Procedure 304 is required.

D.3.4. Direct Examination (DE)

NuStar may use Direct Examination (DE) on exposed steel pipe to locate and evaluate areas of metal loss or mechanical damage. DE is considered Other Technology when used as a standalone IMP technology for covered segments, as identified in Section 1.6, Identification of Segments That Could Affect HCAs; therefore, notification must be submitted for approval to PHMSA 90 days prior, as required by the Rule.

DE is performed using IMP Procedure 305, Direct Examination, which outlines the actual steps that must be followed in performing the DE inspection, its validation examinations, and in classifying and reporting the anomalies discovered. The procedure also addresses PHMSA notification regarding the use of this Other Technology; technician qualifications; the pre-assessment information that must be gathered; and guidelines for remediation. Careful attention to all portions of Procedure 305 is required.

D.3.5. External Corrosion Direct Assessment (ECDA)

NuStar does not currently use or plan to use ECDA as an assessment method used to fulfill the requirements of *§195.452 (c)(i)* on any of its pipelines. Any use of ECDA as a confirmatory inspection would be reviewed, approved, and implemented separately from the integrity management plan.

E: Documentation and References

E.1. Documentation

Key: Drive = Network Drive

Item	Documents…	Responsible Party	Location (Retention Period)	Distributed To…	Manual Section
7000-1 Report	Individual DOT reportable leaks	Regional HSE Dept	Regional HSE Drive (life of pipeline)	PHMSA	6
7000-1.1 Annual Report	Annual infrastructure and performance reports (one per operator ID and product type)	IMP Dept	IMP Drive (indefinitely) IMP Drive and Intranet (5 years)	PHMSA	8
Aerial/Surface Patrol Form	Information gathered from biweekly aerial/surface patrols	Aerial Pilots Field Technicians	Regional HSE Drive (3 years)	Operations/ Maintenance Mangers GIS Dept Regional HSE Dept	5–8
Air Dispersion Analysis Reports	Final drafts of air dispersion analyses performed by qualified vendors on newly-identified HCAs	Air Dispersion Modeling Vendor	IMP Drive (life of pipeline) IMP Intranet (life of pipeline)	HCA Specialist	101
Annual IMP Review Report	Previous year's IMP activities and effectiveness	IMP Dept	IMP Drive (indefinitely) IMP Drive and Intranet (5 years)	Multiple (See manual distribution list on the IMP Drive.)	8
Assessment Schedule	Schedule of ILI assessments and hydrostatic testing; revision log	Assessment Engineer	IMP Drive (life of pipeline) IMP pipeline integrity database (current version)		1–3, 5–8
Corrosion Control Effectiveness Review Form	Corrosion control data on a hydrostatically tested pipeline	Corrosion Manager	Regional Drive (life of pipeline)	Assessment Engineer	3, 303, 6
Client List	ILI inspection data	ILI Service Provider	IMP Drive (life of pipeline) Regional Drives (life of pipeline)	Assessment Engineer	301
Dig/Remediation Records	Dig locations to remediate (Dig Worksheet), checklist of completed digs (Dig Checklist), new/updated pipeline data from the dig (Pipeline Information Report/Defect Evaluation Form), repair documentation for each anomaly	Assessment Project Manager Operations/ Maintenance Personnel	IMP and Regional Drive (life of pipeline)	Operations/ Maintenance Managers Assessment Engineer	3, 301, 4
EFRD Analysis Report	Which EFRD scenarios will be run into RiskCAT for further analysis (EFRD Evaluation Form), EFRD analysis process for current year	Risk Engineer	IMP Drive (life of pipeline)		6
Field-identified HCA Log	Tracking of potential new HCAs identified by NuStar personnel and the final determination by the HCA specialist	HCA Specialist	IMP Drive (life of pipeline) IMP Intranet (life of pipeline)		101
GWUT Service Provider Report	Evaluation of data from guided wave ultrasonic testing	GWUT Service Provider	Regional Drive (life of pipeline) IMP intranet (life of pipeline)	Assessment Engineer	3

Item	Documents…	Responsible Party	Location (Retention Period)	Distributed To…	Manual Section
HCA Analysis Reports	Three reports resulting from the HCA analysis: Overall HCA report, Direct HCA Intersections, HCA Could-Affects	HCA Specialist	IMP Drive (life of pipeline) IMP Intranet (life of pipeline)		101
Hydrostatic Test Leak Report	Leak events during hydrostatic testing	Operations/ Maintenance Personnel	Part of the O&M Hydrostatic Test Report		3, 302
Hydrostatic Test Documentation	Final document, including all information outlined in the Hydro Test Documentation Checklist and the Final Hydrostatic Test Report (See O&M Procedure 609, Section 3.10.6)	Operations/ Maintenance Personnel	Region PHMSA Files Copy to: IMP Drive (life of pipeline)	Assessment Engineer	2
ILI Data Manager	Application for analysis of ILI vendor clientlist	Assessment Engineer	IMP Drive (life of pipeline)	Assessment Engineer Assessment Project Mgr.	301
ILI Service Provider Technical Questionnaire	Pipeline data provided to the ILI Service Provider for tool design	ILI Service Provider	IMP Drive (life of pipeline)	ILI Service Provider	203, 301
ILI Service Provider Tracking Report	Record of deliverables and deadlines for entire ILI assessment cycle	Assessment Project Manager	Regional Drives (life of pipeline)		3
HSE Incident Report	Known details of an incident (e.g., accident, pipeline leak) from first reporting through investigation	Operations/ Maintenance Personnel	Incident management system program Regional HSE Drive (life of pipeline)		8
Inspection Survey Report, Final	Inspection results and analysis	ILI Service Provider	Regional Drive (life of pipeline)	Assessment Engineer	2–3, 301
Inspection Survey Report, Preliminary	Preliminary ILI Service Provider data	ILI Service Provider	Part of Final Inspection Survey Report	Assessment Engineer	3
Internal Corrosion Coupon Report	Examination of coupons and other types of internal corrosion monitoring equipment	Corrosion Personnel	Regional Drive (life of pipeline)		5
Integrity Risk Analysis Report	ILI data and analyses	Risk Engineer	IMP Drive (life of pipeline)	Operations/ Maintenance Personnel Project Engineering Regional HSE	5
Longitudinal Seam Susceptible Segments List	Pipe with longitudinal seam susceptibility	Risk Engineer	IMP pipeline integrity database (life of pipeline)		2, 201
Mitigation Spreadsheet	Assessment/repair cycle data (dates, repairs made, etc.)	Assessment Engineer	IMP Drive (life of pipeline)	Operations/ Maintenance Personnel Assessment Engineer	3, 301
P&M Measure Suggestion Form	Data regarding possible P&M measures to be considered in a P&M meeting	Operations/ Maintenance Personnel and SMEs	IMP Drive (life of pipeline)	Risk Specialist P&M Meeting Attendees	6
P&M Measure Tracking Report	Tracking of P&M measures from P&M Measure Meetings or AFEs	Risk Engineer	IMP Drive (life of pipeline)		6–8
PHMSA Notification	Delay justification 180 days prior to the end of the 5-year (68-month) reassessment interval	IMP Dept	IMP Drive (life of pipeline)		2

Item	Documents…	Responsible Party	Location (Retention Period)	Distributed To…	Manual Section
Pipe Specimen/Sample Analysis Report	Data collected from Pipe Testing Protocol tests	IMP Dept	IMP Drive, GIS Regional Drive (life of pipeline)	Assessment Engineer	3, 302
Pipeline Encroachment/ Damage Education Report	Contacts with public agency personnel and excavators	Regional HSE	Regional HSE Drive (3 years)		8
Pipeline Information Report/Defect Evaluation Form	New/additional information about an excavated pipeline and its terrain or environment	Operations/ Maintenance Personnel	IMP Drive (life of pipeline) O&M Intranet (life of pipeline)	GIS Dept	3–8
Pipeline Integrity Profile Sheet	Mapping with collection data bands of ILI, corrosion, and risk data for evaluating pipeline integrity	HCA Specialist	HCA Specialist Hard Drive (annual archive)		1, 3, 6
POE Analysis Report	Third-party assessment of remaining defects	IMP Dept	Regional Drive (life of pipeline)		3, 6
Post-Audit Task List	Tasks required to close IMP gaps noted by an audit	IMP Technical Writer	IMP Intranet (current year)	IMP Team	8
PPTS Annual Infrastructure Report	System specs (one each for operator IDs 10012 and 31454)	IMP Dept	IMP Drive (indefinitely) IMP Drive and Intranet (5 years)	API	8
Seam Analysis Report	Third-party analysis of seam susceptibility and the remaining time-to-failure of flaws surviving previous hydrostatic test	Mechanical Testing Laboratory	IMP Drive (life of pipeline)		2, 201
Site Survey Report, Preliminary	Preliminary confirmation that inspection data is accurate	ILI Service Provider	Regional Drive (life of pipeline) IMP Drive (life of pipeline)	Assessment Engineer ILI Service Provider	3
Risk Model Algorithm Index Manual	Variables per index (threat and consequences) and, in the revision log, changes to the algorithm	Risk Specialist	IMP Drive (life of pipeline)		5
RiskCAT Analyses Documentation	HCA identification procedures for prior vendor studies	American Innovations	IMP Drive (life of pipeline)		1
Safety Bulletin	Safety lessons learned from an Incident Investigation Report (O&M Procedure 206)	Corporate HSE Group	Corporate HSE Drive	All NuStar employees	8
Temporary Pressure Reduction Form	Request to either enact or release a temporary reduction in operating pressure	Assessment Project Manager Drive	Regional Drive (life of pipeline)	Assessment Engineer Operations GMs Maintenance Managers Control Center Manager/ Supervisor SCADA Project Manager IMP Department	301, 4
Top 10% Risk-Ranked Segments within an HCA	Top 10% risk-ranked segments for the current year	Risk Specialist	IMP Drive (life of pipeline)		6
IMP Team Training Log	Employee training and meetings with vendors	IMP Team	IMP Drive (annual archive)		3, 7

E.2. References

Item	Manual Section
49 CFR §195.452 Integrity Management Program	All
49 CFR §195.6 Unusually Sensitive Areas (USAs)	Intro, 1
§8.101 Texas Administrative Code	Intro
B31.4 - Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids (American Society of Mechanical Engineers [ASME]/ American National Standards Institute [ANSI] 1998)	301, 4
API Standard 653 – Tank Inspection, Repair, Alteration, and Reconstruction	5, 6
API Recommended Practice 1130 – Computational Pipeline Monitoring for Liquid Pipelines	6
API Recommended Practice 1160 – Managing System Integrity for Hazardous Liquid Pipelines	Intro, 3, D, G
API Standard 1163 – In-line Inspection Systems Qualification	3, 301, D
NACE 35100 – In-line Nondestructive Inspection of Pipelines	301, D
NACE SP0102-2010 – In-line Inspection of Pipelines	301, D
Automated Resource for Chemical Hazard Incident Evaluation (ARCHIE)	H
Bureau of Transportation Statistics database	101
Benefits and Limitations of Hydrostatic Testing (John Kiefner and Willard A. Maxey)	3
Continual Validation of RSTRENG (Kiefner, Vieth, and Roytman, December 20, 1996)	3
NuStar Corrosion Control Manual	Intro, 2, 3
Emergency Flow Restriction Device (EFRD) Analysis Documentation	1, 5, 6
Enhanced River Reach File (distributed by USGS/EPA)	1
NuStar Facility Response Plan (FRP)	1, 6, H
Table C-5: Past Manufacturers of ERW Pipe in *History of Line Pipe Manufacturing in North America* (ASME ISBN 0-7918-1233-2)	201
HSE Safety Bulletin	8
HVL Release Air Modeling on the Trans Texas Products Pipeline and the El Paso Products Pipeline (Plexus Data Solutions and RTP Associates. 2003)	1
NuStar Integrated Contingency Plan (ICP)	6
NuStar Liquid Pipeline Emergency Response Plan	6
Manual for Determining the Remaining Strength of Corroded Pipelines (ASME/ANSI B 31.G, 1991)	301, 4
Safety Data Sheets (SDS)	1
A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (AGA Pipeline Research Committee Project PR-3-805, December 1989)	3
National Hydrology Dataset (NHD)	1
National Elevation Dataset (NED) (distributed by USGS)	1
National Land Cover Dataset (NLCD)	1
National Pipeline Mapping System (NPMS)	1, 101
OILMAP Land User’s Guide (Applied Science Associates, Inc., February 2007)	1
NuStar Oil Spill Response Plan	6
OPS TT05–Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation. Michael Baker, Jr. 2004	2, 201
NuStar Operations and Maintenance Manual	Intro–4, 6, 7
Release and Dispersion Calculations for the Kaneb Ammonia Pipeline System (Quest Consultants, Inc. 2004)*Release Dispersion Calculations* for former Kaneb Pipe Line Partners	1
Release and Dispersion Calculations for the Kaneb Propane Pipelines and Terminal Storage (Quest Consultants, Inc. 2004)	1
Resource Conservation Recovery Act (RCRA) Plan and Emergency Response Procedures	6
Risk Model Algorithm Index Manual	5, 501
Risk Model Training Manual	5, 501
Risk Model User Reference Manual	5, 501
NuStar Spill Prevention Control and Countermeasure (SPCC) Plan	6

Item	Manual Section
NuStar Storm Water Pollution Prevention (SWPP) Plan	6
NuStar Waste Analysis Plan	6

E.3. Online Resources

Web Site	Web Address
USGS National Hydrology Dataset User Help	http://nhd.usgs.gov/problems.html
PHMSA Hazardous Liquid Integrity Management	http://primis.phmsa.dot.gov/iim/
PHMSA National Pipeline Mapping System	https://www.npms.phmsa.dot.gov/
USGS National Elevation Dataset	http://ned.usgs.gov/
Multi-Resolution Land Characteristics Consortium (MRLC) National Land Cover Database (NLCD)	http://www.mrlc.gov
BTA Research and Innovative Technology Administration (RITA) Geospatial Information	http://www.bts.gov/programs/geographic_information_services/

E.4. Other Resources

Advanced Consequence Analysis: Emission, Dispersion, Fire and Explosion Dynamics (G.A. Melhem and P.A. Croce)

American Industrial Hygiene Association's Emergency Response Planning Guidelines (ERPG-2)

EPA Guideline for Air Quality Models

EPA Risk Management Program Guidance for Offsite Consequence Analysis

GRI-00/0189 – A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines (Gas Research Institute, October 2000)

HCA Impact Zone Identification Final Reports for former Kaneb Pipe Line Partners

Industrial Source Complex (ISC) Short Term Model

OILMAP Land Technical Manual (Applied Science Associates, Inc.)

Probability Approach Promises Enhanced Maintenance Program (*Pipeline and Gas Journal* – January 2001 – Johnston, Kolovich, Turley [Marathon Ashland Pipeline])

RiskCAT Analyses Documentation

Section 5 of *EPA Risk Management Program Guidance for Offsite Consequence Analysis*

Texas Council of Environmental Quality (TCEQ) meteorological data

U.S. EPA's 1999 BASINS Software

United States Dept. of Energy's SCAPPA Temporary Emergency Exposure Limits (TEEL-2)

Pipeline Safety Improvement Act of 2002

F: Forms

F.1. Corrosion Control Effectiveness Review Form

Distribution:		Report Information:	
Original:	IMP Shared Network Drive	Record Retention:	Permanent
Copies:	Corrosion Control Manager	Frequency:	As Required
Testable Segment Name:		Date of Hydro Test:	/ /

Directions: Answer the following questions. If you mark **No** or **N/A** on any of the questions, then detail the exceptions in the **Comments** area under that particular question. Create action plans to mitigate these items and enter them into CPDM for tracking and completion. Add these recommendations to the **Conclusions/Recommendations** section of this form. Attach any supporting information and documentation.

Questions:	Yes	No	N/A
1. Are there any known locations of inadequate cover?	☐	☐	☐
Comments: _____			
2. Are all casings in good condition/not shorted?	☐	☐	☐
Comments: _____			
3. Have rectifiers been read bimonthly, not exceeding 2.5 months?	☐	☐	☐
a. Are rectifier readings within their limits, have room to be turned up?	☐	☐	☐
Comments: _____			
4. Have interference bonds been read bimonthly, not exceeding 2.5 months?	☐	☐	☐
Comments: _____			
5. Has a pipe to soil survey been performed once a calendar year, not exceeding 15 months?	☐	☐	☐
a. Are all pipe-to-soil readings at test points above the established criteria?	☐	☐	☐
Comments: _____			
6. Has a close interval survey been performed as part of the review (as required by Section 5, Cathodic Protection of *Corrosion Control Procedure Manual)*?	☐	☐	☐
Date Survey Performed: __/__/____			
a. Are previous above-ground surveys available?	☐	☐	☐
b. If yes, have all suspect readings been addressed?	☐	☐	☐
Comments: _____			
7. Have static/native potentials been established?	☐	☐	☐
Comments: _____			
8. Have atmospheric inspections been performed once every three years, not exceeding 3.5 years?	☐	☐	☐
Comments: _____			

Directions: Answer the following questions. If you mark **No** or **N/A** on any of the questions, then detail the exceptions in the **Comments** area under that particular question. Create action plans to mitigate these items and enter them into CPDM for tracking and completion. Add these recommendations to the **Conclusions/Recommendations** section of this form. Attach any supporting information and documentation.

Questions:		Yes	No	N/A
9.	Have transition areas been inspected on an annual basis?	☐	☐	☐
	a. Are air-to-ground interfaces in good repair?	☐	☐	☐
	Comments: _____			
10.	Has a coating inspection been performed each time the pipeline was excavated?	☐	☐	☐
	a. Do excavation reports indicate that the line/coating is in good or non-deteriorating condition?	☐	☐	☐
	Comments: _____			
11.	Have on/off potentials been performed on all excavated repair areas protected by rectifiers?	☐	☐	☐
	Comments: _____			
12.	Do you have internal corrosion monitoring?	☐	☐	☐
	a. If coupons are used for internal corrosion monitoring, have they been replaced twice a year, not exceeding 7.5 months?	☐	☐	☐
	Comments: _____			
13.	Has the leak history for the line been tracked?	☐	☐	☐
	a. Have all historical leaks been investigated and the causes mitigated?	☐	☐	☐
	Comments: _____			

F.2. ILI Assessment Analysis and Closeout Checklist

Directions for completing this form are found in the "Guidance for ILI Data Validation, Data Integration and Repair Plan Development" document in Appendix L of the IMP Manual

Segment:

Assessment Engineer:

ILI Date(s):

Description	Complete	N/A	Comments
Pre-Analysis			
Review Segment Threats	☐	☐	
Review relevant pipe segment Info	☐	☐	
Review Vendor Written Report	☐	☐	
Data Validation			
Pipe Specifications Validated	☐	☐	
Pipe Segment Features Validated	☐	☐	
Tool Tolerances	☐	☐	
Data Processing			
Data Stretching with Alignment Manager	☐	☐	
ILI Data Manager	☐	☐	
Crack Calculation Worksheet	☐	☐	
Data Integration			
ILI Graphs, pivot charts, etc. assembled & reviewed (individual and comparative)	☐	☐	
External Metal Loss Review	☐	☐	
Internal Metal Loss Review	☐	☐	
Mechanical Damage	☐	☐	
Review Past ILI Anomalies/Areas selected to Monitor	☐	☐	
Other Reported Issues	☐	☐	

Repair Plan Development			
Compile List of Recommended Repairs	☐	☐	
Review Recommended Repairs with Area Manager, etc. and Finalize Repair List	☐	☐	

Description	Complete	NA	Comments
Post-Assessment			
Review as-found results to determine if additional digs are warranted	☐	☐	
Update the Mitigation Spreadsheet with as-found data	☐	☐	
Provide feedback to the ILI Vendor regarding tool accuracy.	☐	☐	
Finalize Data Manager per Final Repair List	☐	☐	
Close Out Checklist	☐	☐	
Questionnaire	☐	☐	
Meeting Minutes	☐	☐	
Site Survey Report	☐	☐	
Tool Failure	☐	☐	
Preliminary Report(s)	☐	☐	
Final Report(s)	☐	☐	
Data Manager	☐	☐	
Temporary Pressure Restriction	☐	☐	
ILI Graphs	☐	☐	
Mitigation Spreadsheet	☐	☐	
Third Party Analysis	☐	☐	
PHMSA Notifications	☐	☐	
Observations, Recommendations and Closeout	☐	☐	

Confirmation of Closeout Completion:

Analyst Signature ______________________

Date ______________________

F.3. Dig File Checklist

INSTRUCTIONS

The following forms and records are used for region documentation of digging/repair activity and are integrated with HQ IMP files on the IMP Network Drive as necessary to fully document the connection between analysis and repair activity

Description	Complete	N/A	Comments
REQUIRED FORMS			
Permit(s) (e.g. Corps of Engineers, Road Crossing, Railroad Crossing, etc.)	☐	☐	
One-Call Ticket(s) (issued and completed)	☐	☐	
Work Permit Form(s) (P**TW)** **(NuStar Form 5101)**	☐	☐	
Job Safety Analysis (JSA) **(NuStar Form 5105)**			
Pipeline Information Report (PIR) **(REQUIRED Any Time Pipe is Exposed)**	☐	☐	
Defect Evaluation Form **(REQUIRED Any Time Pipe is Exposed)**	☐	☐	
ILI Tool Dig Sheets (and attached spreadsheets)	☐	☐	
Operator Qualifications **(NuStar Form 6401)**			
Welder Certification	☐	☐	
Welder OQ	☐	☐	
NuStar Welding Procedure			
Ultrasonic Thickness Record	☐	☐	
Magnetic Particle Test Report	☐	☐	
NDE Test Qualification	☐	☐	
X-Ray Technician Certification	☐	☐	
X-Ray Technician OQ (Must have OQ tasks 38.1-4)	☐	☐	
NuStar X-Ray Procedure (NuStar X-Ray procedure number must be listed on vendor’s Radiographic Qualification Report	☐	☐	
Material Test Reports (MTRs) for pipe,			

Description	Complete	N/A	Comments
sleeve material, or Clockspring			
Photographs			
Hydrostatic Test for Replacement Pipe			
Hydrostatic Test Planning Report			
Hydrostatic Test Report Checklist			
Hydrostatic Test Leak Report			
(if applicable)			
Pressure Test Log(s)			
Pressure Testing Report			
Pressure Plot of Hydrostatic Test Pressure			
Dead Weight Gauge Tester certificate of calibration			
Pressure Recorder certificate of calibration			
Temperature Recorder certificate of calibration			
Recommended Forms			
Rubbing sheets for all interacting pit anomalies			
Agreement of damage Settlement Form			
Contractor Daily Report			

Confirmation of Dig File Checklist Completion:

Analyst Signature

Date

F.4. ILI Closeout Report Template

This template is to be used as a guide for recording observations and recommendations arising from the ILI Analysis effort. The headings below can be copy and pasted to begin the report construction with appropriate verbiage, forms and other documents added as appropriate.

Assessment Summary

[Summarize ILI as-called data analysis observations. These may include the comments recorded in the Data Manager summary sheet and/or during the Post-ILI Review.]

Dig Observation Highlights

[From the review of the dig records, note any apparent coating damage, third-party damage, active corrosion, abnormal pipe-to-soil potential readings, root-cause analyses, or other conditions that provide insight into the integrity of the pipeline.]

Unity Curves and Tool Accuracy Comments

[Discuss conclusions from the unity curves, stating whether the tool met the specified tolerance. If the tool was out-of-specification, note any investigation and/or corrective action that the vendor performed to resolve the issue.]

Site Survey Reports, Failed ILI Runs, and Root Cause of Failures Comments

[Attach the ILI Service Provider's site survey report and discuss any failed ILI runs or abnormal operational issues associated with the assessment. Include references to any root cause analysis reports completed by the vendor.]

ILI Supplemental Reports/Analyses

[List any supplemental reports (e.g., PCA Reports, Baker Study, Industry Reports) that were generated because of the assessment.]

Preliminary P&M Measures

[Describe areas of concern for consideration in the next P&M meeting, based on the Assessment Engineer's evaluation of the assessment data and the results of the Post-ILI Review. For example, describe the results of preliminary data integration, including non-prescriptive repair decisions. These are not official P&M measures until they are accepted as part of the P&M measures process.]

Preliminary Reassessment Interval Recommendations

[State the reassessment interval based on the limiting anomaly. Also, state the corrosion rate assumption used for the analysis. State the number of scheduled repairs that are outstanding at the time of the report and that must be completed in order to meet the recommended reassessment interval. (All scheduled repairs should be listed in the Mitigation Spreadsheet).]

F.5. ILI Service Provider Technical Questionnaire

SAMPLE VENDOR

CORROSION DETECTION SURVEY
and
ELECTRONIC GEOMETRY SURVEY

SAMPLE TECHNICAL QUESTIONNAIRE

PIPELINE COMPANY: ___________________________________

LINE SEGMENT: ____

Pipeline Company:____
Address:____
City: ____
State: ____
Zip Code: ____

Telephone No.: ____
Fax No.: ____

Name of Contact Person Project MGR:______________________________
Telephone No.: ____
Name of Contact Person Field:__________________________________
Telephone No.: ____
Geographical Location of Pipeline:________________________________

Pipeline Segment or Reference:__________________________________
Location of Launcher: ____________________________________
Location of Receiver: ____________________________________

Overall Length of Line:____________________________________
Minimum Nominal Bore of Pipeline: ______________________________
Is the Pipeline Onshore, Offshore, or Both:__________________________

PIPELINE WALL THICKNESS, MATERIAL, and GRADE

Please specify the range of pipeline wall thicknesses present in the pipeline section (trap to trap). Where possible, specify the nominal wall thickness of line pipe employed and the actual length in miles for each nominal value.

Please enter the pipe steel grade in the appropriate column for the pipe material type.

Nominal Wall Thickness	Length	Design Pressure	MAOP (MOP)	Seam Welded	Spiral Welded	Seamless	ERW	Other
Total Section Length								

DETAILS OF PIPELINE FITTINGS

BENDS

Minimum Bend Radius	Nominal Bore of Bends	Type of Bends

VALVES

Type (Gate, Ball, Check, etc.)	Model Number	Min Nominal Bore

Can Check Valves be locked open during survey? ________________________________
Any Known problems in the past with valves?________________________________
If so, please describe the problem: ________________________________

____

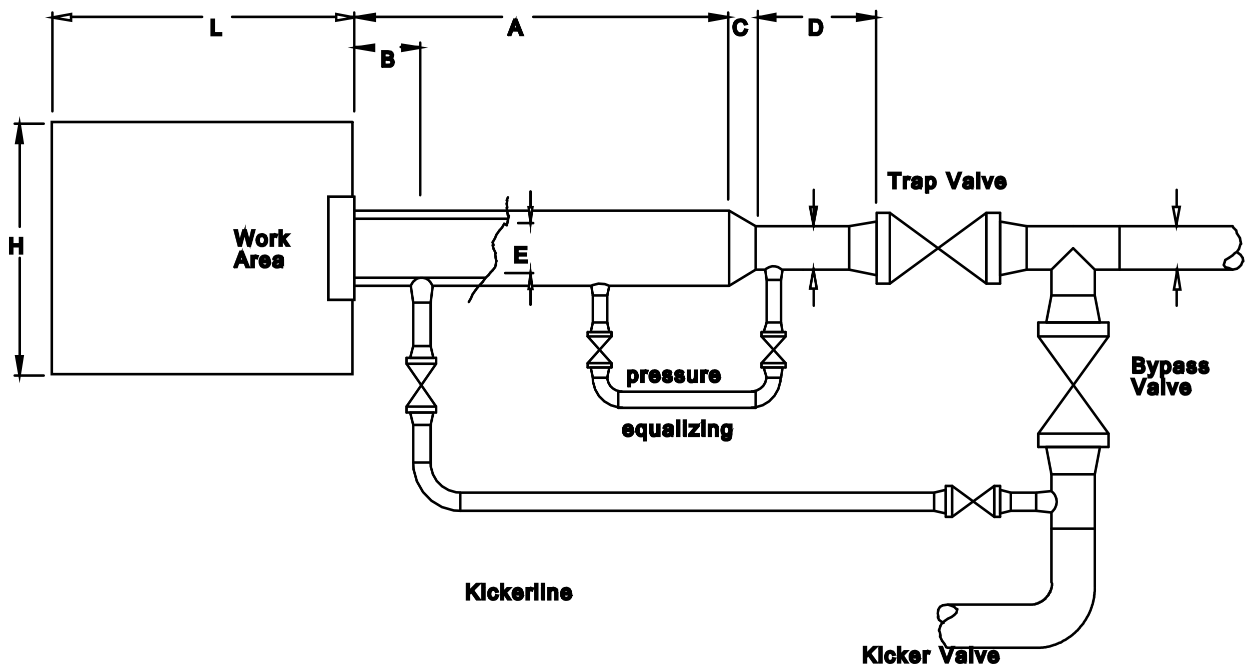
OTHER INSTALLATIONS (Tees, Branches, Flanges, Etc.)

Type of Tee(s)		Are Bars Fitted?	
Diameter of Takeoff		Can Side Flows be Controlled ?	
O'clock Position of Takeoff		Distance between Adjacent Tees & Other Fittings, Valves, Etc.	
Angle to Pipeline			
Type of Flanges		Minimum ID	

Please indicate which of the following are present in the pipeline:

Installations	YES	NO	Distance
Repair Clamps (Sleeves)			
Bell and Spigot Coupling			
Thread and Collar Coupling			
Miter Joints			
Cathodic Protection			
Sacrificial Anodes			

DETAILS OF LAUNCHING and RECEIVING TRAPS



Please enter the following Launching and Receiving Trap Dimensions:

	Launcher	Receiver
A		
B		
C		
D		
E		
H		
L		

	Launcher	Receiver
Concentric or Eccentric Taper Section Fitting		
Angle and Direction of Trap if not Horizontal		
Trap Construction Welded or Forged		
Height of Trap above Access Area		

DETAILS OF PIPELINE PRODUCT AT TIME OF INSPECTION

Type of Product:___________________________

	Minimum	Maximum	Normal	At Time of Inspection
Operating Temperature				
Operating Pressure				
Possible Flow Rate During Inspection				
Wax Content				
CO2 Content				
H2S Content				
Throughput in BBLs/Day				
Total Line Fill in BBLS				
Other				

PIPELINE HISTORY

Date of Pipeline Construction:___________

Date of Last Inspection Survey:____________

Previous Inspection Co.:________________

Is Pipeline Currently Operational? __________

Are Cleaning Pigs Run on a Regular Basis?
____

Type of Cleaning Pigs Used:_______________

Type of Internal Coating:________________

Type of External Coating :_________________

Is there any Known Pipeline Damage? ____

If so, please describe:____

____

BENCHMARKER LOCATION SYSTEMS

Will the HRE Benchmarker System be used? ____

At how many marker locations will the pig be tracked? ____

Will these locations be accessible, even during adverse weather conditions? ______________________

Will these locations be close to heavily traveled roads?____

Are these marker locations properly marked? ____

How many marker crews will be available for setting marker boxes? ___________________________

Date Questionnaire Completed:__________________________

Signature:____

PLEASE RETURN TO FAX #: (____) __________

LIST OF REQUIRED IMFORMATION

Item No.	Item	Available	Date Sent	Time Item Required
1	Technical Questionnaire			Min 30 Days Prior to Survey
2	Address for shipment of Gauge Pigs			Min 30 Days Prior to Survey
3	Directions to Onsite Location and Contact Person			Min 30 Days Prior to Survey
4	Alignment Sheets	Yes/No		1 Week After Survey
5	Installation List	Yes/No		1 Week After Survey
6	Main Line Valve List	Yes/No		1 Week After Survey
7	Previous Inspection Reports	Yes/No		1 Week After Survey
7A	Pipe Tally	Yes/No		1 Week After Survey
7B	Installation List	Yes/No		1 Week After Survey
7C	Marker List	Yes/No		1 Week After Survey
8	Above Ground Marker List	Yes/No		1 Week After Survey
9	Pipe Inventory List	Yes/No		1 Week After Survey
10	Site Specific Safety Requirements	Yes/No		30 Days Prior to Survey

F.6. LVR/EFRD Scenario Evaluation Form

RECORDS **Retention:** Permanent **Location:** IMP Network Drive	**System:** **Segment:** **Meeting:**
Attendees:	**Date:**

Type of Study: ___ LVR ___ EFRD

Note: For LVR complete page 1 only. For EFRD complete page 1 and page 2.

LVR Model Inputs:	**Value:**	**Comment:**
Leak Detection Type:	___ Advanced Leak Detection ___ Computational Pipeline Monitoring ___ Press Mon ___ Hourly Reports ___ Local	Methodology documented by Control Group.
Leak Detection and Isolation Category	___ 15 min ___ 1 hour ___ 2 hour	
Response Time		The time to begin response activities, as documented in NuStar Energy's Facility Response Plan
Type of Commodity Carried		
Maximum Hourly Flow Rate		
MOP		
Valve Count:	Manual: Check: LBO: Pneumatic – LBO:	Motorized – Local: Motorized – Non-Remote: Motorized – Remote:

Valve Table:

Valve Station	Valve Number/ID	Valve Type	Isolation Segment

Valve No./ID	MBV	MBV	MBV	MBV	MBV	MBV
Valve Station	ft	ft	ft	ft	ft	ft
Location						

	Isolation Segment 1 Start: End:			Isolation Segment 2 Start: End:			Isolation Segment 3 Start: End:			Isolation Segment 4 Start: End:			Isolation Segment 5 Start: End:		
Valve Number	MBV	Max Drain Down Volume [bbls]	Change in Volume	MBV	Max Drain Down Volume [bbls]	Change in Volume	MBV	Max Drain Down Volume [bbls]	Change in Volume	MBV	Max Drain Down Volume [bbls]	Change in Volume	MBV	Max Drain Down Volume [bbls]	Change in Volume
	Isolated?			Isolated?			Isolated?			Isolated?			Isolated?		
Baseline															
Scenario 1															
Scenario 2															
Pipeline Topography:															
Terrain between Pipeline and HCA:															
Potential for Ignition:															
Proximity to Power Sources:															
Location of Nearest Response Personnel:															
Recommendations:															

F.7. OPS Integrity Management Notification Form

This form is provided for use as a guide to gather the necessary information required by the online OPS Notification Form. The final form is that which is printed from the OPS website.

General Section					
Operator:					
Submitted by:			**Job Title:**		
Contact Email:			**Date Submitted:**		
Type: (at least one type must be checked) ☐Repair ☐Technology ☐Interval					
Summary: (brief summary statement describing the purpose of the notification)					
Commodity:			**Size:** in.		
Material:		**Weld Type:**		**Coatings:**	
Design Pressure: psi		**MOP:** psi		**Wall Thickness:** in.	
Year Manufactured:	**Year Installed:**	**Date Last Pigged:**	**Pigging Report:**	**Date of Last Hydro:**	
Additional Pipeline Details: (any additional details about the affected pipeline)					
Segment Location: (for each affected segment, information, such as milepost, country, state, etc.; "Entire System" may be entered if applicable)					
Segment Details: (any additional information describing the affected segment[s])					
Must check one: ☐ **Interstate Pipeline** ☐ **Intrastate Pipeline**		**Affected states:**		**HCA Miles:** (segment length that can affect an HCA) **mi**	
Type of HCA Affected: (can be more than one)					
☐ **High Population Area** ☐ **Other Populated Area**		☐ **Ecological USA** (enter the resources affected below) ☐ **Navigable waters**		☐ **Drinking Water USA**	
HCA Interaction: (nature of HCA interaction, such as intersects, release can affect, etc.)					

Use one of the following three forms, as appropriate.

Repair Section
Category: (at least one type must be checked) ☐ Immediate ☐ 60-Day ☐ 180-Day
Defects: (description of defects requiring repair, including whether multiple and/or clustered defects exist, and a characterization of any defects that have been excavated)
Repairs Required: (description of the repairs needed)
Reason for Delay: (factors within and outside of operator’s control)
Pressure Reason: (reason the pressure cannot be reduced; justification of adequate safety for the expected operating period)
Safety Basis: (basis for concluding that the delay will not jeopardize public safety or environmental protection)
Schedule: (proposed schedule for repair)
Mitigation: (other mitigative actions planned)
Other Info: (other information relevant for OPS review, including a brief description if additional supporting material has been forwarded by email)

Technology Section
Assessment Schedule: (scheduled date of assessment)
Description: (other technology to be used)
Equivalency Basis: (basis for concluding that the equivalent understanding of pipe condition will be provided)
Other Info: (other information relevant for OPS review, including a brief description if additional supporting material has been forwarded by email)

Interval Section
Basis Type: (at least one type must be checked) ☐ Engineering Basis ☐ Unavailable Technology
Last Assessment: (both the date of the last assessment and the method used)
New Interval: (proposed new interval—applies only to engineering basis)
Schedule: (proposed schedule for completion—applies only to unavailable technology)
Additional Actions: (actions to provide equivalent understanding, if on an engineering basis or an interim evaluation of pipeline integrity, if because of unavailable technology)
Basis: (summary of the engineering basis for extended interval, or the reason the required interval cannot be met)
Other Info: (other information relevant for OPS review, including a brief description, if additional supporting material has been forwarded by email)

F.8. P&M Measure Suggestion Form

DISTRIBUTION: P&M Coordinator **Retention**: Permanent **Location:** IMP Drive

REPORT INFORMATION:

☐ Pipeline ☐ Tank ☐ Pump Station ☐ Meter Station ☐ Other

System/Site:______________________________

Segment/Facility:______________________________

Name(s):______________________________

Date:______________________________

Threat/Underlying Issue:

☐ Third-Party (TP) ☐ Incorrect Operations (IO) ☐ Internal Corrosion (IC)

☐ External Corrosion (EC) ☐ Construction (CONS) ☐ Weather/Outside Forces (WOF)

☐ Equipment Failure (EQ) ☐ Manufacturing (MFG) ☐ Stress Corrosion Cracking (SCC)

☐ Other (Explain):______________________________

Suggested P&M Measure:______________________________

____

____

Background (what prompted the suggestion):

☐ Aerial patrol ☐ Safety-related condition ☐ One Call

☐ Foot patrol ☐ Recent integrity assessment ☐ Close Interval Survey

☐ Routine inspection ☐ Recent CP analysis ☐ Audit

☐ Other (Explain): ______________________________

Rationale (need for the suggested measure):______________________________

____

____

Additional Comments:______________________________

____

____

(P&M COORDINATOR USE ONLY):

☐ Rejected If so, reason for rejection:______________________________

☐ Potential P&M Measure If so, research needed:______________________________

☐ Accepted P&M Measure If so, implementation date and other pertinent information:____________

Persons making the decision:______________________________

Persons responsible for implementing:______________________________

F.9. Temporary Pressure Reduction Form

Status: ☐ **Reduction Order** ☐ **Reduction Release**

General Information					
Pipeline System:		**Pipeline Assessment Segment:**			
Inspection Vendor:		**Inspection Date:**		**Discovery Date:**	
Issued by:		**Comments:**			

Anomaly Description (attach additional sheets if necessary)

☐ **Eminent Threat (e.g. Immediate Condition)** –reduce pressure as soon as practicable (see IMP Procedure 401)

☐ **Non-Eminent Threat (e.g. additional remedial action) –** implement pressure reduction within specified timeframe.

DIG #	Odometer	HCA?	Description
		YES	
		YES	
		YES	
		YES	
		YES	
Comments:			

Pressure Reduction

Original MOP:		**Temporary MOP:**		**Date Ordered:**		**Implement By Date:**	

Temporary MOP Basis:					
☐	A calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (incorporated by reference, see §195.3) and PRCI PR-3-805 (R-STRENG) (incorporated by reference, *see* §195.3)				
☐	Min. 20% reduction based on highest actual operating pressure in preceding 60 days.	**Date of highest pressure:**		**Highest pressure:**	
☐	Other	Explain:			

Pump Station:	**Field Pressure Switch**		**Control Center Discharge Set Point**		**Control Center High/High Alarm**		**Comments:**
	Original	**Temporary**	**Original**	**Temporary**	**Original**	**Temporary**	

Control Center Personnel Notified:		**Date and Time:**		**Note:** Control center and operations maintenance personnel shall send the assessment engineer Form 6102 and form 6626 documenting the date and time that the reduction was implemented.
Operations/Maintenance Personnel Notified:		**Date and Time:**		
Comments:				

Pressure Reduction Release

Reduction Released:	NO	**Date:**		**Reinstated MOP:**		**Reduction Released by:**	
Comments:							

Revision History		
#	**Date**	**Description of Changes**

Documentation
Distribution: Regional IMP (original), Control Center Manager ,Console Personnel, Regional Operations/Maintenance Manager, Sr. VP Operations, VP Operations, Regional GM, Director of Operations, Pipeline Area Manager, Regional Engineering Manager, and Corporate IMP **Record Retention:** Original – Permanent (including previous revisions), Copies – no retention required, destroy previous revisions.

F.10. Magnetic Particle Testing Report for Defect Investigation

Description of Item Tested: ______________________________

Station Number or Location: ______________________________

TEST VARIABLES

Equipment: AC/DC Yoke

Equipment Mfr: ______________________________

Current Used: AC

Direction of Field: 0 degrees and 90 degrees

Examination Method: Continuous

Type Magnetization: Longitudinal

Inspection Media: Oil- or water-based suspension particles on white contrast paint

Inspection Method: Wet

Color of Particles: ______________________________

Results

Length of Pipe Inspected: ______________________________

Circumference of Pipe Inspected: ______________________________

Description of relevant indication(s): ______________________________

____

____

____

____

____

____

Technician: ______________________________

Date: ______________________________

F.11. SCC Site Assessment Forms

The SCC Site Assessment Form package, found on the NuStar Intranet, includes the following forms:

Form	Responsible Party
Report Cover Page	All parties
Site Overview	Vendor
Site Location Data	NuStar IMP
Above Ground Resistivity Survey	Corrosion Technician
Terrain Description	Corrosion Technician
In-the-Ditch Survey Reference	Corrosion Technician
Trench Wall Observations	Corrosion Technician
End-of-Trench Observations	Corrosion Technician
Electrolyte Assessment	Corrosion Technician
Corrosion Deposit Assessment	Corrosion Technician
Coating Assessment	Corrosion Technician
Pipe Surface Conditions	Corrosion Technician
Pipe to Soil Potentials	Corrosion Technician
General Anomalies Data	Non-Destructive Testing Technician
Linear Indications Data	Non-Destructive Testing Technician
SCC Colony Photos	Non-Destructive Testing Technician
Inspection Summary	All parties
Mitigation Report	NuStar SMEs

G: Preventive and Mitigative Measures–Risk Threats Matrices

The two tables in this appendix lay out the kinds of assets that can be helped by various P&M measures.

Table G-1. Consequence of Failure Reducers (Mitigative) Matrix

	Reference	Asset Type
Be involved with emergency drills	195.402	All
Dam or dyke facilities from HCAs		All
Emergency Flow Restrictive Devices (EFRDs)	195.452, API 1160 10.3.7.2, FAQ 9.7	Pipelines
Emergency shutdown devices	195.262	All
Fire/smoke detection		Pump stations, ASTs, meter/delivery stations
Have on-site spill containment equipment and material	195.264, API 1160 12.3.6,	All
Install impervious barriers or linings under tanks and piping	API 1160 12.3.7,	All
Enhanced leakage control measures	Table 4 ASME B31.8S	All
Enhanced leakage detection methods	FAQ 9.7	All
New CPM leak detection installed, per API 1130	195.134, 195.444	Pipelines
On-site fire fighting equipment	195.430	Pump stations, ASTs, meter/delivery stations
Over-pressurization protection	195.428	Pipelines and facilities
Participate in joint response groups	195.262, API 1160 12.3.6, FAQ 9.7	All
Vapor detection	API 1160 12.3.5	Facilities
Reduce response time for incidents	API 1160 10.3.3	All
Communication*	195.408	All
Control system redundancy*		All
Inspecting and maintaining ROW*	195.412, API 1160 10.1.6 and 10.1.7, Table 4 ASME B31.8S	All
Line relocation*	Table 4 ASME B31.8S	All
O&M procedures*	195.402, Table 4 ASME B31.8S	All
Operator training including emergency response*	195.403, 195.505, Table 4 ASME B31.8S	All
Presence of auxiliary power*	195.262	All
Public education*	195.440, API 1160 10.1.5, Table 4 ASME B31.8S	All

* also listed as a likelihood of failure reducer.

Note: Under Asset Type, “all” includes pipelines, pump stations, ASTs, and meter/delivery stations.

Table G-2. Likelihood of Failure Reducers (Preventive) Matrix

	Operating Errors (IO)	Non-Pipe Equipment Errors (EQ)	Gasket or O-Ring (EQ)	Internal Corrosion (IC)	External Corrosion (EC)	Vandalism/ Third Party (TP)	Previously Damaged Structure/ Equipment (TOP)	Weather and Outside Forces (WOF)	Defective Materials (MGF)	Construction (CONS)	Welds (CONS)	Coupling (CONS)	Stripped Thread (CONS)	Stress Corrosion Cracking (SCC)	Reference	Asset Type
Assessment frequency	•	•	•	•	•	•	•	•	•	•	•	•	•	•	FAQ 9.7	All
Avoid low flow and dead legs				•											API 1160 12.3.7	Pipelines
Barricades						•										All
Coating age				•	•									•		All
Coating inspection				•	•									•	API 1160 10.2.1, API 1163 4.4, API 1163 7.2.2.e,195.557, 195.561	All
Compliance audit	•														Table 4 ASME B31.8S	All
Construction inspection		•	•	•	•				•	•	•	•	•		195.204, Table 4 ASME B31.8S	All
Corrosion inhibitors				•											Table 4 ASME B31.8S, 195.579	All
Coupons				•											195.579	Pipelines
CP monitoring/maintenance	•	•		•	•		•							•	195.573, API 1160 10.2.1, Table 4 ASME B31.8S, FAQ 9.7	All
Design specifications	•	•	•	•	•	•	•	•	•	•	•	•	•	•	195.132, Table 4 ASME B31.8S	All
Do not bury threaded or flanged connections					•							•			API 1160 12.3.7	Pipelines
Ensure proper fencing and security measures						•									195.264	All
External coating repair					•									•	Table 4 ASME B31.8S	All
Factory acceptance tests		•							•							All
Frequency of training review/update	•														FAQ 9.7	All
Increase depth of cover						•									API 1160 10.1.4, Table 4 ASME B31.8S	Pipelines
Installing locks on valves	•	•				•										All
Internal cleaning	•	•		•											API 1160 10.2.3, Table 4 ASME B31.8S	All

	Operating Errors (IO)	Non-Pipe Equipment Errors (EQ)	Gasket or O-Ring (EQ)	Internal Corrosion (IC)	External Corrosion (EC)	Vandalism/ Third Party (TP)	Previously Damaged Structure/ Equipment (TOP)	Weather and Outside Forces (WOF)	Defective Materials (MGF)	Construction (CONS)	Welds (CONS)	Coupling (CONS)	Stripped Thread (CONS)	Stress Corrosion Cracking (SCC)	Reference	Asset Type
Internal coating repair				•										•	195.561, Table 4 ASME B31.8S	ASTS
Internal/external coating		•		•	•										195.557	All
Intruder detection						•										All
Line and facility patrols						•									195.412, Table 4 ASME B31.8S	All
Manufacturer inspection		•	•	•	•		•		•						Table 4 ASME B31.8S	All
Material specifications	•	•	•	•	•	•		•		•	•	•	•	•	195.132, Table 4 ASME B31.8S	All
Movement monitoring								•								All
NDE testing		•		•	•		•		•	•	•	•		•	195.234	All
One-Call						•									195.442, API 1160 10.1.1,Table 4 ASME B31.8S	Pipelines
Operator qualifications	•									•	•	•	•		195.505, 195.509	All
Pipe or equipment replacement		•	•	•	•	•	•	•	•	•	•	•	•	•	Table 4 ASME B31.8S	All
Pipeline markers						•									195.410, API 1160 10.1.2,Table 4 ASME B31.8S	Pipelines
Pressure reduction	•	•	•	•	•	•	•	•	•	•	•	•	•	•	195.262, 195.264, 195.452, API 1160 10.4,Table 4 ASME B31.8S	All
Reduce external stresses		•	•								•	•	•	•	Table 4 ASME B31.8S	Pipelines, facilities
Rehabilitation		•	•				•		•			•	•		API 1160 10.2.2, Table 4 ASME B31.8S	All
Replacements prior to life expectancy		•	•									•			API 1160 12.2,	All
Transportation inspection		•	•		•		•		•			•	•		195.206, Table 4 ASME B31.8S	All
Visual/mechanical inspection program	•	•	•	•	•	•	•	•	•	•	•	•	•		195.204, 195.206, API 1160 12.3, Table 4 ASME B31.8S	All

	Operating Errors (IO)	Non-Pipe Equipment Errors (EQ)	Gasket or O-Ring (EQ)	Internal Corrosion (IC)	External Corrosion (EC)	Vandalism/ Third Party (TP)	Previously Damaged Structure/ Equipment (TOP)	Weather and Outside Forces (WOF)	Defective Materials (MGF)	Construction (CONS)	Welds (CONS)	Coupling (CONS)	Stripped Thread (CONS)	Stress Corrosion Cracking (SCC)	Reference	Asset Type
Warning tape						•									API 1160 10.1.10, Table 4 ASME B31.8S	Pipelines
Communication*	•	•													195.408	All
Control system redundancy*																All
Inspecting/maintaining ROW*						•									195.412, API 1160 10.1.6 & 10.1.7,Table 4 ASME B31.8S	All
Line relocation*						•									Table 4 ASME B31.8S	All
O&M procedures*	•	•	•	•	•	•	•	•	•	•	•	•	•	•	195.402, Table 4 ASME B31.8S	All
Operator training including emergency response*	•	•	•	•	•	•	•	•		•	•	•	•	•	195.403, 195.505, Table 4 ASME B31.8S	All
Presence of auxiliary power*		•													195.262	All
Public education*						•									195.440, API 1160 10.1.5, Table 4 ASME B31.8S	All

*also listed as a Consequence of Failure reducer

Note: Under Asset Type, “all” includes pipelines, pump stations, ASTs, and meter/delivery stations.

H: Glossary

Acronym/Term	Description
Abandoned Pipeline	Pipeline that is permanently inactive (i.e., it will not be put back into service at a later date)
Active pipeline	Pipeline that is currently in service
AFD	Axial Flaw Detection
AFE	Authorization for Expenditure
AGA	American Gas Association
AIHA	American Industrial Hygiene Association
Air dispersion analysis	Process used to determine the air dispersion of a spill: • The ARCHIE model (maintained by the DOT) requires the user to provide the thermo-physical properties of the pipeline contents (e.g.: vapor pressure, density, LFL, heat capacities, molecular weight, temperature, pressure, flow, etc.). • Bass-Trigon presents the user with models for pool spills, tank spills, and pipeline spills. • The user then runs the model for a “pipeline containing liquid under pressure.” • The model predicts the spill rate for a full separation of the pipeline (Guillotine break) with the hole size set at the pipeline diameter. • This spill rate and duration of spill (time) are used in the dispersion, fire, and explosion models.
ANSI	American National Standards Institute
AOPL	Association of Pipelines
API	American Petroleum Institute
ARCHIE	Automated Resource for Chemical Hazard Incident Evaluation
ASME	American Society of Mechanical Engineers
BAP	Baseline Assessment Plan
BASINS	Better Assessment Science Integrating Point and Nonpoint Sources
BBL	Barrel
BPH	Barrels per Hour
Buffer Zone	Represents the worst-case discharge of any pipeline segment between EFRDs

Acronym/Term	Description
CAOP	Calculated Allowable Operating Pressure
CFR	Code of Federal Regulations
CIS	Close Interval Survey
CLP	Cleaning (and gauging) Pig
COF	Consequence of Failure
Commercially Navigable Waterway (CNW)	Waterway with a substantial likelihood of commercial navigation; identified in the National Waterways Network, a geographic database created by the National Waterways Geographic Information System Design Committee
CONS	Construction (an LOF threat)
COR	Corrosion Detection Tool
Could Affect	Pipeline segment laid near but not directly through an HCA
CP	Cathodic protection
CPM	Computational Pipeline Monitoring
CPDM	Cathodic Protection Data Manager
Dead Zone	Pipeline area immediately adjacent to the transducer collar (3–6 feet from the collar with Teletest or 1–2 feet with GUL) within which the GWUT unit is not able to obtain reliable results
DEF	Deformation tool
DMS	DOT Docket Management System
DOT	Department of Transportation
DW	Drinking Water
EC	External Corrosion (an LOF threat)
EFRD	Emergency Flow Restriction Device
Environmentally Sensitive Area (ESA)	Area containing endangered species, ecological communities, or migratory water bird areas
EPA	Environmental Protection Agency

Acronym/Term	Description
EQ	Equipment (an LOF threat)
ERF	Estimated Repair Factor
ERPG	Emergency Response Planning Guidelines
ERW	Electric Resistance Weld
ESRI	Environmental Systems Research Institute, Inc.
FBE	Fusion-Bonded Epoxy
FEMA	Federal Emergency Management Agency
FRP	Facility Response Plan
Galvanic Corrosion	Corrosion in which one piece of metal corrodes because of its proximity to another, dissimilar piece of metal
GIS	Geographic Information System
GIS data	Calculations used in HCA Analysis
GITA	Geospatial Information and Technology Association
GRI	Gas Research Institute
GWUT group	Collection of GWUT inspections performed on pipe with similar pipe features with the same equipment and analysis techniques
HAZWOPER	Hazardous Waste Operations and Emergency Response
High Consequence Area (HCA)	Area of the environment that has been designated as unusually sensitive to oil spills (a USA). USAs are defined in *§ 49 CFR 195.6* High Consequence Area which could be a Highly Populated Area, Other Populated Area, Drinking Water, or Ecological
High Population Area (HPA)	Urbanized area that contains 50,000 or more people and has a population density of at least 1,000 people per square mile
HSE	Health, Safety and Environmental
HVL	Highly Volatile Liquid
IC	Internal Corrosion (an LOF threat)
ICP	Integrated Contingency Plan

Acronym/Term	Description
ID	Inside Diameter
Idle pipeline	Currently inactive pipeline segment that is either in-service (contains hazardous liquids but is now static or unused) or out-of-service (effectively isolated from active pipe and contains de-product or inert gas)
ILI	In-line inspection
IMP	Integrity Management Program (or Plan)
IO	Incorrect Operations (an LOF threat)
IOB	Impact on Business (a COF Impact category)
IOE	Impact on Environment (a COF Impact category)
IOP	Impact on Population (a COF Impact category)
ISC	Industrial Source Complex
Kb tank	Storage tank for volatile organic liquids; refers to *40 CFR Subpart Kb*, *Standards of Performance for Volatile Organic Liquid Storage (Including Petroleum Liquid Storage Vessels)* for which construction, reconstruction, or modification commenced after July 23, 1984 (fulfilled by the requirements of *40 CFR 63 Subpart R)*
LEPC	Local Emergency Planning Committee
LFL	Lower Flammability Limit
Linear Polarization Resistance	Corrosion monitoring method in which the electrical current response to an electrode immersed in a fluid sample is measured
LOF	Likelihood of Failure
LQG	Large Quantity Generator
MFG	Manufacturing (an LOF threat)
mm	Millimeter
MOP	Maximum Operating Pressure
MOV	Motor Operated Valve
MSDS	Material Safety Data Sheets
MS SQL	Microsoft® Structured Query Language

Acronym/Term	Description
MTBE	Methyl Tertiary-Butyl Ether
NDT	Nondestructive testing
Near field	Paired pipeline areas on either side of the Dead Zone (typically 1–2 feet beyond it depending on the pulse echo collection method used by the tool) within which results are affected by pipeline geometry; dramatically reduced when two separate collars are used in collaboration (e.g. GUL)
NED	National Elevation Dataset
NHD	National Hydrology Dataset
NPMS	National Pipeline Mapping System
NPS	Nominal Pipe Size
O&M	Operations and Maintenance
OD	Outside Diameter
OPS	Office of Pipeline Safety
OSHA	Occupational Safety and Health Administration
OSRO	Oil Spill Response Organization
Other Populated Area (OPA)	Area, as defined and delineated by the U.S. Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area
P&M	Preventive and Mitigative
PDEP	Project Development and Execution Process
PHMSA	Pipeline and Hazardous Materials Safety Administration
piggable	Pipeline segment that can receive and accept an inspection tool
Pipe	Steel pipe, exclusive of protective coatings or attachments, used to transport crude oil, refined products, or HVLs
Pipeline	Portion of the pipeline system between the pump stations including the pipe, protective coatings, cathodic protection system, field connections, valves, and other appurtenances attached or connected to the pipe

Acronym/Term	Description
Pipeline system	All portions of the physical facilities through which gas moves during transportation including pipe, valves, and other appurtenances attached to the pipe, such as pump units, metering stations, delivery stations, holders and other fabricated assemblies. (See *49 Code of Federal Regulations Part 192* and *Part 195*)
Planktonic bacteria	Free-floating bacteria
PODS	Pipeline Open Data Standard
POE	Probability of Exceedance
POF	Pipeline Operator's Forum
PPTS	Pipeline Performance Tracking System
PREP	Preparedness for Response Exercise Program
psi	Pounds per square inch
RCRA	Resource Conservation and Recovery Act
Region of Concern (ROC)	Portion of the pipeline that is of primary consideration for the GWUT inspection; In the case of a GWUT inspection to assess the integrity of the carrier pipe inside of a casing, it is the carrier pipe within the casing; for inspections not performed at a casing, it is the area intended for evaluation
ROF	Risk of Failure
ROW	Right-of-Way
SCADA	Supervisory Control and Data Acquisition
SCC	Stress corrosion cracking
Sessile bacteria	Bacteria that permanently attach themselves to a fixed object (e.g., the inside wall of a pipe)
SME	Subject Matter Expert
SPCC	Spill Prevention Control and Countermeasure
Spill path	Represents the distance of a worst case discharge traveling from the centerline of the pipeline in the most downhill direction until the maximum release volume is consumed
STASGO	State Soil Geographic Database
Supplemental region	Area of pipe assessed that is coincidental with the GWUT inspection; for testing of pipe inside of a casing, it is the area of pipe assessed that is outside the casing

Acronym/Term	Description
SWPPP	Storm Water Pollution Prevention Plan
TCEQ	Texas Commission on Environmental Quality
TEEL	Temporary Emergency Exposure Limits
Telvent	A pipeline leak detection application
TNT	Tri-Nitro Toluene
TP	Third-Party Damage (an LOF threat)
Trap	Pipeline facility for launching and receiving tools and pigs
Unusually Sensitive Area (USA)	Drinking water and ecological resources that are unusually sensitive to environmental damage from hazardous liquid pipeline releases
USDA	United States Department of Agriculture
USDOE	United States Department of Energy
USDOT	United States Department of Transportation (commonly referred to as the DOT)
USGS	United States Geological Survey
UT	Ultrasonic Technology
WOF	Weather and Outside Forces (an LOF threat)

I: SCC Management Plan

Introduction

This plan provides a structured approach to assess NuStar Energy's mainline pipe for susceptibility to stress corrosion cracking (SCC).

Scope

This procedure applies to all jurisdictional liquid pipeline systems operated by NuStar.

Resources

NACE SP0204-2008 Standard Practice SCC Direct Assessment Methodology

CEPA SCC Recommended Practices, 2nd Edition

ASME STP-PT-011 Integrity Management of SCC in Gas Pipeline HCAs

ASME/ANSI B31.8S Managing System Integrity in Gas Pipelines

API RP 1176, Recommended Practice for Assessment and Management of Cracking in Pipelines, 1st edition (in draft form as of publication)

OPS – TT08 Stress Corrosion Cracking Study (Baker report)

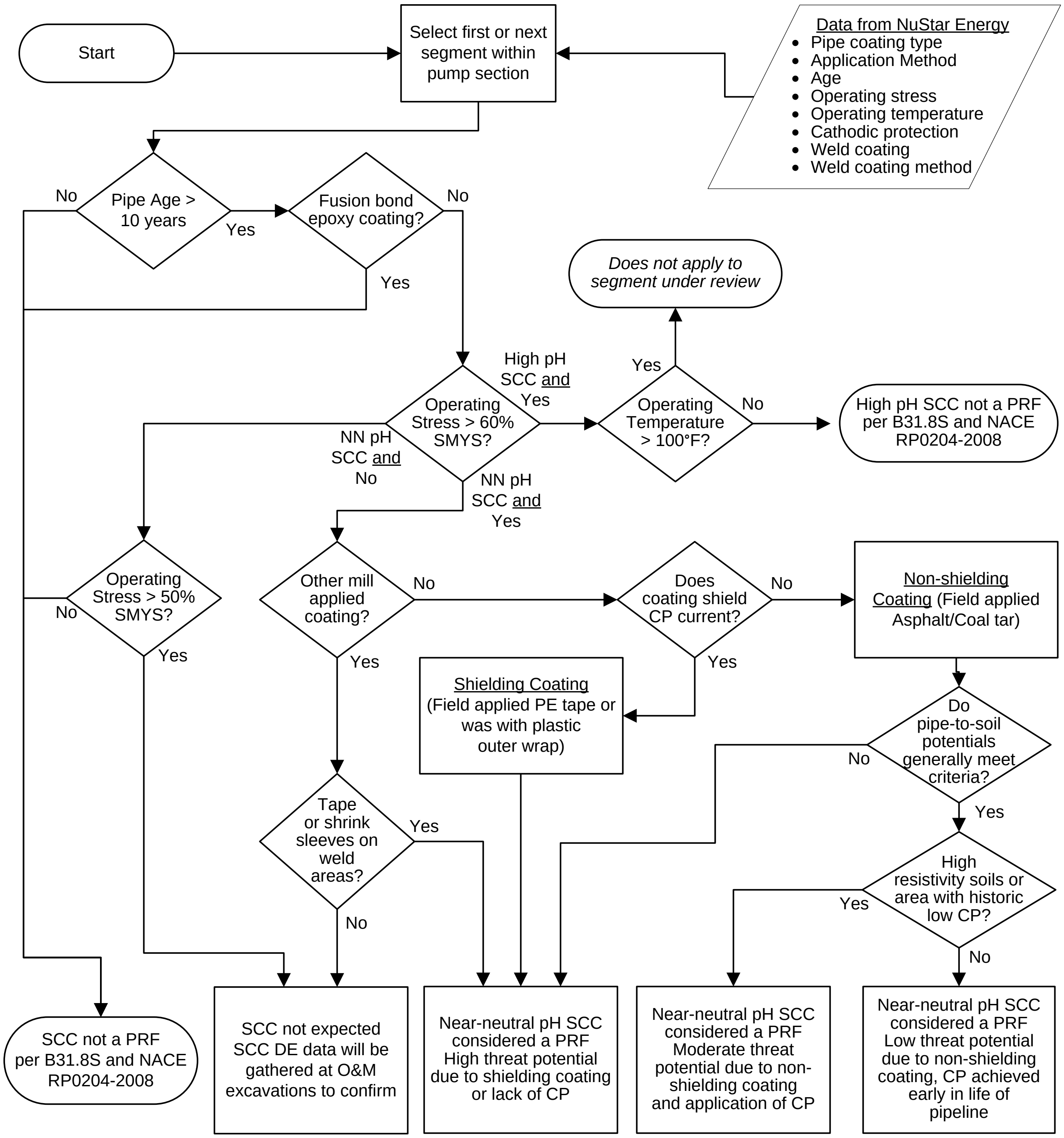
NuStar Operations & Maintenance Manual (O&M Manual)

Procedure

I.1. Initial Screening

NuStar conducts an initial screening to identify pump sections and segments of pump sections where SCC is potentially a specific risk factor independent of whether such segments could affect an HCA. Figure I–1 below illustrates this process. For both information and prioritization purposes, the segments which are considered to be a PRF are separated into high, moderate, and low threat potentials using basic mechanistic considerations.

Figure I–1: Initial Screening for SCC Susceptibility



I.2. SCC Direct Examination

Segments identified from the initial screening for SCC susceptibility as a High PRF will be further investigated to determine if SCC does actually exist within the segment. This section provides additional explanation to the processes where excavation and SCC Direct Examination (SCC DE) will be conducted within pump sections. The purpose of this step is to identify the most likely sites for SCC to occur. SCC DE will be carried out at those sites.

Initially, the pump segment will be assessed by conducting directed SCC DE excavations at what are considered the most likely locations for SCC. If these directed examinations indicate that “noteworthy” size SCC is not potentially widespread at these sites, then SCC is not considered a threat for the entire pump segment.

However, if examination of the most likely locations for SCC in the pump segment indicates that the risk of “noteworthy” size SCC, per ASME STP-011-2008, is potentially widespread, then—in addition to carrying out mitigation in accordance with NACE SP0204-2008 Section 6.2 as part of normal pipeline operations—one of two approaches will be followed:

- SCC would be considered a specific risk factor for all potentially affected HCAs on the pump segment in accordance with 49 CFR 195.452. The pump sections potentially affecting the HCA(s), as determined by the initial SCC DE screening, would be included in the Integrity Management Plan, and be subject to periodic assessment in the form of in-line inspection (ILI) appropriate for SCC or hydrostatic testing, or
- Two SCC DEs would be conducted in the most likely locations affecting each of the HCAs. If found that the risk of “noteworthy” size of SCC—per NACE SP0204-2008—is potentially widespread in any segment potentially directly affecting any HCA, those segments will be mitigated in accordance with NACE SP0204-2008, Section 6.2, and—unless replaced or recoated per Section 6.2—be included in the Integrity Management Plan and be subject to periodic assessment in the form of ILI appropriate for SCC or hydrostatic testing.

The field activities required for conducting SCC DE are described in the *IMP Manual*, Appendix J, "SCC Site Assessment Procedure."

I.2.1. Pre-Assessment

NuStar gathers available data to select specific sites within the identified High PRF segments. The types of data collected may consist of any of the following:

- Construction Records
- Operating and Maintenance History
- Alignment Sheets
- Corrosion Survey Records
- Above ground Inspection Records
- Inspection Reports from prior integrity evaluations or maintenance activities

An important aspect of the SCC Management Plan is the ongoing gathering and integrating of data for the purposes of

- Identifying if SCC is a PRF in segments not identified as such by the ASME B31.8S and NACE SP0201-2008 criteria,
- Aiding identification of sites in segments where SCC DE will be carried out, and
- Assessing the root cause of SCC meeting the criteria of "noteworthy" size, where discovered

These findings will be fed back into all steps of the SCC Management Plan.

I.2.2. Site Selection

When available, the following indirect inspection data may be integrated for all segments where SCC is considered to be a High PRF:

- CIS Survey
- Coating Condition Survey (DCVG or ACVG)
- MFL tool run
- Caliper tool run
- Terrain information
- Resistivity (spot Wenner or inferred from soils and terrain)

NuStar SMEs will identify sites for SCC DE in the identified High PRF segments using a prioritized list of SCC susceptibility conditions as provided in NACE RP 0204-2008, Section 3.3.3.

I.2.3. Direct Examination Process

The SCC DE process includes the following:

- Verification of field sites selected based on the pre-assessment and indirect examination steps
- Excavation, data collection, and coating/deposit examination
- Determination of the amount of pipe surface to inspect by MPI

The field activities required for conducting SCC DE are described in the *IMP Manual*, Appendix J, "SCC Site Assessment Procedure."

SCC DE is an iterative process and the decision to undertake SCC DE on a covered segment may be triggered at any, or all, of the major processes comprising the overall SCC DE procedure, including the initial screening, pre-assessment, direct examinations site selection, or post assessment processes.

I.2.3.1. Direct Examination Based Upon Primary Coating

For over-the-ditch applied coatings, the SCC DE procedures require that a minimum of five direct examinations be conducted in each pump segment. The SCC DE procedures require that 50 feet of pipe be fully exposed for 360 degrees around its circumference. The coating will also be removed 360 degrees over this length regardless of condition of the coating.

I.2.3.2. Direct Examination Based Upon Hand Applied Shielding Coatings

For hand applied shielding coating of field welds, the SCC procedures require that a minimum of three direct examinations be conducted. All pipes where the coating has been removed will be inspected by 360 degrees around its circumference by MPI. Each excavated weld at the site will be treated as though it were a single SCC DE excavation.

I.2.3.3. Purpose of Direct Examination Site Data

Gathering data at SCC DE sites serves to

- Identify direct examination site and length of pipe to inspect;
- Accumulate integrated data lists confirming CP is achieved or identifying where it is or has been difficult to achieve;
- Understand the coating conditions for each pipeline;
- Identify similar locations with absence or presence of SCC; and
- Validate and improve the SCC predictive risk model.

I.3. Data Integration

Both discovery and absence of SCC will be used to develop, validate, and improve the SCC predictive risk model. It is expected that the predictive risk model will continuously improve as it is updated with data from the overall SCC DE process. Table I–1 provides a general dataset that may be gathered during the SCC DE and the purpose of each data element based upon the list in NACE SP0204-2008.

Table I–1: Pipeline SCC DE General Data Set

Data Element	When Collected	Use and Interpretation of Results
Pipe-to-soil potential	Prior to coating removal	Useful for comparison with ground surface pipe-to-soil potential measurements and integrating with pipe surface pH and deposit data.
Soil resistivity	Prior to coating removal	Related to soil corrosiveness and soluble cation concentration of soil. Useful for soils comparisons of soil and groundwater analyses.
Soil Redox	Prior to coating removal	Near-neutral pH SCC occurs in anaerobic conditions, either under coating or in the soil surrounding the pipe. Can usually be inferred from soil color.
Soil samples	Prior to coating removal	Useful in confirming drainage conditions. Soil analysis results can be trended in predictive model.
Groundwater pH	Prior to coating removal	Useful for confirming elevated pH measurements on pipe surface > 8.5 are due to CP.
Coating type	Prior to coating removal	Required element. Used for field site verification and in predictive model development.
Coating condition, rebonded vs. missing, vs. intact but disbanded (estimated percentage)	Prior to coating removal	Can be related to extent of SCC found.
Electrolyte pH	Prior to coating removal	Important variable to determine if CP achieved on pipe surface. Near-neutral pH SCC occurs in absence of CP. May be useful in establishing type of cracking (not definitive if value >7, since CP could have been achieved after near-neutral pH SCC grew).
Photograph of dig site	Prior to coating removal	Useful in confirming terrain conditions, coating type, and coating condition.
Data for other integrity analysis	Before and after coating removal	Data for other analyses (e.g., dent measurements) may be related to occurrence of SCC.
Deposit description	After coating removal	Useful in establishing type of cracking and whether CP is achieved.
Deposit analysis	After coating removal	Useful in establishing type of deposit (e.g., weak acid spray to distinguish calcareous deposits from iron carbonate deposits).
Identification and measurement of corrosion defects	After coating removal	Used for integrity assessment of corrosion defects. Also used in establishing type of SCC, if present.

Data Element	When Collected	Use and Interpretation of Results
Photograph of corrosion defects	After coating removal	Used in integrity assessments.
Identify weld seam type	After coating removal	Required element. Used in field site verification.
MT inspection	After coating removal	Required element for SCC DE. Establishes whether SCC is present.
Location and size of each colony of significant size SCC	After coating removal	Required element for SCC DE. Used to establish correlation of location with other parameters measured.
Crack length and depth measurements of significant size SCC	After coating removal	Required element for SCC DE. Used to establish significance of cracking and determine whether there is an immediate integrity concern.
In situ metallography	After coating removal	Used to try to establish type of SCC, but is complex and has unproven reliability.
Photograph clusters of significant SCC	After coating removal	Required element for SCC DE. Used to confirm crack measurements.
Wall thickness measurements	After coating removal	Required element. Used in integrity assessments and field site verification.
Measure pipe diameter	After coating removal	Required element. Used in integrity assessments and field site verification.

I.4. Post Assessment

The Post Assessment steps address the activities following the data gathering and non-destructive inspection for SCC, including the following:

- Determining actions if SCC found in direct examination of excavation
- Determining actions if SCC not found
- Determining additional direct examination requirements
- Determining whether general SCC mitigation is required
- Determining discrete mitigation requirements
- Identifying potential preventative and mitigative measures
- Determining reassessment intervals
- Evaluating the effectiveness of the SCC DE approach
- Assessing repair options

A full review of SCC DE results, integrated with other data, will be conducted by subject-matter experts as part of the P&M Meeting process outlined in Section 6, "Preventative and Mitigative Measures" and Procedure 601, "Preventative and Mitigative Measures Meetings" of the IMP Manual.

I.4.1. Post Assessment Process

If MPI reveals no SCC in an excavation, the data is still both required and useful for this SCC Management Plan. The length of pipe examined without finding SCC, along with the pipe and coating information and the relevant environmental data, may be useful for improving the SCC predictive risk model.

If SCC is found, the following additional data should be recorded:

- Number of colonies

- Total length of colonies
- Total area of colonies

This data will be considered along with the relevant environmental data in the SCC predictive risk model development, regardless of the size of SCC found. In addition, it is necessary to include small and "non-noteworthy" SCC in the model improvement process as a proxy for SCC susceptibility.

If an SCC colony is found that is potentially of "noteworthy" size as defined by Section I.4.2 below, or is estimated by the NDE Technician to exceed 10% of the wall thickness, the buffing procedures in the O&M Manual, Section 615, "Buffing Procedure for Repair and Measurement of Cracks Due to SCC," may be followed. In addition to describing data to be recorded, this procedure specifies the method for measurement of defect depth by buffing. If the colony is 100% removed by buffing and the buffing limit (B31G or other approved criterion specified by NuStar Energy) is not exceeded, the repair is complete—except for recoating. If the buffing limit for operating at MOP is exceeded, the colony will be repaired by one of the methods outlined in Section I.4.7 below.

If, after measuring the maximum depth of the SCC by buffing, it is determined that the SCC colony is of "noteworthy" size, the following steps are required:

- Assess the cause of the "noteworthy" size SCC
- Record SCC colony measurements
- Remove or repair colony (if not 100% removed by buffing)
- Identify potential site specific preventative and mitigative measures

Additionally, if "noteworthy" size SCC is discovered, it must be determined whether the risk of "noteworthy" size SCC is potentially widespread in the segment. This determination process is described in Section I.4.2. If the answer is "yes," general mitigation per NACE RP0204-2004, Clause 6.2.2 is required. If the answer is either "no" or "uncertain," additional direct examination may be required.

I.4.2. Noteworthy Size Criterion

The conservative criterion specified by ASME STP-PT-011-2008, described below, will be used to distinguish whether SCC colonies are of "noteworthy" size to warrant consideration of remedial action.

ASME STP-PT-011-2008 defines a "noteworthy" sized flaw as follows:

- An SCC crack or colony is of noteworthy size (1) if the maximum crack depth is greater than 10% of the wall thickness and (2) if the maximum interacting crack length is more than the critical length of a 50% through-wall crack at a stress level of 110% SMYS.
- Any SCC colony having a crack with a depth exceeding 30%, for which no more than 10% is corrosion will also be considered to be of "noteworthy" size, regardless of colony length.

Per NACE SP0204-2008, "crack interaction is dependent on the circumferential and axial separation between individual (or interlinked) cracks and is calculated as follows:"

- Circumferential spacing of axial crack indications:

  $Y \leq (0.14)(L1 + L2)/2$

- Axial Spacing of axial crack indications:

  $X \leq (0.25)(L1 + L2)/2$

- Where: L1 and L2 are the axial lengths of the two cracks.

The interacting length is the total axial length of the grouping of interacting cracks and is treated as a single crack for the purpose of the ASME STP-011-2008 "noteworthy" size calculation.

I.4.3. General Mitigation Criterion

General mitigation is indicated when the risk of "noteworthy" size SCC could potentially be widespread within a particular segment or segments of a pipeline, and the segment is too long to repair by discrete mitigation.

I.4.3.1. Determination when General Mitigation Required

NuStar SCC SMEs determine the risk of potentially widespread, "noteworthy" size SCC within a segment, if either of the following is true:

- Any colony found in the HCA has a failure pressure ≤ 110% SMYS and is not due to a unique condition, or
- A total of 10 or more "noteworthy" size colonies are found in an HCA, and these colonies are found in two or more separate excavations.

If any of these criteria are met, then the segment being assessed will be subjected to general mitigation as defined by NACE SP0204-2008, Section 6.2.2, unless discrete mitigation as defined by Section I.4.4of this document is appropriate.

I.4.3.2. Actions Pertaining to HCAs if General Mitigation is Indicated

If it were to be determined that general mitigation, per NACE SP0204-2008, Section 6.2.2, is indicated, several actions are required by this SCC Management Plan, in addition to conducting general mitigation as part of normal pipeline operations. These additional actions address the segments within the pump section that could affect an HCA. If general mitigation were to be indicated per Section I.4.3.1 of this document in any segment within a pump section, one of the following two approaches is required by the SCC Management Plan:

- SCC would be considered a specific risk factor for all potentially affected HCAs in the pump segment in accordance with 49CFR Part 195.452. The pump sections potentially affecting the HCA(s) for which SCC is considered to be a PRF, would be included in the Integrity Management Plan and be subject to periodic assessment in the form of ILI appropriate for SCC or hydrostatic testing, or
- SCC DE would be conducted in the most likely locations that could affect each of the HCAs. If it is found that the risk of "noteworthy" size SCC, per NACE SP0204-2008, is potentially widespread in any segment potentially directly affecting any HCA, those segments will be mitigated in accordance with NACE SP0204-2008 Clause 6.2, and (unless replaced or recoated per Clause 6.2) included in the Integrity Management Plan, subject to periodic assessment in the form of ILI appropriate for SCC or hydrostatic testing.

I.4.3.3. Response and Remediation – General Mitigation

The types of general mitigation per NACE SP0204-2008 are:

- Hydrostatic Testing
- ILI with proven crack detection tool
- Pipe replacement
- Recoating

The SCC Management Plan Procedure will require a spike test to a minimum of 1.39 x MOP, followed by a 49 CFR Part 195, Subpart E hydrostatic test.

When an ILI assessment for SCC is completed, repairs will be made in accordance with API RP 1176.

I.4.4. Discrete Mitigation

Discrete mitigation, as defined by NACE SP0204-2008, Section 6.2.1, is used to "address isolated locations where 'noteworthy' SCC has been detected during the course of the field examination program."

NuStar defines discrete mitigation as follows:

- Where the "noteworthy" size colonies have not been removed during the inspection by MPI (e.g., due to reaching the buffing limits), the standard O&M repair procedures will be followed. (See Section I.4.7, Repair Options.) Such measures may be taken over short sections at isolated locations as contemplated by the NACE definition of discrete mitigation.

- Where “noteworthy” size SCC found by several SCC DEs are associated with another anomaly that is reliably identifiable by ILI, or an indirect inspection method. A SME analysis would then be carried out to determine if discrete mitigation over all the segments that could affect an HCA is both possible and practical. If so, such discrete mitigation will be implemented and will involve locating, excavating, examining, and as necessary, completing repairs at each such location.

I.4.5. Preventative and Mitigative Measures

If “noteworthy” size SCC is discovered, an assessment of the cause of the SCC will be conducted and used to identify preventative and mitigative measures that could reduce the risk of SCC.

Based upon the ongoing data gathering and risk assessment refinement, the locations most susceptible to SCC will likely become better defined over time and preventative and mitigative measures could be applied discretely at those locations.

I.4.6. Determining SCC DE Effectiveness

The methods used to assess SCC DE effectiveness may include

- Comparison of results for selected dig sites with results from other sites;
- Comparison of results of SCC DE for selected segments with results of ILI;
- Statistical analysis of data from SCC DE digs to identify statistically noteworthy factors associated with the occurrence and/or severity of cracking;
- Successive applications of SCC DE to a pump section; and/or
- Assessment of SCC predictive models with respect to reliability of predicting locations and severity of SCC.

I.4.7. Repair Options

Per *O&M Manual*, Section 614, NuStar prescribes the following acceptable repair methods for SCC:

- Replacement
- Buffing repair, per *O&M Manual*, Section 615
- Type B, pressurized sleeve
- Plidco Clamps (permanent)

I.5. Record Keeping

NuStar will archive records concerning the implementation of the SCC management plan, including decisions made and results of SCC analysis and dig observations.

J: SCC Site Assessment Procedure

Purpose

This procedure is used to establish a standardized method for inspecting and reporting sites investigated for stress corrosion cracking (SCC) on NuStar facilities and pipelines.

Scope

This procedure is required for all SCC Direct Examinations (SCC DE) where NuStar retains Site Assessment Technicians (Corrosion Technicians and Non-Destructive Testing [NDT] Technicians) to carry out both the Site Assessment and Magnetic Particle Inspection (MPI).

The Site Assessment Technicians are responsible for completing the site assessment and magnetic particle inspection (MPI) per this procedure and shall record all observations and measurements described in this procedure on the NuStar SCC Site Assessment Form.

References

- NACE SP0204-2008
- ASNT SNT-TC-1A-2006
- CEPA *Stress Corrosion Cracking Recommended Procedures, 2nd Edition*
- NuStar *Operations and Maintenance Manual (O&M Manual)*
- NuStar *Corrosion Control Manual (Corrosion Manual)*
- SCC Site Assessment Form
- Magnetic Particle Testing Report for Defect Investigation
- Pipeline Information Report

Procedures

J.1. Locate Excavation Site

The NuStar IMP Department will conduct the site selection and identify the location(s) to the Site Assessment Technicians, per the *IMP Manual*, Appendix I, "Stress Corrosion Cracking Management Plan."

The length of pipe to be inspected will be determined as follows:

- SCC DE directed at pipe coating—50 ft minimum length
- SCC DE directed at girth weld coating—no minimum length

J.2. Complete Above Ground Survey

The Corrosion Technician completes above ground surveys by measuring the soil resistivity using the Wenner 4-pin method at both 5 ft and 10 ft spacing with wire perpendicular to axis of the pipe. NuStar prefers that the technician conduct these measurements at three locations, at the beginning, middle, and end of the planned excavation. For smaller excavations, the technician may use the soil box to measure the soil resistivity.

J.3. Describe Terrain

The Corrosion Technician describes and photographs the terrain.

1) Describe the terrain topography within 1000 ft of the excavation.

Table J-1: Typical Topography and Site Position Classifications

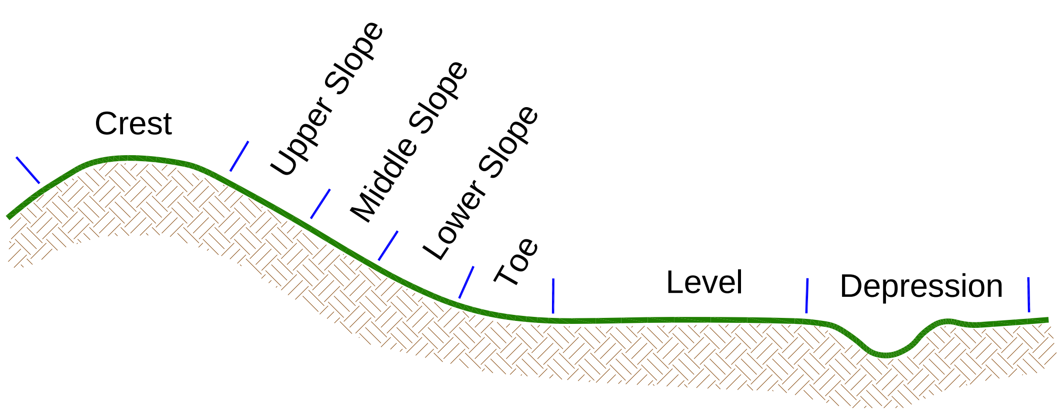
Descriptor	Symbol	Explanation
Undulating	U	Regular sequence of gentle slopes forms alternating concave and convex patterns (wavelike)
Ridged	R	Sharp crested or dome shaped, usually with a steep side slope
Inclined	I	Sloping surface
Inclined to Level	I-L	Sloping to flat to very gently inclined
Level	L	Flat to very gently inclined
Depressed	D	Topographically low-lying area
Side Slope	S	Side slope of an incline, perpendicular to the pipeline right-of-way

2) Describe the terrain features at the excavation site.

Table J-2: Terrain Features

Descriptor	Explanation
Crest	The upper most portion or apex of a slope
Upper Slope	The upper most portion of a slope immediately below the crest
Middle Slope	The area between the upper and lower slope
Lower Slope	The lower portion of a slope immediately above the toe
Toe	The lower most portion of a slope
Level	Any level area
Depression	Any area that is concave in all directions

Figure J-1: Terrain Diagram



3) Photograph the excavation site looking downstream and perpendicular to the right-of-way.

J.4. Excavate the Pipe

Prior to inspection, qualified personnel excavate and fully expose the following lengths of pipe:

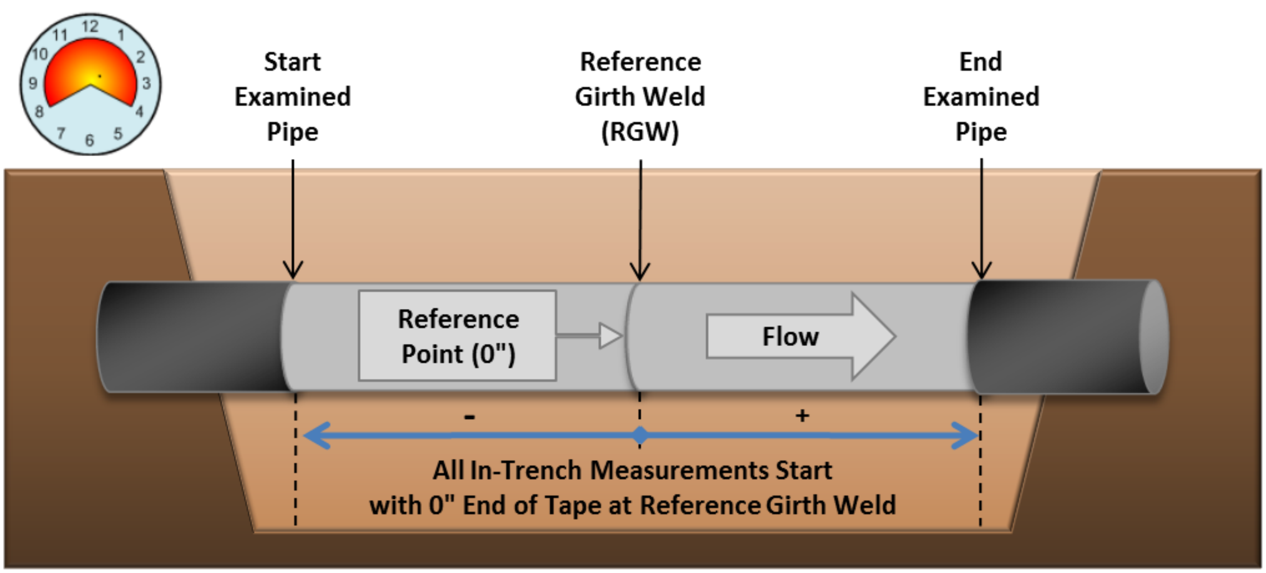
- For SCC DE excavations directed at pipe coating, excavate 360° of pipe for a minimum length of 50 ft.
- For SCC DE excavations directed at girth weld coating, excavate 360° of pipe (no minimum length).

J.5. Establish an In-the-Ditch Survey Reference

A Site Assessment Technician identifies, marks, and photographs the in-the-ditch survey references.

1) Establish an in-the-ditch reference point on the top of the pipe at the reference girth weld.
2) Mark the reference point with spray paint.
3) Measure upstream from the reference girth weld to the start of the examined pipe and record the distance as a negative number (e.g., -2.5 ft).
4) Measure downstream from the reference girth weld to the end of the examined pipe and record the distance as a positive number (e.g., +54.0 ft).
5) Place the “0” end of a measuring tape on the reference point at the reference girth weld and measure all axial pipe distances required by this procedure with the tape so placed, recording all measurements upstream of the reference girth weld as negative numbers and all measurements downstream of the reference girth weld as positive numbers.
6) Gage all pipe circumferential measurements as the o’clock position looking downstream.
7) Photograph the pipe and trench with a label (e.g., 8 ½ in. by 11 in. paper or whiteboard) identifying the dig site location and flow direction.
8) Use the following diagram as a reference:

Figure J-2: In-the-Ditch Survey Reference



J.6. Record Trench Wall Observations

The Corrosion Technician records the trench wall observations.

1) Note the soil characteristics at pipe depth and any soil transitions using the following classifications:
   - Organics—predominant, some, or none

- Clays—predominant, some, or none
- Rock—coarse sand, small stones, large rock, bedrock, or none

2) Note the depth of aeration layers, if present.
   - Depth of oxidized layer (depth of rust-colored layer)
   - Depth below which soil is anaerobic year-round (gleying; i.e., dark or grey soil with no evidence of oxidation)
   - Layer with seasonal or partial aeration (mottled layer; i.e., rust colored patches on gleyed background)

J.7. Record End-of-Trench Observations

The Corrosion Technician records end-of-trench observations for the following:

- Predominant soil texture against the top and bottom of the pipe using the same classification as described in Section J.6, Record Trench Wall Observations
- Whether the soil appears oxidized or anaerobic (gleyed) at both top and bottom of pipe
- Whether there is evidence of water transport along top and bottom of pipe
- For comparison with undercoating pH measurements, measure soil pH with Antimony rod at top and bottom of pipe

J.8. Record Drainage Observations

Based on soil characteristics found at pipe level, the Corrosion Technician records the following drainage observations:

- Depth to impermeable layer, if observed
- Whether the trench is likely to act as a drain when surrounding soil is dry
- Major soil transitions along trench
- Whether the trench is likely to be in one of the conditions listed in Table J-3

Table J-3: Drainage Classification Definitions

Descriptor	Symbol	Explanation
Well-Drained	W	Oxidizing environment throughout the year.
Imperfectly Drained	I	Alternating oxidizing and reducing environment, as a result of a fluctuating water table. Mottling of soils observed, orange in color
Poorly Drained	P	Primarily reducing conditions. May be saturated throughout most of the season. Mottling more present, some gleying of soils noted, blueish soil color
Very Poorly Drained	VP	Reducing conditions throughout the entire year. The soil would be saturated year round
Very Poorly –Very Poorly Drained	VP-VP	Reducing conditions throughout the entire year. The soil would consist of organic material and would be saturated year round

J.9. Perform Electrolyte and Corrosion Deposit Assessment

The Corrosion Technician completes the electrolyte and corrosion deposit assessments.

- Take pH measurements of any water found between the coating and pipe with pH paper and mark value on pipe with marker.
- Identify any corrosion deposits or cathodic protection (CP) deposits (as initially found color and texture) and mark on the pipe.

- Deposits indicating current or historical local absence of CP include
  - Rust
  - Iron carbonate—white paste (new)
  - Iron carbonate—greenish (old, oxidized)
  - Bacterial deposits—hydrogen sulfide (H_2S) smell with black sludge (enhance with weak acid and/or use microbially induced corrosion [MIC] test kits)
- Deposits indicating current protection by CP include
  - Calcareous deposits—hard white to multi-colored deposits (occasionally white powdery calcite) that fizz rapidly after applying dilute hydrochloric acid (1/10 HCl)
  - Crystals
- Photograph all corrosion deposits, including any identifying markings made on the pipe

J.10. Perform Coating Assessment

The Corrosion Technician performs the coating assessments and records observations on the NuStar SCC Site Assessment Form.

The following list describes possible coating conditions by coating type:

- Non-shielding Coatings (asphalt or coal tar)
  - Bonded and pliable
    - Some coal tar coating retains this condition in all soils.
    - Some asphalt coatings remain so only under year-round wet conditions.
  - Brittle and disbonded – estimate percentage of surface area
    - Sometimes hollow sound upon tapping
    - Undercoating evidence of corrosion deposits or CP deposits sufficient to scrape a sample
    - Bulk water
- Shielding Coatings (polyethylene tape, shrink sleeves, or wax with plastic outer wrap)
  - Bonded
  - Disbonded – estimate percentage of surface area
    - Tenting over Double Submerged Arc Welded (DSAW) weld – estimate percentage of length
    - Bubbles or “softness”
    - Easy to remove small patch
    - Sagging at bottom of shrink sleeve

Refer also to the Corrosion Control Procedure Manual, Section 4.2.1., "Inspecting and Completing the Pipeline Information Report," for guidelines to categorizing and describing the coating condition.

1) Examine coating over the initial length of pipe. If the site has not been selected at a known anomaly, center the examination on a girth weld.
2) Identify missing coating or holidays in the coating and record on the pipe the start and end axial distances from the reference girth weld as well as the o’clock position looking downstream.
3) Identify intact but disbonded coating, circle with a marker on the pipe, and record on the pipe the start and end axial distances from the reference girth weld as well as the o’clock position looking downstream.
4) Identify any tenting in the coating and record on the pipe the start and end axial distances from the reference girth weld as well as the o’clock position looking downstream.
5) After the coating assessment is complete, the Corrosion Technician photographs the coating. Photographs of the coating should include the following:

a) One or more photographs showing the general condition of the coating
b) Close-up photographs of areas of interest such as wrinkles, holidays, and disbondment
c) For sites where more than one area contains a particular type of defect, obtain a representative photograph

J.11. Remove Coating and Clean Pipe Surface

The Excavator properly cleans and prepares steel surfaces for NDT prior to inspection. Surface preparation for MPI should be carried out by high pressure (>20,000 psig) water jet or by grit blasting.

- For SCC DE excavations directed at pipe coating, excavate 360° of pipe for a minimum length of 50 ft.
- For SCC DE excavations directed at girth weld coating, excavate 360° of pipe (no minimum length)

Re-establish the in-the-ditch reference as described in Section J.5 and use the reference girth weld to determine all measurements. For all defects, record begin and end locations in both the axial and circumferential (o'clock) directions.

J.12. Label Pipe Surface Conditions

The Corrosion Technician marks the following surface conditions on the pipe:

- The presence of any shiny metal patches as "SM"
- Any passivated superficial pitting < 0.020 inches deep as "OSM" (old shiny metal)

The Corrosion Technician then photographs a representative sampling of patches with label identifying dig site location, flow direction, distance, and o'clock position from the reference girth weld.

J.13. Measure Pipe-to-Soil Potentials

The Corrosion Technician records pipe-to-soil measurements.

- Use a half cell to measure the pipe-to-soil potential in the soil adjacent to the pipe. Ensure the metal contact probe is directly in contact with the steel.
- Record pipe-to-soil potentials on the pipe as the distance from the reference girth weld and the o'clock position looking downstream.

J.14. Record Pipe Surface Conditions

The Corrosion Technician records the following pipe surface conditions on the NuStar SCC Site Assessment Form:

- All data marked on pipe per Sections J.9– J.13
  - All pH measurements as distance from the reference girth weld on pipe and o'clock position looking downstream
  - All corrosion deposits and patches as the start and end distances from the reference girth weld on the pipe and the start and end o'clock positions looking downstream
  - All missing coating/disbonded coating areas as the start and end distances from the reference girth weld on the pipe and the start and end o'clock positions looking downstream
  - Pipe-to-soil potentials as distance from the reference girth weld on pipe and o'clock position looking downstream

For all measurements, the technician uses the reference girth weld—as established in Section J.5—to record the start and end locations in both the axial and circumferential (o'clock) directions.

J.15. Perform Defect Assessment

The NDT Technician performs a defect assessment to determine the remaining wall thickness of the pipeline. The NDT Technician also performs an MPI on all areas to look for possible cracking, per Section J.16.

For all measurements, the technician uses the reference girth weld—as established in Section J.5—is used to record the start and end locations in both the axial and circumferential (o'clock) directions.

J.15.1. Prepare for Defect Assessment

For each joint of pipe inspected, the NDT Technician

- Measures nominal wall thickness using approved UT thickness probe
- Records pipe diameter, nominal wall thickness, and seam orientation
- Identifies any features and writes a unique label (e.g., A1, A2) on the pipe identifying all anomalies to ensure clear documentation on the completed report
- Records each defect location as the distance from the reference girth weld and the circumferential (o'clock) position on the pipe

J.15.2. Measure and Document All Defects

The NDT Technician performs a visual inspection of the pipe for defects on a joint-by-joint basis and, for each defect, marks the pipe with the following information:

1) Measure and record the length (axial orientation) and width (circumferential orientation) for each anomaly.
2) Measure and record the remaining wall thickness for each anomaly. Remaining wall thickness can be obtained in one of two ways.
    - Indirect measurements—Indirect methods to measure remaining wall thickness require the measurement of the pit depth subtracted from the known uncorroded wall thickness. The equipment that may be used for indirect measurements includes pit gauges, scales or profile gauges, micrometers, bridging bars, strait edges or rulers.
    - Direct measurements—Direct measurements of corrosion features require that the remaining wall thickness within the corrosion feature be obtained. Ultrasonic thickness gauges are typically used to measure remaining wall thickness.
3) Record the depth of all corrosion anomalies as the remaining wall thickness subtracted from the nominal wall thickness.
4) Record the OD Reduction depth of all dents as the distance of the reduction from the normal pipe surface to the deepest part of the reduction.
5) Photograph all anomalies. Photographs should include, at minimum
    - The unique label identifying the feature
    - A label placed on the pipe identifying the dig site location
    - The flow direction and the distance from the reference girth weld
    - The circumferential (o'clock) position of the feature on the pipe
    - The length, width and depth measurements of the feature

J.16. Perform Magnetic Particle Inspection

The NDT Technician continues the defect assessment by performing MPI to evaluate for SCC, per the *IMP Manual*, Procedure 306, "Magnetic Particle Inspection."

- For SCC DE excavations directed at the pipe coating, conduct MPI over 360° over the length of the fully exposed pipe, minimum 50 ft

- For SCC DE excavations directed at the girth weld coating, conduct MPI over 360° over the length of the fully exposed pipe (no minimum length requirement).

J.17. Assess SCC Indications

Cracks occur in many different forms and may occur in isolation or within colonies. Correct identification of the crack is required to determine the course of remedial action. Regardless of the type of crack, the crack or colony size should be documented by measuring the length, width, and depth of the defect.

For SCC, it is important to identify any features associated with an SCC colony. Features commonly associated with SCC include:

- Corrosion (general, pitting, etc.)
- Stress risers (dents, scrapes and arc burns)
- Toe cracking

The NDT Technician completes the SCC assessment by measuring and documenting the SCC features or colonies found by MPI. Measurements methods include Shear Wave Ultrasonic (UTSW) Technique or the Phased Array Ultrasonic (UTPA) Technique.

J.17.1. Measure the SCC Features and Colonies

J.17.1.1. Shear Wave Ultrasonic (UTSW) Technique

If required, the NDT Technician performs UTSW using the contact single or dual transducer A-Scan technique according to the following procedure:

1) Prior to inspection, clean prepared steel surfaces of all oil, dirt, or spurious weld spatter.
2) Use a suitable couplant to allow sound transfer into the pipe without causing any corrosion of the surface prior to inspection.
    - Suitable couplants include U-TX, Ultragel II, and Sonoglide, etc.
    - Typical A-Scan Flaw Detectors that will facilitate UTSW are the Krautkramer USN-58L, Panemetrics Epoch III or IV, or the Sonotest Site Scan 230 models or higher versions.
3) Use suitable calibration blocks to ensure proper calibration with reproducible results.
    - Use a 90° single or dual transducer is required to ensure that no laminar type flaw is located in the area of inspection.
    - Use at least two or more degrees—45°, 60°, and 70° are the most common—for the UTSW transducers (single/dual).
4) Scan the 90° transducer in two directions with the scanning sensitivity to be set at +6dB above the reference height as set during calibration.
5) Scan the UTSW transducers in four directions with the scanning sensitivity set at +14dB above the reference as set during calibration.

J.17.1.2. Phased Array Ultrasonic (UTPA) Technique

If required the NDT Technician performs UT Phased Array (UTPA) using the contact PA 16 Element transducer Linear and Sectorial Scan technique described below.

1) Clean prepared steel surfaces of all oil, dirt, or spurious weld spatter prior to inspection.
2) Perform UTPA using a suitable couplant to allow sound transfer into the pipe without causing any corrosion of the surface.
    - Suitable couplants include U-TX, Ultragel II, and Sonoglide, etc.
    - Typical Flaw Detectors that will facilitate UTPA include the GE Phasor, Olympus Omni Scan, or the Harfhang models or higher versions. Unless otherwise allowed by the Work Authorization, NuStar recommends the Olympus Omniscan model.

3) Use suitable calibration blocks to ensure proper calibration with reproducible results.
4) Use the 90° single or dual transducer to ensure that no laminar type flaw is located in the area of inspection.
5) Use at least two or more degrees for the UTPA transducers.
   - Note: The UTPA transducer uses an array of degrees from 0° to 90°, therefore qualifying as two degrees or more.
6) Scan the 90° transducer in two directions with the scanning sensitivity set at +6dB above the reference height as set during calibration.
7) Scan the UTPA transducers in four directions with the scanning sensitivity set at +14dB above the reference as set during calibration.
8) Employ a bi-directional and skewed scanning pattern once the system has been properly calibrated.
   - Use a pattern that will produce the greatest reflected or perpendicular signals from cracks.
   - Perform these scans from the side of the colony that produces the greatest reflected signals. NuStar recommends that the colony be scanned from two sides.
   - Scan the deepest crack found at a probe position that provides optimum depth signal readout.
   - Run an encoded scan for the entire length of the deepest known crack.
9) Save the data in a permanent record.
10) Document the profile of the deepest portion of the SCC colony in a minimum of 10% of wall thickness (WT) increments (e.g., length > 90% WT, length > 80% WT, length > 70%).
   - This may require two or more scans along the axial direction to account for “stepping” of cracks in the circumferential direction.
   - Two cracks spaced circumferentially within a distance of 14% of the average axial length of the two cracks is considered to be a single interacting crack.

J.17.2. Document the SCC Features and Colonies Prior to Buffing

Consistent documentation practices are needed to allow correlation between excavations. NuStar recommends that documentation is done on a joint-by-joint basis and an appropriate ID is given to each feature to ensure that when the report is compiled, it is clear which feature is discussed. Once the colony is appropriately identified and the location of the colony is recorded as described below, specifics about the colony should be recorded.

For all measurements, the technician uses the reference girth weld—as established in Section J.5—to record the start and end locations in both the axial and circumferential (o’clock) directions.

For each joint of pipe inspected, the NDT Technician will

1) Measure nominal wall thickness using approved UT thickness probe.
2) Record pipe diameter, nominal wall thickness, and seam orientation.
3) Identify any SCC features or colonies. Write a unique label (e.g., A1, A2) on the pipe identifying all anomalies to ensure clear documentation on the completed report.
4) Record each defect location as the distance from the reference girth weld and the circumferential (o’clock) position on the pipe.
5) Record the length and width of each SCC crack or colony.
6) NDT Technicians may use a UTSW or UTPA tool to estimate the depth of the SCC colony and therefore the amount of pipe surface to remove for repair (within the prescribed limits set forth in the O&M Manual, Procedure 615, "Buffing Procedure for Repair and Measurement of Cracks Due to SCC").
7) A minimum of two photographs shall be taken of each SCC colony.

a) Each photograph should include the following (see Figure J-3 and Figure J-4):
   - a visible scale placed on the pipe immediately under the colony
   - the unique label identifying the colony

b) . At least one photograph should include a label placed on the pipe identifying the following:
   - Dig site location
   - Flow direction
   - Current wall thickness measurement

c) The close-up photo must clearly show the individual cracks and the scale. It should be taken as close to perpendicular to the indications as practicable. Overlapping photos may be used as required to capture the entire SCC colony (see Figure J-4).

d) Note and provide a description of any association with other pipe anomalies such as dents, gouges, corrosion, welds, etc.

e) Record whether there is any observable corrosion within 1 ft of the SCC anomaly. If so, record the maximum depth, length, and width, as well as the start and end locations in both axial and circumferential (o'clock) directions for all corrosion, regardless of size or depth.

Figure J-3. Example Photograph of SCC Colony

Figure J-4. Example Photograph of SCC Colony Close-up

J.17.3. Buffing for SCC Depth Measurements

A qualified Maintenance Technician—not the Site Assessment Technicians—performs all buffing and grinding on NuStar pipe. A NuStar Inspector remains present throughout the buffing process to ensure the NuStar buffing procedure is followed (see the *O&M Manual*, Procedure 615, "Buffing Procedure for Repair and Measurement of Cracks Due to SCC").

The NDT Technician shall carry out frequent measurements of remaining wall thickness and confirm existence of remaining SCC by MPI as described in Section J.16 Buffing shall cease when one of the following conditions is met:

- SCC indications have been completely removed,
- P_{safe} limit has been reached, or
- Remaining wall thickness is greater than 80% of nominal wall thickness.

J.17.4. Record Final Measurements

The NDT Technician records the final measurements on the NuStar SCC Site Assessment Form.

1) Measure the remaining wall thickness using approved UT thickness probe. Record the final remaining wall thickness.
2) Document if SCC indications are completely removed by buffing.
3) If SCC indications are not completely removed by buffing, use UTSW or UTPA tool to measure depth of SCC colony. Record the SCC colony depth measurements.
4) Photograph the SCC colony as prescribed in Section J.17.2.

   Note: Every photograph of SCC should include a visible scale placed on the pipe immediately under the colony and show a unique label identifying the colony.

J.18. Documentation

J.18.1. Documentation by Site Assessment Technicians

The Site Assessment Technicians complete all documentation and photographs pertaining to the excavation (see Table J-4), clearly identifying the pipeline, the location, and the date(s). The Site Assessment Technicians forward all records to the NuStar Pipeline Integrity Department. The SCC DE final report shall include the NuStar SCC Site Assessment Form and proof of Site Assessment Technician qualifications, per Section J.18.2.

Table J-4. Site Assessment Technicians' Roles and Responsibilities

	Corrosion	NDT	Either Technician
Pre-excavation	• Above-the-ground survey • Terrain description		• Proof of qualifications
Pre-coating Removal	• Trench wall observations • End-of-trench measurements • Drainage observations • Electrolyte (pH) measurements • Corrosion deposit assessment observations • Coating assessment		• In-the-ditch survey reference
Post-coating Removal	• Pipe surface documentation • Pipe-to-soil measurements • Record pipe surface conditions	• Magnetic Particle Inspection • Corrosion assessment • SCC assessment • Record final measurements • Buffing for SCC depth measurements (must be present only)	• Documentation

J.18.2. Documentation by NuStar Inspector

The NuStar Inspector is responsible for recording and validating all required fields on the Pipeline Information Report (PIR). The NuStar Inspector also completes the Magnetic Particle Testing Report for Defect Investigation.

J.18.3. Record Retention

All documentation resulting from the SCC DE will be kept for the life of the pipeline. Hard copies may be kept at the region headquarters, while electronic copies will be kept in the corporate archive.

J.19. Qualification Requirements

J.19.1. Corrosion Survey and Data Collection Requirements

NuStar requires that the Corrosion Technician who conducts the indirect inspections and performs the data collection regarding the terrain, trench wall, drainage observations, coating assessment, electrolyte, and corrosion deposit assessment, meet the qualification of a certified NACE Coating Inspector (CIP) Level II or III or NuStar agreed equivalent qualification.

J.19.2. Non-Destructive Testing Qualification Requirements

Except as noted below, NuStar requires that the NDT Technician performing and interpreting NDT—using the MPI method for detection and identification of SCC, the 90° ultrasonic Penprobe (90° UT) for determination of wall thickness, and either the shear wave ultrasonic (UTSW) or phased-array (UTPA) ultrasonic methods for determination of SCC flaw depth—meet one of the following qualifications:

- Be certified as ASNT NDT Level II or III, or hold ASNT Central Certification Program (ACCP) certificates as ACCP Level II or ACCP Professional Level III, or Canadian General Standards Board (CGSB) Level II or III.
- Be certified in accordance with ASNT Recommended Practice No. SNT-TC-1A-2006 as SNT Level II or SNT Level III for MPI and UT. The minimum examination level for NDT interpretation is Level II.

The following additional requirements also apply, depending upon the type of ultrasonic methods each NDT Technician will use:

- **UTSW Technicians**—NuStar may require, at it's discretion, additional testing on NuStar test blocks and a short written exam prior to an NDT technician performing UTSW, unless they have completed the following two J. Mark Davis courses at the contractor's expense, in which case no further testing is required:
    - Flaw Detection and Flaw Characterization - 1week
    - Crack Sizing - 1 week
- **UTPA Technicians**—NuStar requires the completion of the following four J. Mark Davis courses, completed at the contractor's expense, prior to an NDT technician performing UTPA. No further testing is required:
    - Flaw Detection and Flaw Characterization - 1week
    - Crack Sizing - 1 week
    - Introduction to Phased Array - 1 week
    - Phased Array for Weld Inspection and Crack Sizing - 1 week

K: Examination of Exposed Portions of Buried Pipelines

Purpose

This document provides personnel with recommended investigative excavation protocols for the assessment and documentation of pipe, coating, terrain, and environment conditions at an investigative excavation to ensure consistency and accuracy in data acquisition.

Resources

CFR §195.55

CFR §195.569

CFR §195.585

Corrosion Control Manual

Procedure 614: Detailed Pipeline Repair Procedures in the *Operations and Maintenance Manual*

Pipeline Information Report / Defect Evaluation (in the *O&M Manual*)

Procedures

K.1. Overview of Investigative Excavation

NuStar conducts investigative excavations to verify the integrity of the pipe, while documenting complete records of all investigation findings. A comprehensive investigation procedure should include components such as the following.

- Documentation of construction and operating parameters
- Site Location Verification
- Terrain Identification and Classification
- Coating Assessment –the amount of adhesion, degree of disbondment, location and size of coating holidays
- Identification and documentation of pipeline corrosion deposits and electrolyte
- Cleaning of the external pipe surface at 100% of the disbonded areas, the nondestructive inspection of the pipe for stress corrosion cracking (SCC), internal weld defects (when required) and external pipe defects
- Assessment of any corrosion or dent features
- If detected, quantification of cracking, obtaining size, depth, length, etc.
- Removal of cracking and SCC colonies as required

The following sections discuss each step that should be completed to ensure all required data is collected, assessed, and documented to promote consistency and allow accurate data correlation. A data collection checklist is provided to ensure all necessary data is collected during each phase of the investigation. See the Examinations of Exposed Buried Pipeline Data Collection Checklist at the end of this section.

K.2. Pipeline Data

Prior to arriving on-site for the excavation, NuStar should review the prepopulated pipeline information on the PIR and update as necessary. Table K-1 lists some of the data used in integrity assessments and also during field site verification.

Table K-1. Required Pipeline Data

Data Element	When Collected
Pipe manufacturer	Before Excavation
Pipe diameter	Before Excavation and verified after coating removal
MOP	Before Excavation
Specified Minimum Yield Stress (SMYS)	Before Excavation
Nominal wall thickness	Before Excavation and verified after coating removal
Coating type	Before Excavation and verified after excavation
Year of manufacture	Before Excavation
Weld seam type and orientation	After Coating Removal

K.3. Soil Data

Table K-2 lists the required elements for describing the soil data features. The sections following the table go into detail about each required element.

Note that this material has been simplified to provide a consistent classification system for pipeline applications. Pipe to Soil Potentials are required for all excavations.

Table K-2. Soil Evaluation Elements

Data Element	When Collected	Use and Interpretation of results
Soil Resistivity – Wenner 4-Pin Method or srm 100 digital soil resistivity & ph probe	Before Excavation	Related to soil corrosiveness and soluble cation concentration of soil. Useful for soils comparisons of soil and groundwater analyses.
Pipe-to-Soil Potential	After Coating Removal	Useful for comparison with ground surface pipe-to-soil potential measurements and integrating with pipe surface pH and deposit data.
Soil Redox	Prior to coating removal	Near-neutral pH SCC occurs in anaerobic conditions either under coating or in the soil surrounding the pipe. Can usually be inferred from soil color.
Soil Samples	Prior to coating removal.	Useful in confirming drainage conditions. Soil analysis results can be trended in predictive model.

K.3.1. Pipe-to-Soil Potential Tests

Pipe-to-soil potential is a measurement of the flow of current from the surrounding soil to the pipe surface. Measurement of the pipe to soil potential using a CuCuSO4 electrode in conjunction with a multimeter is one of the most commonly performed test in the corrosion industry. Pipe to soil potential test should be completed every time an excavation is conducted.

Drainage also determines whether a soil is anaerobic (reducing) or aerobic (oxidizing).

K.3.2. pH

The acidity or alkalinity of the soil, corrosion deposit or electrolyte is expressed in terms of pH, which is essentially a measure of hydrogen ion concentration in the environment, Corrosion rates for uncoated carbon steel increase significantly as pH drops below about 4.5.

K.3.3. Coating Samples

Coating samples may be collected if requested by NuStar Engineering, but this is not required. Subsequent analysis of the coating can provide information pertaining to electrical and physical properties of the coating.

K.4. Deposits Assessment

Table K–3 presents the elements required when conducting a deposit assessment for any SCCDA or ILI directed dig:

Table K–3. Required Elements for ILI Directed Digs

Data Element	When Collected	Use and Interpretation of Results
Deposit description	After coating removal	Useful in establishing type of cracking and whether CP is achieved.
Deposit analysis	After coating removal	Useful in establishing type of deposit (e.g. weak acid spray) to distinguish calcareous deposits from iron carbonate deposits.

K.4.1. Corrosion Deposits Assessments

When corrosion features are encountered, the coating should be removed (if coating exists) and the corrosion should be examined to identify if the corrosion is active or inactive.

In field situations, active corrosion sites can be identified by the presence of a wet surface on the corrosion and the presence of fresh (wet or pasty) corrosion by-products. Inactive corrosion sites will be identified by a dry surface and the presence of hard or dried out corrosion by-products. In each joint of pipe that is exposed, a representative number of areas should be inspected to determine if corrosion deposits are present, and if they are present, what is their composition. Areas that typically contain corrosion deposits are located along welds where the coating was tented, along wrinkles in the coating caused by soil stresses, and under areas of disbonded coating. Corrosion deposits should be properly inspected to allow for field identification. Corrosion deposits in pipeline environments may be categorized according to color, texture, and distribution. Industry experience has found that common corrosion deposits found beneath pipeline coatings include the following:

- Iron carbonate, Siderite ($FeCO_3$) – typically white and pasty, Anaerobic Corrosion, Active
- Calcium carbonate ($CaCO_3$) – typically white and powdery, effective CP, corrosion unable to form
- Iron hydroxides and oxides (FeO [OH], Fe_3O_4) – typically orange and powdery or scaly, Aerobic corrosion
- $FeCO_3$ and FeO – Mixture, white creamy and brown, Anaerobic corrosion turning Aerobic
- Nacholite ($NaHCO_3$) – white crystals
- Magnetite (Fe_3O_4) – black and powdery
- MIC (FeS) –
- Black and smelly, Anaerobic MIC corrosion
- Black, smelly and scaly, Anaerobic MIC becoming Aerobic

The different deposits are associated with different types of corrosion and cracking. For example, non-classical SCC is commonly associated with iron carbonate ($FeCO_3$) while classical SCC has been associated with the presence of Nacholite ($NaHCO_3$) and Magnetite (Fe_3O_4).

The identification of the corrosion deposit in the field is very important as it assists with understanding the pipeline environment.

K.4.2. Corrosion Deposit Sampling

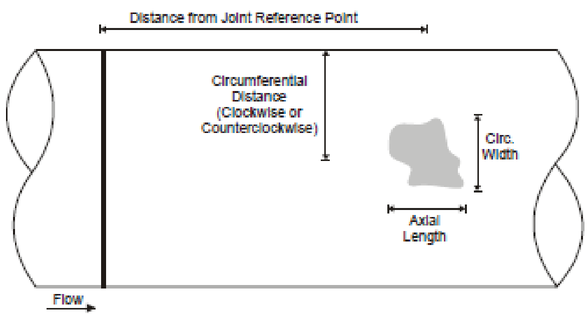
Unless requested, sampling of the corrosion deposits is not required. If further analysis is needed, collect sample with sterile equipment and send to lab.

Identifying and Locating Corrosion Deposits

All corrosion deposit samples must be identified and located on the pipe. The identification and location information is used to assist with correlation between the presence of corrosion or stress corrosion cracking defects. Identification of corrosion deposits and electrolyte should be consistent from one excavation to the next to allow for tracking. Locating the corrosion and electrolyte sample requires the position of the sample be obtained relative to the excavation reference point. Obtain the position by (a) measuring the distance upstream or downstream from the reference point and (b) measuring the circumferential distance around the pipe either clockwise (CW) or counter clockwise (CCW) from the top of the pipe.

Figure K–1 shows the measurements that are required to properly locate a corrosion deposit or electrolyte sample. The distance from the joint reference point and the circumferential distance are measured to the center of the corrosion deposit or electrolyte sample. The length and width of the corrosion deposit or electrolyte sample are then recorded, allowing for the extent of the deposit to be recorded.

Figure K–1. Measurements for Corrosion Deposits and Electrolyte Samples



K.5. Defect Assessment

K.5.1. Selection of Area for Inspection

All defects must be identified and located on the pipe. Identification of defects should be consistent from one excavation to the next to allow for tracking. Locating defects requires the position to be obtained relative to the excavation reference point. Obtain the position by (a) measuring the distance upstream or downstream from the reference point and (b) measuring the circumferential distance around the pipe either clockwise (CW) or counter clockwise (CCW) from the top of the pipe.

K.5.2. Corrosion, Dents, Mechanical Gouging and Weld Defects

Care should be taken to ensure that the abrasive blasting medium does not cut through the reduced metal area and to eliminate peening of the metal leading to the masking of relevant discontinuities. The selected feature might just barely pass burst pressure calculations; aggressive metal removal due to blasting could cause the pipe to fail calculations. All areas blasted should be blasted to a clean near white finish NACE #2/SSCP –SP 10 where ever possible. All areas that are blasted should be examined using Black and White Wet Particle MPI.

Care should be taken when obtaining the measurements of the axial and circumferential positions because this information will be used to correlate the defect with any corrosion deposit or electrolyte samples that were obtained. For all repair decisions concerning specific defects please refer to Section 3, Integrity Assessment.

K.5.2.1. Corrosion

Corrosion defects should be identified by measuring the axial and circumferential location as described. In addition, the defect size should be documented by measuring the length and width of the defect. The length of the defect is the distance the defect extends axially, while the width of the defect is the distance the defect extends circumferentially. It is recommended that documentation is done on a joint-by-joint basis and an appropriate ID is given to each feature to ensure that when the report is compiled, it is clear which feature is discussed. All corrosion areas should have MPI done to ensure no cracking.

All corrosion features should be interacted before reporting the anomaly length, currently NuStar uses the Pipeline Operator's Forum (POF) method of interaction, which states two individual metal loss features interact and shall be clustered when the axial spacing between the metal loss feature edges is less than the smallest metal loss feature length, and the circumferential spacing is less than the smallest metal loss feature width.

The POF criterion plays an important role in determining the length of the metal-loss area that NuStar uses for its metal-loss remaining strength calculation. The interaction criteria described above are continued until an area of sound pipe is reached. The sum length of all grouped metal-loss anomalies becomes the total length of the new interacted feature. NuStar uses the metal-loss group length and the maximum depth to calculate the predicted burst pressure for the metal-loss area. The POF criteria are sufficiently conservative to properly capture the influence of adjacent metal-loss areas.

K.5.2.1.1. Corrosion Assessment

Corrosion Assessment is completed to determine the remaining wall thickness of the pipeline, which can be used to determine the remaining strength of the pipe. Remaining wall measurements may be made indirectly by measuring the depth of the defect or directly by measuring the wall thickness using a non-destructive testing method such as Ultrasonic Testing (UT).

Corrosion assessment and mapping may be completed by:

- A pit depth measurement and length measurement
- A crayon rubbing with isolated pit depth measurements using a pit gauge
- A detailed pit depth mapping using a grid with pit gauge
- A detailed remaining wall mapping using an ultrasonic pencil probe
- A high-resolution inspection using ultrasonic or optical methods.

The method that is employed will depend on the engineering requirements and the equipment available. Some of the information contained in this section can also be used to assess dents.

Recommended Photographs include

- Detailed photographs of each corrosion feature (each feature should be labeled and each photo should include a reference scale such as a ruler), and
- Photographs of the corrosion feature once the grid is placed on the defect.

K.5.2.1.2. Measurement Techniques

Defect measurements can be obtained in one of two ways.

- Indirect measurements – where a pit depth is measured and the remaining wall thickness is calculated based on the known non-corroded wall thickness.
- Direct measurements – where the remaining wall thickness is measured using ultrasonic techniques.

K.5.2.1.2.1. Indirect Methods – Pit Gauge and Optical Techniques

Indirect methods to measure remaining wall thickness require the measurement of the pit depth subtracted from the known non-corroded wall thickness. The equipment that may be used for indirect measurements includes the following:

- Pit gauges

- Scales or profile gauges
- Micrometers
- Bridging bars
- Straight edges or rulers

The most commonly used tool is a pit gauge. The pit gauge provides a quick and accurate measurement of the depth for isolated pits and simple corrosion features. When more complex corrosion geometries are encountered, such as patch corrosion, circumferential or spiral corrosion, and corrosion near a long seam or weld, pit gauges have limited success. In those situations a scale or profile gauge would be more appropriate as these tools provide the ability to take an imprint or cross section of the corrosion defect shape. However, this tool is limited to defects that are shorter in length than the length of the tool.

In situations where a larger area is corroded a bridging bar may be used to provide a suitable measurement surface. Bridging bars can be used for work in and around weld caps as well. To accommodate the weld cap the bridging bar may need to be raised. The depth measurements can be adjusted for the raised amount to provide accurate measurements.

The indirect measurements are then used to calculate the remaining wall thickness by subtracting the pit depth from the known uncorroded wall thickness. A shortcoming to this method is that if there is any bulging or curvature that changes the profile of the corrosion, the calculated remaining wall may be under- or over-estimated.

More advanced technologies for indirect assessment include automated inspection systems that utilize optical inspection methods such as laser techniques or ultrasonic methods. The use of automated inspection methods provides accurate, detailed mappings of a corrosion defect that provide a permanent record for future analysis.

K.5.2.1.2.2. Direct Measurements - Ultrasonic Techniques

Direct measurements of corrosion features require that the remaining wall thickness within the corrosion feature be obtained. Ultrasonic thickness gauges are typically used to measure remaining wall thickness.

To obtain accurate measurements using the ultrasonic equipment, the tip of the ultrasonic probe must be able to fit within the corrosion feature. This may not be difficult in general corrosion but may prove more difficult in high-relief channel and pitting corrosion.

Since the ultrasonic thickness measurement is measuring the remaining wall thickness, it is not dependent on a bridging bar when mapping larger corrosion areas. Additionally, since the true wall thickness is measured, there is no need to calculate the remaining wall by using a non-corroded wall thickness measurement, reducing the possibility of an erroneous measurement due to bulging of the metal surface.

Automated systems that utilize Ultrasonic Testing have been introduced into the market and allow for both pit depth and remaining wall measurements to be obtained.

K.5.2.1.3. Obtaining Corrosion Feature Measurements

Using either indirect or direct methods, a representative number of measurements is required from a corrosion feature to allow further assessment. The method used to obtain measurements will depend on the engineering requirements and other factors, such as the type of corrosion feature and the time allowed for defect assessment. The methods typically employed to assess a corrosion feature include the following:

- **Pit Depth or Wall Thickness Along with a Length Measurement**—In situations where the corrosion is minor or a pit or channel requires assessment, some operators elect to use one individual measurement combined with the axial length of the defect. This method provides a very efficient means for getting a quick assessment of the defect and how it affects the remaining pipe strength.
- **Crayon Rubbing with Isolated Measurements**—A commonly used method in the assessment of corrosion defects is the use of a crayon rubbing of the defect along with isolated measurements within the more significant pits and channels. The crayon rubbing provides a permanent record of

the corrosion geometry and the pit depth and/or the remaining wall measurements providing the quantitative measurements. Spatial distances can then be measured off the crayon rubbing.

- **A Grid Format with Measurements**—A systematic approach to corrosion assessment requires that a grid be established over the corrosion feature. The pit depths and/or remaining wall measurements are then obtained within the grid. Typical grid sizes that are used are 1/2" or 1". Minimum remaining wall is typically measured within each cell to represent worst-case scenario. This method will generally provide the most conservative approach when assessing "predicted burst pressure" values.

K.5.2.1.4. Corrosion Mapping Procedure

The following are the steps that need to be followed to standardize the mapping of corrosion areas:

1. Identify and clean the area to be mapped.
2. Determine if a 1/2" or a 1" grid is required. This will create a checkerboard pattern on the data sheets. Please see attached diagram.
3. Spray the template onto the pipe. If a template is not available the tried and true method of drawing a grid onto the pipe can also be done.
4. Measure wall thickness or pit depth in the area of each grid node. Try to measure the corrosion pitting in the vicinity of the grid node. This means that the measurement does not have to be exactly on the grid note center.
5. Ensure that the grid used encompasses all of the corroded area. This means that the measurements at the outside edges of the grid should be, or be close to, nominal wall thickness.
6. Locate cell A1. 1 is ALWAYS in the top left corner of the grid. Note that this differs from the past way of mapping corrosion pitting when the grid was set up in a downstream direction. Low direction is NOT a factor in determining grid design. 1 will be in the top left corner of the grid when you are facing the pipe looking at the grid.
7. Cell A1 should be measured in from the reference girth weld and either the top of pipe (TOP) or a longseam, provided the longseam location is documented. Please provide the longseam location in terms of clock position and in degrees from the top of pipe.
8. The grid nodes will be labeled in the following manner.
    a. Columns are labeled…Z, AA…AZ, BA…BZ, CA…CZ, DA…DZ, etc.
    b. Rows are labeled: 1, 2, 3, 4, etc.
9. Photograph the entire grid with the proper labeling on the pipe. Also photograph in detail any areas of interest.
10. If you are using different techniques, such as UT wall thickness and pit depth, please make it clear that you have done so.
11. Complete a diagram of where the corrosion pitting is located on the pipe.

K.5.2.2. Cracks

Cracks occur in many different forms and may be isolated or within colonies. Correct identification of the crack is required to determine the course of remedial action. Regardless of the type of crack, the crack or colony size should be documented by measuring the length and width of the defect. The length of the defect is the distance the defect extends axially, while the width of the defect is the distance the defect extends circumferentially.

For stress corrosion cracking (SCC) cracks it is important to identify any features associated with an SCC colony. Features commonly associated with SCC include the following:

- Corrosion (general, pitting, and channel),
- Stress risers (dents, scrapes, and arc burns), and
- Toe cracking.

Note: The sections below recommend light buffing to improve visible indications of this type of defect, however, NuStar prohibits the use of buffing on the longitudinal seam weld ("long seam").

K.5.2.3. Fusion Line (Toe) Cracks

Indications found along the toe or centerline of either the girth weld or long seam can be caused by either the manufacturing process or by in-service stresses. The following identifies some of the manufacturing defect weld indications commonly detected along pipeline systems:

- Lack of fusion (centerline found on ERW welds and toe of SAW welds)
- Undercut (toe of weld only)
- Roll over (toe of weld only)
- Slag (toe of weld only)

Often manufacturing defects and in-service defects have very similar surface appearances. Removing surface scale by lightly buffing the indication can greatly improve the indication outline to assist in interpretation.

K.5.2.4. Non-Crack Indications

Common indications often misinterpreted as crack indications include the following:

- **Surface Laminations**—Surface laminations are very common throughout pipeline systems. Their appearance is relatively smooth with either a gentle curve or completely straight. If numerous shorter laminations are detected close together, they can have the appearance of an SCC colony or crack. Light buffing will define the indication outline to determine the existence of tails or tapered ends. Surface laminations are generally shallow in relation to their length.
- **Blisters**—Some surface blisters can exhibit one or two distinct surface breaking edges. Several blisters clustered together can have the appearance of an SCC colony. Blisters usually have a raised center and can be felt by touch. Surface blisters are usually shallow and can be removed easily by buffing.
- **Corrosion**—Some corrosion profiles such as striated corrosion can inhibit the detection of SCC. The sharp valleys hold the particles and if SCC exists at the bottom of the corrosion, it may not be detected unless tails are apparent at the edges of the corrosion. If the corrosion is shallow, it can be buffed off to determine if SCC is located at the valley bottom. The walls of corrosion found in general or pitted corrosion can sometimes appear to be SCC colonies. Blowing on the particles can help determine if the indications are corrosion walls.
- **Inclusions and Stringers**—Inclusions and stringers are commonly misinterpreted as SCC. These discontinuities are generally more rounded without the sharp edge. Stringers are more isolated and do not have the colony effect seen with SCC. Porosity often is found clustered together, but unlike SCC the roundness of the indications is distinct.
- **Mill Scale**—Mill scale is often misinterpreted as SCC. Unlike SCC, mill scale has surface edges that can be felt. Light buffing will remove these false indications.

K.5.2.5. Dents

When dents are located, each dent should be examined to determine, if possible, the cause of the dent. It should be determined if the dent was caused by mechanical damage during construction or if it is the result of subsurface conditions. Dents should be located and documented in a similar manner as corrosion defects. All dents should be MPI inspected to ensure no cracking exists within the dented region.

Dents are caused in many ways, including mechanical damage during pipe installation or an impact by a rock or other object. The result is that the integrity of the pipe may be reduced, and therefore the extent of the dent must be assessed. Because dents are not the result of wall thinning but rather the result of a deformation of the pipe curvature, the methods used to assess denting should be indirect methods. The use of a pit gauge and bridging bar, if the area is extensive, will allow the depth of the dent to be determined. Ultrasonic methods will report consistent wall thickness with the nominal pipe thickness unless internal corrosion is present.

When performing a dent assessment it is best to set up a grid over the dented area and obtain a suitable number of measurements within the grid. If the dent is small there may be no need to perform a grid inspection but only a simple maximum dent depth and axial and circumferential extent measurements. Magnetic particle inspection is recommended on 100% of the dent area to ensure cracking has not initiated due to stress risers or ingress of a potent environment.

K.5.2.6. Gouges

When gouges are located, each gouge should be examined to determine, if possible, the cause of the gouge. It should be determined if the gouge was caused by mechanical damage during construction or if it is the result of subsurface conditions. Gouges should be located and documented in a similar manner as corrosion defects. NuStar recommends that all gouges be MPI inspected to ensure no cracking exists within the region

K.6. Reporting

Two critical components of the investigative excavation are the accuracy and comprehensive documentation of investigative results. It is important to prepare complete documentation, as once the pipe is repaired, recoated and the excavation is backfilled, the pipe section will no longer be available to collect additional information. The key items to good reporting include the following:

- Clarity—all material should be legible and should clearly describe the observation
- Completeness—all documentation should be complete providing a reader with a comprehensive description
- Accuracy—all documentation should contain accurate descriptions and measurements.

PIR & Defect Evaluation forms shall be used to document the data collected during the investigative excavation.

K.7. Photography Recommendations

Table K–4 lists the recommended photographic data elements.

Table K–4. Recommended Photograph Elements

Data Element	When Collected	Use and Interpretation of results
Photographs of dig site	Prior to coating removal	Useful in confirming terrain conditions, coating type, and coating condition..
Photographs of corrosion deposits	After coating removal	Used in integrity assessments. See Recommended Pictures for examples and orientations.
Photographs of defects	After coating removal	Used in integrity assessments. See Recommended Pictures for examples and orientations.

K.7.1. Sample Photograph Labeling Procedure

NuStar recommends the following information appear in all photographs:

- Pipeline Name
- Date
- Reference Point, Station, Valve #
- Site Chainage, Wheel Count, Mile Post
- Chainage from U/S weld
- Orientation i.e.; U/S, D/S
- Flow Direction

K.7.2. Site Terrain Pictures

NuStar recommends the following photographs be taken prior to excavation:

1. View facing upstream
2. View facing downstream
3. View facing across the excavation looking towards the working side of the excavation
4. View facing across the ditch towards the defect side of the excavation

K.7.3. Excavation Conditions

NuStar recommends the following photographs be taken once the pipe has been excavated:

1. View facing upstream showing excavation conditions (includes pipe, excavation bottom, and upstream ditch wall).
2. View facing downstream showing excavation conditions (includes pipe, excavation bottom, and downstream ditch wall)
3. Soil Profile – this may require one or more photographs in various locations within the excavation depending on the soil conditions. NuStar recommends that soil profile photographs be obtained in locations where the soil profile can be clearly seen in the ditch wall.

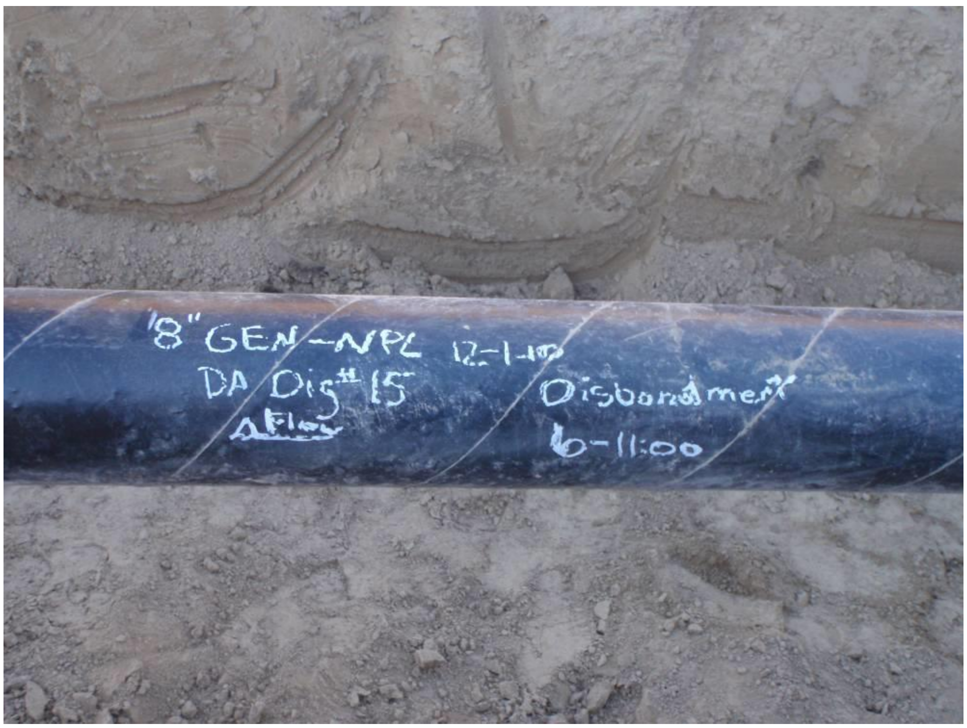
Figure K–2. Example Excavation Condition Photograph

K.7.4. Coating Conditions

Once the excavation is opened and it is safe to enter, photographic documentation of the coating conditions should be completed. Photographs of the coating may include the following:

- One or more photographs of the coating showing the condition of the coating.
- Close-up photographs of areas of interest such as wrinkles, holidays, and disbondment. At sites where more than one area contains a defect, a representative photograph can be obtained.

Figure K–3. Example Coating Condition Photograph



K.7.5. Corrosion Deposits

If corrosion deposits are encountered during the coating inspection a representative number of photographs of the corrosion deposits should be obtained. Each photograph should be clear, taken at a suitable distance, and should include:

- One or more photographs of deposits.
- Close-up photographs of areas of interest.

Figure K–4. Example Corrosion Deposit Photograph

K.7.6. Mechanical Damage, SCC, and Other Defects

NuStar recommends that all dents, gouges, SCC, or other defects be photographed for future reference. Follow the photography labeling protocol set forth in Section 0. Also include close up of defect.

Figure K–5. Example Defect Photograph 1

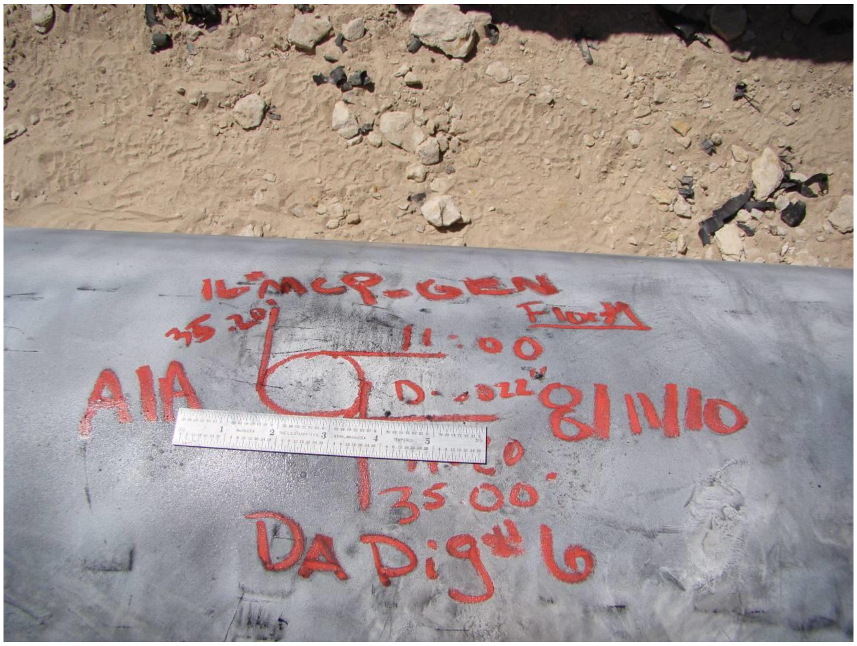


Figure K–6. Example Defect Photographs 2

K.8. Documentation and Record Retention

NuStar documents external inspections on the Pipeline Information Report/Defect Evaluation Forms, all other photographs, rubbings, and other information should be kept with region responsible, along with copies forwarded NuStar Corporate IMP and Corrosion Departments.

L - Guidance for ILI Data Validation

While this document is not meant to be all-inclusive of analysis techniques and 'what to look for', it presents a general guideline for assessing ILI assessment data. Additional references available to the assessment engineer include the API best practices *Distillation of Data Integration and Interpretation Survey Results* as well as NuStar specific practices detailed in the NuStar IMP Manual.

Prior to conducting an analysis of the ILI assessment data the Assessment Engineer should review and gather relevant information for the segment including: potential or identified threats specific to the segment (AC corridors, SCC, etc), previous PM measures, segment coating types, and product type (current and historical). Assessment Engineer should document all activities and ensure that any work completed during the analysis (spreadsheets or otherwise) are easily followed for future reference.

L.1. Pre-Analysis

L.1.1. Review Segment Threats

Review past inspection documentation or discuss with the Region IMP engineer if there are specific threats associated with the segment to be analyzed. For example, the presence of AC corridors, the presence of SCC, or past history with long seam issues may provide hot spots of focus for the analyst.

L.1.2. Review Relevant Pipe Segment Environment

Understanding of the pipe coating type and condition, soil types and conditions encountered along the right-of-way, the presence of waterway crossings or water bodies, etc. can also provide insight to a successful segment analysis. Collect and review this information from the GIS data or discuss with Region Operations personnel

L.1.3. Review Vendor's Written Report

Close review of the ILI Vendor's written report is necessary to determine if there are any specific areas of concern that require early evaluation. Also, the vendor may have provided information from past inspections that will be helpful guidance.

L.2. ILI Data Validation

Prior to beginning the in-depth ILI data integration and analysis the pipe data and features identified in the vendors ILI assessment data should be validated.

L.2.1. Pipe Specification Validation

The pipe specifications included in the ILI clientlist provided by the tool vendor should be crosschecked with the current pipe data in the GIS database, to determine correctness or if there are any differences that warrant further investigation. Accuracy of the pipe data is critically important for the data analysis to avoid unnecessary repairs and in determining the risk of any potentially injurious features. Pipe data that should be reviewed includes:

- Wall Thickness
- OD
- SMYS

  - If SMYS is unknown and the yield strength has not been determined by tensile tests, 24,000 is assumed per 49 CFR §195.106 (b). For anomalies under unknown SMYS, assuming MOP is valid, consider B31G for repair criteria, which allows for substitution of MOP.
- MOP
  - Calculate design pressure at all wall thickness changes. Compare pressure to MOP, if it doesn't reconcile, then discuss with HSE for compliance review. If completed for previous ILI assessments, and assuming the MOP is unchanged, no review is necessary.

If differences in pipe specifications are identified, follow-up with ILI tool vendor to determine the reason for any differences. If the difference is a result of an error on the tool vendors part, a corrected clientlist should be issued. In the event that differences in wall thickness (or OD) are identified and tool vendor confirms upon review data is correct, contact the NuStar GIS department to initiate a review of the pipe data in question.

L.2.2. Pipe Segment Feature Validation

Assessment engineer should review features identified by the tool such as: taps, stopples, tees, sleeves, weld plus ends, valves, flange, casings, or other pipeline attachments unknown or installed with unapproved or unknown installation methods. These pipeline segment features should be compared to the features found in the current GIS database as well as previous ILI results (counts, locations, etc.).

As an example, valves identified by the ILI should be verified that they are truly valves and not other features, such as wrinkle bends. Reference the NTSB Pipeline Accident Report - *Rupture of Piney Point Oil Pipeline and Release of Fuel Oil near Chalk Point, Maryland; April 7, 2000.* Additionally, awareness of the presence of legacy patch or half-sole repairs on the segment is important. The presence of such repairs, coupled with current pipe condition and location risk factors may be an early indication of a need for pipe replacement as opposed to full-encirclement sleeve repair.

L.2.3. Tool Tolerances

Ensuring that the proper tool tolerances have been indicated for the assessment is critical. Good practice is to confirm with the vendor upon receipt of the final report. Early awareness of changes in anomaly sizing protocol (i.e. discrete vs. "bucket" sizing for crack-like features) will prevent confusion later in the data analysis process.

L.3. Data Integration

Data integration of the ILI results is key to the engineering criticality process for identifying repairs. Data integration activities should include graphing of the current ILI data individually and also comparatively with previous assessment data (templates are available for many of these graphs) to look for trends in the data. Pivot charts can also be utilized to help determine areas of concern (e.g. joint by joint) to determine the 'volume' of metal loss. Review any anomalies from past assessments that were selected to monitor.

Elevation data should be integrated with the ILI data (if elevation deviates more than 100') and a "local" MOP calculated. The ERF can then be recalculated for all anomalies as the vendor does not adjust the ERF for elevation.

Assessment Engineer should utilize the tool vendor, as needed, for areas, or anomalies, of concern.

L.3.1. Metal Loss

In addition to the external/internal metal loss analysis detailed in this section, a review of the metal loss pattern on the line should be completed and compared with the tools probability of sizing to determine if proper technology was used. Anomaly dimension classes, beyond the clusters, should also be reviewed. Also, review for event type changes from assessment to assessment (internal to external or vice versa).

External Metal Loss

External metal loss anomaly should be compared to pass assessment data to help determine if any growth may be occurring. Review Google Earth plots of the ILI data for additional cause identifiers. Metal loss density, per joint, may provide indication of disbonded coating or help to identify higher priority evaluation areas. Review CIS survey data in areas of concern.

Review any air to ground interfaces for corrosion, possibly indication coating failure at interface (look for metal loss features downstream of and in proximity to a bend).

External metal loss identified in areas with FBE coated pipe should be aggressively investigated.

Axially oriented corrosion (thin and long) should be investigated to determine if there is the potential threat of preferential seam corrosion. If available, data between MFL and high resolution UT or AFD tools should be integrated.

Internal Metal Loss

Internal metal loss should be reviewed against past assessment data, if available, to determine the potential for growth. Internal coupon data should be also be reviewed as an indicator of corrosion growth rates as well and to help determine if any growth is possibly due to tool deviation or if it is actual growth occurring. If corrosion rates can be calculated, re-process the ILI data in the Data Manager to determine if a reduced re-assessment interval may be recommended.

Pipeline elevation data should be reviewed and integrated with the ILI data to determine if low spots in the pipeline is where the internal metal loss is congregating.

L.3.2. Mechanical Damage

Dents

Review TOP dents for possible third party damage. For example, look for multiple dents or deformations in close proximity, dents in areas of shallow pipe such as creek crossings, cultivated fields, etc. Additionally, deformations could be potentially miscalled (could be a dent w/ metal loss or mechanical damage). Compare to previous assessment data and review one-call information. In addition, review previous dent repairs to determine if any dents repaired were also found with metal loss. Raw data signals (i.e. Rosoft or Pigtrap C-scans) can be reviewed in-house or by following up with vendor for concerns.

Review BOP dents for any changes in dimensions or call identification from previous assessments or if the dents are 'new'. Look for any dents potentially affecting girth welds or long seams.

Review for any off-axis or multi-apex dents and perform additional investigation, as warranted.

Manufacturing Defects

Review the assessment data for clusters of manufacturing defects, defects affecting welds, increases in anomaly dimensions or change in event type when compared to previous assessment data.

L.3.3. Casings

Metal loss inside casings should be compared to previous assessments to determine the probability of anomaly growth and growth rate. Validate casing protection is in place, if applicable, and working (i.e. not shorted). Report any metal loss calls within casing to corrosion manager. Integrate casing inspection data from CPDM.

L.3.4. Other

Review extra metal (gain) events. Compare to previous assessments to determine if gains have been identified before, are 'new' events, or if the gains were previously identified as a different event (MNFG one assessment vs. EXME on reassessment, etc.). Review GIS for foreign pipelines in proximity to EXME to determine if CP system interference may be occurring. Identify and review any circumferential gain events.

Review previous repair areas. Vendors should be reporting metal loss anomalies underneath previous repairs. These anomalies can be used to validate the as-called data. In addition, review for any significant dimension changes of these anomalies since they have been repaired.

L.4. Repair Plan Development

After the data integration and analysis is completed, the Assessment Engineer should identify potential dig locations, based upon the analysis, for review with the pipeline segments Area Manager and other interested parties (corrosion techs, corrosion manager, etc.). Note HCA/Non-HCA location of potential digs, digs within close proximity of each other and any other pertinent information. After review with the interested parties finalize dig book and note any anomalies of concern, not selected for digging, for monitoring in future assessment analysis. Upon receipt of dig results and comparison to the as-called data, re-asses for additional digs as needed.

Version and Revision Log

Current Section, Procedure, and Appendix Versions

[redacted]

Revision Log

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]