Risk Assessment

Hazardous Liquid Pipeline Integrity

January 2021

TODAY'S SPEAKER

Bryan Louque, P.E.

Vice President of Asset Integrity and Corrosion
Audubon Companies

Bryan Louque has over 25 years of experience in the midstream & downstream energy industry, actively involved in pipeline safety. His primary experience is associated with the design, construction, and operations & maintenance of midstream and downstream assets. He is an expert on corrosion control, asset integrity and regulatory compliance programs for natural gas (Parts 191/192) and hazardous liquids (Part 195) pipeline systems. He has previously held corrosion control, pipeline integrity and regulatory compliance management positions with global EPC firms and the Department of Transportation (PHMSA).

SAFETY START

Get Out and Look (GOAL)

TABLE OF CONTENTS

RISK 101

Why Should I Bother?

- Objectives
  - Prioritize pipeline segments for:
    - Integrity assessments
    - Mitigating action
  - Quantify benefit of mitigating action
  - Align mitigation measures versus identified threats
  - Determine cost / benefit for modified assessment intervals
  - Optimize resource allocation

QUANTITATIVE RISK ANALYSIS

Expected Loss (EL) Units

- **Time Dependent** Threats
  - Corrosion
    - External
    - Internal
  - Cracking
    - Fatigue
    - Enviro-assisted Cracking
- **Time Independent**
  - Third Party
  - Geohazard / Weather
  - Incorrect Operations
  - Sabotage

- **Probability**
  - Exposure
  - Mitigation
  - Resistance
    - Manufacturing
    - Construction
    - Equipment
- **Consequence**
  - Ignition vs. Non-ignition
  - Cost impact in dollars
    - Human/Safety
    - Environmental
    - Commercial

REGULATORY BACKDROP

49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

- Integrity Assessment Schedule 452 (e)
- Information Analysis 452 (g)
  - New “MegaRule” Requirement
- Preventative & Mitigative Measures 452 (i)
- Integrity Assessment Intervals 452 (j)

PHMSA
Pipeline and Hazardous Materials Safety Administration

Inch Wide Mile Deep

THE PIPELINERS ASSOCIATION OF HOUSTON
EST. 1953

ASSESSMENT SCHEDULE (e)

Integrity Management in High Consequence Areas

BAP / CAP

Risk Factors Used to Determine Reassessment Intervals

- **Minimum Consideration**
  - **ILI, ECDA, Hydro**
- **Relevant Threats**
  - **Risk based assessment schedule**
- **Omission of Risk Factors**
  - **Technical justification for not considering the minimum**

(i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;

(ii) Pipe size, material, manufacturing information, coating type and condition, and seam type;

(iii) Leak history, repair history and cathodic protection history;

(iv) Product transported;

(v) Operating stress level;

(vi) Existing or projected activities in the area;

(vii) Local environmental factors that could affect the pipeline (*e.g.*, seismicity, corrosivity of soil, subsidence, climatic);

(viii) geo-technical hazards; and

(ix) Physical support of the segment such as by a cable suspension bridge.

(2) Appendix C of this part provides further guidance on risk factors.

THE PIPELINERS ASSOCIATION OF HOUSTON
EST. 1953

INFORMATION ANALYSIS (g)

Risk Assessment Using Integrated Data

DATA INTEGRATION

MegaRule Part 1

- **Minimum Consideration**
  - **21 proscriptive data sets**
  - **Anomaly spatial relationship development**
  - **GIS platform / tools to get the job done**
- **Relevant Threats**
  - **Document threat inclusion or omission basis**
- **Information Interrelationship Analysis**
  - **Risk (PoF & CoF)**
    - **Absolute, rate of change, etc…**
- **Important Dates**
  - **Effective – 01 OCT 20**
  - **Compliance – 01 OCT 22**

(i) Pipe diameter, wall thickness, grade, and seam type;

(ii) Pipe coating, including girth weld coating;

(iii) Maximum operating pressure (MOP) and temperature;

(iv) Endpoints of segments that could affect high consequence areas (HCAs);

(v) Hydrostatic test pressure including any test failures or leaks—if known;

(vi) Location of casings and if shorted;

(vii) Any in-service ruptures or leaks—including identified causes;

(viii) Data gathered through integrity assessments required under this section;

(ix) Close interval survey (CIS) survey results;

(x) Depth of cover surveys;

(xi) Corrosion protection (CP) rectifier readings;

(xii) CP test point survey readings and locations;

(xiii) AC/DC and foreign structure interference surveys;

(xiv) Pipe coating surveys and cathodic protection surveys.

(xv) Results of examinations of exposed portions of buried pipelines (*i.e.*, pipe and pipe coating condition, see §195.569);

(xvi) Stress corrosion cracking (SCC) and other cracking (pipe body or weld) excavations and findings, including in-situ non-destructive examinations and analysis results for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipeline;

(xvii) Aerial photography;

(xviii) Location of foreign line crossings;

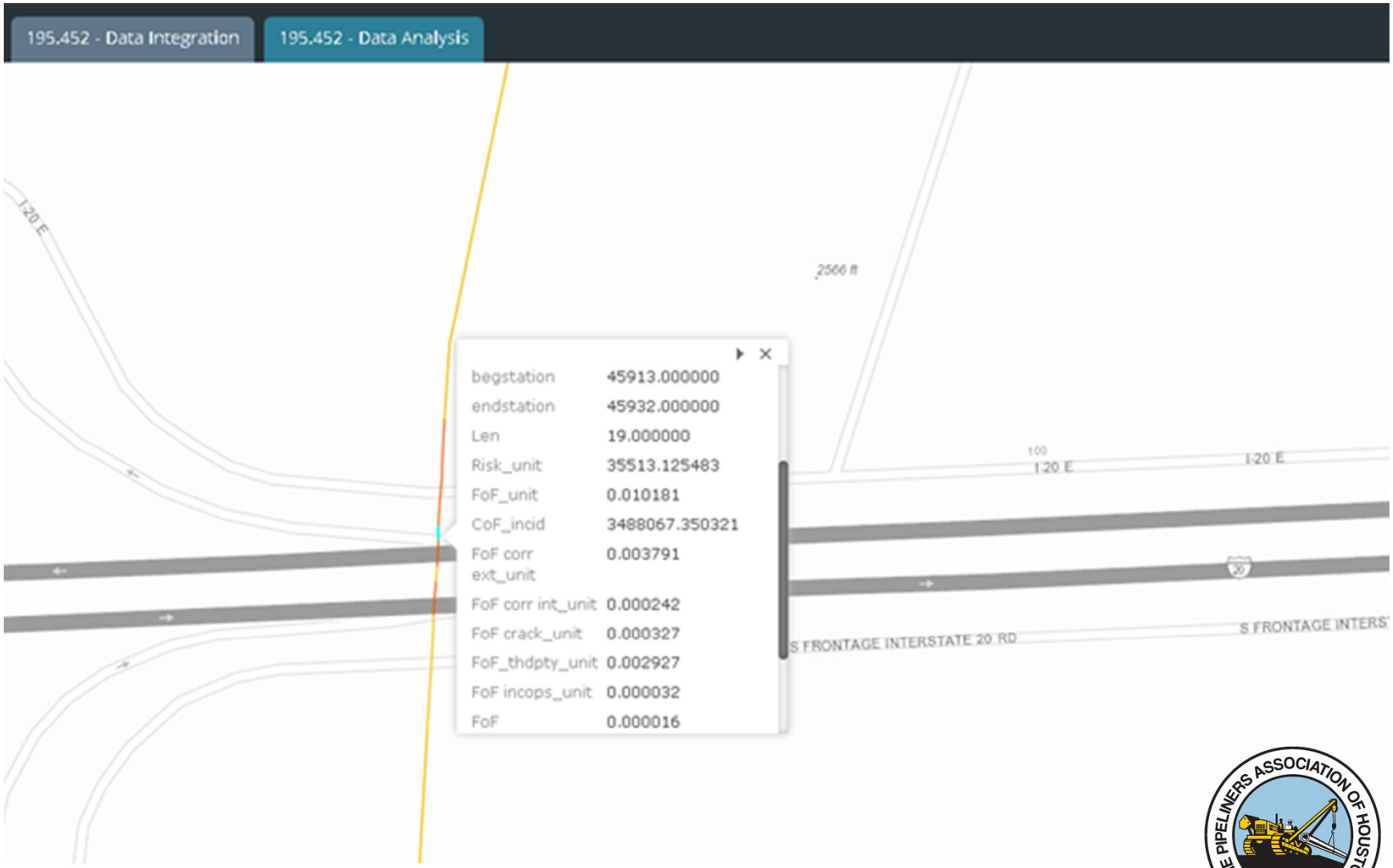
(xix) Pipe exposures resulting from repairs and encroachments;

(xx) Seismicity of the area; and

(xxi) Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this part.

THE PIPELINERS ASSOCIATION OF HOUSTON
EST. 1953

INFORMATION ANALYSIS



P & MM'S (i)

Cost / Benefit Analysis

RISK MANAGEMENT

Enhance Public Safety or Environmental Protection

- Minimum Consideration
  - Additional measures to improve pipeline system safety
  - Implement actions that offer "significant" risk reduction
- Relevant Threats
  - Documented for significant integrity threats
- Omission of any P&MM's
  - Technical justification for not implementing those that reduce risk

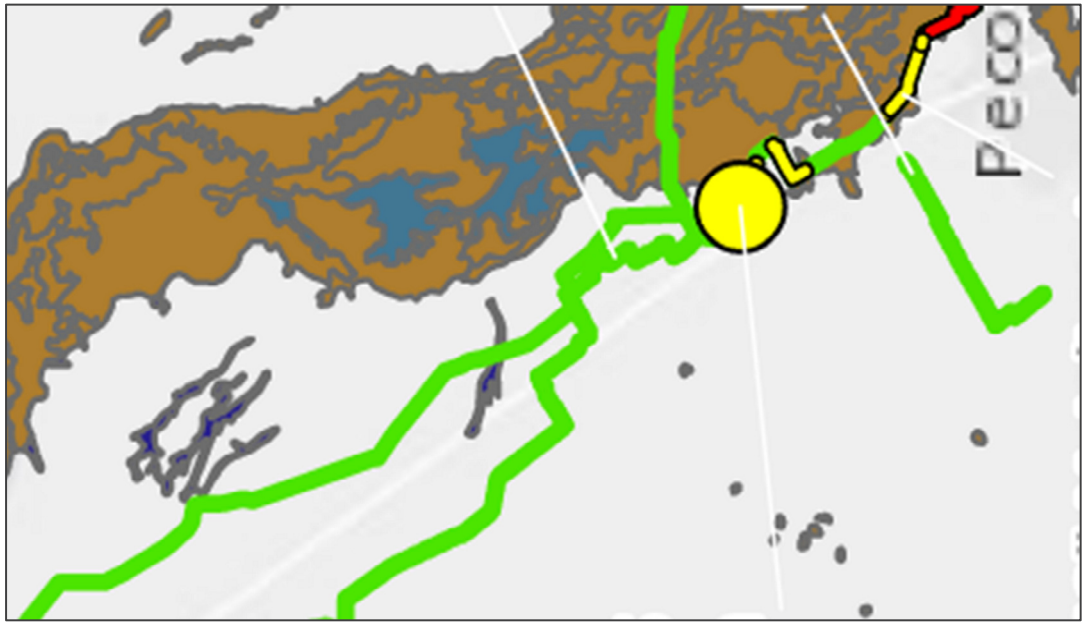
Threat	Problems Identified through Data Gathering and Integration	Preventive Measures
External corrosion	Leak history; external ILI anomalies and/or low cathodic protection readings.	Conduct appropriate cathodic protection and/or stray current surveys. Increase cathodic protection. Rehabilitation of coating in suspect areas.
Internal corrosion	Leak history, internal UT anomalies; increased corrosiveness of sampled transported fluids; analysis of pigging debris.	Conduct fluid sampling; performance of the corrosion inhibitor injection program; conduct a scraping/swabbing program; run cleaning pigs more frequently. Install additional internal corrosion coupons.
Selective Seam Weld Corrosion (SSWC)	Axially oriented anomalies identified with circumferential or helical ILI in a low-frequency ERW seam and low cathodic protection readings. Hydrostatic test failure.	Conduct appropriate cathodic protection and/or stray current surveys. Increase cathodic protection.
Environmentally Assisted Cracking (EAC)	Ultrasonic crack detection or electromagnetic acoustic transducer (EMAT) anomalies discovered in a pipe with tape wrap coating.	Increase cathodic protection on pipelines without shielding coatings. Reduce operating pressures and/or temperatures.
Manufacturing defects	Ultrasonic crack detection or EMAT anomalies discovered in pipe with a low-frequency ERW seam.	Reduce the magnitude and/or frequency of pressure cycles. Reduce the operating pressure.
Construction and fabrication defects	Defective girth weld found in a location with ground movement.	Run inertial mapping unit tool to find possible locations of ground movement.
Equipment failure	Seeps or stains in facilities at fittings or flanges.	Replace gasket materials at specific intervals or when inspections indicate gasket deterioration. Develop flange torque procedures.
Mechanical damage with immediate failure	Hits from landowners not making one-calls.	Install line-of-sight markers, trim right-of-ways more frequently, enhance contact with landowners, or establish agreements not to cultivate. Increase depth of cover;
Mechanical damage with delayed failure	Alignment of ILI anomalies with geometric anomalies reveals locations of previous damage to pipelines.	Increase frequency of aerial and foot patrols in areas of frequent new construction.
Incorrect operations	Surges caused by poorly coordinated start-ups and unexpected shutdowns from power failures. Third party valve operations.	Conduct advanced hydraulic studies to optimize start-up procedures and train operators to use the new procedures. Install improved electrical gear at remote stations to minimize power outages.
Weather/outside force	River crossing inspections identify exposed pipe due to river scouring.	Install protective mats in some cases or replace crossings with directional drills.

THE PIPELINERS ASSOCIATION OF HOUSTON
EST. 1953

P&MM CONSIDERATION

Example - Pump Station in a Flood Plain

- **What Are Options Additional Measures?**
- **What is the Relative ROI Among Options?**



ANALYSIS CRITERIA

Simulated Pipeline Release in a High Consequence Area

- **Minimum Consideration**
  - Nature & location of most significant risks (CoF)
  - Likelihood of pipeline release (PoF)
  - Demonstrate risk reduction benefits of P&MMs

(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;

(ii) Elevation profile;

(iii) Characteristics of the product transported;

(iv) Amount of product that could be released;

(v) Possibility of a spillage in a farm field following the drain tile into a waterway;

(vi) Ditches along side a roadway the pipeline crosses;

(vii) Physical support of the pipeline segment such as by a cable suspension bridge;

(viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure;

(ix) Seismicity of the area.

- **Relevant Threats**
  - Documented for all relevant risk factors
  - Identify dominant risk drivers

- **Omission from Analysis**
  - Technical justification for failure to identify risk reduction impacts

THE PIPELINERS ASSOCIATION OF HOUSTON
EST. 1953

ASSESSMENT INTERVALS (j)

Pipeline Integrity Assessment

INTERVAL ESTABLISHMENT

Based on Line Pipe Risk Posed to High Consequence Areas

- **Minimum Consideration**
  - **Assessment interval based on**
  - **Prioritize assessments by risk posed by line pipe to HCAs**

(i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;

(ii) Pipe size, material, manufacturing information, coating type and condition, and seam type;

(iii) Leak history, repair history and cathodic protection history;

(iv) Product transported;

(v) Operating stress level;

(vi) Existing or projected activities in the area;

(vii) Local environmental factors that could affect the pipeline (*e.g.*, seismicity, corrosivity of soil, subsidence, climatic);

(viii) geo-technical hazards; and

(ix) Physical support of the segment such as by a cable suspension bridge.

(2) Appendix C of this part provides further guidance on risk factors.

- **Assessment Interval**
  - **Documented based on risk factors**

- **Omission from Analysis**
  - **Technical justification for defaulting to 5 year maximum interval**

INTERVAL ESTABLISHMENT

Time-To-Failure / Remaining Life

- Essential Element of Risk Analysis

- Requires Two Pieces of Information
  - Largest remain defect
  - Mils Per Year (MPY) degradation rates

- Common Oversights
  - Failure to address dominant threats
  - Degradation mechanisms; either unknown or coincident
  - Plausible loadings on defect types and orientation
  - Failure to estimate and document key values including safety factors and other considerations of uncertainty

audubon
FIELD SOLUTIONS

Bryan Louque

Vice President – Asset Integrity & Corrosion

D: (918) 514-5800 **C:** (913) 221-3446

O: (918) 514-5879 **F:**

blouque@audubooncompanies.com

Audubon Field Solutions

People | Flexibility | Relationships | Experience

New Orleans | Houston | Tulsa | Pittsburgh | Clarksburg