ILI: An Improvement Over Pressure Testing for Pipeline Integrity Management

Gas MegaRule MAOP Verification Requirements - Advantages from Using ILI w/ Probabilistic Fracture Mechanics Analysis

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Overview of Presentation

▪ Background
▪ Update on Megarule Requirements for MAOP Verification
▪ Why ILI w/FM is better than other options allowed under §192.624
▪ A New Way to Look at Fracture Mechanics
▪ Application to Pipeline Integrity Concerns:
  • Stress Corrosion Cracking (SCC) Susceptible Line (High Toughness/Aggressive Crack Growth)
  • ERW Seam Welds (Low Toughness/Slow Crack Growth)
▪ Reality Checks
▪ Summary and Conclusions
And Then - The Perfect Storm

- Gulf of Mexico oil spill - 4/20/2010
- Marshall, MI, HL transmission / oil spill - 7/26/2010
- San Bruno, CA, N. gas transmission - 9/9/2010
- Wayne, MI, N. gas distribution - 12/29/2010
- Philadelphia, PA, N. gas distribution (CI) - 1/19/2011
- Fairport Harbor, OH, N. gas distribution - 1/24/2011
- Allentown, PA, N. gas distribution (CI) - 2/9/2011
- Minneapolis, MN, N. gas transmission - 3/17/2011
- More...
Congressional Mandates & NPRM Overview

- PHMSA issued ANPRM- August 25, 2011
- PHMSA issued preview version of NPRM for *Safety of Gas Transmission and Gathering Pipelines* on March 17, 2016 (549 pages). Official version in the April 8, 2016 FR
- Addresses five congressional mandates, one GAO recommendation and six NTSB recommendations
- Most significant PL safety rulemaking since the original PL regulations were promulgated in 1970
- Revises much of Part 192, including Design, Construction, Operations, Maintenance, Transmission Integrity Management
PHMSA Split rulemaking into three rulemaking packages:

- **Gas Transmission-** MAOP exceedance, material verification, MAOP reconfirmation, amendments to §192.619, non-HCA assessments and MCA definition
- **Gas Transmission-** Repair criteria (HCA and non-HCA), inspections following extreme events, MOC, corrosion control, IM clarifications, strengthening assessment requirements
- **Safety of Gas Gathering Lines-** Defines what is jurisdictional, appropriate safety regulations for gas gathering
Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, (2137-AE72 - existing)

Rulemaking addresses the following proposals:

- 6-month grace period for 7-calendar-year reassessment intervals
- Seismicity
- MAOP exceedance reporting
- Material verification, MAOP reconfirmation, & amendments related to §192.619
- Non-HCA assessments and MCA definition
- Related record provisions
PHMSA’s Basic Principles of IVP

▪ Apply process to both grandfathered (pre-code) steel pipe and any other steel pipeline that does not have T, V & C pressure test & material records including MTRs / chemistry to validate MAOP

▪ Allow operator to select among several options:
  • Pressure Test w/spike test
  • De-rate
  • Engineering Critical Assessment commensurate with specific shortcomings of segment (to include ILI program if needed)
  ➢ Or replace

▪ Must do material verification even if you conduct Pressure Test, De-rate or ECA
Revised NPRM Requirements Re Material Records, Testing and MAOP Verification

- §192.67- Records: Materials
- §192.127- Records: Pipe design
- §192.205- Records: Pipeline components
- §192.607- Verification of Pipeline Material
- §192.619- MAOP: Steel or plastic pipelines
- §192.624- MAOP verification: Onshore steel transmission pipelines
NPRM Overview- Part 192, MAOP Verification

§192.624 MAOP Verification: Onshore steel T. pipelines

(a) **Locations.** Operators of onshore steel transmission pipeline segments meeting one or more of the following conditions must establish MAOP using one or more of methods in 192.624(c)(1)-(6):

1. PL has experienced a reportable incident since last subpart J pressure test due to M. defect, C. defect, fab. defect or cracking defect and segment is located in:
   - HCA
   - Class 3 or 4 location
   - A MCA if the segment can accommodate an ILI
   - [Move (1) to new 192.917(e)(6)]

2. Pressure test Records to establish MAOP per subpart J in accordance with §192.619(a)(2) or (c) at the time of construction are not RTVC and PL is located in:
   - HCA
   - Class 3 or 4 location

3. A pipeline segment that has a MAOP that results in hoop stress ≥ 30%SMYS that was established per 192.619(c) before effective date of Rule and located in:
   - HCA
   - Class 3 or 4 location
   - A MCA if the segment can accommodate inspection by means of a free swimming ILI tool
NPRM Overview- Part 192, MAOP Verification

§192.624 MAOP Verification: Onshore steel T. pipelines

(b) Completion Date. For PLs installed before the effective date of Rule, all actions must be completed according to the following:

(1) Develop and implement Plan w/in 1 year of effective date of Rule

(2) Operator must complete all actions required on 50% of mileage identified in (a) by 8 years of effective date of Rule

(3) Operator must complete all actions on 100% of mileage identified in (a) by 15 years of effective date of rule, or as soon as practicable, but not to exceed 4 years after the segment first meets the conditions of §192.624(a), whichever is later.

(4) If constraints limit operators from meeting times, may petition PHMSA for 1 yr. extension
§192.624 MAOP Verification: Onshore steel T. pipelines

(c) **Maximum Allowable Operating Pressure Determination** - Operators of PL segments defined in (a) must establish MAOP using one of following methods:

1. **Method 1: Pressure test**
   - (i) Perform a pressure test in accordance with §192.505(c) Subpart J. New MAOP = test pressure divided by greater of 1.25 or applicable Class Location factor. Add requirement for opportunistic material testing per §192.607
   - (ii) If legacy pipe or legacy construction or incident due to M&C or material defects, **spike test**
   - (iii) If reason to believe that segment may be susceptible to cracks or crack-like defects, remaining life calculation in accordance with §192.624(d) (Fracture Mechanics).

2. **Method 2: Pressure Reduction** - MAOP ≤ highest operating pressure in last 18 months divided by greater of 1.25 or applicable CL factor. Add requirement for opportunistic material testing per §192.607
   - (i) If segment has had a change in CL, reduce the segment MAOP as follows:
     A. If CL changed from 1-2, 2-3, or 3-4, use actual pressure in past 18 months divided by 1.39, 1.67 or 2.00 respectively.
     B. If CL changed from 1-3, reduce MAOP to ≤ actual pressure in past 18 months divided by 2.00

3. **Method 3: Use Engineering Critical Assessment (ECA) to establish material condition and MAOP.** ECA is an analytical procedure, based on fracture mechanics, material properties, operating history, environment, in-service degradation, possible failure mechanisms, defect sizes etc. to determine max. tolerable sizes for imperfections. Verify material properties in accordance with §192.607 if information/ records not TVC.
§192.624 MAOP Verification: Onshore steel T. pipelines
(c) **Maximum Allowable Operating Pressure Determination (con’t)**-

(4) Method 4: Pipe Replacement

(5) Method 5: Pressure Reduction for Segments w/ Small PIR. and Diameter—PLs w/ MAOP < 30%, PIR ≤ 150 ft., D ≤ 8”, AND can’t assess using ILI or PT may establish MAOP as follows:

(i) Reduce MAOP to ≤ highest pressure in past 18 mos–5 years divided by 1.1
(ii) Conduct ECDA and ICDA
(iii) Implement procedures for NDT and assessments for cracks at all excavations (except 3rd party)
(iv) Conduct monthly patrols in CL 1&2 locations NTE 45 days, 4 x per year, weekly in CL 3 NTE 10 days and semi-weekly in CL 3&4 locations 6 x per year NTE 6 days
(v) Conduct monthly instrumented leak surveys in CL 1&2 locations 4 x per year NTE 45 days, weekly in CL 3 NTE 10 days and semi-weekly in CL 3&4 locations 6 x per year NTE 6 days
(vi) Odorize gas in segment, AND
(vii) If reason to believe susceptible to cracking (e.g. vintage), must estimate remaining life w/ FM

(6) Method 6: Use of Alternative Technology- Notify PHMSA 90 days in advance of use

(d) **Fracture mechanics modeling for failure stress and crack growth**—Move to new §192.712
Re Conservative Default Values for Toughness

§192.624 MAOP Verification: Onshore steel T. pipelines
(c)(3) Method 3: Use Engineering Critical Assessment (ECA) to establish material condition and MAOP. **Verify material properties in accordance with §192.607 if information/records not TVC.**

(d) Fracture mechanics modelling for failure stress and crack growth analysis- Moved to §192.712

**NOTE:** In the NPRM, both Method (c)(3) and Section (d) require operators to use a conservative Charpy energy value to determine the toughness based on material program in 192.607; or use values of 5.0 ft-lb for body cracks and 1.0 ft-lb for seam cracks

- SI conducted a study for INGAA re appropriate toughness default values when there are not T,V&C material records and determined that appropriate values are 13.0 ft-lb and 4.0 ft-lb, respectively
- At the March 26-28 GPAC, SI provided public comment and GPAC/PHMSA agreed with SI’s proposed toughness default values
WHY ILI WITH FRACTURE MECHANICS IS BETTER THAN PRESSURE TESTING-

- PHMSA’s Megarule (§192.624) requires the following actions for MAOP Verification:
  - Pressure test w/ Material Verification (MV), or
  - Pressure reduction from highest in last 5 years w/ MV, or
  - ECA with MV, or
  - Replacement, or
  - Pressure reduction for small PIR, or
  - Alternative technology w/ notification to PHMSA

- But most of these options are untenable for operators!
A New Way to Look at Fracture Mechanics

- **Probabilistic vs. Conventional (Deterministic) Analysis**

  - **Deterministic: Single Analysis**
    - Conservative values assumed for input parameters
    - Safety Factors generally mandated
    - Single conservative result, such as predicted failure pressure or remaining life

  - **Probabilistic: Millions of Analytical Simulations**
    - Input parameters randomly sampled from statistical distributions
    - Realistic analysis; no conservatisms or safety factors, so a predicted failure is really a failure
    - Probabilistic Results (e.g. Probability of Failure versus time)
    - Supports Cost-Benefit analysis to optimize integrity management decisions
Probabilistic Fracture Mechanics (PFM) Analysis

- Probabilistic Analysis:
  - Many Values Used
  - Stress
  - Fracture Toughness
  - Crack Growth Rate
  - Defect Size

- Deterministic Analysis:
  - Conservative Value Used

SLIDE 18
PFM Analysis of Pipelines: Key Parameters

- Flaw density and size distribution
- EMAT/ILI accuracy
  - Probability of Detection (POD)
  - Sizing error margins
- Flaw Repair (dig) Criteria
- Crack Growth Rate (SCC or Fatigue)
- Material Toughness (Weld or Pipe Body)
- Predicted Failure Pressure (PFP)
- Monte Carlo Analysis
  - Employs millions of simulations to compute probability of failure versus time
SCC Features Detected by ILI

- **Features**
- **Repair Curves**

The graph shows the relationship between the depth and length of anomalies, categorized based on different criteria. The features detected by ILI are visualized with markers, and repair curves are indicated for various categories.
Flaw Density & Size Distributions

SCC Flaw Density:
(97 flaws - 27 repairs)/46 mi. = 1.52 flaws/mi.

SWA Flaw Density:
16 flaws/79 mi. = 0.20 flaws/mi.
EMAT/ILI Accuracy: POD and Sizing Error

- Various PODs analyzed
  - 90%, 95%, 99%
  - Graded POD

- ILI features validated via in-ditch PAUT and metallurgical exams
  - Confirmed vendor 80% confidence bounds:
    - ± 0.050” on Feature Depth
    - ± 0.75” on Feature Length
Flaw Repair Criteria (ILI or Hydrotesting)

- Various repair (dig) criteria analyzed for EMAT ILI cases
  - Repair all Cat. 2 or greater features (i.e. PFP ≤ 1.1 x SMYS)
  - Enhanced criteria: Cat. 2 + all features with length ≥ 2”

- Hydrotest repair assumption
  - All flaws predicted to fail at hydrotest pressure are repaired and thus removed from population
SCC Growth Rate: Model Adapted from IPC Paper

Adaptation included:
- PL stress and geometry
- SCADA data
- Observed features

ASME recommended 0.012 in./year
Material Toughness Distributions

CVN Cumulative Distributions

- Pipe Body Specific
- Pipe Body Generic
- ERW Pipeline Specific
- ERW Generic

Percentile
CVN (Ft-Lbs)
Results - SCC Susceptible Line

PFM RESULTS
SCC; Base Metal Toughness

Failure Rate (per year per pipeline mile)

- FEMA Historical Failure Rate Estimate (1989)
- ILI 1 PL Specific Base
- Hydro PL Specific Base
- ILI 2 Generic Base

Years Following Hydro or ILI

1 2 3 4 5 6 7 8 9 10
Results - ERW Seam Welds

PFM RESULTS
Moderate FCG (Gas Line); ERW Toughness

FEMA Historical Failure Rate Estimate (1989)
Results - Sensitivity to POD

PFM Results - Sensitivity to POD

FEMA Historical Failure Rate Estimate (1989)

Failure Rate (per year, per pipeline mile)

Years following Hydro or ILI

- Spike Hydrotest (1 x SMYS)
- EMAT/ILI POD=99%
- POD=95%
- POD=90%
- Graded POD
Results - Enhanced Repair (Dig) Criteria
(Illustration of Cost-Benefit Decision Process)

PFM Results - Sensitivity to Repair Criteria

- Spike Hydrotest (1 x SMYS)
- EMAT/ILI - CAT 2 Repairs
- Enhanced Repair Criteria
- SCC Mgt. Program

FEMA Historical Failure Rate Estimate (1989)

3-yr Hydro Required by SCC Mgt. Program

Equivalent 6.5-yr ILI
SCC Features Detected by ILI

Features

Original Repair Curve

Enhanced Repair Curve

Interacting ILI Lengths Plotted vs Flaw Locs

- Cat 2 Threshold
- Cat 3 Threshold
- Cat 4 Threshold
- ILI IL Cat 1
- ILI IL Cat 2
- ILI IL Cat 3
- 2-inch Flaw Length Threshold
Reality Check (versus recent notable PL ruptures)

Flaw Sizes that led to ruptures were at far tails of distributions (99.99 %-tile)
And would have been readily detected had EMAT/ILI been performed
Summary and Conclusions:

- MAOP verification methods allowed by §192.624 are generally untenable. ILI w/FM offers a more practicable alternative technology.
- For an SCC susceptible pipeline, high quality ILI outperforms Hydrotesting in terms of probability of failure versus time.
- Both Hydrotesting and ILI are effective integrity management tools for ERW seam welds.
- ILI results very sensitive to accuracy of the inspection methods (POD and sizing accuracy).
- PFM analysis supports cost-benefit decisions:
  - Evaluate tradeoffs among integrity management tools (e.g. ILI vs. Hydrotesting).
  - Optimize reassessment intervals.
  - Establish dig/repair criteria.
Thank You
Questions??

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