# NPRM: Safety of Gas Transmission & Gathering Pipelines

(Docket: PMHSA-2011-0023)

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Comment period ends - July 7, 2016

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# Timeline

- Advance Notice of Proposed Rulemaking (ANPRM) published on August 25, 2011, “Pipeline Safety:  Safety of Gas Transmission Pipelines” (PHMSA-2011-0023)
- PHMSA sought public comment on 15 topics (122 questions)
- 103 comment letters received
- Included topics covering NTSB recommendations from San Bruno and Marshall, MI accidents, and Mandates from 2011 Pipeline Safety Act.

# Summary of Proposed Changes

PHMSA proposing rule changes in the following areas for gas transmission and gas gathering pipelines -

1. Require Assessments for Non-HCA's
2. Strengthen repair criteria for HCA and Non-HCA
3. Strengthen requirements for Assessment Methods
4. Clarify requirements for validating & integrating pipeline data
5. Clarify functional requirements for risk assessments
6. Clarify requirement to apply knowledge gained through IM
7. Strengthen corrosion control requirements
8. Add requirements for selected P&M measures in HCAs to address internal corrosion and external corrosion

# Summary of Proposed Rule

9. Management of change
10. Require pipeline inspection following extreme external events
11. Include 6 month grace period (w/notice) to 7 year reassessment interval (Act § 5(e))
12. Require reporting of MAOP exceedance (Act § 23)
13. Incorporate provisions to address seismicity (Act § 29)
14. Add requirement for safety features on launchers and receivers
15. Gathering lines- Require reporting for all & some regulatory requirements
16. Grandfather clause/Inadequate records - Integrity Verification Process (IVP)




# 1. Require Assessment for Non-HCAs

- **ISSUE** – Non-HCA pipelines are not currently required to be assessed. Accidents do happen in non-HCAs.
- **PHMSA IS PROPOSING** to require integrity assessments for the following non-HCA segments: All Class 3 and 4 Locations and newly defined Moderate Consequence Area's that are piggable.
  – Initial assessment within 15 years
  – Periodic reassessment every 20 years thereafter
  – Operators can take credit for prior assessments of MCA segments that were conducted in conjunction with and HCA assessment without performing another initial assessment

- **BASIS:**
  - **19,872 miles of GT pipe in HCAs.**
  - **30,591 miles in MCAs must be assessed (of which 7,400 have not had a prior assessment and do not require MAOP verification)**

# 1. Require Assessment for Non-HCAs (cont.)

- **Moderate Consequence Area (MCA):**
  - Non-HCA pipe that are populated in PIR (proposed 5 or more houses or occupied site)
  - House count and occupied site definition same as HCA, except for 5 houses or 5 persons at a site (instead of 20)
  - Also, if interstate highway ROW is within PIR

# 2. Revise Repair Criteria in HCAs & Apply Same Criteria to Non HCAs**

- **ISSUE -** Greater assurance is needed that injurious anomalies and defects are repaired before the defect can grow to a size that leads to a leak or rupture.
- **PHMSA IS PROPOSING** to add repair criteria to be consistent with HL rule
  - 80% metal loss (immediate)
  - Corrosion near seam (immediate)
  - Areas of general corrosion > 50% wt (one year**)
  - Metal loss calculation that shows a FPR (one year**): ≤ less than or equal to 1.25 for Class 1 locations, ≤ 1.39 for Class 2 locations, ≤ 1.67 for Class 3 locations, and ≤ 2.00 for Class 4 locations.
  - Additional dent criteria (one-year**)
  - Selective Seam Corrosion (SSWC)/Significant SCC (immediate)
  - All other SCC and crack-like defects (one-year**)

** Except that response time for non-immediate conditions would be tiered. Defects requiring a <u>one-year response for HCAs</u> would require a <u>two-year response in non-HCAs.</u>

- **BASIS:**
  - Addresses NTSB P-12-3 (Marshall, MI) for SCC and crack-like defects
  - Addresses existing gaps in repair criteria
  - Would require repairs be made for any defect predicted to fail a Subpart J pressure test





# 3. Strengthen Requirements on Selection and Use of Assessment Methods

- **ISSUE** - Current rule is silent on a number of issues that impact the quality and effectiveness of ILI assessments (except for a general reference to ASME B31.8S)
- **PHMSA IS PROPOSING to:**
  - Clarify selection and conduct of ILI per new mandatory reference to NACE, API, and ASNT standards
  - Clarify consideration of uncertainties in ILI reported results.
  - Add the following allowed methods:
    - GWUT in accordance with criteria in a new Appendix F
    - Excavation and *in situ* direct examination
    - “Spike” hydrostatic pressure test
  - Allow Direct Assessment only if line is not piggable.
- **BASIS:**
  - Following the San Bruno accident, determined that Direct Assessment was relied upon by PG&E even when not effective for the specific application
  - Include additional assessment methods known to be effective for specific situations (e.g., GWUT for crossings) or threats (e.g., Spike hydro for SCC)





# 4. Improving Rqts. for Collecting, Validating & Integrating Pipeline Data

- **ISSUE** - Operators are collecting much information but an integrated and documented analysis is often inadequate.

- **PHMSA IS PROPOSING TO:**
  - Clarify that data be verified and validated
  - Clarify requirements for integrated analysis of data & information
  - Establish minimum pipeline attributes that must be included
  - Require use of validated, objective data whenever practical
  - Address requirements for use of SME input
- **BASIS:**
  - San Bruno highlighted weakness in this area
  - Congressional mandate to validate data





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# 5. Add Specific Functional Requirements for Risk Models

- **ISSUE** – More specificity is needed for the nature and application of risk models to improve the usefulness of these analyses to control risks from pipelines.
- **PHMSA IS PROPOSING** to enhance requirements for performance-based risk assessments to:
  - Add a new definition for "quantitative risk assessment" that adequately evaluates the effects of:
    - interacting threats.
    - Identify the contribution to risk of each risk factor
    - Account for uncertainties in the risk model and data used
  - Require validation of risk models in light of incident, leak, and failure history & other historical information [codifies NTSB P-11-29 recommendation to PG&E]
- **BASIS:**
  - Addresses NTSB recommendations and lessons learned from the San Bruno accident investigation
  - Address input from July 2011 Risk Management workshop

# 6. Strengthen Requirements for Applying Knowledge Gained Through the IM Program

- **ISSUE** - Strengthening requirements related to operators' use of insights gained from its IM program is prudent to ensure effective risk management.

- **PHMSA IS PROPOSING to:**
  - Clarify expectation that operators use knowledge from risk assessments to establish and implement adequate Preventive & Mitigative measures
  - Provide <u>more explicit examples of the type of P&M measures</u> to be evaluated
  - Clarify requirement that risk models adequately reflect data integration analyses and are validated against incident and failure experience

- **BASIS:**
  - Stronger rule emphasis on fundamental goal of risk based IM
  - Address NTSB recommendations following San Bruno





# 7. Strengthen Corrosion Control

- **ISSUE** - Current rules for external & internal corrosion need strengthening

- **PHMSA IS PROPOSING to require:**
  - Expansion of corrosion controls required in Subpart I
  - Specific Preventive and Mitigative measures for HCAs to address both external and internal corrosion
    - Similar to measures required for pipe segments operating under the alternate MAOP rule per 192.619

- **BASIS:**
  - Disbonded coating and corrosion were significant contributing factors in the Marshall, MI & Sissonville, WV incidents





# 8. Add P&M Requirements to Address Ext. Corrosion and Int. Corrosion in HCAs

- **ISSUE -** Prescriptive preventive and mitigative measures are needed to assure that public safety is enhanced in HCAs and affords greater protections for HCAs.

- **PHMSA IS PROPOSING to require:**
  - Enhance internal & external corrosion control programs in HCAs to provide additional protection from corrosion commensurate with Alt MAOP pipelines
  - Consider other measures, such as additional right-of-way patrols and hydrostatic tests in areas where material has quality issues or lost records
  - Address seismicity in evaluating P&M measures for outside force damage

- **BASIS:**
  - Disbonded coating and corrosion were significant contributing factors in the Marshall, MI & Sissonville, WV incidents
  - Implement Act § 29 (seismicity)





# 9. Management of Change

- **ISSUE -** Codifying the specific attributes of the Management of Change process will enhance the visibility and emphasis on these important program elements.

- **PHMSA IS PROPOSING to:**
  - Codify the specific attributes of the Management of Change process from ASME/ANSI B31.8S, Section 11 (already incorporated by reference).
  - Require operators to develop and follow a Management of Change process and address risk as part of the general requirements of Part 192.

- **BASIS:**
  - Address lessons learned from San Bruno and Marshall, MI with respect to operational and other decision-making that affects risk.



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# 10. Require Pipeline Inspection Following Extreme Events

- **ISSUE –** Current rules do not address extreme events that can damage pipelines or disrupt pipeline operations

- **PHMSA IS PROPOSING to:**
  - Clarify that inspection (visual +ILI or other) of pipeline and right-of-way for "other factors affecting safety and operation" includes extreme weather events, man-made, and natural disasters, and similar events
  - Specify the timeframe for performing inspections & remedial actions

- **BASIS:**
  - Recent example of extreme event (Yellowstone River scouring caused by flooding) that resulted in pipeline incident





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# 11. Include 6-month Grace Period to 7-Year Reassessment Interval

- **ISSUE -** Subsection 5(e) of the Pipeline Act of 2011 identifies a technical correction to Title 49 of the United States Code.

- **PHMSA IS PROPOSING to:**
  - Clarify that periodic reassessments must occur, at a minimum of once every 7 calendar years, but that the Secretary may extend such deadline for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension.

- **BASIS:**
  - This codifies Act § 5(e) technical correction.



# 12. MAOP Exceedance Reporting

- **ISSUE -** Section 23 of the Act requires PHMSA to promulgate rules for reporting exceedance of the maximum allowable operating pressure (MAOP).

- **PHMSA IS PROPOSING to:**
  - Require operators to report each exceedance of the MAOP that exceeds the build-up allowed for operation of pressure-limiting or control devices.

- **BASIS:**
  - This codifies the specific requirement from Act § 23.



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# 13. Incorporate Provisions to Address Seismicity

- **ISSUE -** Section 29 of the Act states that in identifying and evaluating all potential threats to each pipeline segment, an operator of a pipeline facility shall consider the seismicity of the area.

- **PHMSA IS PROPOSING to:**
  - Include seismicity in evaluating P&M measures for the threat of outside force damage.
  - Include seismicity of the area in the data gathering and integration of information about pipeline attributes and other relevant information.

- **BASIS:**
  - This codifies the specific requirement from Act § 29.





# 14. Add Requirements for Safety Features on Launchers and Receivers

- **ISSUE -** Current regulations for liquid pipelines (Part 195) contain safety requirements for scraper and sphere facilities. Part 192 does not explicitly address this area.

- **PHMSA IS PROPOSING to add a new section to:**
  - Require launchers & receivers be equipped with a device (safety valve) capable of safely relieving pressure in the barrel before insertion or removal of inline inspection tools, scrapers, or spheres.
  - Require use of a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent opening if pressure has not been relieved.

- **BASIS:**
  - Some incidents have occurred at launchers and receiver stations.





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# 15. Expand Requirements for Onshore Gas Gathering Lines

- **ISSUE -** PHMSA determined additional information about gathering lines is needed to fulfill its statutory obligations. Also, recent developments in the field of gas exploration and production, such as shale gas, indicate that the existing framework for regulating gas gathering lines may no longer be appropriate.

- **PHMSA IS PROPOSING to:**
  - Repeal exemption for all gas gathering line operators to report incidents, safety related conditions, & annual pipeline data.
  - Repeal use of API RP 80 for determining gathering lines and add a new definition for “production facility or production operation” and a revised definition for “gathering line”.
  - Extend regulatory safety requirements to Type A lines in Class 1 locations (8” or greater).

- **BASIS:**
  - API RP 80 contains conflicting and ambiguous language.
  - Shale gas gathering lines operate at higher pressures and are a greater hazard than typical legacy gathering lines.





# 16. Integrity Verification Process (IVP)

- Statutory Mandates and NTSB Rec.
- Records
- Material Documentation
- MAOP Determination





# "Grandfathered" Pipe & Related Issues

- ***PSA of 2011 - §23(a) 60139(d) mandate "Testing Regulations"*** - pressure testing or alternative equivalent means such as ILI program for all Gas Transmission pipe (Class 3, 4 and all HCAs) not previously tested;
- ***NTSB P-11-14 "Delete Grandfather Clause"*** - recommends all grandfathered pipe be pressured tested, including a "spike" test;
- ***NTSB P-11-15 "Seam Stability"*** - recommends pressure test to 1.25 x MAOP before treating latent manufacturing and construction defects as "stable."
- ***NTSB P-11-17 "Piggable Lines"*** - Configure all lines to accommodate smart pigs, with priority given to older lines





# Basic Principles of IVP Approach

- **IVP is based on 4 principles**
  1. Apply to high risk locations
     - High Consequence Areas (HCAs), Class 3 and 4 Locations and Moderate Consequence Areas (MCAs)
  2. Screen segments for categories of concern (e.g., “Grandfathered” segments; bad records)
  3. Assure adequate material and documentation
  4. Perform assessments to establish MAOP



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# Principle #1
# Apply to High Risk Locations

- **High Consequence Areas (HCAs)**: 19,872 miles
- **Class 3 and 4 - Non-HCA:** 17,767 miles
- **Class 1 and 2; MCA:**
  - Piggable: 12,824 miles
  - Non-piggable: 8,623 miles

# Principle #2
# Screen for Categories of Concern

- **Apply process to pipeline segments with:**
  - Grandfathered Pipe
    - HCA/Class 3 locations/Class 4 locations and Piggable MCA lines
  - Lack of Material Documentation and Pressure Test Records
    - HCA/Class 3 and Class 4 Locations
  - History of Failures Attributable to M&C Defects
    - HCA/Class 3 locations/Class 4 locations and Piggable MCA lines

  - *PHMSA estimates approximately 8,089 miles of GT pipe (approximately 3% of total GT mileage) would meet screening criteria & require IVP assessment to establish MAOP*





# Principle #3
# Know & Document Pipe Material

- **If Missing or Inadequate Validated Traceable Material Documentation, in HCA or Class 3 or 4 Location then Establish Material Properties by an approved process:**
  - Cut out and Test Pipe Samples (Code approved process)
  - *In Situ* Non-Destructive Testing (if validated and Code approved)
  - Field verification of code stamp for components such as valves, flanges, and fabrications
  - Other verifications





# Principle #4
# Methods to Establish MAOP

- Allow Operator to Select Best Option to Establish MAOP
- **Main Options for Establishing MAOP**
  - Pressure test with Spike Test
  - Pressure Reduction
  - Engineering Critical Assessment
  - Replace

# MAOP Determination

- **§ 192.624 (c) MAOP Determination**
  – Method 1: Pressure Test
    - 1.25 or class location test factor times MAOP
    - Spike test segments w/ reportable in-service incident due to legacy pipe/construction, SSC, SSC, etc.
    - Estimate remaining life, segments w/crack defects
  – Method 2: Pressure Reduction
    - Reduce pressure by MAOP divided by 1.25 or class location test factor
    - Estimate remaining life, segments w/crack defects



# MAOP Determination

- **§ 192.624 (c) MAOP Determination**
  - Method 3: Engineering Critical Assessment (ECA)
    - ECA analysis - MAOP based upon lowest predicted failure pressure (PFP)
      - Segment specific technical and material documentation issues
      - Analyze crack, metal loss, and interacting defects remaining in the pipe, or could remain in the pipe, to determine PFP
      - MAOP established at the lowest PFP divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii)

# MAOP Determination

- **§ 192.624 (c)  MAOP Determination**
  - Method 4: Pipe Replacement
  - Method 5: Small PIR
  - Method 6: Alternative Approach





# Compliance Deadlines

- **§ 192.624 (b) Compliance Deadlines**
  - Develop plan – 1 year
  - 50% mileage by end of Year 8
  - 100% mileage by end of Year 15
  - Operational or environmental constraints limit meeting deadlines may petition AA of OPS for 1-year extension
  - Reassessments maximum of 20 Year Interval

# Fracture Mechanics Modeling

- **§ 192.624 (d) Fracture mechanics modeling for failure stress and cyclic fatigue crack growth analysis**
  - Pipe susceptible to cracks or crack-like defects...
  - Fatigue analysis techniques
  - Analyze microstructure(ductile/brittle or both), location and type of defect, and operating conditions/pressure cycling
  - 2nd re-evaluation before 50% of the remaining life has expired, but within 7 years
  - Results confirmed by an independent 3rd party expert





# Spike Test (192.506)

- **Applies to those pipelines that:**
  - Are required to be assessed, have a hoop stress of 30% SMYS and have integrity threats that cannot be otherwise addressed by ILI ; or
  - Have their MAOP established in accordance with Method 1, Pressure Test, in 192.624 and the pipeline includes legacy pipe or segments that has had certain incidents (e.g., crack, manufacturing, or installation related, see 192.624(c)(1)(ii)).
- **Test method**
  - Spike Test minimum of the lessor of:
    - 1.50 times MAOP, or 105% SMYS
  - Spike Duration: 30-minutes
  - Total Test Duration: 8-hours

# Any Questions