PENNSYLVANIA
PUC
PUBLIC UTILITY COMMISSION

Distribution Integrity Management Program

Why DIMP?

- Distribution incidents continue to occur, resulting in significant consequences
- Effecting a significant reduction in pipeline accidents, deaths, and injuries cannot be done without addressing distribution
- Integrity management principles cause operators to focus on risks that are important to their systems
- 2006 PIPES Act requires it

PIPES Act 2006

- Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES) includes provisions for DIMP (Section 9)
- DOT is required to issue standards (i.e., a rule)
- Operators covered under the standards would be required to develop and implement IM programs

What Principles Underlie DIMP?

- DIMP requires operators to better understand and mitigate system risks:

  Know your systems, Identify the threats

  Rank risks, Mitigate the risks

- NPRM does not stipulate specific assessment or mitigation actions,
- In combination with the GPTC Guidance – NPRM provides direction to operators and allows the regulator to investigate internal operator risk management practices

NPRM Structure

- Requires risk-based written IM program including the seven elements
- Requires appropriate mitigation measures, including leak management and enhanced damage prevention
- Requires installation of EFVs
- Requirements are high-level, performance-based - Guidance needed for implementation details

Subpart P

192.1001 What do the regulations in this subpart cover?

192.1003 What definitions apply to this subpart?

192.1005 What must a gas distribution operator (other than a master meter or LPG operator) do to implement this subpart?

192.1007 What are the required integrity management (IM) program elements?

192.1009 What must an operator report when plastic pipe fails?

192.1011 When must an Excess Flow Valve (EFV) be installed?

192.1013 How does an operator file a report with PHMSA?

192.1015 What records must an operator keep?

192.1017 When may an operator deviate from required periodic inspections under this part?

192.1019 What must a master meter or liquefied petroleum gas (LPG) operator do to implement this subpart?

Written Program [1005.(b)]

- Assures completeness and consistency
- Available for review/audit
- Facilitates agreement on what an operator must do to implement

IM Program Elements [1007]

- Know your System
- Identify Threats
- Analyze Risks
- Mitigate Risks
- Performance Measures
- Periodic Evaluation & Improvement
- Report Performance Measures

Know your System [1007.(a)]

- Must demonstrate and understanding of the gas distribution system
- Identify characteristics
- Understand information
- Plan to improve knowledge over time
- Process to refine and improve
- Gather data (minimum- location, appurtenances, material)

Identify Threats [1007.(b)]

- **Must consider eight categories**
  - Corrosion
  - Natural Forces
  - Excavation Damage
  - Other Outside Force
  - Material/Weld Failure
  - Equipment Failure
  - Inappropriate Operation
  - Other Concerns that could threaten the integrity of the pipeline
- **Identify existing and potential threats**
  - Incident/leak History
  - Surveillance/patrolling
  - Excavation Damage Trends
  - Corrosion Records
  - Maintenance History
  - Human Error
- **All operators don't face all threats**

Evaluate & Prioritize Risk [1007.(c)]

- Risk = likelihood x consequences
- Consider current **&** potential risk
- Not necessarily complicated systems may be divided in areas of similar characteristics
- Simple techniques may be described in GPTC DIMP Guidelines

Mitigate Risks [1007.(d)]

- Implement changes to pipeline systems and processes
- Implement effective leak management and enhanced damage prevention programs
- Focus activities where needed most
- Draw “Additional and Accelerated (A/A)” Actions from industry noteworthy practices

Leak Management

- Process for managing leaks
  - ***L*ocate** the leak
  - ***E*valuate** its severity
  - ***A*ct** appropriately to mitigate the leak,
  - ***K*eep** records
  - ***S*elf-assess** to determine if additional actions are necessary to keep the system safe
- Better national data reporting & expansive analysis by operator

Damage Prevention

- Preventing excavation damage is critical to reducing distribution incidents
- The rule requires that operators enhance the damage prevention programs required by 49 CFR192.614
- Operators can only do so much; legislation needed to reach other stakeholders
- Experience has shown State programs with nine elements are most effective

Damage Prevention Elements

1. Enhanced communication
2. Fostering partnerships
3. Performance measures
4. Training partnership
5. Public Education/Awareness
6. Dispute resolution
7. Fair/consistent enforcement
8. Use of Technology
9. Data analysis

Performance Measures [1007.(e)]

- Needed to evaluate effectiveness
- Seven measures required for all (except Master Meter/LPG)

(i) Number of ***hazardous*** leaks (Grade 1) eliminated or repaired (by cause)
(ii) Number of excavation damages;
(iii) Number of excavation tickets
(iv) Number of EFVs installed;
(v) Total number of leaks eliminated or repaired (by cause)
(vi) Number of hazardous leaks eliminated or repaired (by material)
(vii) Additional measures to evaluate effectiveness in controlling each identified threat

Periodic Evaluation & Improvement

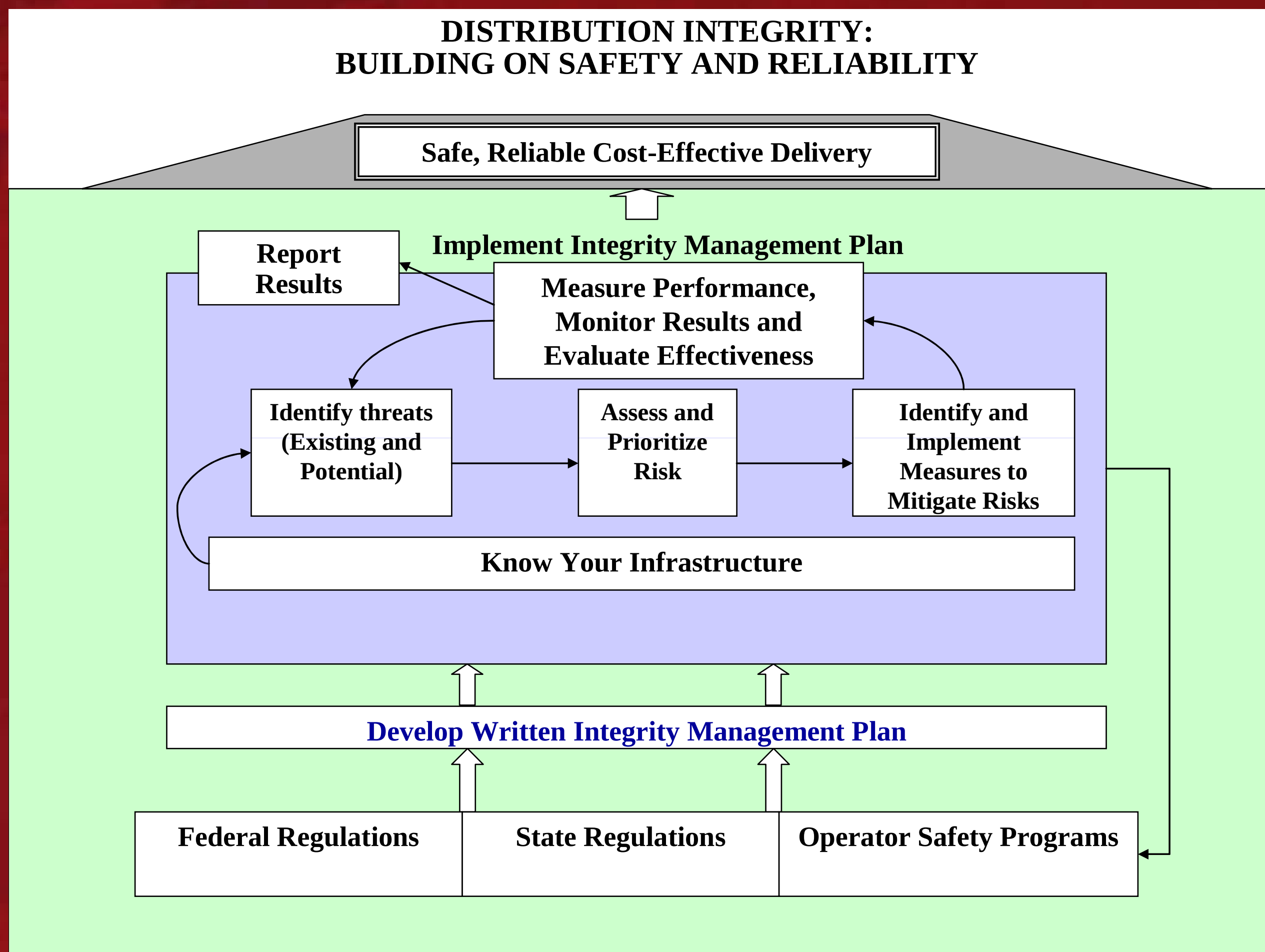
[1007.(f)]

- Continually re-evaluate threats and risk
- Evaluate effectiveness in reducing human error (PTP)
- Complete program re-evaluation at least every five years
- Consider performance measures

Report Performance Measures[1007.(e)]

- Report on annual report by March 15
- Report to State where distribution system is located
- Four measures to report
  - (i) Number of ***hazardous*** leaks eliminated or repaired (**by cause**)
  - (ii) Number of excavation damages
  - (iii) Number of excavation tickets
  - (iv) Number of EFVs installed

Elements of DIMP



Required Elements

Element	"Private/Municipal" Operators	Master Meter / LPG
Written Program	Required	Simple (checklist)
Know system	Relevant factors	Location/material
Identify threats	Thorough analysis	Checklist approach
Analyze risk	Required	Not required
Mitigate risk	Required	Required
Performance Measures	7 plus threat-specific	Leaks by cause
Review/revised	Required	Required
Report Perf Measures	4 measures	Not required

Additional Issues

- Mechanical fitting failure reporting (1009)
- EFV installation   (1011)
- Allowing alternate time intervals for certain requirements currently in Part 192   (1017)
- Consideration of compression coupling failures in the threat analysis
- DIMP programs to include a Prevention Through People (PTP) component

Mechanical Fitting Failure Reporting

(1009)

- Must report each mechanical fitting failure, **excluding** failures that don't result in a hazardous leak, this includes all types of failures regardless of material
- Calendar year data No later than March 15, of the following calendar year.
- Information Reported Information on DOT Form PHMSA F-7100.1-2
- Must report to PHMSA and State Authority

Excess Flow Valves (1011)

- Applies to new or replaced service lines serving single-family residences
- Unless the following conditions is present
  - Service line does not operate at 10 psig or greater throughout the year
  - Contaminants in line
  - EFV interfere with operation or maintenance
  - EFV performance not commercially available
- Implements provision of PIPES Act

File a Report with PHMSA (1013)

- An operator must send any performance report required by this subpart to the Information Resource Manager as follows:

  (a) http://PHMSA.dot.gov;

  (b) Via facsimile to (202) 493-2311; or

  (c) Mail: PHMSA-Information Resource Manager
  US Dept. of Transportation-East Building
  1200 New Jersey, SE
  Washington, DC 20590

Records Operators Must Keep (1015)

- Operator must maintain, for the useful life of the pipeline, records demonstrating compliance with the requirements of this subpart

- Records for review during DIMP inspection
  - A written IM program (§192.1005)
  - Documents supporting threat identification (§192.1007(b))
  - A written procedure for ranking the threats (§192.1007(c))
  - Documents to support any decision, analysis, or process developed and used to implement and evaluate each element of the IM program (§192.1007(f))
  - Records identifying changes made to the IM program, or its elements, including a description of the change and the reason it was made (§192.1007(f))
  - Records on performance measures must be retained for ten years (§192.1007(e))

Alternate Time Frames (1017)

(a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart. Operators may propose reductions only where they can demonstrate that the reduced frequency will not significantly increase risk.

Alternate Time Frames (1017)

(b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or the State agency responsible for oversight of the operator's system. PHMSA, or the applicable State oversight agency, may accept the proposal, with or without conditions and limitations, on a showing that the adjusted interval provides a satisfactory level of pipeline safety.

Why Alternate Timeframes

- The regulations now require that operators perform these actions at time defined intervals.

- This is not risk-based. These regulations may require frequent actions that results in little safety benefit, or may not be done often enough to realize full benefit.

Time Defined Regulations

	Subpart I
• Part 192.465	CP Testing Rectifier Inspection
• Part.192.465	Pipelines w/no CP
• Part 192.481	Exposed Pipe Inspection for Corrosion

Time Defined Regulations

	Subpart M
• Part 192.721	Main Patrolling
• Part 192.723	Leak Surveys
• Part 192.739	Pressure Limiting Devices Tested
• Part 192.747	Emergency Valves
• Part 192.749	Vault Inspections

How Operators Can Use This

Deviating from set intervals, now specified in sections of Part 192, would allow operators to be more risk-based in the application of their resources.

The resources made available by using alternate intervals, where appropriate, could be used to address more risk-significant threats.

Regulatory Approval

Operators would be required to submit their proposal, with justification, to jurisdictional safety regulators for review and decision to determine if the proposal will show that the adjusted interval provides a satisfactory level of pipeline safety.

Performance Data for Request

Operators must provide data demonstrating that the reduced frequency will not significantly increase risk.

An example could be by providing data that atmospheric corrosion is a low risk to the safety of the system and exposed piping may be inspected every 4 years instead of every 3 years (Part 192.481).

Guidance

- Needed for a high-level performance rule
- GPTC has developed draft guidance
- APGA is developing more-specific guidance for small operators
- Guidance found on PHMSA/OPS webpage

Outreach

- OPS website and web cast
- Industry Sponsored Meeting (s)
- APGA to Assist Small Operators (planning 12 Regional workshops after the final rule)
- NSFMA & NPGA to assist APGA
- States will need to reach out to master meter and LPG operators
- Support for State operator meetings
- PHMSA T&Q training to States, operators including MM and LPG

Website For PHMSA

- http://primis.phmsa.dot.gov/dimp
- DIMP Home
- DIMP Public Meetings/Webcast
- DIMP Documents/Resources
- FAQ's
- Performance Measures
- Questions and Comments for OPS
- Regulator Contacts
- Whats New

Important Dates

- 49 CFR Part 192 Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Final Rule February 2, 2010 (Federal Register December 4, 2009)
- No later than August 2, 2011 18 MONTHS AFTER PUBLICATION OF THE FINAL RULE IN THE Federal Register an operator of a gas distribution pipeline must develop and fully implement a written IM program
- No later than August 2, 2011 18 MONTHS AFTER PUBLICATION OF THE FINAL RULE IN THE Federal Register the operator of a master meter or a liquefied petroleum gas (LPG) gas distribution pipeline must develop and fully implement a written IM program