Distribution Integrity Management Program (DIMP)

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Outline

- Introduction
- Gas Delivery System (a typical overview)
- Need for DIMP
- PHMSA DIMP Rules & Implementation
- GSRB DIMP Inspections

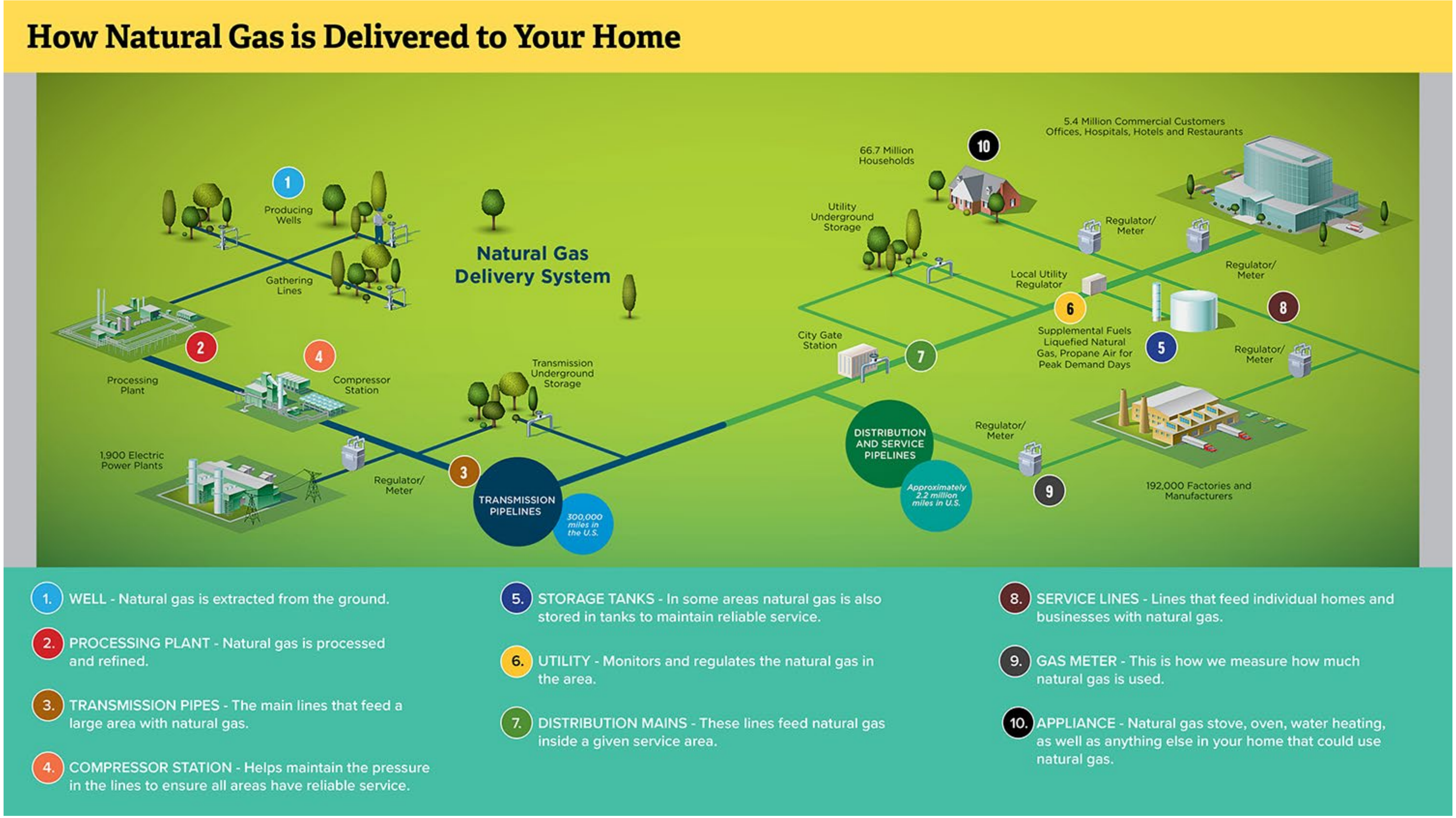
PHMSA = Pipeline & Hazardous Materials Safety Administration

GSRB = Gas Safety and Reliability Branch

DIMP

- Determine Threats
- Assess Risk
- Mitigation
- Performance Evaluation

Gas Delivery System



PHMSA Definitions §192.3

Transmission line means a pipeline or connected series of pipelines, other than a gathering line, that:
(1) **Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer** that is not down-stream from a distribution center;
(2) Has an MAOP of 20 percent or more of SMYS; (MAOP = Maximum Allowable Operating Pressure; SMYS (Specified Minimum Yield Strength)
(3) Transports gas within a storage field; or
(4) Is voluntarily designated by the operator as a transmission pipeline.

Transmission Integrity Management Program (TIMP)

Distribution line means a pipeline other than a gathering or transmission line
Mains - means a distribution line that serves as a common source of supply for more than one service line.
Service - means a distribution line that transports gas from a common source of supply to an **individual customer**, to two adjacent or adjoining residential or **small commercial customers**, or to **multiple residential or small commercial customers** served through a meter header or manifold …

Distribution Integrity Management Program (DIMP)

Other Definitions

Pipeline means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.[1]

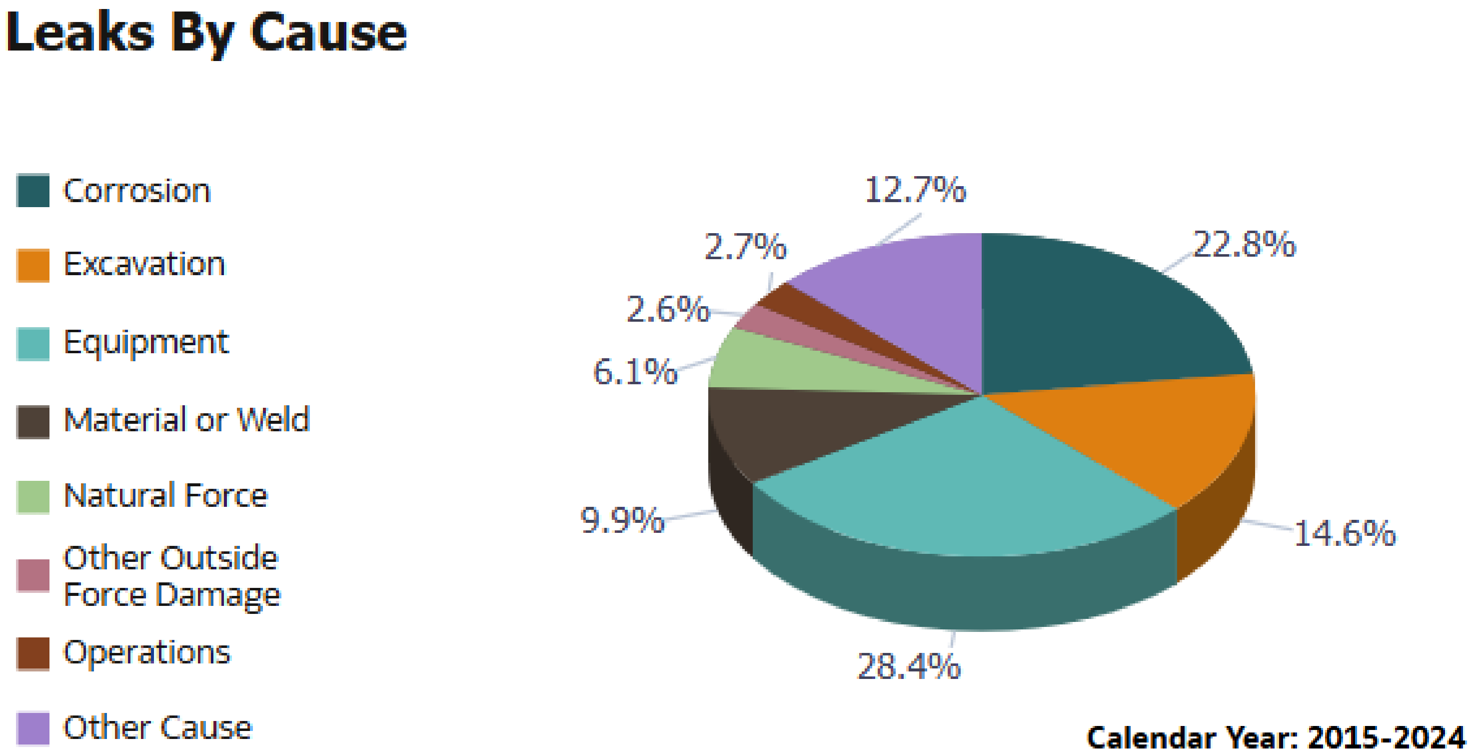
Integrity Assessment refers to measurements made by pipeline operators to determine whether their hazardous liquid or natural gas pipelines have adequate strength – *integrity* – to prevent leaks or ruptures under normal operation and upset conditions.[2]

Safety is the condition of being safe from undergoing or causing hurt, injury, or loss.[3]

Reliability is the likelihood that a component or system will continue to perform its intended function.[4]

Incident means any of the following events:
(1) An event that involves a **release of gas from a pipeline**, …[5]

Aging Pipelines, in general, are not a problem so long as these serve their purpose **– to transport natural gas safely**



PHMSA – DIMP Regulations

- Federal Register dated December 4, 2009 - became law

- Title 49 Code of Federal Regulations – Part 192
  Subpart P—Gas Distribution Pipeline Integrity Management (IM)
  Sections : §192.1001 – 192.1015

§ 192.1005 What must a gas distribution operator (other than a small LPG operator) do to implement this subpart?

No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in §192.1007

§ 192.1007 What are the required elements of an integrity management plan?

(a) Knowledge

(b) Identify threats

(c) Evaluate and rank risk

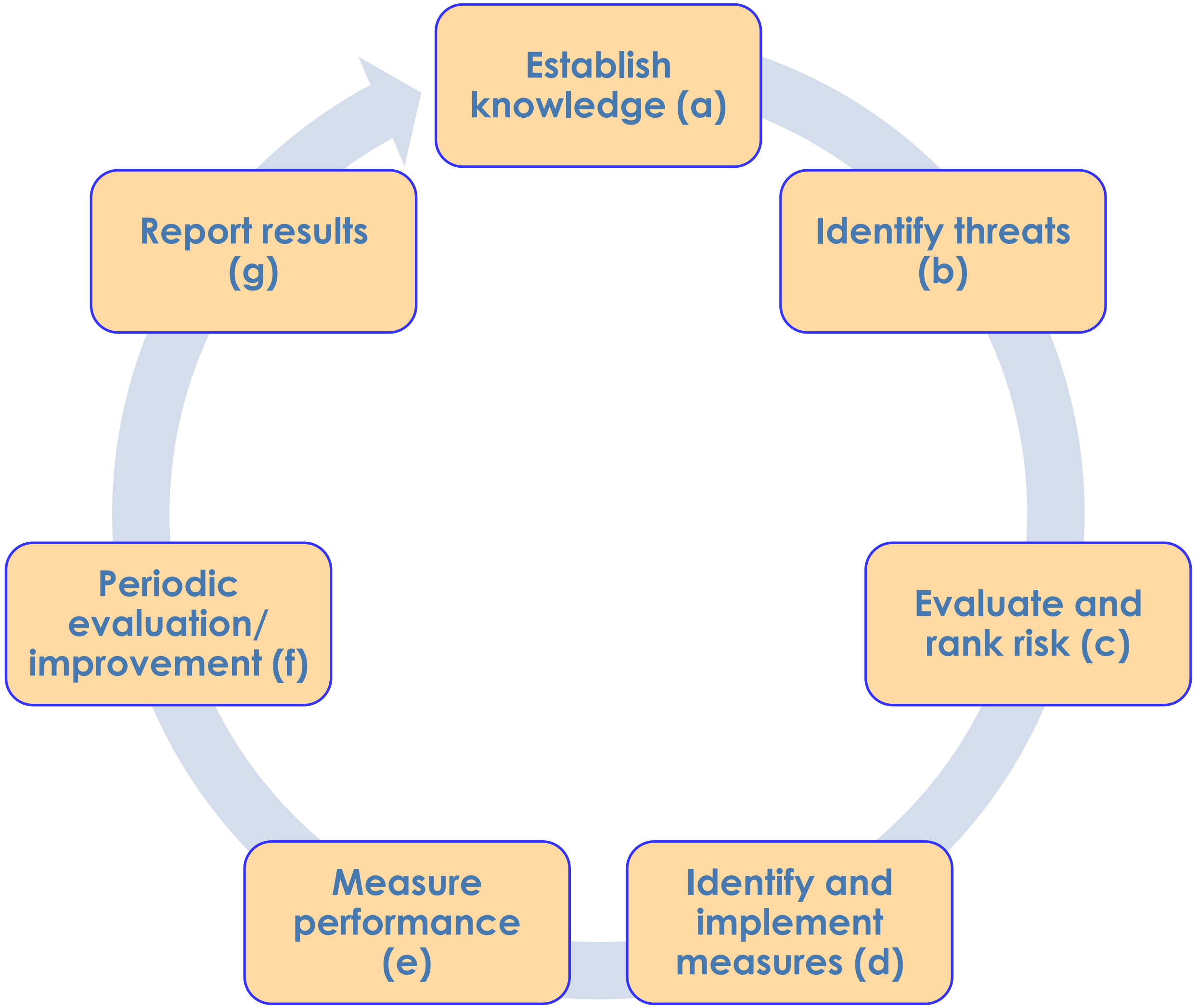
(d) Identify and implement measures to address risks

(e) Measure performance, monitor results, and evaluate effectiveness

(f) Periodic Evaluation and Improvement

(g) Report results

§ 192.1007 What are the required elements of an integrity management plan?



§ 192.1007 What are the required elements of an integrity management plan?

A written integrity management plan must contain procedures for developing and implementing the following elements:

(a) ***Knowledge.*** An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(1) Identify the characteristics of the **pipeline's design and operations and the environmental factors** that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

(2) Consider the information gained from **past design, operations, and maintenance**.

(3) Identify **additional information** needed and **provide a plan** for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

(4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

(5) Provide for the **capture and retention of data on any new pipeline installed**. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

Pipe Design

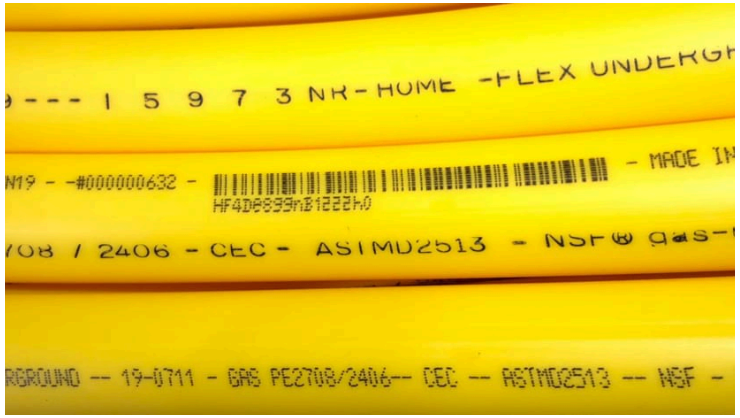
– **Pipe material**
  – Steel, Plastic (PE), Vintage Plastic (e.g., Aldyl – A), Other Plastic (e.g., PVC), Cast Iron, Copper

– **Pipe characteristics**
  – length, diameter, manufacture date, joint etc.

– **Fittings**
  – Couplings, elbows, tee, reducers, cap

– **Valves**
  – Ball valves/Gate valves etc.

COLOR OR STRIPE COLOR	SOLID WALL PIPING APPLICATION
Red	Electric power lines, cable, conduit and lighting cables
Orange	Telecommunication, alarm or signal lines, cables or conduit
Yellow	Fuel gas (methane or propane), oil, petroleum, steam or gaseous materials
Green	Sewers and drain lines
Blue	Potable water
Violet (Purple)	Reclaimed water, irrigation and slurry lines



Operating Conditions

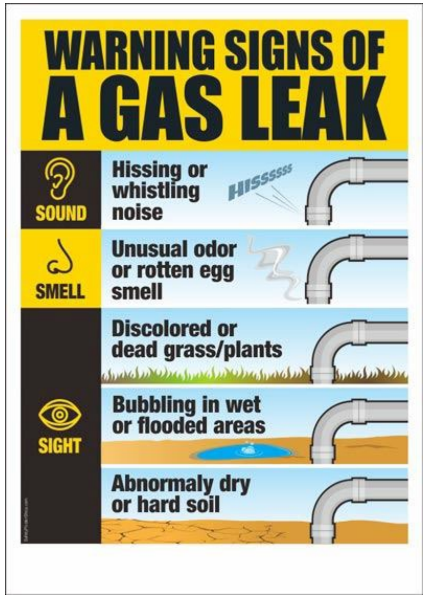
- Design and Operating Pressure in psig (pound per square inch, gage),
- Temperature,
- Operation and Maintenance history,
- External loading

Environmental Conditions

- Local soil characteristics (e.g, composition, corrosivity, resistivity, moisture, etc.),
- Geological features (e.g., washouts, landslides),
- Nearby excavation activity,
- Other local environmental factors

Operation and Maintenance Tasks

- Patrolling (look for possible hazards, ground movement)
- Corrosion monitoring (CP P/S reads, exposed span etc.)
- Regulator station maintenance
- Valves maintenance
- Leak Survey



§192.1007(b) Identify threats

The operator must consider the following categories of threats to each gas distribution pipeline:

- **Corrosion (including atmospheric corrosion),**
- **Natural forces,**
- **Excavation damage,**
- **Other outside force damage,**
- **Material or welds,**
- **Equipment failure,**
- **Incorrect operations,**
- **and other issues that could threaten the integrity of its pipeline**.

An operator must consider reasonably available information to identify **existing** and **potential** threats. Sources of data may include incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

Corrosion

External Corrosion

– Outside surface

– increases with time

Internal Corrosion

– Internal surface

– Corrosion due to containments in gas and gas quality)

Atmospheric Corrosion

– External surface

– Rust

Natural Forces

Natural gas pipeline failures caused by natural forces such as landslides, earthquakes, and floods can have severe consequences on pipeline

Excavation Damage

Failure due to excavation activities (first party, second party, and third party damages)

Other Outside Force Damage

– Failure due to outside force damage, other than excavation damage or natural forces.
– Usually above ground pipeline facilities (e.g. vehicles hitting meter sets, vandalism, etc.)

Material or Welds

Failure from material defect within the pipe, component or joint due to faulty manufacturing procedures, design defects, or in-service stresses such as vibration, fatigue and environmental cracking

Equipment Failure

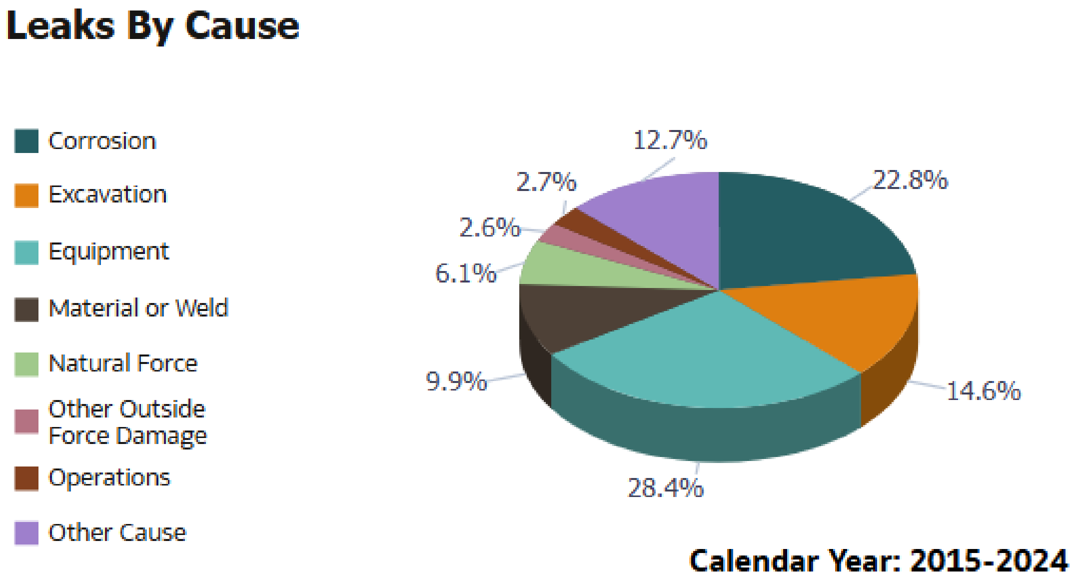
- Failure of control and relief equipment (including regulators, valves, meters, compressors, or other instrumentation or functional equipment)
- Equipment failures may be from threaded components, flanges, collars, couplings and broken or cracked components, or from O-ring failures, gasket failures, seal failures, or failures in packing or similar leaks

Incorrect Operations

- Failure due to inadequate procedures or safety practices, or failure to follow correct procedures, or other operator error (human error/judgement)
- Leaks associated with a component or process that joins pipe such as threaded connections, flanges, mechanical couplings, welds, and pipe fusions from ***poor construction*** should be classified as "**Incorrect Operation**"
- Leaks resulting from **failure of original sound material** from force applied during construction that caused a dent, gouge, excessive stress, or other defect, including leaks due to faulty wrinkle bends, faulty field welds, and damage sustained in transportation to the construction or fabrication site that eventually resulted in a leak, should be reported as "**Pipe, Weld or Joint Failure**"

Other Leak Causes

- Causes that do not fit into the categories mentioned earlier
- This is also sometimes where field crew is unable to classify the gas leak in a check list
- Subsequent analyses may be able to identify the cause and hence classify under already defined threat categories



§192.1007(c) Evaluate and rank risk

– An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the **relative importance of each threat and estimate and rank the risks posed to its pipeline.** This evaluation must consider each applicable **current and potential threat**, **the likelihood of failure associated with each threat, and the potential consequences of such a failure**.

– An operator may **subdivide** its pipeline into regions with similar characteristics and for which similar actions likely would be effective in reducing risk.

  – contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances

  – areas with similar materials or environmental factors

Threats

Current threats
Mostly the operators have threats that they have experienced in the system. In general, these are leak based and fall into defined threat categories.

Potential threat
Threats the Operator has not previously experienced but identified from industry or PHMSA information.

PHMSA/industry references

– PHMSA Safety Advisory Bulletins
– Manufacturer's Alerts
– PRCI (Pipeline Research Council International) Research Reports
– GPTC (Gas Piping Technology Committee)
– Others

Potential Threat Examples

- Over pressurization events
- Regulator malfunction or freeze-up
- Cross-bores into sewer lines
- Materials, equipment, practices, etc. with identified performance issues
- Rodents, plastic eating bugs, tree roots
- Cyber-security (enterprise level, but associated DIMP actions …)
  - Information is exposed to hackers
  - **Locations & data are confidential**, what countermeasures are in place **to avoid sabotage**?
- Near-misses [6]
- Other potential threats specific to the operator's unique operating environment

CPUC General Order 112-F

Near-miss events mean unplanned or undesired events that adversely affect an Operator's facilities or operations but do not result in injury, illness, damage, release of gas, loss of gas service, over-pressurization of gas pipeline facilities, or in a reportable incident, but had the potential to do so. Such events include, but are not limited to:

(a) A subsurface pipeline facility not marked or mismarked for excavation purposes;

(b) Excavation activity near a pipeline facility conducted without a valid Underground Service Alert ticket;

(c) The incorrect, or unintentional, operation of a valve or pressure regulator;

(d) An incorrectly mapped pipeline facility;

(e) Work activity in which a standard, procedure, or process approved by an operator was correctly applied but the activity, nonetheless, resulted in creating a situation or condition where damages or injuries could have easily occurred

RISK

- It is predictive in nature (relative risk)
- How frequently it happens (likelihood)?
- How significant could it be (consequences)?

Risk = Frequency/Likelihood X Consequence

- Likelihood factor for each threat (dig-ins, corrosion, …)
- Consequence factor for each threat (for example: location densely populated, place of gathering, close to building, …)

DIMP Modeling

SHRIMP - ("Simple, Handy, Risk-based Integrity Management Plan") developed by American Public Gas Association. It is an online tool that operators of natural gas distribution systems use to create a complete, written Distribution Integrity Management Program (DIMP) plan customized for the specific needs of their system.

DIMP Model: Large operators use their own models. Main source of data for these come from '**Leak Repair Data**'

DIMP Modeling (cont.)

- Prepare and export required data from "Leak Repair form" such as:

  Pipe data Leak source Cause of failure

- Additional data can be gained from other O&M sources (e.g., patrolling)
- Data may be divided in small geographical areas depending upon type of material (steel, plastic), year of manufacture, fitting types, etc.
- Use the in-house/vendor DIMP model with algorithm to analyze the data
- "Cause of failure" in leak repair form populates and puts each leak in appropriate threat category
- "Likelihood factors" and "consequence factors" are applied
  - These factors are dependent on industry experience, operator's own experience, input from Subject Matter Experts (SMEs)
- Results from model are compiled and threats are ranked
- Results ae discussed with SMEs that do these conform with the field observations, in general
- Mitigation measures are discussed, further analysis done if needed, and measures implemented

§192.1007(d) Identify and implement measures to address risks

– Determine and implement **measures designed to reduce the risks from failure** of its gas distribution pipeline

– These measures must include an effective leak management program (unless all leaks are repaired when found)

– Also referred to as "accelerated/ additional measures"

Mitigation Measures

- Pipe replacement
- Fitting replacement
- Valve replacement
- Corrosion monitoring
- Increased leak surveys

Example Programs

- Gas Pipeline Replacement Program
- Cast iron and pre-1940 steel
- Copper service lines
- Targeted large and small district regulator stations and farm taps
- Vintage pipeline; Aldyl-A, PVC
- Cross Bore Program - inspection of sewer mains and laterals for unintentional boring of gas facilities through sewers
- Medium pressure gas mains and services
- Riser Inspection and replacement
- Others

Good efforts – but actions should be prioritized in each case based on risk

§192.1007(e) Measure performance, monitor results, and evaluate effectiveness

(1) **Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program**. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(i) Number of hazardous leaks either eliminated or repaired as required by § 192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(iv) Total number of leaks either eliminated or repaired, categorized by cause;

§192.1007(e) Measure performance, monitor results, and evaluate effectiveness

(1) **Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program**. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

[…]

(v) Number of hazardous leaks either eliminated or repaired as required by § 192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material; and

(vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat

§192.1007(f) Periodic Evaluation and Improvement

- An operator must **re-evaluate threats and risks on its entire pipeline** and consider the relevance of threats in one location to other areas.
- Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure.
- An operator must conduct a complete program re-evaluation at least every five years.
- The operator must consider the results of the performance monitoring in these evaluations.

§192.1007(g) Report results

Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by § 191.11.

An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

Gas Distribution Annual Report Form F7100.1-1

NOTICE: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty as provided in 49 USC 60122.

OMB No. 2137-0629
Expiration Date 6/30/2026

DOT USE ONLY	
Initial Date Submitted	
Report Submission Type	
Date Submitted	

U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

ANNUAL REPORT FOR CALENDAR YEAR 20___

GAS DISTRIBUTION SYSTEM

PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING YEAR

	Mains		Services	
CAUSE OF LEAK	Total	Hazardous	Total	Hazardous
CORROSION FAILURE				
NATURAL FORCE DAMAGE				
EXCAVATION DAMAGE				
OTHER OUTSIDE FORCE DAMAGE				
PIPE, WELD, OR JOINT FAILURE				
EQUIPMENT FAILURE				
INCORRECT OPERATION				
OTHER CAUSE				

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR ________________

NUMBER OF HAZARDOUS LEAKS INVOLVING A MECHANICAL JOINT FAILURE ____________________

PART D – EXCAVATION DAMAGE

26 Root Cause Categories will be implemented for ***<u>CY 2024 data due on 3/15/2025</u>***

Notification Issue sub-Total	*calc*	**Locating Issue sub-Total**	*calc*
No notification made to the One-Call Center/811		Facility not marked due to Abandoned facility	
Excavator dug outside area described on ticket		Facility not marked due to Incorrect facility records/maps	
Excavator dug prior to valid start date/time		Facility not marked due to Locator error	
Excavator dug after valid ticket expired		Facility not marked due to No response from operator/contract locator	
Excavator provided incorrect notification information		Facility not marked due to Incomplete marks at damage location	
		Facility not marked due to Tracer wire issue	
Excavation Issue sub-Total	*calc*	Facility not marked due to Unlocatable Facility	
Excavator dug prior to verifying marks by test-hole (pothole)		Facility marked inaccurately due to Abandoned facility	
Excavator failed to maintain clearance after verifying marks		Facility marked inaccurately due to Incorrect facility records/maps	
Excavator failed to protect/shore/support facilities		Facility marked inaccurately due to Locator error	
Improper backfilling practices		Facility marked inaccurately due to Tracer wire issue	
Marks faded or not maintained			
Improper excavation practice not listed above			
Miscellaneous Root Causes sub-Total	*calc*		
Deteriorated facility			
One Call Center Error			
Previous damage		**1. Total Excavation Damages**	*calc*
Root Cause not listed		**2. Number of Excavation Tickets**	

§ 192.1011 What records must an operator keep?

An operator must maintain records demonstrating compliance with the requirements of this subpart for **at least 10 years**.

The records must include copies of superseded integrity management plans developed under this subpart.

Gas Safety and Reliability Branch (GSRB) – SED/CPUC DIMP Inspections

Large Operators

- Comprehensive DIMP Program inspection – every 3-4 years
- Annual inspection
  - Previous inspection follow-up
  - Review of any changes made to the DIMP Plan
  - Review of DIMP implementation

LPG Operators

- Gas Safety Inspections (including DIMP) – every 3-5 years
- Some operators may have shorter intervals

Thank You

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