FEDERAL GAS PIPELINE SAFETY TRANSMISSION AND GATHERING RULES

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2 Ways to Write Regulations

✔ Prescriptive Wording

- Tells you precisely what you must do
- Leakage surveys of a transmission line must be conducted at least once each calendar year

✔ Performance Wording

- Tells you what you must accomplish
- But YOU must determine HOW to accomplish it

THINK

- ✔ Outside of the box
- ✔ 20% of the energy (calories) we take into our body gets used by our brain
- ✔ Thinking can be hard physical work – People don’t like to do it!
- ✔ Read good books

Gathering Lines (1)

- §192.3 definition – from production facility to transmission line or main
- §192.8 (how they are determined)
  - See restrictions and details in Code
  - API RP 80
  - See next slide for Types
- §192.9 (the requirements)
  - Detailed
- GPTC Guide

Gathering Lines (2)

§192.8 – Types of Gathering Lines

- ✔ Type A Basically like transmission lines
- ✔ Type B
  - Steel < 20% SMYS
  - Plastic ≤125 psig
- ✔ Type C OD ≥ 8.625 inches and in Class 1
  - Steel ≥ 20% SMYS
  - Plastic > 125 psig
- ✔ Type R All others

Def. of Transmission Line (1)

(§192.3)

Transmission line means a pipeline, other than a gathering line, that:

- ✔ Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center;
- ✔ Operates at a hoop stress of 20 percent or more of SMYS; or
- ✔ Transports gas within a storage field.

Def. of Transmission Line (2)

Note: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

Some New Concepts (1)
§192.3 Definitions

Rupture Mitigation Valve (RMV)
means an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture. See §§192.634 and 192.636.

Some New Concepts (2)
§192.3 Definitions

Entirely replaced onshore transmission pipeline segments

means, for the purposes of §§ 192.179 and 192.634, where 2 or more miles, in the aggregate, of onshore transmission pipeline have been replaced within any 5 contiguous miles of pipeline within any 24-month period.

Some New Concepts (3)
§192.3 Definitions

Notification of potential rupture

means the notification to, or observation by, an operator of indicia identified in §192.635 of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline

Some New Concepts (4)
§192.3 Definitions

Wrinkle bend

- ✔ Old familiar term
- ✔ But first time defined in regulations
- ✔ Very detailed

Some New Concepts (5)

Alternative equivalent technology

- ✔ Not defined in §192.3
- ✔ Requires notification to PHMSA
- ✔ Must meet §§192.634 and 192.636
- ✔ See §192.179(g)

§192.7
What documents are incorporated by reference partly or wholly in this part?

- ✔ Note that a document may be incorporated wholly or in part
- ✔ Note that a specific edition of the referenced document is incorporated
- ✔ Note that the incorporated document applies only to the Section of the Code specified

§192.13(d)

What general requirements apply to pipelines regulated under this part? (1)

- ✔ Must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a **Management of Change (MOC)**
- ✔ ASME/ANSI B31.8S, Section 11

§192.13(d)
What general requirements apply to pipelines regulated under this part? (2)

Management of Change (MOC) must include:

- ✔Reason for change,
- ✔Authority for approving changes,
- ✔Analysis of implications,
- ✔Acquisition of required work permits,

§192.13(d)

What general requirements apply to pipelines regulated under this part? (3)

- ✔Documentation,
- ✔Communication of change to affected parties,
- ✔Time limitations, and
- ✔Qualification of staff.

§192.18
How to notify PHMSA

- ✔ Paragraph (c) is revised
- ✔ Very important for several other Sections of the regulations

§192.179
Transmission Line Valves (1)

New Sections (e), (f), (g), and (h) effective 10/5/2022

- ✔ §192.179(e)
  - If new pipe ≥ 6” is installed, install RMV or “equivalent” whenever a valve is required to meet valve spacing requirements.
  - Class 1 and Class 2 pipe is exempt if PIR is ≤ 150’.

§192.179
Transmission Line Valves (2)

- ✔ §192.179(f)
  - If entirely replaced segments with diameter ≥ 6”, valves spacing valves must be RMVs or equivalent.
  - If equivalent, must notify PHMSA.

§192.179
Transmission Line Valves (3)

- §192.179(g) If equivalent is used,
  - Must comply with §§192.634 and 192.636.
  - Must notify PHMSA, unless the equivalent is a manual compressor station valve that complies with §192.636 and is at a continuously manned station.
- §192.179(h) Valve Spacing Changes

§192.319(d – g)
Installation of pipe in a ditch (1)

- ✓ New Paragraphs (d) – (g)
- ✓ Applicable only to transmission, not to gathering
- ✓ After backfilling, perform assessment for coating damage and integrity of coating
- ✓ Use direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology

§192.319(d – g)
Installation of pipe in a ditch (2)

- ✔ Must notify PHMSA if using other technology
- ✔ Must repair coating damage if severe (NACE SP0502, Section 4)
- ✔ Make and retain documentation for life

§192.461(a) and (f – i)

External corrosion control: Protective coating (1)

- ✔ (a)(4) Coating must have sufficient strength to resist damage due to handling (including transportation, installation, boring, and backfilling)
- ✔ (f) – (i) Applicable only to transmission, not to gathering
- ✔ After backfilling, perform assessment for coating damage and integrity of coating

§192.461(a) and (f – i)
External corrosion control: Protective coating (2)

- ✓ Use direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology
- ✓ Must notify PHMSA if using other technology
- ✓ Must repair coating damage if severe (NACE SP0502, Section 4)
- ✓ Make and retain documentation for life

§192.465(d) and (f)
External corrosion control: Monitoring and remediation (1)

- ✓ (d) & (f) Applicable only to transmission, not to gathering
- ✓ Must promptly correct any deficiencies
- ✓ Must develop a remedial action plan and apply for permits within 6 months

§192.465(d) and (f)
External corrosion control: Monitoring and remediation (2)

✔ Remedial action must be completed promptly and

- Prior to next inspection or test,
- Within 1 year, or
- As soon as practicable, ≤ 6 months after obtaining permits.

§192.465(d) and (f)
External corrosion control: Monitoring and remediation (3)

- ✔ Must determine extent of area with inadequate CP
- ✔ Investigate and mitigate non-systemic or location-specific causes
- ✔ Use close interval surveys for systemic causes

§192.473(c)

External corrosion control: Interference currents (1)

- ✔(c) Applicable only to transmission, not to gathering
- ✔ Programs to minimize stray currents must include:
  - Interference surveys (see details)
  - Analysis of the results
  - Development of a remedial action plan
  - Application for permits within 6 months

§192.473(c)
External corrosion control: Interference currents (2)

- ✓Complete remedial actions promptly, but:
  - Within 15 months after the interference survey,
  - As soon as practicable, but within 6 months after obtaining permits

§192.478
Internal corrosion control: Onshore transmission monitoring and mitigation (1)

- ✓ Applicable only to transmission, not to gathering
- ✓ If there are corrosive constituents in the gas, must develop and implement a **monitoring and mitigation program**
- ✓ Review the monitoring and mitigation program each year

§192.478
Internal corrosion control: Onshore transmission monitoring and mitigation (2)

- ✔ Must evaluate the partial pressure of each corrosive constituent
- ✔ Monitoring and mitigation program must include:
  - Use of gas-quality monitoring where gas enters
  - Technology to mitigate corrosive constituents

§192.485(c)
Remedial measures: Transmission lines

- ✓ Applicable only to transmission, not to gathering
- ✓ If **strength of pipe**, based on actual remaining wall thickness must be determined and documented, follow §192.712

§192.607
Verification of Pipeline Material Properties and Attributes (1)

(a)Applicability.

✓ Wherever required by **this part**, operators of onshore steel transmission pipelines **must** document and verify **material properties and attributes** in accordance with **this section**.

§192.607
Verification of Pipeline Material Properties and Attributes (2)

(b)Documentation of material properties and attributes.

- ✓Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (*e.g.*, yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be **traceable, verifiable, and complete.**

TVC Records (§192.607(b))

- ✔ Applies only to transmission lines
- ✔ Records of Legacy Transmission Lines
  Must be **TVC**
- ✔ **Traceable, Verifiable, and Complete**
- ✔ Defined in Preamble and in FAQ
- ✔ But **Not defined in the regulations**
- ✔ May require MAOP reconfirmation under §192.624

§192.607
Verification of Pipeline Material Properties and Attributes (3)

(b)Documentation of material properties and attributes.

✔ **Charpy v-notch toughness values** established under this section needed to meet the requirements of the ECA method at §192.624(c)(3) or the fracture mechanics requirements at §192.712 **must be maintained for the life of the pipeline.**

§192.607

Verification of Pipeline Material Properties and Attributes (4)

(c)Verification of material properties and attributes.

- ✔ If an operator **does not have traceable, verifiable, and complete records** required by paragraph (b) of this section, the operator **must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments** in **order to verify the material properties** of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities:
  - **Anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations** that are **associated with replacements or relocations of pipeline segments that are removed from service.**

§192.607

Verification of Pipeline Material Properties and Attributes (5)

(c)Verification of material properties and attributes.

✔ The procedures must also provide for the following:

- **For nondestructive tests**, at each test location, material properties for **minimum yield strength and ultimate tensile strength** must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.
- **For destructive tests**, at each test location, a set of material properties **tests for minimum yield strength and ultimate tensile strength** must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.

§192.607

Verification of Pipeline Material Properties and Attributes (6)

(c)Verification of material properties and attributes.

- Tests, examinations, and assessments **must be appropriate** for verifying the necessary material properties and attributes.
- If **toughness properties** are not documented, the procedures must include **accepted industry methods** for verifying pipe material toughness.
- Verification of material properties and attributes for **non-line pipe components must comply with paragraph (f) of this section**.

§192.607
Verification of Pipeline Material Properties and Attributes (7)

(d)Special requirements for nondestructive Methods.

✔ **Procedures developed in accordance with <u>paragraph (c)</u>** of this section for verification of material properties and attributes using nondestructive methods **must**:

- Use methods, tools, procedures, and techniques that have been **validated by a subject matter expert** based on comparison with destructive test results on material of comparable grade and vintage;
- **Conservatively account for measurement inaccuracy and uncertainty** using **reliable engineering tests and analyses**; and
- Use test equipment that has been **properly calibrated** for comparable test materials prior to usage.

§192.607
Verification of Pipeline Material Properties and Attributes (8)

(e)Sampling multiple segments of pipe

- ✔ To verify material properties and attributes for a population of multiple, comparable segments of pipe without TVC, a sampling program may be used.
- ✔ Detailed requirements must be followed.

§192.607

Verification of Pipeline Material Properties and Attributes (9)

(f)Components

- ✔Operators must develop and implement procedures to establish and document the ANSI rating or pressure rating.
- ✔See §192.607(f) for details.

(g)Uprating

- ✔Operator cannot arbitrarily raise the grade or specification.

§192.610
Change in Class Location: Change in valve spacing

- ✓ Different rules if before or after October 5, 2022
- ✓ May require installation of Rupture Mitigating Valves (RMVs)
- ✓ Considers the use of **alternative equivalent technologies**
- ✓ May not apply if replacement < 1,000 feet

§192.613(c)
Continuing surveillance

- ✓ Following an extreme weather event or natural disaster, operator must inspect all onshore transmission facilities
- ✓ Must commence the inspection within 72 hours after operator determines area is safe
- ✓ Must take prompt and appropriate remedial action

Changes to §192.615 Emergency Plans

- ✔ Establish & maintain communications with a public safety answering point (9-1-1)
- ✔ Take necessary actions (shut-down)
- ✔ Notify 9-1-1
- ✔ Actions required by controllers
- ✔ Procedures to determine whether a notification is or is not a rupture

§192.617
Investigation of failures and incidents (1)

- ✔ Post-failure and incident **procedures**. Must establish and follow procedures.
- ✔ Post-failure and incident **lessons learned**
- ✔ Analysis of **rupture and valve shut-offs. Signed by Senior Executive Officer.** N/A to distribution or Types B and C gathering.

§192.617
Investigation of failures and incidents (2)

- ✔ **Rupture post-failure and incident** summary. N/A to distribution or Types B and C gathering.

§192.634
Transmission lines: Onshore valve shut-off for rupture mitigation (1)

- ✔ N/A for Types B & C gathering lines
- ✔ N/A in Class 1 or 2 if PIR ≤ 150 feet
- ✔ Applies to new or entirely replaced onshore transmission pipeline segments with diameters of 6 inches or greater that are located in high-consequence areas (HCAs) or Class 3 or Class 4 locations.
- ✔ Requires installation of RMVs or **alternative equivalent technology**

§192.634

Transmission lines: Onshore valve shut-off for rupture mitigation (2)

- ✔ Defines “shut-off segment”
- ✔ Regulations for RMVs on laterals.
  - In some instances, check valves may be used as an alternative equivalent technology.
- ✔ Alternative equivalent technology may be used in some instances for RMVs on crossovers.

§192.634
Transmission lines: Onshore valve shut-off for rupture mitigation (3)

✔ If a manual valve is used as an alternative equivalent technology, operator must develop and implement **procedures**.

§192.634

Transmission lines: Onshore valve shut-off for rupture mitigation (4)

- ✔ Specifies "shut-off segment" valve spacing
- ✔ May use a manual compressor station valve at a continuously manned station IF it can be closed within 30 minutes of a rupture.

§192.635
Notification of potential rupture

- ✔ Expands on the definition in §192.3
- ✔ An unanticipated or unplanned pressure loss is outside of the pipeline’s normal operating pressures when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less.

§192.636
Transmission lines: Response to a rupture; capabilities of RMVs or alternative equivalent technologies (1)

- ✔ Applies to RMVs and alternative equivalent technologies
- ✔ Fully close RMVs or alternative equivalent technologies within 30 minutes of rupture identification

§192.636
Transmission lines: Response to a rupture; capabilities of RMVs or alternative equivalent technologies (2)

- ✔ RMVs can be left open more than 30 minutes under certain conditions
- ✔ RMVs must be capable of being monitored or controlled either remotely or byo on-site personnel
- ✔ Need back-up power source for SCADA

§192.636
Transmission lines: Response to a rupture; capabilities of RMVs or alternative equivalent technologies (3)

- ✔ The position and operational status of an RMV must be monitored
  - Monitoring not needed if there is the capability to monitor pressures or gas flow rate to identify and locate a rupture.

§192.636
Transmission lines: Response to a rupture; capabilities of RMVs or alternative equivalent technologies (4)

- ✔ Prior to using an ASV as an RMV, need to conduct **flow modeling**
  - Flow modeling must include a time/pressure chart

§192.636
Transmission lines: Response to a rupture; capabilities of RMVs or alternative equivalent technologies (5)

- ✔ If a manual valve in a Class 1 location that is not an HCA is used as an alternative equivalent technology, the operator may request an exemption from the 30 minute closing requirement.

§192.710
Transmission lines: Assessments outside of high consequence areas

- ✔ If a condition that could adversely affect the safe operation of a pipeline is discovered, operator must comply with §§192.485, 192.711, 192.712, 192.713, and 192.714.

§192.745
Valve maintenance: Transmission lines (1)

- ✔ For each **remote controlled valve (RCV)**, must conduct a point-to-point verification between SCADA and the installed valves, sensors, and communications equipment

§192.745
Valve maintenance: Transmission lines (2)

- For each **manually controlled valve**, must achieve a valve closure time of 30 minutes or less through an initial drill and through periodic validation
  - Must review and document the results of each phase of the drill response
- Once each calendar year, randomly select a valve serving as an alternative equivalent technology

§192.745
Valve maintenance: Transmission lines (3)

- ✔ Must achieve a valve closure time of 30 minutes or less through an initial drill and through periodic validation
  - Must review and document the results of each phase of the drill response

§192.745
Valve maintenance: Transmission lines (4)

- ✔ Based on results of response-time drills, include lessons learned in:
  - Training and qualifications programs
  - Design, construction, testing, maintenance, operating, and emergency procedures manuals
  - Any other areas needing improvement

§192.745
Valve maintenance: Transmission lines (5)

- Must develop and implement remedial measures to correct any valve indicated to be inoperable or unable to maintain effective shut-off
  - Repair or replace the valve as soon as practicable but no later than 12 months
  - Designate an alternative valve acting as an RMV within 7 days.

§192.745
Valve maintenance: Transmission lines (6)

✔ If using an Automatic Shut-off Valve (ASV) as a Rupture Mitigating Valve (RMV), must document and confirm the ASV shut-in pressures once a year.

§192.911

What are the elements of an integrity management program?

(k) A **management of change** process as required by §192.13(d)

§192.917
How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program? (1)

(a) *Threat identification*. Must identify and evaluate all potential threats

§192.917
How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program? (2)

(b)Data gathering and integration. To identify and evaluate the potential threats, an operator must gather and integrate existing data and information.

§192.917

How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program? (3)

(b) The evaluation must analyze both the covered segment and similar non-covered segments. If input is obtained from subject matter experts (SMEs), an operator must employ adequate control measures to ensure consistency and accuracy of information.

§192.917
How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program? (4)

(c) *Risk assessment*. Must conduct a risk assessment that follows ASME/ANSI B31.8S, Section 5. Beginning February 26, 2024, the risk assessment must:

§192.917

How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program? (5)

(1) Analyze how a potential failure could affect high consequence areas;

(2) Analyze the likelihood of failure due to each individual threat and each unique combination of threats that interact or simultaneously contribute to risk at a common location;

§192.917
How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program? (6)

(3) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment;
(4) Evaluate the potential risk reduction associated with candidate risk reduction activities, such as preventive anomaly remediation and assessment intervals.

§192.917

How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program? (7)

(5) In conjunction with §192.917(b), an operator may request an extension of up to 1 year for the requirements of this paragraph by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with §192.18.

§192.917

How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program? (8)

The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (c)(5), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

§192.923
How is direct assessment used and for what threats?

(b)(2) Section 192.927 and NACE SP0206 if addressing internal corrosion (IC).

(b)(3) Section 192.929 and NACE SP0204 if addressing stress corrosion cracking (SCC).

§192.927
What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

See details in §192.927.

§192.929
What are the requirements for using Direct Assessment for Stress Corrosion Cracking?

See details in §192.929.

§192.933
What actions must be taken to address integrity issues?

- ✔ Must take prompt action to address all anomalous conditions discovered through the integrity assessment process.
- ✔ Repairs must use pipe and material with TVC records.
- ✔ PHMSA has added to the list of 1-year conditions.
- ✔ Further rules on pressure reduction.
- ✔ Further rules on scheduling repairs.
- ✔ Further rules on repairing cracks.
- ✔ See §192.933 for details.

§192.935
What additional preventive and mitigative measures must an operator take? (1)

✔ If rupture-mitigation valve (RMV) or alternative equivalent technology would be an efficient means of adding protection to a high-consequence area (HCA), then that must be installed.

§192.935

What additional preventive and mitigative measures must an operator take? (2)

- ✔ The above risk analysis must be certified by a SENIOR EXECUTIVE of the company.
- ✔ This must be done once a year

§192.941
What is a low stress reassessment? (1)

- ✔ PHMSA is replacing the term “electrical survey” with “indirect assessment” to accommodate other techniques that are comparably effective.
- ✔ An indirect assessment must be conducted once every 7 years in an HCA.

§192.941
What is a low stress reassessment? (2)

- ✔ An indirect assessment could be conducted using one of the following means:
  - Indirect examination method, such as a close interval survey,
  - Alternating current voltage gradient survey,
  - Direct current voltage gradient survey, or
  - The equivalent of any of these methods.
- ✔ See §192.941 for details.

Final Comments

Questions?
Discussion?

THANK YOU

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