Rulemaking Identification Number RIN2 – Gas Mega Rule

T&D Seminar 6/1/2023

UGI Utilities

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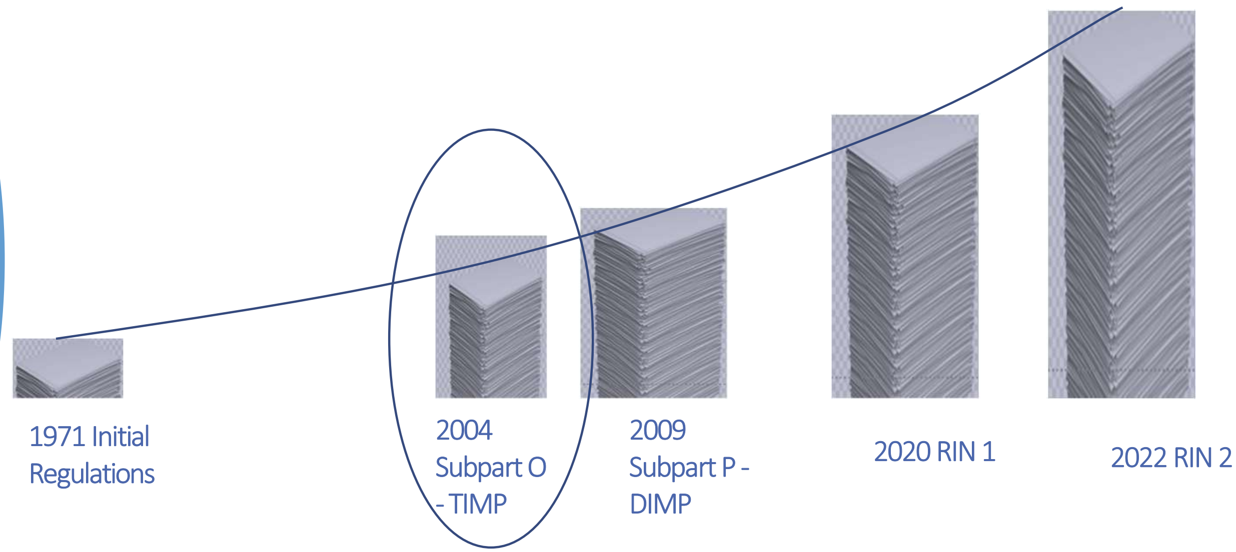
Part 192 Regulations Number of Pages



Gas Mega Rule Time Line

2011
Incident in San Bruno, CA

2011
PHMSA issues ANPRM

2012
Incident in Sissonville, WV

2014
PHMSA issues NPRM

2017–2018
5 Gas Pipeline Advisory Committee (GPAC) meetings

2018
Rule split into 3 final rules

2019
RIN 1 MAOP reconfirm. & others

2021
RIN3 Gas Gathering

2022
RIN 2 , IM improvements, repair criteria

RIN 2 Updates

- Definitions
- Management of Change
- Coating Surveys
- External corrosion monitoring and remediation
- Internal corrosion monitoring and remediation
- Continuing Surveillance
- Repair requirements
- Threat Identification
- Data Integration
- Risk Assessment
- ICDA
- SCCDA
- Remedial Action
- P&M Measures
- Low stress reassessement

Dates and Stay of Enforcements

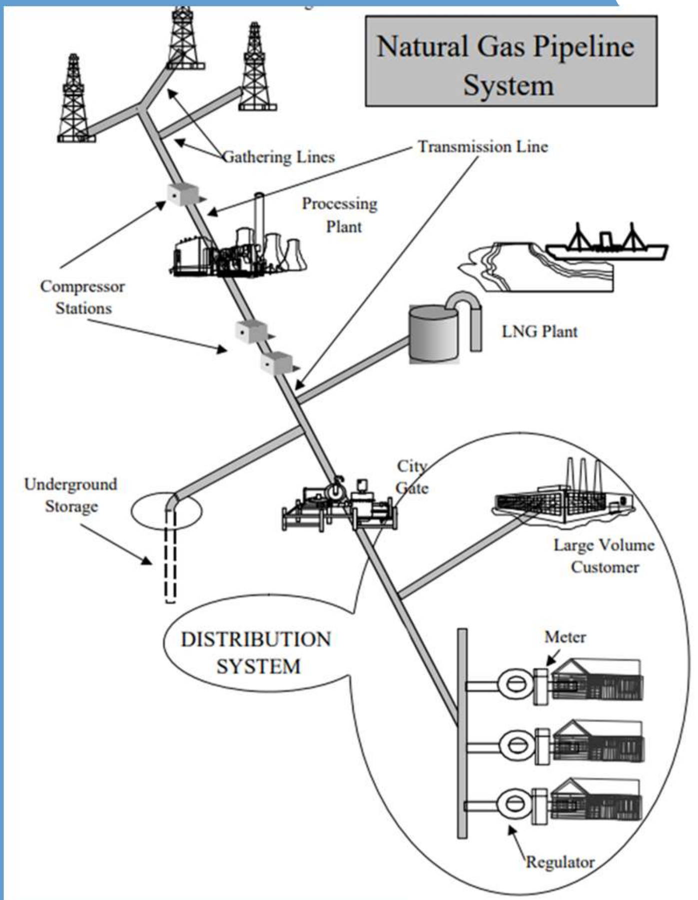
Original rule had an effective date of May 24th, 2023. Several sections had their own effective data.

On 12/6/2022, PHMSA issued a stay of enforcement for existing transmission lines, extending the deadline until February 24, 2024.

Effective Dates

Section	Final Rule – RIN2	Enforcement Discretion
Issue Date	8/24/2022	4/17/2023
Rule Effective Date	5/24/2023	2/24/2024
192.13 Management of Change	2/26/2024	2/26/2024
192.319 Coating Surveys	**5/24/2023**	**5/24/2023**
192.461 Coating Surveys	**5/24/2023**	**5/24/2023**
192.613 Continuing Surveillance	**5/24/2023**	**5/24/2023**
12.917 Begin data integration	**5/24/2023**	**5/24/2023**
192.917 Complete Data Integration	2/26/2024	2/26/2024
192.917 Risk Model	2/26/2024	2/26/2024

192.3 Definitions



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;

(3) Transports gas within a storage field; or

(4) **Is voluntarily designated by the operator as a transmission pipeline.**

Distribution center means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example:

(1) At a metering location;
(2) A pressure reduction location; or
(3) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.

192.13 Management of Change

Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11 that addresses technical, **design**, physical, **environmental**, procedural, **operational**, **maintenance**, and organizational changes to the pipeline or processes, whether permanent or temporary.

Note: the **design, environmental, operational**, and **maintenance** items are not listed in B31.8S.

MOC process must be implemented by 2/26/2024.

MOC is for all pipeline segments, not just HCAs.

Installation of pipe in a ditch
§192.319 & §192.461

If more than 1000 feet of Transmission Line is installed or replaced in a ditch.

- Conduct ACVC or DCVG to identify coating anomalies within 6 months of backfill.

- Must repair any "severe" anomaly within 6 months of assessment

CP Monitoring and Remediation §192.465

Each operator must promptly correct any deficiencies on gas transmission lines

- Develop a remediation plan.
- Apply for permits within 6 months
- Remedial action completed promptly but no later than the following:
  - Prior to the next inspection interval, or
  - Withing 1 year not to exceed 15 months or
  - **As soon as practical not to exceed 6 months after obtaining permits**.

If annual CP test point are below requirements, must determine the extent of the area with inadequate CP.

For systemic causes, must conduct close interval survey (CIS) unless impractical based upon geographical, technical or safety reasons

Interference Currents §192.473

Interference surveys must be conducted when

- potential monitoring indicates a significant increase in stray current (>100 amps per meter squared), or
- when new potential stray current sources are introduced, such as
  - co-located pipelines,
  - high voltage alternating current (HVAC) power lines, including
  - from additional generation,
  - a voltage up-rating,
  - additional lines,
  - new or enlarged power substations

Internal Corrosion Control §192.478

CO2 Partial Pressure (psia)	Level of Concern
< 3	Low Risk
3 – 30	Moderate Risk
> 30	High Risk

TABLE 192.917i

Onshore transmission line operators must develop an implement a monitoring and mitigation program for potentially corrosive constituents such as:

- Carbon dioxide
- Hydrogen sulfide
- Sulfur
- Microbes
- Liquid water

An operator must evaluate the partial pressure of each corrosive constituent, where applicable.

Implement mitigation measures as necessary.

Internal Corrosion Control Monitoring and Mitigation §192.478

Monitoring and mitigation programs must include:

(1) The use of gas-quality monitoring where gas with potentially corrosive contaminants enters the pipeline.

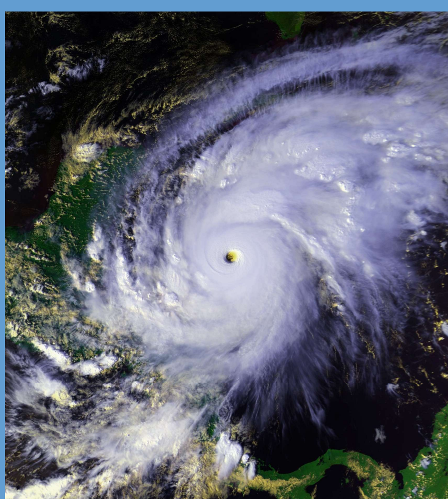
(2) Technology to mitigate the potentially corrosive gas stream constituents such as

- product sampling,
- inhibitor injections,
- in-line cleaning pigging,
- separators,
- or other technology that mitigates potentially corrosive effects.

(3) An evaluation at least once each calendar year, at intervals not to exceed 15 months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

An operator must review its monitoring and mitigation program at least once each calendar year

Continuing Surveillance §192.613



T h i

Following an Event	Following an extreme weather event or natural disaster that potentially affected onshore transmission pipeline facilities an operator must:
Assess	Assess the nature of the event and history of the affected pipeline to determine the appropriate inspection method(s).
Commence	Commence the inspection within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed.
Take	Take prompt and appropriate remedial action

Analysis of Predicted Failure Pressure §192.712

Anomalies and defects need to be analyzed:

- Corrosion: Use ASME/ANSI B31G, R-STRENG (or equivalent i.e. KAPA)
- **Dents: Perform Engineering critical analysis**
  - Dents with a depth greater than 10 percent of the pipe outside diameter or exceed the critical strain for the pipe material properties must be remediated
- Cracks: Criteria did not change from RIN1

Assessment Response Criteria §192.714 and §192.933

Anomaly	Immediate	Scheduled (HCA 1yr non-HCA 2 yr)	Monitored
General metal loss anomalies	PFP ≤ 1.1 x MAOP, or Metal loss > 80% nominal WT	PFP > 1.1 x MAOP Class 1 – follow B31.8S PFP< 1.39 x MAOP in Class 2 PFP< 1.5 MAOP Class 3 & 4	
Metal loss preferentially affecting long seam on DC/LF or HF ERW / EFW	PFP ≤ 1.25X MAOP and JF < 1.0	PFP< 1.39 x MAOP in Class 1 or Class 1 that was uprated to Class 2, PFP< 1.5 MAOP Class 2, 3 & 4 and JF < 1.0	PFP ≥ 1.39 x MAOP for Class 1 or Class 1 that was uprated to Class 2, PFP ≥ 1.5 x MAOP for Class 2, 3, and 4
Metal loss at crossing/circumferential / girth weld		PFP< 1.39 x MAOP in Class 1 or Class 1 that was uprated to Class 2, PFP< 1.5 MAOP Class 2, 3 & 4	
Dents between 8 and 4 o'clock (top 2/3 of pipe)	Dent w/ metal loss, cracking, or stress riser unless strain < critical	Smooth dents with depth > 6% (>0.50" if OD < NPS 12) unless strain < critical	Depth > 6% (>0.50" if OD < NPS 12) and ECA strain < critical
Dents between 4 and 8 o'clock (bottom 1/3 of pipe)		Dent w/ metal loss, cracking, or stress riser unless ECA strain < critical	Depth > 6% (>0.50" if OD < NPS 12) and ECA strain < critical
Dent on weld or longitudinal/ helical seam		Depth > 2% (>0.25" if OD < NPS 12) at weld, unless ECA strain < critical	Depth > 2% (>0.25" if OD < NPS 12) at weld, and strain < critical
Other dents			Dent w/ metal loss, cracking, or stress riser and strain < critical
Crack or Crack-like anomalies	Crack depth + metal loss > 50% of WT, Crack depth + metal loss > tool measurable depth, PFP < 1.25 x MAOP	PFP< 1.39 x MAOP in Class 1 or Class 1 that was uprated to Class 2, PFP< 1.5 MAOP Class 2, 3 & 4	PFP ≥ 1.39 x MAOP for Class 1 or Class 1 that was uprated to Class 2, PFP ≥ 1.5 x MAOP for Class 2, 3, and 4

Note: PFP – Predicted failure pressure, JF – Joint Factor

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

(a)
Threat Identification

(b)
Data Gathering & Integration

Must begin to integrate all data starting May 24th, 2023 with integration complete by February 26th, 2024*

(c)
Risk Assessment

Must be in place by February 26th, 2024*

* An operator may request a 1 year extension to the February 2024 deadline by submitting notification and justification for the extension at least 90 days prior to 2/26/2024.

Threat Identification
§192.917(a)

An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S which are grouped under the following four threat categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Stable threats, such as manufacturing, welding, fabrication, or construction defects;

(3) Time independent threats, such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage, to include consideration of seismicity, geology, and soil stability of the area; and

(4) Human error, such as operational or maintenance mishaps, or design and construction mistakes

Data Gathering and Integration
§192.917(b)

RIN 2 Greatly expands the data elements listed in ASME B31.8S.
Must integrate pertinent information.

- Ultimate Tensile Stress
- Coating inspection reports (jeeping)
- Post backfill coating inspection surveys
- Alternating current, direct current, and foreign structure interference surveys
- Stress corrosion cracking excavations and findings
- Selective seam weld corrosion excavations and findings
- Any indication of seam cracking
- Gas stream sampling
- Internal corrosion monitoring results, including cleaning pig sampling results
- Industry experience for incident, leak, and failure history;
- Aerial photography
- Exposure to natural forces including seismicity, geology, and soil stability of the area.

Data Gathering and Integration §192.917(b)

Data integration includes:

- If input is obtained from subject matter experts (SME), an operator must employ adequate control measures to ensure consistency and accuracy of information. Control measures may include:
  - Training of SMEs
  - Use of outside technical experts
  - Documenting the names and qualifications
  - Identify and analyze spatial relationships among anomalous information
    - corrosion coincident with foreign line crossings o
    - evidence of pipeline damage where imaging shows evidence of encroachment.
- Analyze the data for interrelationships among threats.

Risk Assessment §192.917(c)

Beginning on February 26,2024* the Risk Assessment must:

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;

3. Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

4. Evaluate the potential risk reduction associated with candidate risk reduction activities, such as preventive and mitigative measures, and reduced anomaly remediation and assessment intervals.

* An operator may request a 1 year extension to the February 2024 deadline by submitting notification and justification for the extension at least 90 days prior to 2/26/2024.

Direct Assessment
§192.927 (ICDA)
§192.929 (SCCDA)

Incorporates the following documents:

NACE INTERNATIONAL

NACE SP0206-2006
Item No. 21112

Standard Practice

Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)

NACE INTERNATIONAL

SP0204-2008
(formerly RP0204)
Item No. 21104

Standard Practice

Stress Corrosion Cracking (SCC) Direct Assessment Methodology

P&M Measures §192.935

New measures that operators must consider:

- Correcting the root causes of past incidents to prevent recurrence
- Installing pressure transmitters on both sides of ASVs and RCVs that communicate with the gas control center
- Conducting additional right-of-way patrols
- Conducting hydrostatic tests in areas where pipe material has quality issues or lost records
- Testing to determine material mechanical and chemical properties for unknown properties
- Re-coating damaged, poorly performing, or disbonded coatings
- Performing additional depth-of-cover surveys at roads, streams, and rivers

What is low stress reassessment §192.941

If using low stress reassessment for external corrosion:

- Cathodically protected pipe. At least once every 7 calendar years. an operator must perform an assessment on the covered segment using one of the following:
  - Close interval survey.
  - Alternating current voltage gradient (ACVG) survey
  - Direct current voltage gradient (DCVG) survey;
  - or the equivalent of any of these methods.
- An operator must evaluate the cathodic protection and corrosion threat and include the results of each indirect assessment as part of the overall evaluation. This evaluation must also include, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

QUESTIONS