Managing Internal Corrosion Threat in Unpiggable Pipeline and Facility Dead Legs

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1. Abstract

Dead legs in piping systems create a high risk for internal corrosion because of their no-flow or low-flow condition. Within the Midstream industry, designs continue to include dead legs, so facility integrity management programs must manage the threat of internal corrosion. Due to recent failures, there is a growing interest in providing more guidance on what integrity management programs should include to address the internal corrosion threat to dead legs.

The AMPP SC 15 Pipelines and Tanks committee recently met at the AMPP Gulf Coast Conference. The potential to create an AMPP Standard to address the challenges of managing internal corrosion in midstream dead legs became a strong contender for development.

This paper will discuss what may be included in the new AMPP document. The new standard will draw from existing industry knowledge and is intended to supplement existing standards, such as SP0106-2018 Control of Internal Corrosion in Steel Pipelines and Piping Systems, SP0208-2008 Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines, SP0206-2016 Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas, SP0110-2024 Wet Gas Internal Corrosion Direct Assessment (WG-ICDA), SP0116-2022 Multiphase Flow Internal Corrosion Direct Assessment for Pipelines (MP-ICDA and API 1160 3rd Edition.

This paper will address the following factors:

- Commodity/process service,
- Water and/or air infiltration,
- Orientation of the dead leg,
- Integrity Management,
- Corrosion Control and Mitigation, and
    - Corrosion Coupons,
    - Chemical injections, and
    - Drain blow downs.
- Design.
    - Why are dead legs included in the design?

2. Introduction

For the last 40+ years, there has been varying emphasis on managing internal corrosion in dead leg piping in the oil and gas industry. With the implementation of the OSHA 1910.119 Rules for Process Safety Management, including Subpart j Mechanical Integrity, in 1992, some focus has been on tracking failures and the causes for the downstream refining sector. In 1993, the 1st Edition of API 570 Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-Service Piping

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Systems was published, which is considered recognized and generally accepted as good engineering practices (RAGAGEP). API RP 1160 Managing System Integrity for Hazardous Liquid Pipelines introduced the threat of dead leg internal corrosion risks in 2001. Additional versions have expanded and provided guidance on managing dead legs for the liquids pipeline industry up to the latest 2019 version. With the 5th Edition of API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems published in February 2024, the definition of dead leg was simplified to "section of piping or piping system where there is no significant flow." Interestingly, AMPP does not define dead leg(s), or at least there is none in the NACE/ASTM G193 – 22 Standard Terminology and Acronyms Relating to Corrosion.

This paper will discuss the outline for the AMPP SC-15 Proposed Project Technical Report "Managing Internal Corrosion in Midstream Dead Legs." The Background will discuss how, as an industry, we have reached the point of proposing this document and the potential additional research that may be necessary for the document to be fully successful in managing internal corrosion in midstream dead legs.

3. Background

When looking at "C2023-19041 AMPP Paper and Presentation Evaluation of Dead Leg Piping with Internal Corrosion at A Salt Dome Natural Gas Storage Facility" [1] it explored dead leg threats and fitness-for-service of a natural gas storage facility. This paper started with the following:

> "Internal corrosion in dead legs is a leading cause for failure in pipeline facilities such as pump stations, compressor stations, and terminals. Corrosion management of dead legs is challenging because they are generally unpiggable, difficult to chemically treat, and susceptible to several internal corrosion mechanisms…The American Petroleum Institute (API) has issued multiple Pipeline Performance Tracking System (PPTS) advisories related to facility piping. In 2003, API PPTS Advisory 2003-5 reviewed PPTS data from 1991 through 2001. Of the failures reported, 54% of the corrosion failures were attributed to internal corrosion…The advisory suggested removing dead legs where feasible. Additionally, other PPTS advisories all have talked about internal corrosion in dead legs. They are as follows:

- API PPTS Advisory 2005-4 focused on incidents associated with facilities piping and equipment between 1999 and 2003. The PPTS advisory recommended establishing internal corrosion mitigation measures within facilities and evaluating dead legs to reduce failures.
- API PPTS Advisory 2009-5 was based on the findings of a survey conducted by the Operations Technical Committee (OTC). The advisory identified dead legs, drain lines, and relief lines as three of six distinct areas of concerns. Recommendations included flushing the dead legs and having specific inspection intervals for dead legs appropriate to the relative risk. Inspection should target where water and deposits collect.

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- API PPTS Advisory 2014-1 addressed failures from 2009-2012, where 312 piping failures in facilities were due to internal corrosion. Ninety-six percent of them were due to intermittent flow. The advisory recommended removal of the dead legs that service no purpose. Mitigation and inspection/monitoring programs were also discussed."[1]

After presenting the paper at the AMPP Corrosion 2023 Convention and Expo, a panel discussion for the 2024 API Inspection and Mechanical Integrity Summit – Midstream Division, Corrosion, and Metallurgy Track "Dead Leg Management Panel Discussion" was developed to explore these topics further. Mark Piazza (API, Senior Policy Advisor Midstream facilitated), Ian Stallman (Corrosion Services Manager Marathon Pipe Line), Leslie Ward (Specialist Facility Engineer at Enbridge GTM), Carlos Palacios (CIMA-TQ, LLC), and Rafael Rengifo (Director of Midstream at Becht Engineering, a former Phillips 66 Midstream Director of Engineering, a last-minute substitute for Carmen Seal (Advisor Becht Engineering but recently retired from Pipeline Integrity Manager at CITGO Petroleum)) all shared our experiences. In addition to discussing our different owner-operator experiences, the panel discussed the Natural Gas Pipeline Rupture and Fire near Carlsbad, New Mexico, on August 19, 2000, and how a dead leg was an ancillary cause of the event. This is to say that this failure was not a real dead leg. However, it was due to water accumulation on an uphill section of the line. The poor management of the drip resulted in the water carrying over into the mainline, where internal corrosion progressed uncontrolled. Proper management of the drip would have revealed the amount of water in the system and should have triggered additional inspection and mitigation.

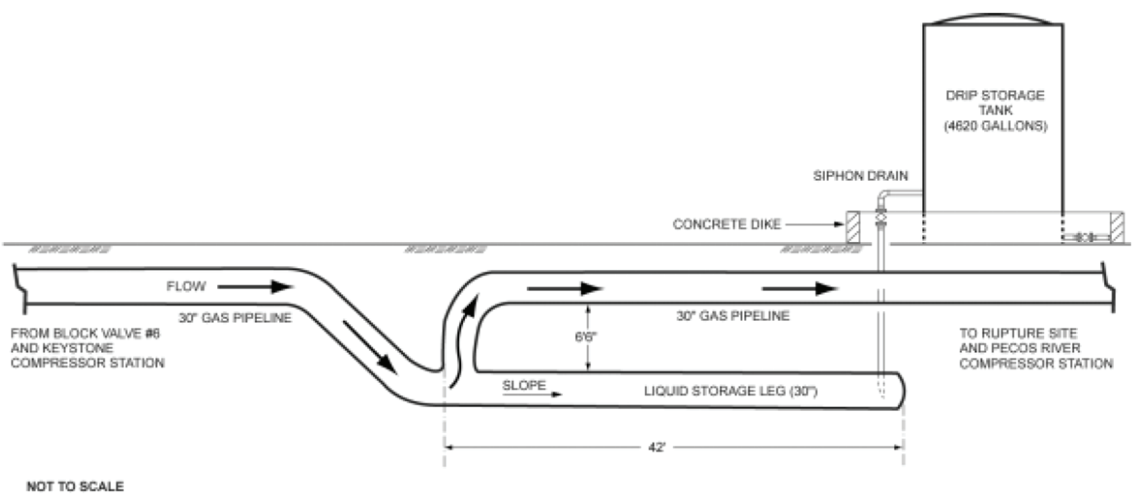

Figure 11. Diagram of line 1103 drip.

Figure 1. Diagram of Drip from the Pipeline Incident Report Natural Gas Pipeline Rupture and Fire Near Carlsbad, NM August 19, 2000 [2]

Two different PRCI projects address issues regarding dead legs. Per Caleb Carpenter, Corrosion Control Process Leader at Marathon Petroleum, the first PRCI project is IC-01-09 – "Geometric Characterization of Branch Connections." The perception of this project is that there is a lack of best practices when looking at API RP 2611 Inspection of In-Service Terminal Piping System and API RP

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581 Risk-Based Inspection Methodology. API RP 2611 has been withdrawn, meaning it is still available but not supported by API anymore. API RP 1188 Hazardous Liquid Pipeline Facilities Integrity Management replaces API RP 2611 per its introduction. API 1188 includes Table 1 Dead Leg Guidance from API RP 2611, as shown in Table 2 (See Table 1 below). From my experience on the API Committee on Refining and Equipment (CRE) Subcommittee on Inspection and Mechanical Integrity (SCIMI), API 570 and API RP 574 have been the primary documents that focus on the strategies regarding inspection and testing for dead legs, though in the downstream sector. The definitions are different between API 570 and API 1188. IC-01-09 believes that failed dead legs all meet the definition (API 2611), but many do and do not corrode. IC-01-09 is set to accomplish two things:

- The project will use computational fluid dynamics (CFD) to determine the rate of accumulation of basic sediment and water (BS&W) in non-flowing branches.
- The accumulation rate (as a surrogate for IC likelihood) can be used directly for risk-based inspection (RBI) or planning mitigation.

Table 1. – API RP 1188 Table 2 - Dead Leg Guidance

Table 2—Deadleg Guidance

Branch Position (O'clock Orientation) on Operating Line [a]	Length of Deadleg [b]	Deadleg
(12:00)	Any	NO
(9:00 and 3:00)	≤ Three (3) x diameter of branch	NO [c]
(9:00 and 3:00)	> Three (3) x diameter of branch	YES
(6:00)	> one (1) x diameter of branch	YES

[a] Black section denotes location of potential deadleg based on a horizontal position of the operating line.
[b] Length to be measured from outside diameter of carrier pipe to end of deadleg branch.
[c] Branch is a deadleg if trap space present.

The second PRCI project is Idea 3584 (Dead Leg Gap Analysis - Official title to be updated), which will go for funding in 2025. Per Caleb Carpenter, the road map for dead leg management includes a variety of sub-topics, including the following:

- Solids & Water Accumulation,
- Flushing Science Investigation,
- Chemical Treatment Delivery,
- Bacteria as Affected by Flow,
- Alternative Mitigations,
- Monitoring No-Flow Conditions, and
- Asset Digitization & D.L Identification.

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The October 2024 discussions about Idea 3584 focused on Solids & Water Accumulations and how to characterize solids to remove them.

The American Fuels & Petrochemical Manufacturers (AFPM) Mechanical Integrity Subgroup (MISG) has developed guidance for managing pressurized piping dummy supports, but only AFPM members can access this information. For those that are not familiar with the term pressurized piping dummy support, it is typically when a tee fitting is used to extend the piping to the next support in a pipe rack or down to grade instead of using an elbow and structural steel or piping not connected to the pressurized process piping. In Figure 2 below, the green piping is the pressurized piping, and the red piping is the piping not connected to the pressurized piping but used as a support. The AFPM MISG is also working on a dead leg guidance document, but only AFPM members can access this information.

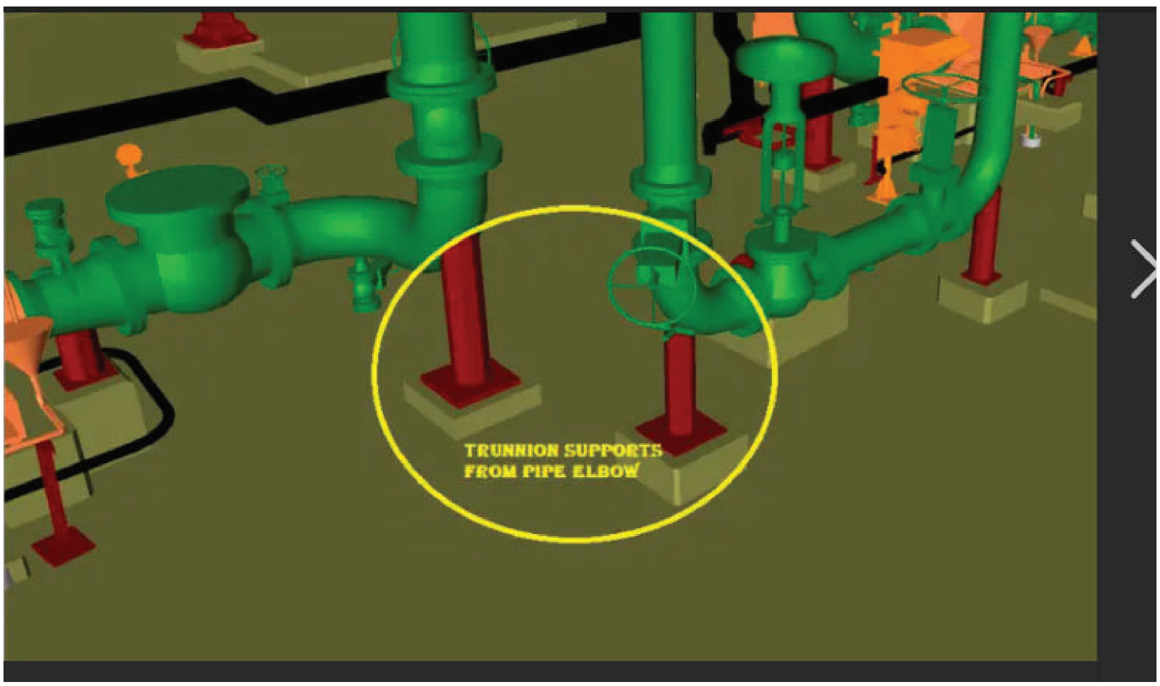

Figure 2. Example of a Corrected Pressurized Dummy Support [3]

3.1. Recent Industry Incidents

Krista Heidersbach, recently retired from P66 and now with Brown Corrosion, presented at the 2024 API Inspection and Mechanical Integrity Summit regarding recent dead leg leaks from the P66 Midstream/Pipeline portion of their business. None of them resulted in a fire, caused any significant damage, and no injuries. One concern is that it is difficult to find information about midstream pipeline dead leg leaks because they do not typically cause fires, significant damage, or injuries.

Internal corrosion failures rarely leave company property, though they are often reportable to PHMSA due to property damage or clean-up costs, not due to fire or injuries/fatalities. This is likely

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why less efforts have been made to address dead legs until recent years have brought more attention to this area.

The introduction discusses PPTS advisories discussed in Lynsay Bensman's NACE Corrosion 2016 Paper No. 7715 "51316-7715-Dead Leg Internal Corrosion Management.pdf." [4] She discusses two "examples of recent facility failures include a 2010 rupture at a Tennessee Gas Pipeline (TGP) station [5] and an Alyeska failure at PS1 in 2011. [6] The TGP failure occurred on a 24-inch diameter discharge header installed in 1947 that experienced no flow during normal operations. The operating pressure at the time of the failure was 720 psig. A dead leg had been established in the header in 2000 when an upstream gathering pipeline was disconnected from the header. Figure 1 (see Figure) shows a drawing of the header configuration, indicating the location of the 24-inch dead leg of the header that failed. An inspection that was performed at the time that the dead leg was created revealed no internal corrosion. The failure mechanism was attributed to microbiologically influenced corrosion (MIC); indications of residual moisture in the dead leg were observed. No internal corrosion was present in two (2) other underground dead legs at the station that were dug up and inspected following the failure. The Alyeska failure was attributed to internal corrosion in the station piping." [4]

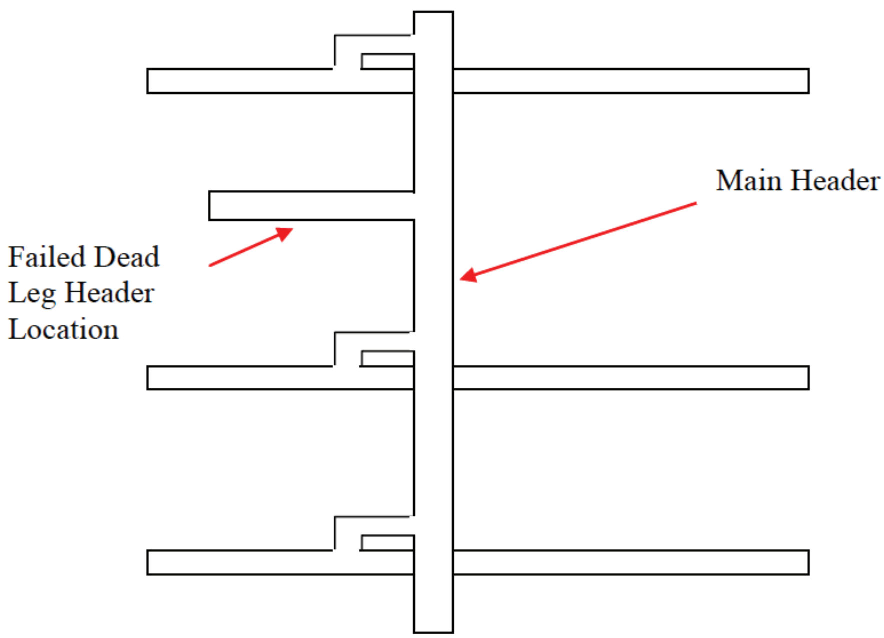

Figure 1: Drawing depicting the TGP station header failure location configuration.

Figure 3. 2010 Rupture at a Tennessee Gas Pipeline (TGP) Station Dead Leg Header Location [4]

The Fractracker Alliance's "2021 Pipeline Incidents Update: Safety Record Not Improving" [7] summarizes pipeline incidents. The PHMSA designated causes of Excavation Damage, Incorrect Operation, Material Failure of Pipe or Weld, Equipment Failure, Natural Force Damage, Corrosion Failure, Other Outside Force Damage, and Other Incident Causes summarize the causes of Pipeline

Incidents in 2020 (see **Figure**). To better understand dead leg failures, we need much more granular data on corrosion failures. The division of corrosion failures needs to be aboveground and belowground piping, internal and/or external corrosion, pipeline or facility location, and the type of dead leg discussed later in the paper.

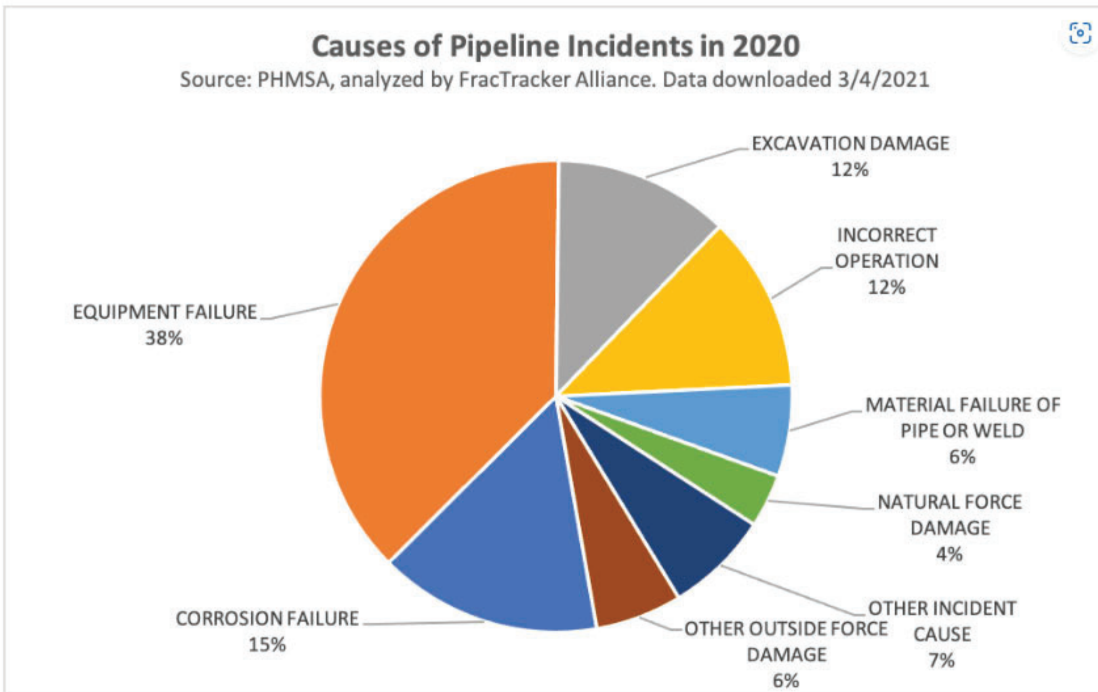

Figure 1. Causes of Pipeline Incidents in 2020. Source: PHMSA, analyzed by FracTracker Alliance. Data downloaded 3/4/2021.

Figure 4. Causes of Pipeline Incidents in 2020 [7]

When reviewing PHMSA Pipeline Failure Investigation reports [8], it was found that of the 113 investigations listed, nine Corrosion Internal failures were listed, three Internal Corrosion failures were listed, and one Corrosion Failure, one Other Miscellaneous, and one Unknown Miscellaneous were listed (total of 15). After reading the summaries and reports, six were dead leg failures, though the term was not always used in the incident report. Low points in piping caused three additional incidents. One could consider those locations as dead legs. The five remaining locations were a buried suction strainer vessel, a tank shell, the tank floor weld, and a check valve body bleeder. The Corrosion Failure was a “leak from crack in weld between tank bottom and wall” and should be reclassified as a weld failure. The Unknown Miscellaneous failure was a “rupture caused by pipe failure at reinforcing saddle” and should be reclassified as Corrosion, External. The Other Miscellaneous failure was determined to be a “localized external corrosion pit” and should be reclassified as Corrosion, External. The inconsistencies of listing and apparent cause create more challenges in collecting data. Table 2 lists the variations of the same or similar causes. As noted in the review of the internal corrosion incidents, some should be reclassified.

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Table 2. – PHMSA Failure Investigation Reports Apparent Causes

3rd Party Excavation
Construction Damage
Corrosion External
Corrosion Failure
Corrosion Internal
Equipment Failure
Equipment Failure - Start Air Valve Malfunction
Excavation Damage
Excavation Damage 3rd Party
Excavation Damage 2nd Party
External Corrosion
External Stress
Incorrect Operation
Incorrect Operation/Equipment Failure
Incorrect Operations
Internal Corrosion
Leak – Material Failure of a Girth Weld – Original Construction-Related
Material Failure
Material Failure - Cracking
Material Failure - Fitting
Material Failure - Pipe
Material Failure - Valve
Material Failure - Weld
Material Weld Failure
Natural Force
Natural Force Damage
Natural Forces Damage
Operator Error
Other - Miscellaneous
Other Incident Cause
Other Outside Force Damage
Other, Miscellaneous
Outside Force Damage
Rupture – Natural Force Damage – Earth Movement
Tank Line Failure Due to Internal Corrosion
Third-Party Excavation
Third-Party Damage
Weld Failure
Weld Leak
Weld Seam Failure

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When reviewing the PHMSA Gas Transmission Gathering, Jan 2010, to present incident data and the PHMSA Hazardous Liquid, Jan 2010, to present accident data, it was found that there is a field to document if a dead leg was the location of the failure. It is listed as INT_DEAD_LOC_IND. The number and percentage of total incidents are 9 – 0.48% and 102 – 1.85%, respectively. The Gas Distribution, Jan 2010, presented incident data did not include a dead leg designation but included one incident caused by a dead leg. The percentage of the total Gas Distribution incidents is 0.07%. Again, during these reviews, some incidents were identified as being caused by a dead leg, but the detailed information/narrative was not clear on how a dead leg was the cause or location. There were many of the total that were found to be caused by a dead leg based on the narrative, but the field INT_DEAD_LOC_IND did not say "yes." Based on the narratives, there were various understandings of the risk of internal corrosion in dead legs. There were statements of 'unknown dead leg' to the company, which has a program to manage internal corrosion in dead legs and is in the process of removing them. From industry experience, it may be that many dead leg leaks do not meet the threshold of being required to report to PHMSA.

API has recognized some challenges with identifying the root causes of the reported corrosion failures. It has begun an initiative to interview companies with PHMSA reportable incidents that are API members. It has developed a comprehensive survey to guide discussions, uncover causes, and, more importantly, direct future guidance and research to address corrosion.

3.2. Existing Industry Documents

The API Standards from various Standards Committees address the internal corrosion and integrity risks of dead legs. These documents offer different perspectives on dead legs, as some focus more on refining, terminals, or pipelines. Some of the different perspectives are based on the potential consequences of a failure. This does need to be understood as the industry continues to study the causes of failures in dead legs and improve guidance for inspection, testing, monitoring, mitigating, and eliminating dead legs.

- API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems
- API RP 574 Inspection Practices for Piping System Components
- API RP 581 Risk-Based Inspection Methodology
- API RP 751 Safe Operation of Hydrofluoric Acid Alkylation Units
- API RP 1160 Managing System Integrity for Hazardous Liquid Pipelines
- API RP 2611 Inspection of In-Service Terminal Piping System – withdrawn
- API RP 1188 Hazardous Liquid Pipeline Facilities Integrity Management
- API RP 2610 Design, Construction, Operation, Maintenance, and Inspection of Terminal and Tank Facilities

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In addition to the API Standards noted above, there are also AMPP (formerly NACE) Standards that address internal corrosion and dead legs.

- NACE SP0106-2018 Control of Internal Corrosion in Steel Pipelines and Piping Systems
- NACE SP0208-2008 Internal Corrosion Direct Assessment (ICDA) Methodology for Liquid Petroleum Pipelines
- NACE SP0206-2016 Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas
- NACE SP0110-2024 Wet Gas Internal Corrosion Direct Assessment (WG-ICDA)
- NACE SP0116-2022 Multiphase Flow Internal Corrosion Direct Assessment for Pipelines (MP-ICDA)

API determined there was a need in the industry to compile a technical report that summarized and provided a comprehensive understanding of the industry of internal corrosion. This meets the API strategic initiatives on reducing corrosion failures pending publication in the 1st Quarter of 2025, which would be a better approach. This will be called API Technical Report 1189 Internal Corrosion in Pipeline Facilities.

3.3. Proposed New AMPP Document

The new proposed project for AMPP SC 15 is to write a technical report, "Managing Internal Corrosion in Midstream Dead Legs." As of December 4, 2024, AMPP had officially communicated that a new project has been assigned to SC 15 as "TR21604 - Managing Internal Corrosion in Midstream Dead Leg." The term midstream is intended to include gas and hazardous liquids in this document. The scope and the description of the need or rationale are below:

> Scope:
> This standard outlines the information for managing internal corrosion in midstream dead legs. It covers various system types, jurisdictional considerations, definitions, and characteristics of dead legs (such as whether they are aboveground or underground, have capped or flanged ends, or involve bypass piping). It also addresses risk factors, existing internal corrosion management practices for dead legs, and design standards to prevent and reduce internal corrosion in these areas.
>
> Description of Need or Rationale:
> Leaks in dead legs within the midstream industry continue to be a concern. NACE SP0106 Control of Internal Corrosion in Steel Pipelines and Piping Systems mentions dead legs only four times with minimal discussion, despite the belief that the relative risk is much higher. Data on leaks generally lack sufficient detail to determine whether failures occur specifically within dead legs. Although industry guidance exists, it primarily targets the downstream sector, such as in API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and

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Alteration of Piping Systems and API RP 574 Inspection Practices for Piping System Components.

4. Considerations when Developing an Integrity Management Program for Pipeline and Facility Dead Legs

It has been suggested that one should start with SP0106 Control of Internal Corrosion in Steel Pipelines and Piping Systems as an outline. This includes

1. General
2. Definitions
3. Internal Corrosion Threat Assessment
4. Internal Corrosion Management Plan
5. System Design
6. Internal Corrosion and Related Parament Measurement
7. Methods for Controlling Internal Corrosion
8. Feedback and Continuous Improvement
9. Corrosion Control Records

With this outline above, the topics that follow will need to be addressed or at least considered subtopics. The layout of "TR21604 -Managing Internal Corrosion in Midstream Dead Legs" has not been determined, but the topics will be considered.

4.1. Commodity/Process Service

The types of commodities/process services or systems that should or should not be included in the dead leg internal corrosion management program must be clearly defined. Some of the more important systems to be considered are:

- Natural Gas (Wet or Dry),
- Liquids (Crude or Petrochemical & Refined Products),
- NGLs,
- Carbon Dioxide (liquids or gas), and
- Hydrogen or Hydrogen blended systems.

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Additional pressurized systems should also be considered. Examples of those systems may be:

- Fuel Gas
- Instrument Air
- Lean/Rich Amine
- Lean/Rich Glycol
- Lube Oil
- Steam
- Brine Water
- Boiler Feed Water
- Cooling Water Supply/Return
- Fire Water

4.2. Types and Orientation of the Dead Legs

As previously noted from Table 1 (API RP 1188 Table 2 -Dead Leg Guidance), the industry has guided the orientation of the dead legs relative to header piping. The variables related to the types of dead legs and their orientation must be considered when setting up a program. Initially, all dead legs, regardless of how they fall within the Table 1 of this paper should be identified. Some of the following are variables types and orientation, the relative risk of those dead legs should be determined based on process service, types, orientation, jurisdiction, and other risk factors as discussed in this paper. Some of the following are variables, types, and orientations to be considered.

- Aboveground or Belowground
- Capped or Flanged ends
    - Blanked (blinded) branches,
    - Headers with tees and capped ends
- Bypass piping
    - Around entire compressor/pump stations
    - Control valve bypass piping,
    - Pump trim bypass lines,
    - Spare pump piping,
- Process
    - Lines with normally closed block valves,
- Small Branches Off Piggable Main Line Pipelines
- Facility Piping
- Taps from Mainline to Metering & Regulator Stations
- Utility Piping
- Drips
- Pressurized Dummy Support Legs
- Level Bridles

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- Pressure Relieving Device Inlet and Outlet Header Piping
- High-Point Vents, Sample Points, Drains, and Bleeders
- Instrument Connections
- Dead legs may also include piping that is no longer in use but still connected to the process. Some refer to this as idled piping. PHMSA is considering defining idled and the integrity requirements around idled piping.

4.3. Water and/or Air Infiltration

Along with considering the process service, another issue is how likely water and/or air can get into the process stream. Some dead legs will not see corrosion until water and/or air infiltrate the system and allow the chemical reactions to happen. Simple things, like ensuring high point vents are kept closed so air and water do not enter the processing system, help manage water and air infiltration.

4.4. Integrity Management

When developing or improving an integrity management program, Jurisdictional Considerations, Risk Factors, Corrosion Control and Mitigation, and Design should all be addressed.

4.4.1. Jurisdictional Considerations

Midstream dead legs primarily fall under Title 49 Transportation Subtitle B Other Regulations Relating to Transportation Chapter 1 Pipeline and Hazardous Materials Safety Administration, Department of Transportation (PHMSA DOT), Subchapter D Pipeline Safety:

- Part 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards
- Part 193 Liquefied Natural Gas Facilities: Federal Safety Standards
- Part 195 Transportation of Hazardous Liquids

Additional jurisdictional requirements examples may include the following:

- OSHA Process Safety Management (PSM)
- EPA Risk Management Program (RMP)
- Intrastate Systems - Pipelines that operate exclusively within one state's boundaries may have additional requirements. For example, the State of Colorado recently published a document that explains the different jurisdictional requirements based on the line type and fluid type, as well as additional state regulations for pipelines under the jurisdiction of the Public Utilities Commission and the Energy and Carbon Management Commission that exceed those of 49 CFR 192 and 195, respectively.

These jurisdictional requirements typically point to industry standards that are RAGAGEP, such as:

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- ASME B31.8S Managing System Integrity of Gas Pipelines,
- API RP 1160 Managing System Integrity for Hazardous Liquid Pipelines, and
- API RP 1188 Hazardous Liquid Pipeline Facilities Integrity Management.

When setting up a focused internal corrosion program for dead legs, one key item is determining how the dead legs that fall within a company's HCAs or MCAs will be managed. Identifying the dead legs within HCAs or MCAs is recommended but managing them within those programs rather than as part of a dead leg-focused program.

4.4.2. Risk Factors

The relative risk factors are based on the design, current operation, and historical operation of the system included in the program. The noted factors will help delineate the relative likelihood of failure and its consequence, hence the relative risk.

When identifying dead legs, design, operational history, inspection locations, results, and leak history of similar pipe segments should be collected. The number of leaks, the process service, the type, and orientation information should be included in the data collected. Some industry data shows that piping that may not be considered a dead leg per Figure 1 above has characteristics that resulted in a leak. These characteristics should be explored further. This information should be considered when determining what dead legs should be included in a program.

Understanding the expectations of water quantity and potential for dropout in either crude, finished liquid products, and dry or wet gas will significantly influence the potential for corrosion in the dead legs in the system. This does depend on how they are received, i.e., through terminals and storage tanks or metering and regulating stations for gas. Tariffs are set up to determine the amount of water and other acceptable constituents in received gas. The industry has seen that when dry gas meets tariffs, there are other ways water may be able to get into the system. This includes salt dome storage facility "workovers" (mechanical integrity reviews) that use water to remove gas from those storage facilities and create brine water after the workovers are completed.

Another constituent in oil and gas corrosion is sulfur. Knowing if crude or gas is sweet or sour is important. Most finished petroleum products have had most of the sulfur removed.

> "Crude oil is defined as 'sour' if its sulfur content exceeds 0.5% or if it does not meet the required threshold for hydrogen sulfide and carbon dioxide levels. Sweet crude, on the other hand, is defined by the New York Mercantile Exchange (NYMEX) as petroleum with sulfur levels below 0.42%."[9] Natural gas is usually considered sour if there are more than 5.7 milligrams of H_2S per cubic meter of natural gas, which is equivalent to approximately 4 ppm by volume under standard temperature and pressure. However, this threshold varies by country, state, or even agency or application." [10]

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Managing the type and volume of debris in the system is important when determining the relative risk of dead legs. May that be paraffin or BS&W in crude lines, scale, black powder, elemental sulfur, and other dry constituents in natural gas lines, or even compressor lubricants, glycol, pipeline condensate, and salts mixed with those dry items can be found in natural gas lines, all can be issues to consider and manage. Having the means to measure these items directly or indirectly will provide additional data, which can be collected via pigging returns at the trap.

In addition to water and sulfur, there are other components in crude oil to consider from a corrosion perspective. Raghvendra Gopal published "The 6 Corrosive Components That Can Be Found in Crude Oil" in CORROSIONPEDIA in May 2023. [11] He lists the following items as his six:

1. Brackish Water (Chlorides)
2. Carbon Dioxide (CO_2)
3. Phantom Chlorides (Organic Chlorides)
4. Organic Acids
5. Sulfur
6. Bacteria

The AMPP TR21604 "Managing Internal Corrosion in Midstream Dead Legs" technical report project should consider the effects of oxygen, excessive drag reducing agents (DRA), and concentrated corrosion inhibitors. The industry has seen these effects exacerbating internal corrosion.

Existing design philosophies that include drain dead legs piping systems are another variable to consider. Some companies include low point drains (hence dead legs) that come off the 6 o'clock position of a buried piping header, which is also a dead leg. The intent was to use these to blow down or flush out any liquid or solid debris that may build up and cause internal corrosion. But when these low point drains were designed, they were piped to nowhere. The lack of a double block and bleed and appropriate connection to line up the low point drain piping to temporary or permanently designed vessels or tanks to accept the liquids and solids from the headers creates an even larger problem. The internal corrosion was not managed in the headers, and additional dead legs were added, doubling the number of dead legs. See Figure , Figure , and Figure for examples of belowground piping dead leg headers and their associated low point drains that are piped to nowhere. If one's company has similar design philosophies and knows where these are, encouraging a change in the design philosophy should be considered.

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Figure 5. Example of Header Dead Leg and Low Point Drain excavated for leak repair. [12]

Figure 6. Example of Header Dead Leg and Low Point Drain excavated for inspection. [12]

Figure 7. Example of the same Header Dead Leg and Low Point Drain in Figure 6. [12]

4.4.3. Corrosion Control and Mitigation

Internal corrosion management for dead legs involves various monitoring and mitigation techniques. The type and combination of monitoring and mitigation should be based on the relative risk of the dead legs. The following are items that have been used in the past are:

- Corrosion coupons,
- Excavate, remove the coating, and perform AUT,
- Profile RT for small bore piping thickness measurement and looking for debris,
- Gamma scan for debris,
- Drain blow downs,
- Chemical treatment, and
- ICDA.

Concepts starting to gain momentum in the industry include permanently installing UT sensors and/or guided wave collars. Installing these on buried piping and obtaining quality data will help in the long run determine when to schedule an excavation or perform additional mitigations, such as flushing or chemical treatment.

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4.5. Design

Managing internal corrosion should start with appropriate design standards to address minimizing internal corrosion in dead legs as a risk. Some concepts that should be considered are:

- Maximizing aboveground piping to make it available for inspection.
- Consider different construction materials or internal liners or coatings that can help manage internal corrosion risks.
- Install blinds or valves instead of dead leg piping in new designs for future expansion to minimize the amount of unused header piping.
- Develop internal corrosion management plans during new project design, procurement, and construction phases.
    - These internal corrosion management plans may include integrity operating windows, which are process variables that can be monitored to ensure they are within acceptable ranges, and if exceeded, actions are defined to monitor for higher corrosion rates.
    - Designing piping that allows access to robotics, tethered in-line inspection (ILI) tools, or other tools for unpiggable piping.
    - Do not allow dummy supports that are pressurized piping to be used in piping design.

Finally, there are times when dead legs are deliberately included in the design. These are typically associated with ultrasonic metering and regulating devices that require certain piping configurations to mitigate ultrasonic noise, which hinders the effectiveness of those devices. Working with the measurement engineers to determine what is needed for the instrumentation also minimizes the risk of internal corrosion.

5. Conclusions

The key is to define the boundaries of the dead leg program based on the variables described above. Subsets of the variables may drive the owner-operator to use different ways to manage internal corrosion. Identification of all potential dead legs should be considered. Then, the internal corrosion management path can be defined based on risk. One management path can be running failure as a leak if that is an acceptable path in the owner-operator's overall integrity management program. Still, the public is much less tolerant of this approach, and operators are moving toward the concept of ALARP (As Low As Reasonably Practical). The dead leg program should include frequent reviews of industry incidents and updates to industry standards and recommended practices. Ultimately, the dead leg internal corrosion management should be equal to or more rigorous than the overall integrity management program due to the difficulty in identifying threat growth and limited ability to control internal corrosion in low- or no-flow piping configurations. Early detection and mitigation should be a priority to reduce leaks, which protect people and the environment.

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