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A methodology for identifying and addressing dead-legs and corrosion issues in a Process Hazard Analysis (PHA)

René Murata, Janet Benaquisto*, Cecily Storey

Risk Integrity Safety Knowledge, Inc. (RISK, Inc.), 30610 Pinemill Hollow Dr. Spring, TX, 77386, USA

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ABSTRACT

Identifying dead-legs and related corrosion issues continues to be a challenge in the process industry. Pipeline corrosion has been a factor in several recent incidents involving releases and fires. A review of incident reports and citations over the past ten years indicates that Process Hazard Analysis (PHA) revalidations have been noted for not addressing the hazards of a process including corrosion mechanisms and dead-legs. In order for the hazards to be addressed, they must first be accurately identified in a PHA and documented along with any recommended actions for preventive maintenance. This paper describes a methodology for identifying and addressing dead-legs and related corrosion issues in a PHA that can be used to update corporate PHA procedures to be more robust in preventing corrosion related incidents.

1. Introduction

Managing process safety means continually and consistently examining the process, procedures and policies to identify and address hazards that may lead to a loss of containment. One of the ways to identify potential hazards is through a Process Hazard Analysis (PHA). The Baker Report for the Texas City incident as well as incident investigation reports from the U.S. Chemical Safety and Hazard Investigation Board (CSB) noted a need for more robust PHAs.

An area that may be discussed within companies, often without clear guidelines, is dead-legs. One method for identifying dead-legs is within the PHA during a systematic review of the unit. Dead-legs can be contributing factors in discussions on corrosion, but present their own challenges. Industry has seen examples of events gone wrong with equipment that has been air gapped, but not properly decommissioned, equipment abandoned in place and forgotten, or even lines that are used intermittently thus still considered part of the process (Wasileski, 2012).

Another topic of discussion is corrosion. Currently, companies address corrosion issues with conventional corrosion monitoring and inspection through their Mechanical Integrity program which is a required OSHA PSM element. Despite having complied with this PSM requirement, leaks due to corrosion continue to occur. In an effort to reduce their corrosion and leak risk, some companies have also begun to include Corrosion as a Deviation in their PHAs; however, no additional guidance is provided to the PHA teams on how to review the process for potential corrosion-based incidents.

A robust PHA should include the identification of dead-legs and corrosion issues and recommendations for maintaining pipeline integrity to prevent incidents. This paper provides a systematic approach for guiding PHA teams in the identification of dead-legs and corrosion concerns.

2. Corrosion mechanisms

Corrosion can weaken the structural integrity of a pipeline and render it unsafe for use. Corrosion control is an ongoing, dynamic process according to NACE International. In their white paper, Pipeline Corrosion (NACE International), they emphasize the importance of evaluating the environment in which a pipeline is located, as well as ongoing maintenance and monitoring. Per NACE, an effective maintenance and monitoring program can be an operator's best insurance against preventable corrosion related problems.

* Corresponding author.
E-mail addresses: Rene.Murata@psmrisk.com (R. Murata), Janet.Benaquisto@psmrisk.com (J. Benaquisto), Cecily.Storey@psmrisk.com (C. Storey).

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Dead-Legs are a particular area of concern for facilities. As defined in a 2011 article in Chemical Processing (Sloley, 2011), dead-legs are “piping segments continuously exposed to the process without normal flow or provision for flow including lines closed by flanges, welded caps or other fittings”. Dead-legs are often more at risk because they may not have been identified, or if identified, may not be monitored for potential corrosion. The article further notes the need to also consider lines with intermittent flow.

To be fully effective, a maintenance and monitoring program must include all aspects of piping that could be exposed to corrosion.

There are multiple mechanisms and contributing factors to corrosion as described in detail in API RP 571 “Damage Mechanisms Affecting Fixed Equipment in the Refining Industry” (API Publication 571 and April, 2011).

3. Review of recent incidents

Corrosion has been a factor in several significant incidents since 2001. The following summary reviews are based on information taken from CSB incident investigation comments and reports, OSHA citations and findings, and EMARS databases. An examination of the incident details reveals that in some cases corrosion issues had not been fully identified and included in monitoring programs. In one incident the PHA was specifically cited by the regulatory agency for not addressing the hazards of the process because corrosion mechanisms common to the service and dead-legs were not identified in the hazard and operability study.

4. A systematic approach to identify and address potential dead-leg issues in a PHA

RISK facilitators use a systematic approach for all PHAs and revalidations to identify and address corrosion and dead-leg concerns. We have introduced this approach at several sites, as well as incorporated it into RISK, Inc. PHA procedure updates. The approach involves a dead-leg review which occurs primarily during the PHA, and a corrosion review which begins during the PHA preparation stage and continues through the PHA(see Fig. 1).

As P&IDs are reviewed with the team, every line is analyzed. RISK, Inc. employs a practice that helps ensure each line is included in the review. The facilitator begins by highlighting the main process lines within the node. Each subsequent line that is discussed within the node is highlighted as it is discussed, such as bypass lines or start up lines. Off plot and outside battery limits (OSBL) lines are included, from the unit under review up to the next unit. The concern with off plot and OSBL is possible mis-manifolding, or lines that are not in use, but are there for “flexibility.” Highlighting in this manner helps identify lines that are not part of normal operations. When the PHA is complete, any lines that are not highlighted can be identified and analyzed for dead-leg corrosion concerns. While highlighting, one color is reserved to identify all potential dead-legs, typically red. Use of a single color for all dead-legs provides a visual cue to ensure that potential dead-legs are reviewed by the team and appropriate recommendations are made.

If a line or equipment is identified as not part of normal operations, or not in operation at all, it is highlighted as a potential dead-leg. Further discussion follows to determine if the line or equipment is a potential source of corrosion concerns in a leak-by

Recent corrosion and dead-leg incidents

When	Where	What happened	Ref.
2001	Refinery	A fire and explosion incident occurred following the catastrophic failure of an overhead gas pipe in the Saturate Gas Plant (SGP) at an elbow just downstream of a water-to-gas injection point that was not part of the original design. An examination showed that the elbow failed owing to an 'erosion-corrosion' damage mechanism.	(Health and Safety Executive)
2003	Chemical	A release of 20 tons of isobutene with trace hydrogen fluoride occurred when a 6″ pipeline failed due to corrosion. The carbon steel pipeline was part of a thermal relief line from a pressure relief valve which discharged back to the process. The site of the failure was close to the tie-in back to the process.	(European Commission Jointa)
2004	Refinery	A fire broke out in the pre-heating oven of the gas-oil hydrodesulphurization (HDS) unit of the refinery. Examination of the oven during the investigation showed multiple forms of corrosion which led to thinning such that the interior tube burst upon reaching operating pressure.	(European Commission Jointb)
2006	Refinery	A leak and subsequent fire led to major production losses when a section of pipeline failed. The incident investigation showed that the piping in the section that failed due to sulfidation corrosion was used only intermittently and had not yet been replaced with higher quality steel.	(European Commission Jointc)
2007	Refinery	A liquid propane release from cracked control station piping led to a massive fire in a propane deasphalting unit (PDA) causing extensive damage at the refinery. The release was likely caused by the freeze-related failure of high-pressure piping at a control station that had been out of service for approximately 15 years, was not isolated or freeze-protected but left connected to the process, forming a dead-leg.	(Chemical Safety Boar, 2008)
2007	Refinery	An insulated pipe feeding the Dehexanizer fractionating column failed due to significant corrosion under insulation (CUI) releasing 48 tons of naphtha causing a fire in the Isomerization plant at the refinery. The primary cause was structural failure of an insulated 200 mm NB Carbon Steel feed pipe to the column.	(European Commission Jointd)
2011	Refinery	A 6″ Reactor Effluent pipeline failed due to corrosion resulting in a rupture in the pipe, releasing diesel and causing an explosion and fire in the Middle Distillate Unifier (MDU) unit. It is thought that the corrosion was caused by a complex process involving ammonium bisulfide, hydrochloric acid, water and hydrogen sulfide,	(City of Regina and Saskatche, October 2011)
2012	Refinery	The Crude/Vacuum Unit at the refinery experienced a loss of containment leading to fire when a 6″ diameter vacuum heater recirculation pipeline to the North Heater of the Vacuum Tower ruptured without warning releasing hot vacuum residuum at 23 ft elevation. The investigation and examination of the South Heater pipeline concluded the pipe ruptured from significant thinning due to corrosion. Both piping circuits were characterized as dead-legs, but had not been included in the site's dead-leg inspection program.	(Washington State Departme and August 16, 2012)
2012	Refinery	A minor leak in a newly built crude distillation unit (CDU) led to caustic material inadvertently seeping into the unit while repairs were being made and ultimately led to the failure of the unit upon start-up. A working theory is “accelerated chemical corrosion” with the corrosion rate doubling with each increase of 10 Celsius degrees.	(Seba et al., June 25)
2012	Refinery	Gas oil leaked from an 8-inch pipe connected to an atmospheric crude oil distillation column in the refinery's crude unit. Workers were diagnosing the source of the leak in the still-operating crude unit when the pipe ruptured catastrophically and the gas-oil formed a large hydrocarbon vapor cloud which ignited and a high burning fire resulted.	(Chemical Safety Boar)

scenario. MOCs are reviewed to determine if the line or equipment section was identified as being placed Out of Service (OOS). Inspectors may be contacted to discuss if the section has been identified as a dead-leg when determining the inspection plan and Metallurgists may be contacted to discuss potential for corrosion.

Discussion around what constitutes a dead-leg occurs throughout the PHA. Dead-legs are defined as equipment and piping not in continuous use. For example an abandoned line or piece of equipment, small piece of pipe or a drain connection, or lines that are used intermittently may all be dead-legs. It is important to review these dead-leg sections with an eye for safety concerns such as corrosion, polymerization or inadvertent personnel exposure. Some of the team discussion may include:

- Are they susceptible to corrosion should a valve leak by?
- If there is material left in it for any length of time, can atmospheric changes lead to increased corrosion?
- Are there concerns with off plot lines or (OSBL) areas?
- Is there non-operational or out of service (OOS) equipment that may be abandoned in place or not attached to the process?

If dead-legs are identified, it is often difficult for the team to identify the“worst credible case” event, and even more difficult to risk rank. Many sites have developed a dead-leg management program and PHA recommendations typically include:

- Review dead-leg use and inspection frequency.
- Conduct a review for proper decommissioning and air gap or remove.
- Redesign. Redesign may entail adding a blind, using tight shutoff valve or installation of double block and bleed.

If a dead-leg management program does not exist at the site an additional recommendation may be made to develop a dead-leg management process.

5. A systematic approach to identify and address potential corrosion issues in a PHA

As part of the PHA preparation, information is gathered in two parts; pre-hazards review and as part of the team discussions. RISK, Inc facilitators begin by determining if the process under review is a new process or chemical with which they have worked. If so, during review of the process description, they look to see if there is discussion on corrosion concerns. They may also perform some research for known corrosion mechanisms within that process. This research may include review of API 571, review of the attached table (Table 1), and other industry information. If it is not already on our company table, and if concerns are identified during the research, then the corrosion issue is added to the table. Occasionally very little information is available to the facilitator prior to team sessions. In this case, once PHA sessions have begun including initial discussions with the team and SMEs regarding the process, the facilitator may perform additional research.

Following review of the process description, other information provided by the site may alert facilitators to potential corrosion concerns; specifically: leaks identified in the incident log, and clamps identified in the MOC log. Note: not all companies capture the use of clamps in the MOC process. If there are no clamps indicated in the MOC log, this is flagged as a topic for PHA team discussions.

Next a metallurgy diagram with materials and corrosion concerns is reviewed. If a metallurgy diagram is not available then a more thorough review of the pipe specifications becomes necessary. If the P&IDs indicate the pipe specs, it may be possible to prepare a list of areas of concern prior to the team review by requesting pipe spec codes. Identifying areas of concern is based on knowledge of the process material, coupled with known corrosion mechanisms for example: H_2S containing material which may be subject to contact with condensate or water in carbon steel piping may be exposed to wet H_2S cracking. This would be flagged as a potential area of concern. If pipe specification information is not available or the process contains a unique or unusual material, there may be additional time spent during the team discussions reviewing pipe specs and potential corrosion concerns.

After the pre-work, there is information that may also be gathered during team discussions. At the beginning of the PHA, there is a general discussion about corrosion. Our facilitators

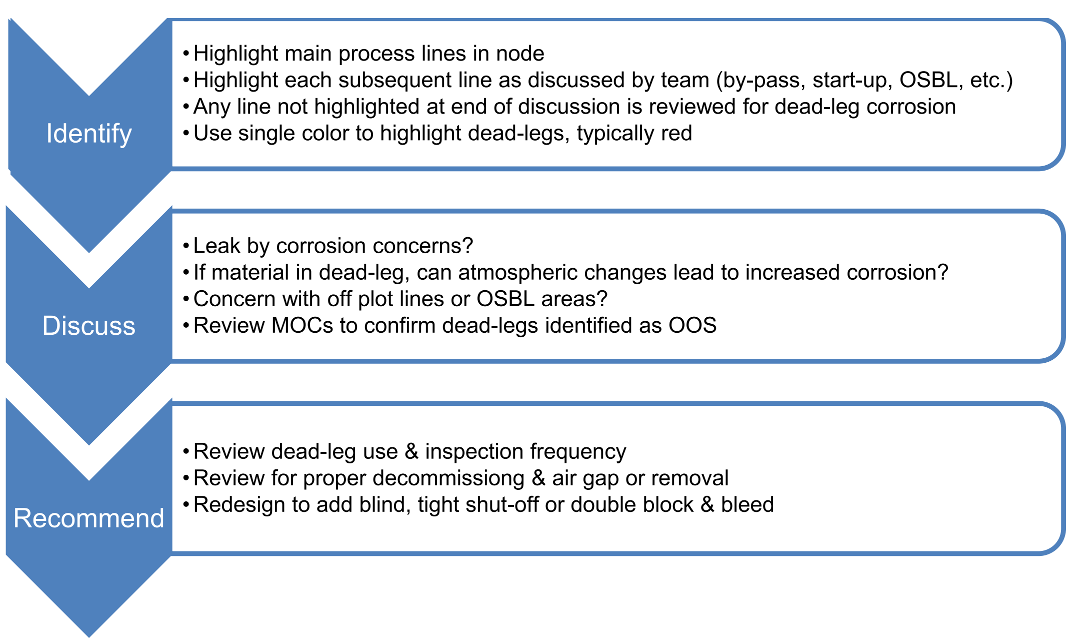

Fig. 1. Dead-leg review process.

Table 1
Corrosion concerns for PHAs. (Note: The information and data presented here are not all inclusive and are examples of those used by the authors and may be different from other sources. Data has been collected over time from multiple sources in addition to field experience.).

Operating unit/ system	Corrosion mechanisms	Variables to look for in PHA	Mitigation measures	Comment	Ref.
Hydrotreater and hydro cracker (naphtha, diesel or other)	Stress Corrosion (aka stress corrosion cracking) from Chloride exposure	>50 ppm chlorides T > 140 F, pH < 7	Water Washing, Blanket austenitic SS piping during downtime with nitrogen,	Some austenitic SS piping has failed during downtime b/c it was not protected from chlorides	(CallisterWilliam, 2000), (Sun and Deyuan, March 2012), (Thomas and Branan, 2005a)
	High temp H_2/H_2S corrosion	T > 500 F, H_2S and CS or low chrome steels, H_2S with any presence of water	Chlorides monitoring of feed, Alloy-Up Stainless Steel - Cladding or weld overlay, etc., corrosion inhibitor injection	H_2S attack can also be issue at low temperatures if water is present	(Thomas and Branan, 2005a), (Thomas and Branan, 2005b), (Cooper and Branan, 2005a)
	Low temp H_2/H_2S corrosion (H_2S embrittlement, Sulfide Stress Cracking with water present)	T < 150 F, H_2S and water present	Alloy-Up Stainless Steel - Cladding or weld overlay, etc., corrosion inhibitor injection, reduce presence of metal surface poisoners such as H_2S and cyanides;	Similar to high temperature hydrogen attack, but occurs at low temperature and in presence of water.	(Thomas and Branan, 2005a), (Thomas and Branan, 2005b), (Cooper and Branan, 2005a)
	HTHA or hydrogen embrittlement or hydrogen stress cracking, blistering	H_2>100psig, T > 400 F, and temperature/pressure relationship, CS or Chrome/Moly piping	Alloy-up, Cladding or weld-overlay; Rigorous monitoring, shutdown procedure to cool vessels down at sufficiently slow rate to reduce hydrogen trapped in material to safe limits; If service is high temperature use Cr–Mo steels if service is lower temperature zones use low carbon or Cr –Mo;	While hydrogen embrittlement is not technically a form of corrosion, it is often caused by hydrogen that is generated from corrosion reactions. Presence of H_2S accelerates H_2 embrittlement	(Thomas and Branan, 2005b), (Cooper and Branan, 2005a)
	Ammonium Bisulfide (NH_4HS) or Ammonium Chloride (NH_4Cl) Corrosion (present from combination of HCl and NH_3)	NH_4HS > 1–2wt%, Wash water injection, area of most concern is approach to reactor effluent air cooler (REAC), separator sour water line, stripper column sour water draw	Balanced water washing, corrosion inhibitor injection, review nelson curve operating limits	Corrosion due to ammonium chloride salts is more difficult to predict than with ammonium bisulfide salts due to the higher temperature limits and unpredictability of deposition location, based on temperature and HCL/ ammonia partial pressures. If the inlet feed has negligible nitrogen content, then ammonium chloride salt corrosion may not be active.	(Sun and Deyuan, March 2012), (Kane et al., September 2006), (API Publication 932-A, September 2002)
Amine Plants or gas plants, acid storage	Hydrogen blistering	High hydrogen concentration, acidic water lines, acid storage tanks, presence of ammonium hydrosulfide	Eliminate water from system, chemical inhibitor injection, coating or linings		18
	Pitting in reboilers	High temperature, in older plants presence of CS reboiler tubes	Alloy-up (Monel or 316SS), decrease operating temperature		(API Publication 932-A, September 2002)
Crude and Vacuum units		High sulfur content of feed	Monitoring silicon content of piping		
	Caustic corrosion due to high temperatures during partial shutdown (hot standby) - caustic vapors in stainless steel piping		Shutdown procedures - Increased monitoring, material upgrade	Also caustic embrittlement when stainless steel material is exposed to caustic solutions	(Cooper and Branan, 2005b)
	Naphthenic acid corrosion	High TAN crude feed, 450 F < T < 750 F, high turbulence and high velocity	Alloy-Up Cr-MO, 317LSS; chemical inhibitor injection	High turbulence and high velocity increase rate of corrosion; Aluminum coating or cladding is not as reliable as 316 or 317SS.	(Cooper and CarlBranan, 2005), (Ng, March 2013)
Reformer	Stress corrosion cracking (polythionic acid (H_2SxO_6) cracking)	Polythionic acid (H_2SxO_6, Polythionic acid is formed in the presence of sulfur, moisture and oxygen	Alloy up, inject corrosion inhibitor, remove water		
Sour Water Stripper	Wet H_2S corrosion, salt corrosion	Deadlegs, turbulent areas	Rigorous monitoring	Increased inspection frequencies and locations.	
Coker or other cyclical operations	Corrosion Fatigue	Corrosion from simultaneous action of cyclic stress and chemical attack	Rigorous monitoring, inject corrosion inhibitors	Concern is cycle of high/low temperature and/or pressures coupled with possible corrosion. The material fatigue may accelerate the corrosion mechanism.	(Thomas and Branan, 2005b)

Coker frac tower overhead	Ammonium Chloride (NH_4Cl) Corrosion	>50 ppm chlorides, SS or duplex	Rigorous monitoring, inject corrosion inhibitors, metal up (Ni or duplex), avoid crude unit desalter bypassing, review nelson curve operating limits	Mechanism is not well understood yet.	(Sun and Deyuan, March 2012)
Vacuum Condenser systems or other cooling systems	Selective leaching - dezincification of brass	Use of brass	Replace brass with upgraded material	Concern is dezincification of the brass	(Thomas and Branan, 2005b)
	Stress corrosion cracking (from NH_3/NH_4+ exposure)	Ammonia exposure to brass (can ammonia get into water system from another source or tube leak elsewhere?)	Replace brass with upgraded material		(Thomas and Branan, 2005b)
FCC or other systems with high velocity and turbulence, pump suctions, elbows, turbine blades, valves, pumps	Erosion corrosion	Possible chemical corrosion combined with high velocity or turbulence, suspended particles, water/steam hammer, pump cavitation	Redesign or replace to reduce turbulence or velocity, upgrade material and/or thickness to increase corrosion allowance		(CallisterWilliam, 2000)
Cooling water systems	Stress corrosion cracking (chloride exposure)	Poor quality cooling water, high cooling water temperature	Improve cooling water quality and/or cooling tower performance (deposit control and corrosion inhibitor), other safeguards to prevent excessively hot materials from reaching cooling water exchangers, sacrificial anodes in cooling water exchangers	Localized boiling in cooling water exchangers can contribute to erosion corrosion, precipitation (calcium carbonate) development in the cooling water which contribute to accelerated corrosion	(CallisterWilliam, 2000)
All	Deadleg, stagnant or crevice corrosion	Identify deadlegs, stagnant or low velocity lines, oversized lines, etc.	Increased inspections; isolate with double block and bleed, blind or air gap; demo		
	Uniform corrosion attack or pitting	External sources such: cooling tower location, leaking condensate or steam lines, underground lines, coastal marine environment or proximity to grade	Replace and coat piping for external protection, upgrade metallurgy		
		Corrosion under insulation	Replace and coat piping for external protection		

Recognize that not all corrosion mechanisms are well understood. A more conservative approach is appropriate for poorly understood interactions and where unknown accelerated corrosion may occur.

request that a metallurgist, inspector or other subject matter experts (SME) spend some time at the beginning of the PHA to discuss potential corrosion concerns for the unit. The SMEs should also be available for consult to the team to discuss additional concerns on an as-needed basis throughout the PHA.

During the PHA brain-storming sessions, the facilitator addresses corrosion issues with the team starting with concerns identified during facilitator preparation and from discussions with SMEs. Discussions may include potential accelerated corrosion during start up, shutdown or standby operations, excessive heating or cooling of a unit that may lead to increased corrosion including salt formation, mis-manifolding opportunities that may introduce the wrong material and could cause increased corrosion (particularly at plot limits), accelerated corrosion due to feedstock changes or run length, accelerated erosion corrosion resulting from capacity or throughput changes.

External corrosion is also addressed during PHA team sessions. This may include environmental effects, such as sea air, or heavy salted areas (winter ice melt), rain levels, location of adjacent equipment such as cooling towers, or leaky steam lines, Corrosion Under Insulation (CUI), and underground piping.

It is important to note that to adequately address corrosion concerns; the process parameters of the node must be properly identified. Some corrosion mechanisms only occur when normal operating conditions are violated. Thus, the team must have a clear understanding of normal and abnormal conditions.

Some sites have added corrosion as a standard deviation; still others have added corrosion as a cause. While either of these prompts discussion, RISK, Inc. prefers to address corrosion as a consequence. RISK, Inc. facilitators guide the team to identify specific causes that may initiate or accelerate corrosion such as sour water carryover to downstream equipment with carbon steel metallurgy. For example: Deviation-high level, Cause-failed control valve, Consequence-sour water carryover to downstream equipment may lead to accelerated corrosion … .

When addressing corrosion, it is often difficult for the team to risk rank the concern as a "worst credible case" event. Some corrosion mechanisms occur over time, or begin as a "seeping" crack. The team discussion with the SME regarding possible failure mechanisms coupled with process material becomes an important starting point in determining potential severity. For example high temperature hydrogen attack is often viewed as a possible catastrophic failure with fatality whereas caustic cracking is often viewed as a seeping leak resulting in possible caustic exposure. The length of time for a corrosion mechanism to result in failure is typically considered when evaluating likelihood. Therefore, being diligent and consistent in proper risk ranking allows the team to determine if appropriate safeguards and/or systems are in place, such as the Mechanical Integrity program, inspection frequencies, corrosion coupons, etc.

As a result of the review, recommendations are made depending on Risk Ranking per site guidelines. The four most common recommendations are:

- Improve Consequence of Deviation (COD) table, procedures or training. Identification of corrosion consequences when operating outside of appropriate parameters may lead to improved understanding and operation and may reduce or eliminate corrosion concerns in some processes.
- Increase inspections frequencies or locations. Revisions to inspection plans may provide advanced warning of areas of concern.
- Upgrade metallurgy including material or thickness upgrade. Upgraded metallurgy may reduce corrosion rate, remove the mechanism or provide additional corrosion allowance.
- Redesign the system. A redesign may be to reduce turbulence, redistribute anti-corrosion injection, whether it is chemical or water wash, etc.

6. Conclusion

RISK, Inc. feels strongly about improving the quality of PHAs. We encourage facilities to review their PSM and PHA programs to see if they include protocols or guidance for identifying dead-legs and corrosion issues. We encourage facilities to develop and/or improve corporate standards to ensure PHAs are more robust in identifying corrosion related concerns with the goal of preventing corrosion related incidents.

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