Can Damage Mechanism Assessment Improve both Efficiency and Safety?

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Over the past few decades, there has been increasing emphasis on ensuring the integrity of fixed equipment and piping that has been driven by the desire to avoid loss of containment scenarios, which usually result in safety incidents and unplanned outages. This emphasis resulted in new or improved inspection programmes, often with the application non-destructive testing (NDT). In many facilities, these inspection programmes were designed and implemented based on prescriptive, traditional inspection and NDT approaches mostly consisting of time-based visual inspection and thickness measurements. These approaches are certainly an improvement over reactive maintenance programmes and may be a first step. However, these approaches have potential pitfalls and there are unexpected equipment and piping failures attributable in part to inspection and NDT programme shortcomings. Some of these shortcoming include: failing to inspect and/or test for unanticipated damage mechanisms, not inspecting in the correct locations or with the wrong NDT technique, and a backlog of inspections due to insufficient resources to maintain the programme.

A key technical activity that is often missing from many inspection and NDT programmes is performance of a Damage Mechanism Assessment/Review (DMA/R). A properly performed DMA/R provides a sound technical basis for inspection and NDT programmes and will address the shortcoming listed above. These reviews are also the building blocks for process safety management activities, such as the following:

- developing damage mechanism-based inspection and test plans,
- implementing risk-based inspection plans based on Loss of Containment scenarios, and
- establishing Integrity Operating Windows to proactively identify process exceedances which could affect integrity over time.

In addition to the technical and safety values, DMA/Rs can provide an economic benefit to many programmes via reduced inspection costs. This presentation provides an overview of DMA/Rs, including a proven work process which will help to maximise the technical, safety and economic benefits.

Keywords: Asset Integrity Management, Damage Mechanism Review, Process Safety

Introduction and Background

Over the past few decades, there has been increasing emphasis on ensuring the integrity of fixed equipment and piping that has been driven by the desire to avoid loss of containment scenarios which usually result in safety incidents and unplanned outages. This emphasis resulted in new or improved inspection programmes, often with the application non-destructive testing (NDT). In many facilities, these inspection programmes were designed and implemented based on prescriptive, traditional inspection and NDT approaches mostly consisting of time-based visual inspection and thickness measurements.

Jarvis & Goddard (2017) presented a review of 100 insurance losses above $50 million USD that occurred in the petrochemical sector between 1996 and 2015. For "Mechanical Integrity Failures" 70% were down to pipework corrosion and 70% of all mechanical integrity failures occurred during normal operating conditions. The authors stated that, "failure to identify potential damage mechanisms and implement inspection programmes to suit……….is considered a fundamental issue underlying most of the losses". This paper looks at the issues with traditional Asset Integrity Management (AIM) schemes and how these can be overcome using Damage Mechanism Assessment/Reviews (DMA/R).

In the UK, ageing plant has been a focus of the Competent Authority for the last 10 years. This was initiated by the publishing of a series of guidance documents setting out the expectations for the management of Ageing plant (HSE, (2010), COMAH Competent Authority, (2010)). This has been followed up by inspection programmes and it is clear from the COMAH Strategic Forum performance reports that ageing plant is a top priority, (COMAH Strategic Forum, (2018)).

Assess Integrity Management

Safe, reliable and economic operation of oil, gas and chemical processes depends on maintaining high integrity levels of pressure containing equipment such as pressure vessels, tanks and piping over the assets' entire life cycle. Understanding how to effectively manage a facility's pressure containing equipment in order to reduce the risk of failures is crucial to avoiding costly delays and downtime.

This full life cycle risk management begins with verifying proper equipment design, fabrication and installation and then progresses to appropriate operational, inspection and testing practices, and finally the proper management of identified equipment damage and degradation. Not minimizing the importance of the proper design, most of the asset risk management activities need to focus on the in-service operational phase of the life cycle because it represents the longest, most critical phase of an asset's service life.

Figure 1 presents a generic barrier model for a system containing a hazardous liquid under pressure. Mechanical integrity is the only barrier under normal operating conditions to prevent a Loss of Containment scenario. Figure 1 also shows example degradation factors for the Mechanical Integrity barrier, and the importance of a robust "Inspection and Maintenance Programme" as a key Control measure. Yet the underlying causes of the losses presented by Jarvis and

Goddard (2017) indicate that many organisations get this wrong.

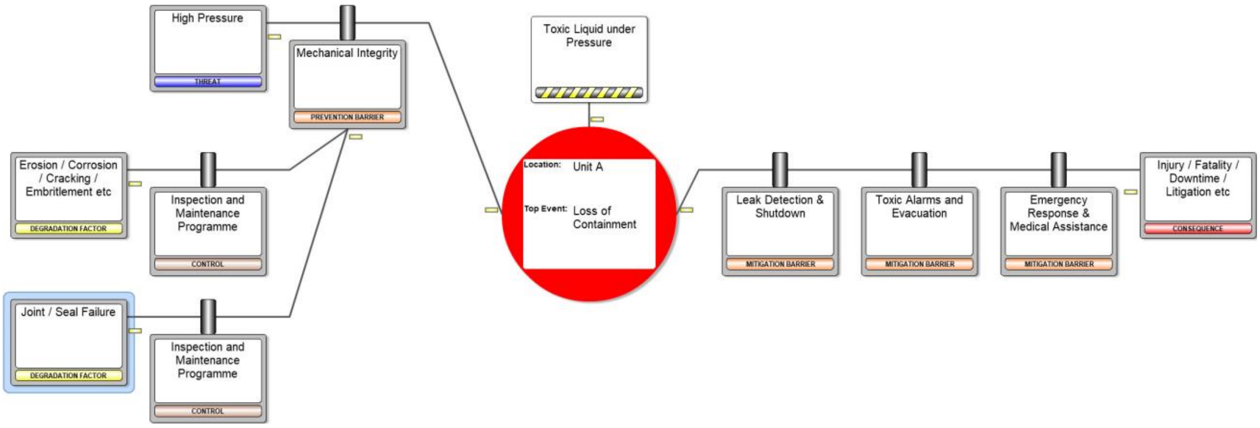

Figure 1 -:- Generic Barrier Model for a Pressurised System Showing Example Degradation Factors for the Mechanical Integrity Barrier

Pitfalls with Asset Integrity Systems

In many facilities, inspection programmes were initially designed and implemented based on prescriptive, traditional inspection and NDT approaches mostly consisting of time-based visual inspection and thickness measurements. These approaches are certainly an improvement for many inspection programmes and may be a good starting point. However, these approaches have some potential pitfalls, such as the following:

- Lack of technical bases for the inspection and NDT, especially with respect to the most appropriate type of and extent of NDT. For example, thickness measurements provide little assessment of cracking damage mechanisms.
- Overabundance of thickness measurements. For example, there is seemingly limited correlation of the number and location of thickness measurements to anticipated corrosion rate and/or whether the corrosion is general or localized. So often NDT requirements consist of many, many thickness measurement locations in the hope of finding corrosion.
- Insufficient resources and time to analyze results to improve and optimize inspections and NDT. This often occurs because the inspection and NDT programmes have become so large that they are unmanageable, and resources are devoted to preparing for the next round of inspections or NDT.
- Little recognition that the risk of equipment failures should drive the extent and frequency of inspections and NDT. For example, equipment and piping with high degradation rates containing hazardous materials are often inspected and tested at the same frequency and same manner as equipment and piping with low degradation rates and containing less hazardous materials.

Even worse than these pitfalls are unexpected equipment and piping failures attributable in part to inspection and NDT programme shortcomings, such as failing to inspect and/or test for unanticipated damage mechanisms, not inspecting in the correct locations or with the wrong NDT technique, and a backlog of inspections due to insufficient resources to maintain the programme. A more accurate and cost effective approach is to use Damage Mechanism Assessment/Reviews.

What is a Damage Meachanism Assessment/Review (DMA/R)?

A key technical activity that is often missing from many inspection programmes is performing a Damage Mechanism Assessment/Review (DMA/R). A DMA/R is a systematic analysis process that is designed to determine credible damage mechanism susceptibilities of pressure-containing equipment. Such equipment includes process vessels, heat exchangers, process piping, storage tanks, and process heaters. A Damage Mechanism can be defined as a mechanical, chemical, physical, or other process that results in equipment degradation. The following are the relevant damage mechanisms suggested by the HSE (2010), which should be considered when developing a strategy for Ageing Plant:

- Corrosion (Uniform, localized and pitting)
- Stress Corrosion Cracking (SSC)
- Erosion
- Embrittlement
- Thermal-related failures

Properly performed DMA/Rs provide a sound technical basis for inspection programmes and are the building blocks for activities such as risk-based inspection (RBI) and corrosion management.

Many refining and chemical processes are not always steady state operations. This may be due to process unit feedstock variations and/or upsets in operation. When processes and operating parameters change, new damage mechanisms may be introduced as well as acceleration of existing damage mechanisms. Thus, an understanding of the process/operating conditions and the potential resulting damage mechanisms is often needed in order to establish and maintain a robust mechanical integrity programme (see API (2011), API (2014), ABSG Consulting Inc (2019), API (2016(b)) and API (2019(c)). Understanding damage mechanisms is important for several reasons, including:

- Selecting appropriate equipment inspection intervals/due dates, locations, and techniques,
- Making decisions (e.g., modifications to a process, materials selection, monitoring frequencies) that can help eliminate or reduce the probability of a specific damage mechanism, and
- Determining the type of failures that could occur,

All these have a clear relationship with Process Safety Management.

How to Perform a DMA/R

DMA/Rs are typically performed using a systematic approach (see Figure 3). The six steps are (1) obtain data, (2) develop information, (3) conduct DMA/R, (4) identify DMs, (5) document DMA/R, and (6) use DMA/R results.

Step 1 - Obtain Data

Data required in performing a DMA/R include process data, operating data, and equipment/piping design/fabrication data. Site-specific information associated with risk-based inspection studies, preventive maintenance inspections, results from inspections, and failure history should be available electronically for reference during the study.

Step 2 - Develop Information

A DMA/R includes (1) generating a corrosion materials diagram, (2) preparing a DMA/R worksheet, (3) identifying initial corrosion loops, and (4) identifying potential damage mechanisms.

Developing corrosion loops is an important step in performing a DMA/R. A corrosion loop is defined as a section of a process that shares common damage mechanism susceptibilities with similar anticipated rates of damage. A corrosion loop is typically comprised of similar materials exposed to similar process/environmental conditions and asset characteristics (materials of construction, insulation type, coatings, heat tracing present, buried, etc.).

Corrosion loops are developed using the following guidelines:

- Maintain a single process chemical (for example, a major indication of a loop boundary is when the service that is flowing through the piping undergoes a change that greatly affects the composition),
- Maintain a single phase, and
- Use the inlet/outlet of a major piece of equipment (pressure vessel, separator, heat exchanger, column, etc.) as a loop boundary.

Step 3 - Conduct DMA/R

A DMA/R team typically includes a corrosion engineer/specialist, unit inspector, unit process engineer, unit operations representatives, unit mechanical/reliability engineer, unit subject matter experts for licensed technologies (if needed), and a facilitator knowledgeable in the DMA/R process. The team (1) conducts a process overview, considering operating and maintenance procedures, and (2) collects unit-specific process data and discusses mechanical failure history.

The steps in conducting a DMA/R include:

1. Developing color-coded process flow diagrams (PFDs) to illustrate various corrosion loops in each process. PFDs, P&IDs, piping isometric drawings, and process stream heat and material balances are normally used to generate color-coded PFDs, See Figure 2.

2. Collecting materials of construction and fabrication records to be added to the PFDs so corrosion materials diagrams (CMDs) can be developed. The CMD is a modified process flow diagram or database containing relevant equipment and piping corrosion mechanisms, operating conditions, materials of construction, and corrosion circuits.

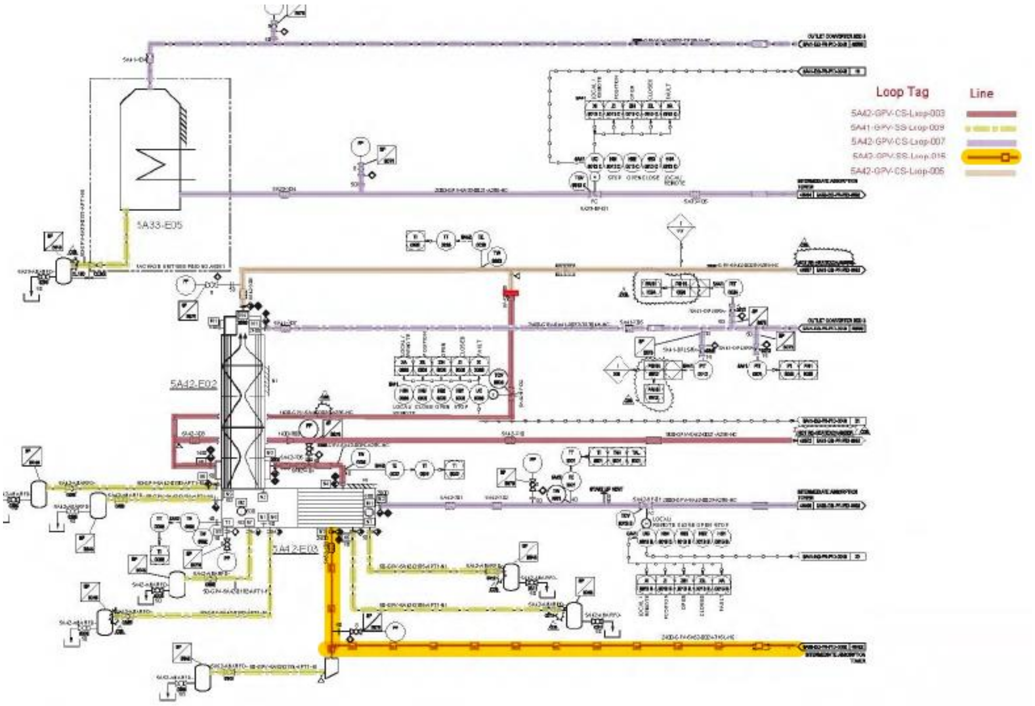

Figure 2. Example Corrosion Loop Diagram

Step 4 - Identify Damage Mechanisms

Damage mechanisms are identified from a review of established corrosion/materials literature, company- specific studies, and industry guidance documents such as API (2011), HSE (2010). API RP 571 classifies damage mechanisms into the following major groups:

- Mechanical and Metallurgical Failure Mechanisms,
- Uniform or Localized Loss of Thickness,
- High Temperature Corrosion (>400ºF [204ºC]), and
- Environment – Assisted Cracking.

Expected damage rates, susceptible locations, and susceptibilities to damages are documented, and recommendations are developed as needed.

Step 5 - Document DMR

A DMA/R report contains the information needed to understand materials damage issues in a specific type of operating process unit at a plant site. The detailed DMA/R report includes corrosion loop drawings, corrosion damage mechanism tables, and documented findings and recommendations from the DMA/R. It is recommended that the report include the team member composition, the DMA/R approach, and data used in performing the review.

Step 6 - Use DMA/R Results

Once completed, the DMA/R report can be used in a variety of ways, including (1) inspection plan development, (2) corrosion monitoring location (CML) placement, (3) integrity operating window development, (4) PHA meetings, (5) management of change reviews, and (6) incident investigations.

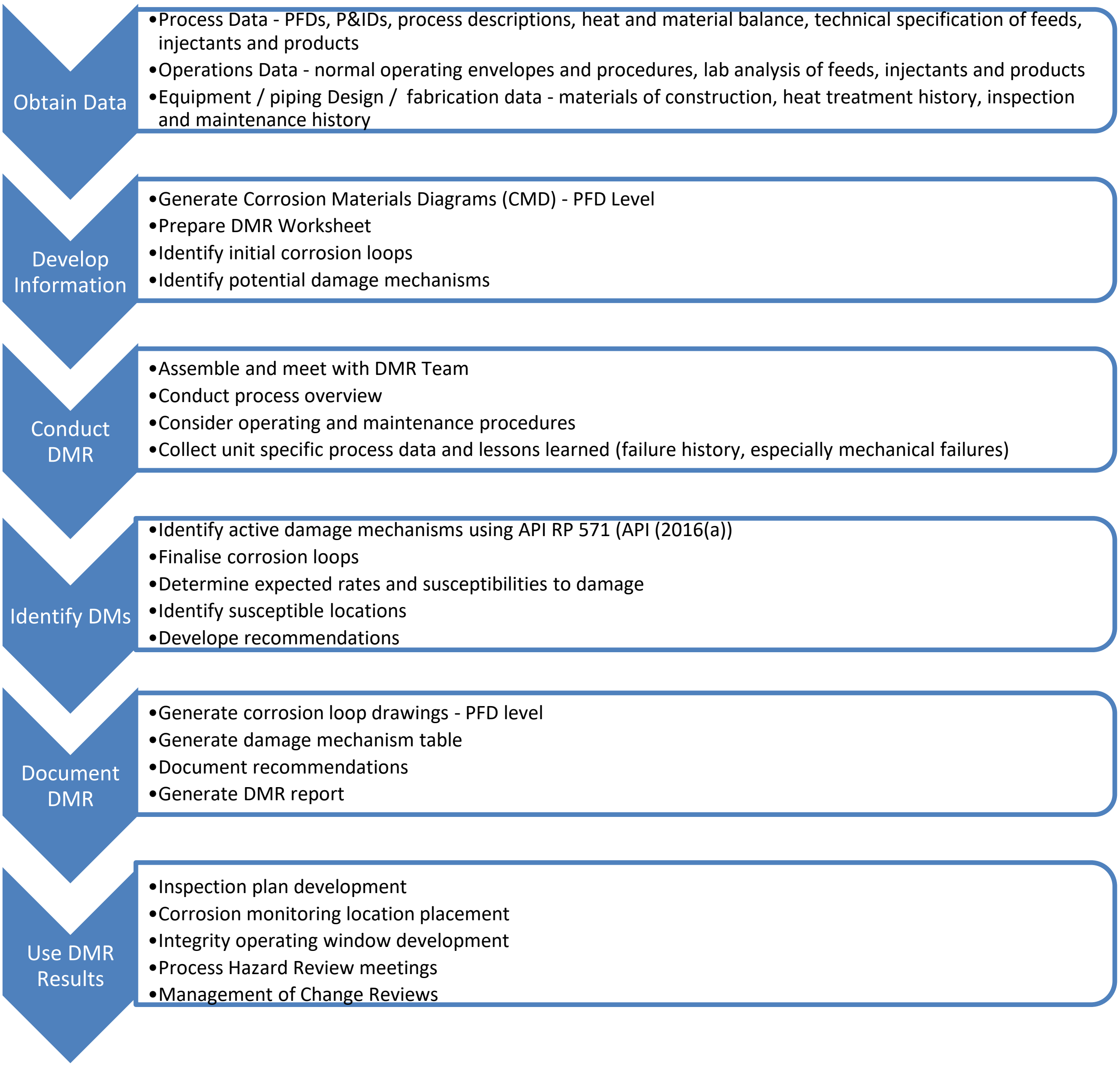

Figure 3. How to Perform a DMA/R

DMA/R and Process Safety

One of primary process safety benefits is the reduction in number and severity of fixed equipment and piping loss containment events. DMA/R results will allow a facility to:

- Developing damage mechanism-based inspection and test plans
- Implementing RBI programme to reduce loss of containment risk
- Establishing Integrity Operating Windows (IOWs) to improve operational controls and proactively identify process exceedances potentially impacting integrity

Damage mechanism-based inspection and test plans help ensure the proper inspection and NDT techniques are used and the extent and location of inspection and NDT are used to assess fixed equipment and piping condition and rate of degradation. Failing to base the inspection and test plans on damage mechanism reduces the inspection and test effectiveness, which means increased likelihood of failing to identify degraded conditions (due to not inspecting and testing in the correct way at the most likely degraded location). It is anticipated that damage mechanism-based inspection plans are a key to reducing the likelihood of loss of containment events.

RBI is a proven tool for helping manage loss of containment risks. Specifically, RBI also helps ensure that inspection and testing activities are focused on the right potential loss of containment issues. RBI achieves this better ensuring limited resources are allocated to perform inspection and tests on fixed equipment and piping more likely to have degradation potentially leading to equipment failures. The application of RBI also can significantly reduce the likelihood of loss of containment events by helping inspection and test resources focus on the assets likely to have degradation.

The third major use of the DMA/R results relates to establishing IOWs. DMR/A-based IOWs define operating conditions (e.g., temperature, pressure, containment levels) needed to help ensure fixed equipment and piping integrity. Specifically, these IOWs identify conditions, when exceeded, that potentially impacting asset integrity by introducing new damage mechanisms and/or increasing degradation rates. In addition to the parameters, IOWs include corrective actions needed to help avoid (or at least control) the potential integrity impacts. These actions include operational actions (e.g., controls process conditions) and often include inspection and test actions (e.g., event-based inspections). IOWs are key to ensuring (1) the operating conditions are maintained within acceptable limits, which were an input into the inspection programme and (2) appropriate actions are established to reduce immediate loss of containment events and re-assess potential equipment degradation when warranted.

In our experience these three integrity-related activities are very dependent on the DMA/R results and when effectively implemented, they can reduce damage mechanism-based loss of containment events by as much as 30 to 50%.

In addition, the results of these DMA/Rs can also provide additional relevant information for Process Safety Management (PSM) Activities. Figure 4 presents the relationships between relevant PSM elements a DMA/R. Of all the PSM elements Process Hazard Analysis (PHA) is likely to benefit the most from a DMA/R.

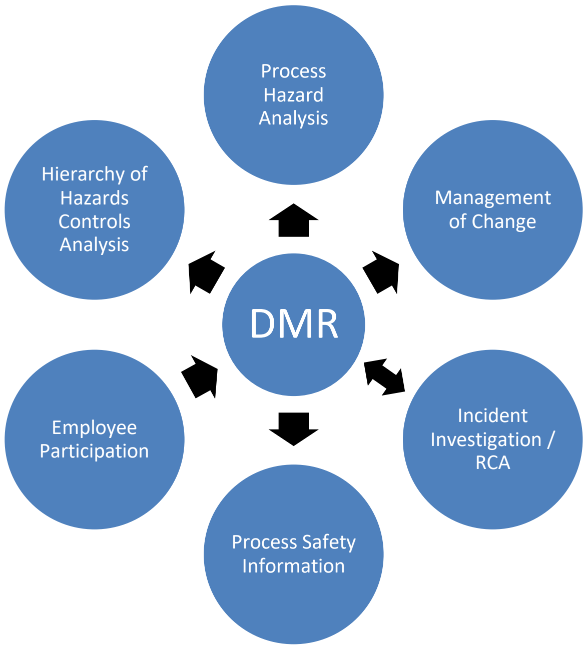

Figure 5 – Incorporating a DMA/R into PSM Elements

How to Address the Results of a DMA/R in the PHA

The DMA/R report serves as additional process safety information for reference during the PHA. To help effectively address this requirement, the primary PHA methodology (e.g., HAZOP and/or what-if analysis) may be supplemented with a DMA/R-specific checklist to help the PHA team identify hazardous scenarios, while considering the results of any DMA/R report(s) applicable to the process unit.

It should be noted that some damage mechanisms may be identified using the primary hazard evaluation technique (HAZOP and/or what-if analysis) during the PHA. However, supplementing the primary hazard evaluation with a specific checklist allows the PHA team to further address damage mechanisms in a systematic fashion to ensure more thorough coverage than that afforded by the primary analysis technique(s) alone.

We have found that a checklist approach also helps the PHA team (1) discuss the contents of the DMA/R report(s) prepared for the process unit and (2) communicate how the damage mechanisms are being managed by the mechanical integrity group for the process unit. The checklist can also guide the discussion of hazards and potential major incidents associated with any identified damage mechanisms.

Table 1 illustrates a suggested corrosion and materials DMA/R checklist that can be used by a PHA team that has expertise in damage mechanisms. The application and contents of the checklist can help the PHA team confirm items such as whether (1) known corrosion and damage mechanisms (e.g., high temperature hydrogen attack, chloride stress corrosion cracking) are understood and controlled, (2) the existing DMA/R report appropriately documents applicable damage mechanisms in the process unit, (3) a DMA/R is performed for incident investigations where a damage mechanism is identified as a contributing factor, and (4) a process unit change (i.e., management of change) has an effect on damage mechanisms or integrity operating windows.

The contents of the checklist include a set of questions that allows the PHA team to confirm that questions that deal with the specific damage mechanisms known to occur in that facility. The questions are related to specific types of damage mechanisms (e.g., high temperature, low temperature corrosion and stress corrosion cracking, external damage, mechanical damage, and other) and include questions developed from industry standards as well as incidents related to mechanical integrity issues see, HSE (2010), API (2011) and NACE (2003).

The checklist is constructed to include topic-specific items and questions to help a PHA team leader elicit responses from the team. The intent of the questions is to allow a PHA team to brainstorm and discuss the damage mechanism report prepared for the process unit being analyzed, along with ensuring that the report was prepared to include damage mechanisms applicable for all potential operating modes (e.g., normal startup and shutdown). This is similar to a PHA team using a facility siting checklist in a PHA to help identify any facility siting issues while considering the results of any separate facility siting study report conducted for the process unit (API (2009) and/or API (2007).

Potential responses to the questions could include an acknowledgement that the PHA team understands which specific damage mechanisms may be present in the process unit and a discussion of how the damage mechanisms are managed (i.e., inspection programmes, defined integrity operating windows, etc.). If a corrosion mechanism listed in the checklist is not present in the process unit being analyzed, the team can respond by indicating it is not applicable.

The checklist discussion may also help to (1) identify other damage mechanisms that may not have been identified during preparation of the DMA/R report that could occur from a process parameter deviation (flow, temperature, pressure) and (2) ensure mechanical integrity plans are robust and have taken into consideration any process changes identified by the PHA team.

Table 1. Process Hazards Analysis Corrosion and Materials Damage Mechanism Review (DMA/R) Checklist

No.	Question
I. General	
1	Does a DMR report exist that addresses the applicable damage mechanisms for the process unit? If not, was there a determination that no damage mechanisms exist and was the rationale documented?
2	Was the DMR report for the process unit available to the PHA team?
3	Are the known corrosion and materials damage mechanisms understood and controlled? (Note: Refer to sections II through V of this checklist)
4	Was a DMR conducted where a damage mechanism exists on (1) new processes and/or (2) major changes that have been implemented in the process unit prior to initial startup and/or implementation of the change?
5	Have any incident investigations for the unit identified a damage mechanism as a contributing factor of the incident?
II. High Temperature Damage Mechanisms	
1	Is there a potential for carbon steel and/or 0.5Mo steel to exceed the Nelson curve and be exposed to high temperature hydrogen attack (HTHA)? Include consideration of piping in a normally closed bypass being overheated.
2	Is there a potential for accelerated creep due to operating outside of the operating window (e.g., higher temperature)?
3	Is there a potential for liquid metal embrittlement?
4	Is there a potential for accelerated sulfidic corrosion from a gradual increase in sulfur content?
5	Is there a potential for accelerated corrosion from increased concentration of naphthenic acids in crude oil or various distillation cuts?

No.	Question
6	Is there a potential for accelerated corrosion as a result of organic chloride contamination in crude oil or other feeds?
7	Is there a potential for spontaneous ignition of materials (including titanium, zirconium, structured packing, iron sulfide, etc.) from HCl, Cl_2, O_2, and/or air?
8	For alloys operating above 700 °F, are there any high temperature aging embrittlement phenomena that might lead to brittle behavior when equipment is pressurized at lower temperatures?
III. Low Temperature (Aqueous) Corrosion and Stress Corrosion Cracking Damage Mechanisms	
1	Is there a potential for severe corrosion downstream of alloyed equipment due to process upsets that cause unneutralised corrosive materials or contaminants to flow downstream into systems constructed of materials not designed for such corrosive conditions?
2	Is there a potential for rapid corrosion at or downstream of injection or process mixing points due to heating/cooling, condensation/evaporation, reaction, between the injecting and mixing streams, etc.?
3	Is there a potential for rapid corrosion at or near an injection point due to a change in flow rate, a change in flow pattern, or failure of the injection system to perform as intended?
4	Is there a potential for rapid corrosion due to a change in flow rate or flow regime (e.g., vaporization, flashing, or other multiphase flow conditions)?
5	Is there a potential for localized corrosion or cracking of austenitic stainless steels during shutdowns where polythionic acids may be present?
6	Is there a potential for rapid localized corrosion at hot spots as a result of direct contact between heat tracing and process piping (e.g., lack of standoff or improper use of heat transfer material)?
7	Is there a potential for accelerated corrosion from fluids and/or solids trapped in deadlegs?
8	Is there a potential for process upsets to introduce moisture into moisture-free environments (e.g., anhydrous HCl or Cl_2) or to result in insufficient moisture in environments reliant on moisture for the protection of the system (e.g., anhydrous NH_3 and alcohols)?
9	Is there a potential for accelerated corrosion by the activation or deactivation of a piping segment (e.g., a bypass line or other alternate flow path) or the installation of a temporary flow path?
10	Can changes in pump or compressor capacity (including the use of a spare pump/compressor) lead to increased corrosion rates?
11	Can increase or decrease in pH (inadvertent or undetected) lead to increased corrosion or stress corrosion cracking?
12	Can minor changes in feed compositions (e.g., loss of trace amounts of corrosion inhibitors, presence of organic chlorides, etc.) adversely affect corrosion rates?
13	Can non-post weld heat treated equipment containing caustics or amines be steam cleaned/purged leading to a potential for cracking?
14	Is there a potential for air and/or moisture ingress into otherwise oxygen-free and/or dry environments (e.g., breather valves on tanks) that could cause accelerated corrosion or cracking?
15	Can solids be present causing increased erosion and/or corrosion (e.g., catalyst carryover, accumulation of corrosion products, etc.)?
16	Is there a potential for increased corrosion or cracking downstream of piping specification breaks due to process changes or upsets?

No.	Question
17	Is there potential for increased corrosion in a pipe or tube inlet zone or at a vapor/liquid interface?
18	Is there a potential for caustic cracking of bolted connections from small leaks of boiler feed water or other caustic solutions? Is there potential for caustic cracking of non-stress relieved equipment from heat exchanger tube leaks or caustic carryover?
19	Is there a potential for bolting to be exposed to process environments that could lead to catastrophic fracture due to stress corrosion cracking such as caustic, amine and wet H_2S, etc.?
20	Is there a potential for process contamination that could cause stress corrosion cracking (e.g., wet H_2S, caustic, amines, chlorides, polythionic acids) or corrosion fatigue of deaerators?
21	Is there a potential for accelerated corrosion from the installation of incorrect materials of construction in highly hazardous systems?
22	Is there a potential for localized corrosion or cracking of heat- affected zones in sensitized stainless steels?
23	Is there a potential for hydrogen embrittlement or hydrogen blistering from increased concentrations of hydrogen sulfide or cyanides?
24	Is there a potential for sulfuric acid concentrations falling below critical limits due to process upsets or changes and causing accelerated corrosion?
25	Is there a potential for temperature, pressure, or other process changes that cause shifts in dew point, and therefore, create or shift areas where corrosive compounds condense leading to accelerated corrosion?
IV. External Damage Mechanisms	
1	Is there a potential for unmitigated and undetected external corrosion that can lead to rupture (e.g., soil-to-air interface, downstream of cooling water sprays, etc.)?
2	Have there been changes in the monitoring or maintenance of cathodic protection systems that could lead to increased corrosion of buried piping or tank bottoms?
3	Can changes in process conditions lead to increased corrosion under insulation, (e.g., idling of normally hot equipment, equipment in cyclic service above and below 250 °F, or exposure of stainless steel equipment to external chloride cracking)?
V. Mechanical and Other Damage Mechanisms	
1	Is there any potential for low temperatures causing freezing of water in piping deadlegs, especially in light hydrocarbon systems, resulting in piping rupture?
2	Is there a potential for liquid slugging of piping (including flare lines) that could cause piping failure due to hydraulic shock, water hammer, and other transient overstress conditions?
3	Is there a potential for accelerated corrosion, fouling, or plugging of inlet or outlet piping of relief devices or flare systems?
4	Has the impact on relief capacity been reviewed for any increases in unit throughput?
5	Can temperature changes on piping systems cause mechanical overload because of lack of expansion capability in piping design?
6	Is there a potential for overstressing or shocking brittle materials of construction (e.g., cast iron, aged or embrittled steels)?
7	Is there a potential for overpressuring equipment or piping when using high pressure fluids and/or positive displacement pumps to unplug a line?

No.	Question
8	Is there a potential for brittle fracture of heavy wall equipment from being fully pressurized before the metal temperature has reached approximately 200 °F?
9	Is there a potential for pressurization or impact during low temperature conditions that may cause brittle fracture of equipment that is not designed for such conditions (i.e., stress applied below minimum design metal temperature)?
10	Is there a potential for vibration (either applied or induced) that could lead to fatigue fracture of vibrating piping, over-stressed threaded connections, unsupported or over-hung weight, or exchanger tubes?
11	Is there a potential for thermal fatigue cracking due to sudden or severe swings in temperature?
12	Is there a potential for cavitation from rapid pressure or temperature changes?
13	Could heat tracing be inadvertently shut off on critical equipment or relief systems and result in impairment (e.g., plugging leading to failure of a relief system to function on demand)?
14	Are there check valves in the process that can lead to a process safety incident if they fail to function properly?
15	Are there any vents and drains downstream of block valves that may require additional protection from pipe plugs/caps to prevent releases?
16	Are temporary repairs and clamps identified for scheduled removal at the next maintenance opportunity?
17	Can the failure or malfunction of internal elements such as exchanger bundles, trays, distributors, steam rings, etc., lead to overpressure, accelerated corrosion, and/or metallurgical damage to equipment and piping?
18	Is there a potential for temperature changes that might cause brittle fracture of equipment constructed of materials with low toughness due to (1) thermal shock during steady-state operation or (2) transient conditions experienced in normal startup or shutdown of heavy walled vessels?
19	Is there a potential for excessive temperatures or hot spots that could cause rupture from short- term overheating of furnace tubes, transfer lines, or catalyst- containing vessels?
20	Is there a potential for presence of molten salts or liquid metals that could cause very high rates of corrosion or cracking?
21	Is there a potential for liquid carryover into gas streams or velocity changes of mixed phase streams causing accelerated corrosion-erosion of elbows, tees, and other areas subject to downstream turbulence (e.g., downstream of control valves)?
22	Is there a potential for changes in feed compositions where trace amounts of certain chemical compounds previously provided corrosion inhibition?
23	Is there potential for accelerating corrosion rates in sour hydrocarbon service from gradual increase of sulfur content or inadvertent increase in content of other sulfur compounds such as H_2S or mercaptan?
24	Is there a potential for changes in water treating chemistry or procedures that could accelerate water-side corrosion?
25	Is there any potential for ammonium hydrosulfide, ammonium chloride, or amine salt deposition and resultant corrosion rate acceleration with increased concentrations of ammonia, sulfides, or chlorides or insufficient water washing?
26	Are there any other known corrosion mechanisms that may be of concern during normal, abnormal, or non-routine operating modes that are unique to the process unit? If so, are they currently managed by the mechanical integrity group?
27	Is there a potential for brittle fracture (e.g., hydrogen embrittlement, temper embrittlement, 0.5Mo steel) of heavy wall hydro processing equipment from rapid heating/cooling or pressurizing when the equipment temperature is below the minimum pressurization temperature?

No.	Question
28	Is there a potential for catastrophic brittle fracture (hydrogen embrittlement) of hydro processing equipment from rapid cooling?

Other DMA/R Benefits

Obviously, the most important benefit from DMA/R relates to the improved process safety performance (i.e., reduction in loss of containment events). However, DMA/R have demonstrated to improve the effectiveness and efficiency of inspection-related activities resulting in significant cost reductions. Specifically, our experience in applying DMA/R has resulted in the following types of cost reductions:

- Reduction in piping inspection circuits. When using DMA/R results to establish piping inspection circuits (versus the traditional process function approach), piping for most process services can be combined into larger inspection circuits. Our experience is number of piping circuits can be reduced by 10 to 25%. These means fewer inspections to perform and manage.
- More optimal CML placement. The DMA/R results provide improved, additional information in which to base the number and location of CMLs. For example, assets with predictable low corrosion rates can utilize fewer and farther spaced CMLs to assess equipment conditions than an asset with less predictable and higher corrosion rates. Likewise, assets with cracking or other similar damage mechanisms often need very few thickness related CMLs. Based on our experience, CMLs for some facilities can be reduced by 20 to 50%.

These two improvements can significantly reduce inspection and testing costs while helping ensure asset conditions are being adequately assessed.

Similar to inspection and test cost reductions, the application of DMA/R results can provide the following benefits:

- Improved turnaround management. When DMA/R results are used to develop inspection and test plans, the onstream effectiveness (in assessing potential asset degradation) are improved. This type of improvement helps reduce the “surprises” during the turnaround inspections. In addition, the increased on-stream effectiveness will help identify assets needing replacement or extensive repairs prior to the turnaround; thus, providing the opportunity to plan for these activities.
- Turnaround inspection interval extension. When DMA/R results and RBI are combined, some unit turnaround intervals can be extended by one or two years with confidence.
- Reduced unplanned asset downtime. The implementation of DMR/A-based inspection plans, RBI and IOWs provide a technically robust means for understanding, assessing and managing potential asset degradation (which can result in loss of containment events). The objective and bottom line results of these activities is a reduction in the number of loss of containment failures by helping ensure asset are operated within acceptable limits (i.e., IOWs) and periodically performing appropriate inspections and tests to assess asset conditions.

The cumulative economic impact for these benefits related to the value to increased asset uptime by helping reduce turnaround downtime and reducing the number of unplanned equipment failures. These improvements typically provide very high rate of return (e.g., paybacks of less than 1 year.)

Conclusion

As industry continues to recognize the value of conducting and documenting DMA/Rs to enhance mechanical integrity programmes and mitigate the risk of loss of containment events, the results of these DMA/Rs can also provide additional relevant information for assisting PHA (and management of change) review teams in identifying potential hazardous scenarios for processes. A checklist, such as the one presented in Table 1, can be an effective method for PHA teams to efficiently identify and discuss DMR issues identified in separate, detailed DMR reports when conducting their hazard evaluations.

An appropriate DMA/R can play a key role in improving uptime, reducing inspection costs, satisfying regulatory safety and environmental obligations and driving operational excellence.

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