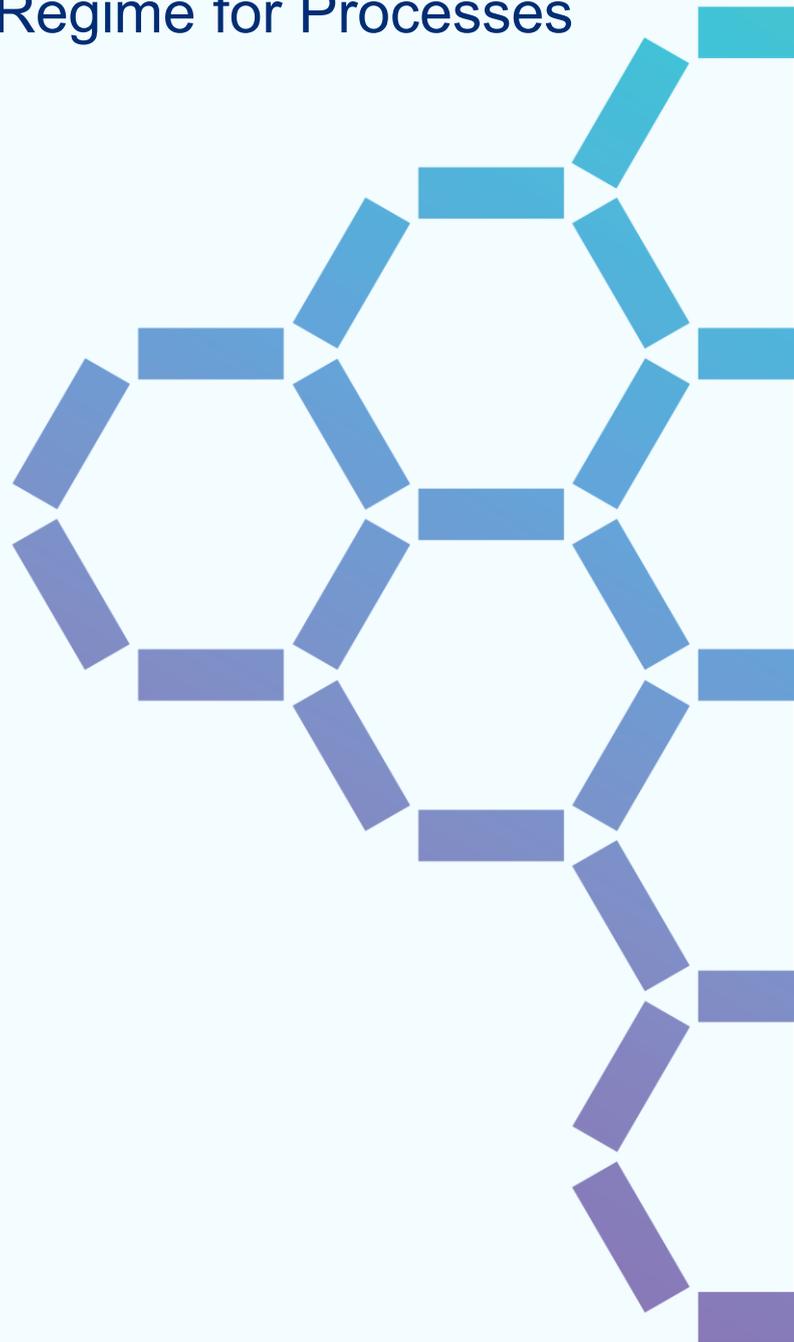


Hydrofluoric Acid Guidance - Section G

Establishing an Inspection Regime for Processes Handling HF



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Chemical Industries Association

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Introduction

The Hydrofluoric Acid Sector Network of the Chemical Industries Association (CIA) has developed this Guidance. It provides Guidance on the inspection of HF handling process facilities and is based upon industry experiences and best current practices. It is intended as a recommendation and not as a mandate to which manufacturers and users of HF must adhere. The Guidance is not to be used as a substitute for any applicable specific legislative requirement. Whilst all reasonable efforts have been made to ensure the accuracy of the contents and any references to legislative requirements at the time of publication, readers must refer to these themselves to ensure their compliance with current legal duties.

Acronyms

aHF	Anhydrous Hydrogen Fluoride	PMI	Positive Materials Identification
Al	Aluminium	PSSR	Pressure Systems Safety Regulations
API	American Petroleum Institute	RP	Recommended Practice
COMAH	Control of Major Accident Hazards Regulations	RBI	Risk-Based Inspection
Cr	Chromium	SCC	Stress Corrosion Cracking
Cu	Copper	SOHIC	Stress Orientated Hydrogen Induced Cracking
ELD	Engineering Line Diagram (or P&ID)	Ti	Titanium
Hg	Mercury	TML	Thickness Measurement Location
HIC	Hydrogen Induced Cracking	USTM	Ultrasonic Thickness Measurement
NACE	National Association of Corrosion Engineers	UT	Ultrasonic Testing
NDT	Non-Destructive Testing	WFMT	Wet Fluorescent Magnetic Testing, or Magnetic Particle Inspection
Ni	Nickel	WSE	Written Scheme of Examination
P&ID	Piping & Instrumentation Diagram		

G1 Asset Register

When establishing an inspection regime, it is firstly important to know what equipment is on site. Therefore, an accurate and up-to-date inventory should be held as an Asset Register that clearly identifies all primary containment safety-critical mechanical equipment (tanks, vessels, pumps, piping, relief valves and so on.) which, if they fail, could give rise to a major accident hazard. The Asset Register should also be mirrored by accurate up-to-date engineering drawings, Piping & Instrumentation Diagrams (P&IDs), and other plant or process documentation. Most sites will have both digital and hard copied records with this information but often in different formats, some collected together others not. Format is not an issue as long as the information regarding the primary containment boundary of the hazardous process fluids is easy to access and use. The importance of updating the Asset Register should be recognised in a documented management of change system for the site.

G2 Inspection Regime

The following information will present some suggested guidelines, information and ideas that HF users and manufacturers may use to help establish an inspection regime or incorporate into their existing program. The document is not meant to be all-inclusive, and the HF operator should review the information contained to determine its suitability for their operating facility together with any company directives and legislative requirements.

It is the responsibility of the owner/operator of each HF operating facility to develop and maintain comprehensive written inspection procedures aimed at preserving equipment mechanical integrity. [In the United Kingdom \(UK\) there are specific duties for periodic examination under the Control of Major Accident Hazards Regulations 2015 \(COMAH\) and under the Pressure Systems Safety Regulations 2000 \(PSSR\), as applicable.](#) Under PSSR this is a legal requirement and is defined as a Written Scheme of Examination (WSE). Adherence to these procedures is one of the most important measures in preventing a release of HF to the atmosphere. A written inspection procedure should be individually linked to the inspection of each item of equipment that will be in service within the operating envelope of the unit. This written procedure should define the extent, method, frequency and as necessary the techniques used to perform the inspection.

To aid the development of an inspection procedure it is good practice to first of all understand the operating conditions of the equipment under consideration such as pressure, temperature and the operating fluid or mixture of fluids being contained. Secondly it is important to know what the materials of construction are for each item of equipment. Putting this together will assist in determining what material degradation mechanisms are likely and therefore what inspection methods and regimes can be put in place to detect such a mechanism. A good methodology for determining damage mechanisms for a large inventory of equipment is by dividing a process unit up into corrosion loops that have similar pressures, temperatures, flowrates, fluids and metallurgy. If there is an inspection finding on one particular item of equipment [this should initiate a review of other items in the same loop. The review should establish if changes to the inspection procedures or due dates are required.](#)

This information is also required if using a Risk-Based Inspection (RBI) methodology to establish an inspection regime. RBI assessment evaluates both the probability of failure and the consequence of failure. The probability of failure is a culmination of potential damage mechanisms, current equipment condition and the effectiveness of any previous inspection. Identifying the process fluid(s) together with the potential harm to personnel, the environment, equipment and the business impact are needed to determine the consequence of failure. The output from this assessment can assist in a focused inspection initially targeting resource on the high-risk items.

G3 Damage Mechanism Relating to Equipment Containing HF

The following mechanisms relate to the containment of HF and should be considered in the development of an inspection regime. Other mechanisms outside the scope of this document should also be considered based upon local operating conditions.

G3.1 HF Corrosion of Carbon Steel

Anhydrous HF or HF with very low water content forms a passive iron-fluoride scale that protects the surface of the steel from further corrosion. However, there are a few ways for this passive scale to breakdown and cause accelerated corrosion:

- **Water content:** As shown in *Figure 1 - Corrosion rate against HF concentration*, the water content in HF can significantly affect the corrosion rate of carbon steel. This is due to the iron-fluoride scale hydrating in the presence of dilute acid at approximately 65% HF or less. This then dissolves in HF and new scale is formed thus forming a continuous corrosion cycle.
- **Oxygen:** Any oxygen or other oxidising agents present in the process can cause the passive film to shrink, become porous and non-protective.
- **Temperature:** At temperatures above 60°C the iron-fluoride scale loses passivity due to dehydration and shrinkage and again a continuous corrosion cycle is formed whereby scale is formed and removed. See *Figure 2 - Corrosion rate against HF temperature*.

- Velocity:** At high flowrates or changes in direction, the velocity could be such that it removes, or strips, the iron-fluoride scale from the internal surface of the pipe. Common areas of concern are pipe elbows, downstream of injection or mixing points, around orifice plates or throttled valves. Where this occurs, it is therefore good practice to establish and maintain a site limit for velocity to avoid this occurrence.

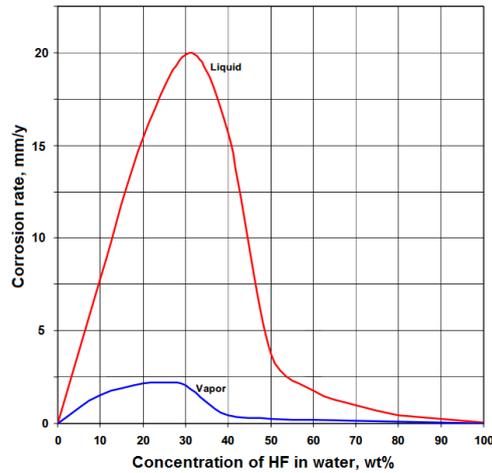


Figure 1 - Corrosion rate against HF concentration.

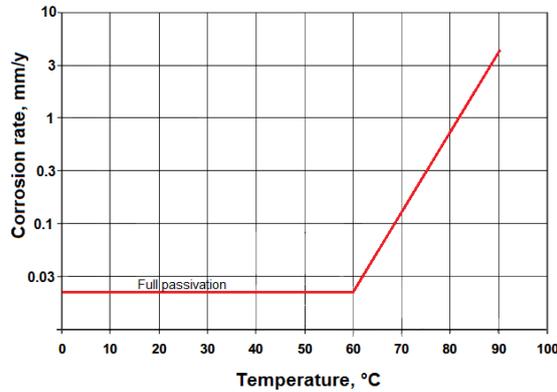


Figure 2 - Corrosion rate against HF temperature.

- Dewpoint corrosion:** This occurs at locations where HF either vaporises or condenses on the internal surface of piping, vessels or exchangers and is prone to increased localised corrosion. Equipment that operates around the boiling point of HF (see Figure 3 - Boiling point of HF) may have areas where local cooling can occur due to the presence of external attachments such as lifting lugs, support bracings, U-bolts and pipe hangers. These can act as a heat sink causing HF to condense internally. Corrosion can occur in the vapour space of piping that contains HF such as that on the inlets to pressure relief valves. Insulation termination points often act as cold spot locations that could contribute to a condensing environment. These locations should be identified and minimised to reduce the potential of high corrosion rates.

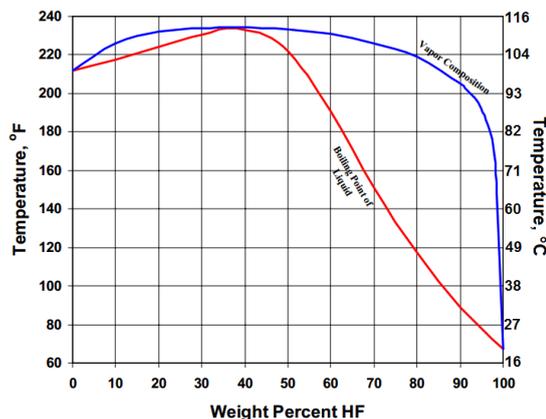


Figure 3 - Boiling point of HF.

- Deadleg corrosion:** Deadlegs in piping present stagnant flow conditions and includes piping that is no longer [in use but still connected to the process](#). Over time deposits such as iron-fluoride scale can build up to significant levels which lead to under deposit corrosion. Deadlegs are also vulnerable to dewpoint corrosion. All deadlegs should be identified and minimised wherever possible. [This should include consideration of not normally flowing lines, or operational deadlegs such as infrequently used routings or bypasses. Further examples of deadlegs are given in American Petroleum Institute \(API\) Standard 510 - Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration²](#). The iron-fluoride passive scale can build up and cause blockages in deadlegs. This is of particular concern on the inlets to pressure relief valves and so checks for fouling and blockages of these lines should be considered on a periodic basis. Fouling studies for relief stream studies could indicate potential areas of blockage.
- Galvanic corrosion:** This occurs at the junction of dissimilar metals in contact with each other and in the presence of a suitable electrolyte. The susceptibility of metals and metal alloys to galvanic corrosion is dependent on their relative position on the galvanic series. The more active material (anode) will corrode in preference to the more noble material (cathode). An electrolyte is a fluid that can conduct a current. The conductivity of HF increases 50-fold with just 1% water making it a good electrolyte. Common dissimilar material junctions used in the HF industry are carbon steel and Monel 400 with Monel being the noble material which then corrodes the carbon steel at an accelerated rate than if it were not joined to the Monel material at all (see [Figure 4 - Photo and sketch of a carbon steel vessel with a Monel 400 liner in the bottom half. Corrosion has occurred to the carbon steel leaving the Monel and the weld intact](#)). Dissimilar joints should be avoided by design, however as a minimum they should be identified and subject to close visual examination at each opportunity. Monel and carbon steel has been satisfactorily welded together for use in HF service using an intermediate nickel butter layer between that isolates contact between the two dissimilar materials.

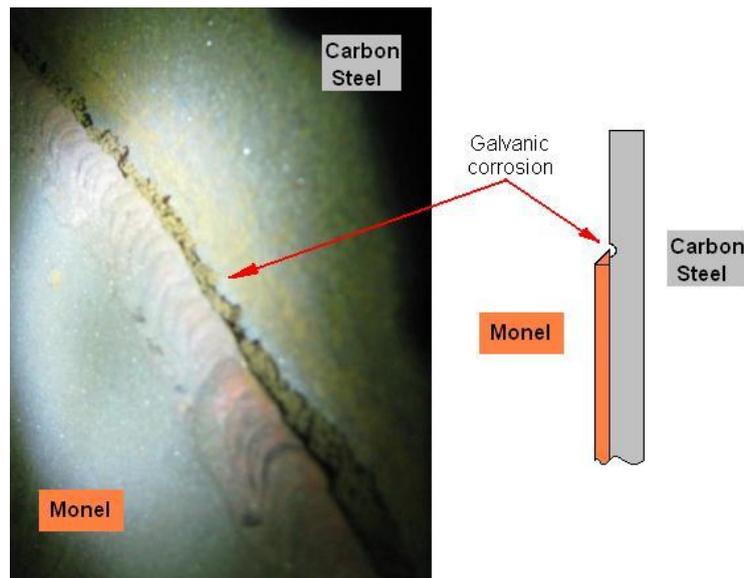


Figure 4 - Photo and sketch of a carbon steel vessel with a Monel 400 liner in the bottom half. Corrosion has occurred to the carbon steel leaving the Monel and the weld intact.

- Residual elements:** There is industrial experience and past incidents of high localised HF corrosion that have occurred due to differences in the chemistry of carbon steel especially between pipe and fitting. The combination of the carbon (C) content and the residual element content such as [chromium](#) (Cr), [nickel](#) (Ni), [copper](#) (Cu) can increase the non-uniform corrosion by five times compared to baseline measured corrosion rates. [Figure 5- Cross-section of a welded carbon steel pipe containing high residual elements](#) shows a carbon steel butt weld with preferential corrosion of the pipe with high residual element content on the right as compared to the low residual pipe section at the left of the weld. Results of further research concluded that for base metals the optimum specification would be $C > 0.18 \text{ wt } \%$ and the $\text{Cu} + \text{Ni} < 0.15 \text{ wt } \%$, and for weld metals (where C levels are intentionally lower) the specification should be $\text{Cu} + \text{Ni} + \text{Cr} < 0.15 \text{ wt } \%$. Conducting a retrospective positive material identification (PMI) program is one method to identify the susceptibility of existing equipment and piping.

When conducting a thickness measurement program for corrosion rate predictions, it is important to take note of the selective behaviour of this damage mechanism and ensure that at least one measurement is taken on each vessel or piping component especially including the pipe fittings.

Sourcing carbon steel with chemistry compliant with the above restrictions can prove to be difficult due to the amount of scrap steel that gets recycled. ASTM standards for typical carbon steel specifications such as ASTM A516, ASTM A106, ASTM

A333, ASTM A960, and ASTM A961 now include supplementary requirements for carbon steel used in HF service that can be used in specifications and procurement.

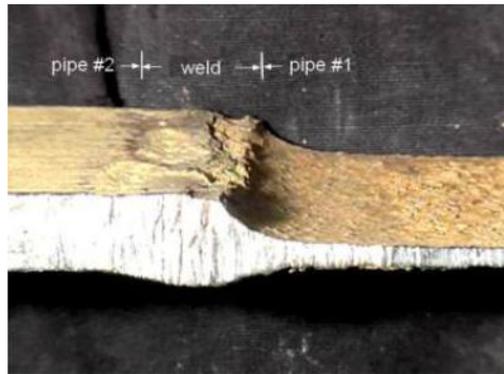


Figure 6- Cross-section of a welded carbon steel pipe containing high residual elements.

- Crevice corrosion of flanged joints:** The crevice created on the inside diameter of a flanged joint is a location often associated with localised HF corrosion, see Figure 6 – Left: Cross-section through a raised face flange showing the position of a spiral wound gasket with a PTFE inner ring. Right: Corrosion of a flange face initiating at the bore of the flange. Over time, the corrosion of the flange face may extend into the gasket sealing area which then compromises the seal integrity of the flanged joint. The recommended practice, see *API RP 751 Safe Operation of Hydrofluoric Acid Alkylation Units*, for refineries operating a HF alkylation unit is to inspect flanges in **the most susceptible services** every 10 years **unless effective flange joint integrity assurance processes are in place and HF specific gaskets are used, in which case sampled flange inspection and longer intervals might be justifiable**. Upon opening and inspecting a flanged joint, corrosion may be masked by the tightly adhered scale that forms on the surface. This should be carefully and fully removed for flange face assessment avoiding any further mechanical damage to the sealing area. The most effective method of assessing the corrosion is by using a straight edge such as a steel rule across the joint face to measure the loss. If the amount of corrosion is considered unacceptable then it is possible to re-machine some flanges depending on the original tolerances in the flange design code and should therefore be measured and checked before being carried out. Latest developments in phased array **non-destructive testing** (NDT) have been used to evaluate the condition of flange faces without the need to break open the flange. If using this for the first time, it is recommended to validate the findings by comparing the results of the NDT with a visual inspection at the next available opportunity, see Figure 7 – Left: Results of a phased array inspection of a flanged joint prior to breaking the joint. Right: Verification of findings by visual examination. This will build confidence in the use of the technique and can be used to demonstrate its effectiveness to regulatory or external auditing bodies.

Crevice corrosion can also occur in the crevice between a heat exchanger tube and the tube sheet. Auto-welded tube ends are beneficial as this process is less likely to produce cold laps or other fabrication defects that could create an unwanted crevice.

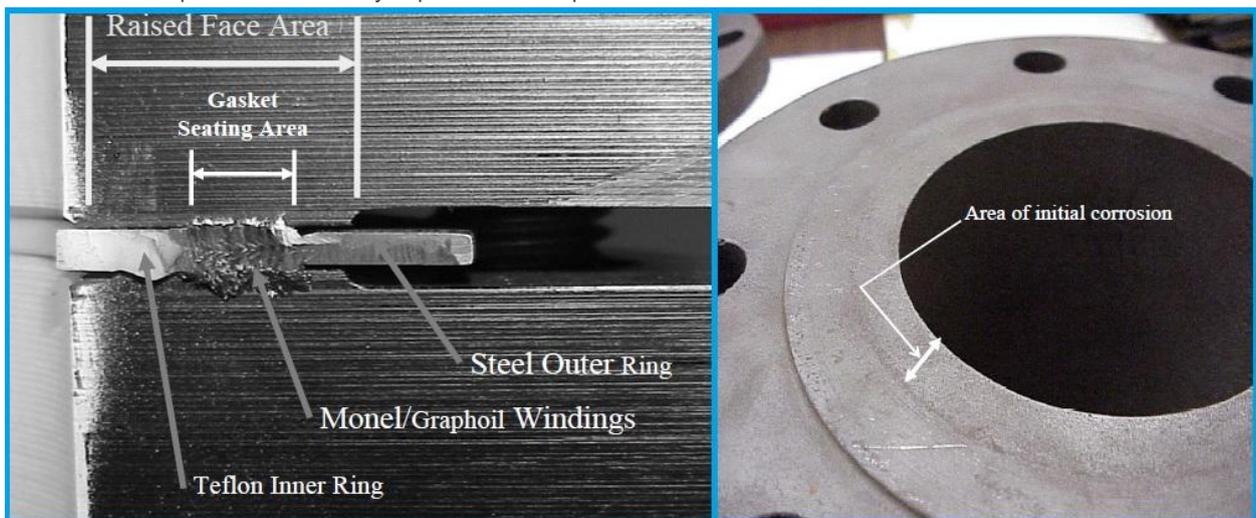


Figure 7 – Left: Cross-section through a raised face flange showing the position of a spiral wound gasket with a PTFE inner ring. Right: Corrosion of a flange face initiating at the bore of the flange.

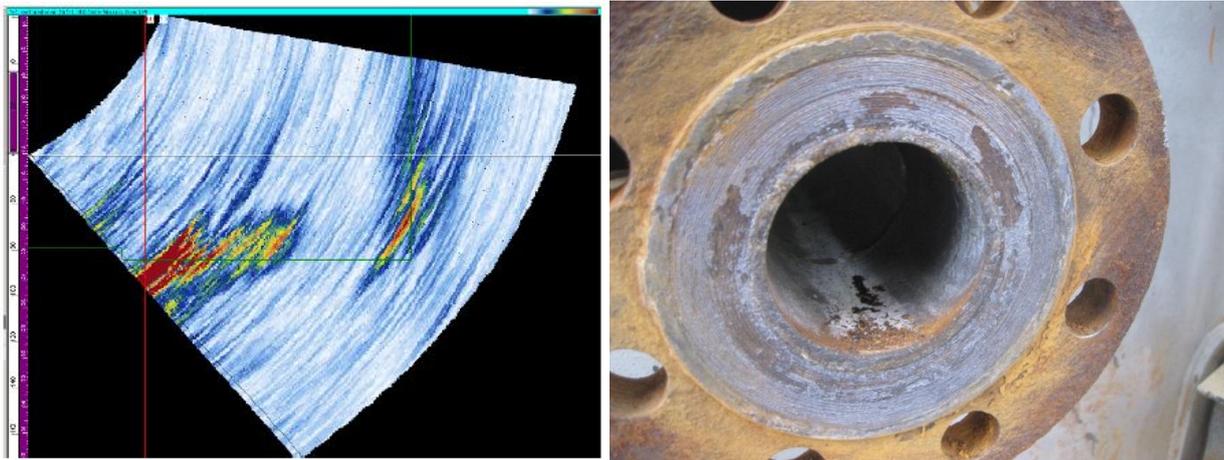


Figure 8 – Left: Results of a phased array inspection of a flanged joint prior to breaking the joint. Right: Verification of findings by visual examination.

G3.2 Cracking of Carbon Steel Due to Exposure to HF

As part of the corrosion process of carbon steel that is exposed to HF, atomic hydrogen is produced that can then diffuse into the metal. If the hydrogen atoms re-combine in minuscule voids of the metal matrix, they form hydrogen molecules which then cannot escape and start creating pressure from inside the cavity they are in. This pressure can increase to levels where the metal has reduced ductility and tensile strength up to the point where it cracks open. This can manifest as hydrogen stress cracking, hydrogen induced cracking (HIC), or stress-orientated hydrogen induced cracking (SOHIC).

- **HF hydrogen stress cracking:** The areas most susceptible to hydrogen stress cracking are on the surface of high strength low alloy steel and carbon steel with highly localised zones of high hardness in the weld metal and the heat affected zones. High hardness welds (greater than 237 BHN Brinell Hardness or C22 Rockwell Hardness) are particularly susceptible to HF Hydrogen stress cracking. When carrying out welding or weld repairs the weld procedure must consider the requirements needed to prevent making a hard susceptible welded joint. NACE SP0472 gives good Guidance on how to best control weld hardness. The best method of detection is by close internal visual examination together with wet fluorescent magnetic particle inspection (WFMT or wet FMPI testing detects surface and near-surface defects in ferromagnetic materials). U-tube bends are also susceptible to cracking due to work hardening during forming and are commonly stress relieved to prevent its occurrence.
- **Hydrogen induced cracking (HIC):** Steels with inclusions, or laminations (typically components originally made from plate materials such as welded pipe or vessels) can suffer hydrogen blisters, which can join up to form through-thickness "step-wise" cracking. This is best identified using compression wave ultrasonic scanning to map potential blisters, and then using angle beam ultrasonics to assess blisters for edge cracking, leading to step-wise through thickness cracking. Specifying "HIC resistant" plate steels should ensure 'clean' steels with low levels of tramp elements, and which have been HIC and or ultrasonically tested which improves their resistance.
- **Stress-orientated HIC (SOHIC):** Is usually driven by residual stresses at welds and therefore a stress relieving post weld heat treatment is a typical control. SOHIC will usually initiate as embedded defects, so can be detected soonest by using angle beam ultrasonics to scan welds. It can also be identified using the same techniques as hydrogen stress cracking when surface breaking.

G3.3 Use of Metal Alloys & Non-Metals for HF

G3.3.1 Monel

- **General corrosion:** In the refining industry, Monel 400 (70Ni/30Cu) is a commonly used material for applications up to 149°C. At and below these temperatures the corrosion rate is typically around 0.01mm/yr in aHF. However, if there are oxidising elements, such as air, oxygen(O₂), chlorine (Cl₂), sulphur dioxide (SO₂) and trioxide (SO₃) contained within the process then this can have a detrimental effect increasing the corrosion by up to a factor of 10 depending on the temperature and HF composition.
- **Weld corrosion:** HF acid rapidly attacks reactive metals such as titanium (Ti) and aluminium (Al). These alloying elements are added to welding consumables by only 1% or 2% to assist with the welding process but can cause the root of the weld to corrode preferentially to parent material. Volumetric NDT methods such as radiography or [angle beam ultrasonic testing \(UT\)](#) are typically required to assess this type of corrosion loss non-intrusively, but this should be validated with intrusive close visual inspection. Two examples of weld root corrosion in Monel equipment are given in *Figure 8 - Vessel shell (left) and a section of pipe (right) both constructed from Monel showing significant root loss due to HF corrosion.*
- **Stress corrosion cracking (SCC):**The corrosion product that forms from HF and Monel 400 is cuprous fluoride (CuF). This is a passive protective film, however, in the presence of oxygen the CuF is oxidised to cupric fluoride, CuF₂, and is a SCC agent. SCC can typically be found in the vapour phase due to the condensation of HF vapour. Cold worked material, such as U-tube bundle

bends, are also an area prone to SCC. [Post weld, post-cold-forming stress relief](#) of Monel is one method [of reducing susceptibility of Monel 400 to SCC](#).

- **Denickelification:** This occurs when the nickel-copper alloy corrodes in the presence of both HF and an oxidising agent. The more noble material being copper, is then deposited back on to the substrate material giving a reddish/copper appearance. This has also been termed as 'selective leaching' because it appears that the nickel has been removed leaving the copper behind. Denickelification is easily identifiable with close visual examination. Figure 9 shows two examples of where Denickelification has occurred *Figure 9 - Left: Bottom dished head of a solid Monel vessel with significant denickelification after 31 months of service. Right: Monel bellows taken from a pressure relief valve after 3.5 months in service.*
- **End grain attack:** This can occur when bar stock material is used for components such as small-bore nozzles or thermowells. Dependant on the process conditions, the end grain of the material can be more susceptible to localised pitting resulting in high corrosion rates. Figure 10 shows the effect of end grain corrosion on a thermowell, *Figure 10 – Top pair of images: Showing end grain corrosion of a Monel thermowell. Bottom pair of images: Depth of through-wall pitting on the thermowell after sectioning* and Figure 11 shows this effect on a nozzle, *Figure 11 - Effect of end grain corrosion on a nozzle constructed from bar stock instead of piping component. Left: Pitting present in the weldment and the nozzle wall of a Monel nozzle. Right: A nozzle subject to regular water washing showing the impact of water retention within the inner joint ring of the gasket.* The use of bar stock material exhibiting this open grain structure should be identified and highlighted when reviewing fabrication drawings and so on.
- **Liquid metal embrittlement (LME):** This is an identified damage mechanism in form of cracking that results specifically when elemental mercury, Hg, contacts Monel 400. In refining, mercury can enter the system via the crude oil and tends to follow butane streams. The use of the mercury cell process in chlorine production is potentially another source of contamination. The monitoring of feed streams combined with regular visual examination for mercury plating out on equipment is an effective method of identification. A range of crack detection techniques can also be employed.



Figure 9 - Vessel shell (left) and a section of pipe (right) both constructed from Monel showing significant root loss due to HF corrosion.



Figure 10 - Left: Bottom dished head of a solid Monel vessel with significant denickelification after 31 months of service. Right: Monel bellows taken from a pressure relief valve after 3.5 months in service.



Figure 11 – Top pair of images: Showing end grain corrosion of a Monel thermowell. Bottom pair of images: Depth of through-wall pitting on the thermowell after sectioning.



Figure 12 - Effect of end grain corrosion on a nozzle constructed from bar stock instead of piping component. Left: Pitting present in the weldment and the nozzle wall of a Monel nozzle. Right: A nozzle subject to regular water washing showing the impact of water retention within the inner joint ring of the gasket.

G3.3.2 Hastelloy

Under certain conditions some grades of Hastelloy, such as C276, C22, C2000, have been found to provide benefits over Monel 400 especially in valve trims, thermowells and pump components. It is recommended that confidence is gained based on service life and inspection history. Hastelloy should not be considered immune to stress corrosion cracking or corrosion issues and may not perform better than Monel 400 in all conditions.

G3.3.3 Plastics

The use of plastic pipework and tanks is more commonly used in chemical manufacturing facilities than in the refining industry. They have typically been considered as 'fit and forget' items in the past with a fixed lifetime set by the manufacturer. This has led to both expensive failures in use, and/or the unnecessary scrapping of serviceable equipment. For this reason, there are working groups within industry set aside to discuss and develop Guidance to cover the operation, maintenance and inspection of plastic equipment. Plastic equipment can deteriorate with time. Some typical modes are through UV degradation and temperature related creep or distortion. Mechanical damage of linings or jointing faces through maintenance activities may initiate leak paths which then could attack surrounding steelwork such as backing flanges. Other than routine external visual inspection, there is little in the way of detection and assessment techniques available. It is therefore the responsibility of the owner/operator to establish site experience based on the duty to aid an end-of-life replacement strategy.

G4 Post Inspection Review & Inspection Periodicity

The previous section should assist with determining likely damage mechanisms and from that, identify the specific suitable NDT techniques required to detect the early onset of damage before failure occurs. Following an inspection, a review of the findings can feed back into the inspection regime for the next inspection. An important factor to take into account is that the inspection data should be used to only increase or decrease the inspection interval within legislative requirements. It is also important to review and re-assess these intervals whenever operational changes or process upsets have occurred, as these can greatly affect the mechanical integrity of the equipment. Examples of this could be temperature excursions, acid carry over, excessive water in the acid and so on. In lieu of an RBI assessment, the recommended practice API 751 for refineries operating a HF alkylation unit specifies a maximum interval of 5 years to carry out a visual external inspection for each pressure vessel and piping circuit. **Pressure vessels which are susceptible to the highest corrosion rates** should receive an internal inspection at a frequency not to exceed one half the estimated remaining life of the vessel based on corrosion rates or 5 years, whichever is less. **All other pressure vessels** receive an internal visual inspection not to exceed one half the estimated life of the vessel based on corrosion rate or 10 years. **It is important to note that this is a recommended maximum interval and the period chosen is to be justified as suitable to manage and inspect for known degradation that can be detected.** The use of a rigorous RBI system could support intervals exceeding this if there is adequate and relevant history of multiple inspections.

G5 Onstream Examinations

This type of examination is carried out whilst the unit is being operated and is mainly limited to external access of the equipment and piping. The scope of this inspection is not just limited to the unit's process piping but can also be applied to the unit's equipment. The main purpose of conducting this form of inspection is to identify areas of deficiencies whether it is corrosion or hydrogen blistering, for example, prior to an actual turnaround/ overhaul. Methods that can be used to carry out such inspection tasks include but not limited to:

- **Visual inspection:** This may be as simple as walking around the equipment and piping and so on looking for obvious leaks or external corrosion. On doing this it is ideal for the inspector to consult with the units' operators to identify areas that the plant operators feel are suspect, such as discolouration of HF detecting paint, inoperable valves, new deadlegs, wet insulation and so on. Once these have been established then a detailed plan can be executed. This is the simplest form of onstream inspection.
- **Ultrasonics thickness measurements (USTM):** Can also be undertaken with the visual inspection. This will give an indication of the current wall thickness and if previous readings have been taken then the corrosion rate and predicted remaining life can be calculated. Data collection software can be used that automatically trends the corrosion rate for each thickness measurement location (TML). Using this data, it is possible for timely maintenance repairs or wholesale replacement plans to be made.
- **Radiography:** Can be used as a stand-alone method or used along with USTM particularly for small bore piping components or for detecting blockages caused by scale.
- **Angle beam ultrasonics:** Including both manual and automated UT (such as Time-of-Flight Diffraction and Phased Array) can be used to inspect for volumetric and crack-like defects including hydrogen stress cracking, HIC and SOHIC. Implementation and interpretation of these inspection techniques in order to distinguish original weld defects from in service damage may require specialist competency and experience.
- **Leaks:** Monitoring for leaks from flange joints, valve stems or other threaded components is important as early detection, and rectification can reduce the risk of further deterioration and significant failure. Bolts contacted by HF should be changed out to prevent stress corrosion cracking. Leaks can be detected visually due to discolouration of equipment. Assistance can be provided by the use of acid detecting paint, weak ammonia spray solution or optical gas imaging cameras.

G6 Shutdown Examination

The owner / operator must make equipment available for the internal inspection of equipment as per the developed inspection procedure and before the end of the endorsed period from the previous inspection report. This gives the opportunity to carry out the required NDT that has been identified to detect the likely internal damage mechanisms as described in an earlier section. The inspection plan needs to show the right NDT technique has been selected to search for the relevant failure mechanism. The same techniques as described for onstream examinations are appropriate for an internal inspection i.e. visual inspection supplemented with USTM with the likely addition of wet fluorescent magnetic testing (WFMT) when looking for cracking due to HF induced hydrogen damage.

G7 Inspection Qualification and Competency

All personal involved in or responsible for inspection activities shall have appropriate qualifications, training, experience and satisfactory knowledge of the requirement of the inspections to be carried out and deemed as competent by the owner/operator. BS EN ISO 17020:2012 *Conformity Assessment. Requirements for the operation of various types of bodies performing inspection* sets out the requirements for the operation of various types of bodies performing inspection. Accreditation to this standard is available through United Kingdom Accreditation Service (UKAS). When bringing in contractor third party inspectors it is the site owner/operator responsibility to check with the contractor company (for example, insurance body) that the individual inspectors carrying out work onsite can demonstrate they have the appropriate required competence for each inspection activity being carried out.

G8 Auditing

In order to ensure that relevant procedures and standards are maintained, regular auditing of HF [inspection](#) procedures and methods is imperative. Periodic auditing will confirm that systems are working correctly and are being followed. Auditing should be considered at different levels of independence - for example, relatively frequent audits from within the work group and less frequent, external auditing by non-facility personnel.

- **Internal auditors** - Example internal groups could be the site's own trained audit staff or Company trained headquarters auditors.
- **External auditors** - Example external groups could be external consultant auditors, UKAS, or the Health and Safety Executive (HSE).

All audits and the findings generated should be fully documented with individual actions and responsibilities clearly identified and followed up. Audits should focus on, but not be limited to, a review of inspection procedures, methods, and schedules. Records should be up to date and should reflect the current condition of the unit. Reports of inspections findings and the status of recommendations should be reviewed.

G9 Supplementary Information

This Guidance has been prepared with the knowledge of various other relevant documents that readers may wish to consult for additional information. Legislation, standards, practices, weblinks and so on are updated over time, and the reader is recommended to seek out the latest versions. Whilst not an exhaustive list, the principal supplementary information sources relevant to this Guidance are as follows:

1. COMAH Competent Authority Operational Delivery Guides: Ageing Plant Operational Delivery Guide, with the later Operational Delivery Guide, Mechanical Integrity
 - a. <https://www.hse.gov.uk/comah/assets/docs/mechanical-integrity-delivery-guide.pdf>
 - b. <https://www.hse.gov.uk/comah/assets/docs/mechanical-integrity-intervention-tool.pdf>
2. API Standard 510 - Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration, 11th edition.
3. <https://www.honeywell-hfacid.com/wp-content/uploads/2014/06/Honeywell-HF-Properties-TD-v4.pdf>
4. Guidelines for Corrosion Control in HF Alkylation Units, Henk P.E. Helle. 1993, ISBN: 9789051663235.
5. API Recommended Practice 751, Safe Operation of Hydrofluoric Acid Alkylation Units. 5th Edition, 2021.
6. Corrosion resistance of carbon steel in hydrofluoric acid alkylation service, Hisham Hashim and William L. Valerioti, Materials Performance, 1993.
7. NACE SP0472-2020, Methods and Controls to Prevent In-Service Environmental Cracking of Carbon Steel Weldments in Corrosive Petroleum Refining Environments.
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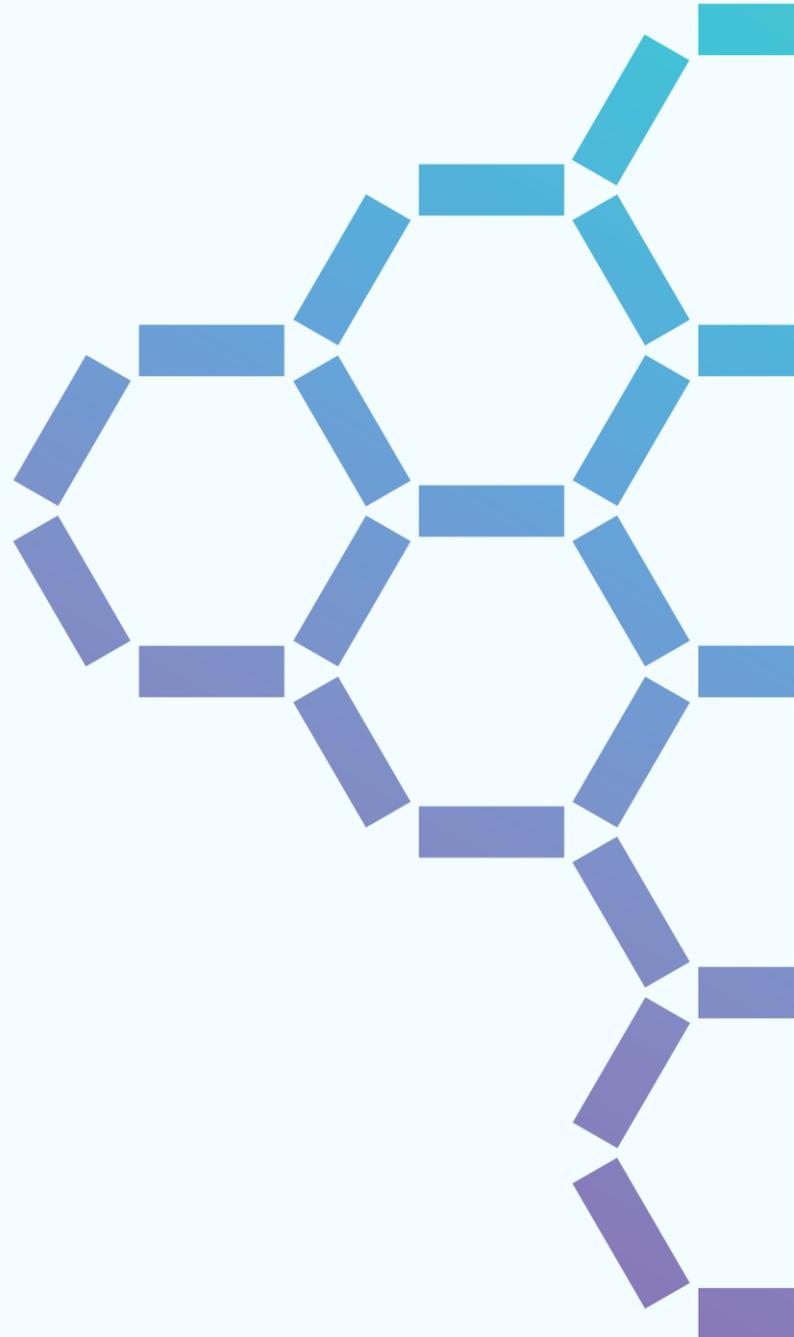
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