DRAFT LICENSE RENEWAL INTERIM STAFF GUIDANCE

LR-ISG-2013-01

AGING MANAGEMENT OF LOSS OF COATING INTEGRITY FOR INTERNAL SERVICE LEVEL III (AUGMENTED) COATINGS

INTRODUCTION

This draft license renewal interim staff guidance (LR-ISG) LR-ISG-2013-01, "Aging Management of Loss of Coating Integrity for Internal Service Level III (augmented) Coatings," provides changes to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," and NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," (SRP-LR), as described below. These changes provide one acceptable approach for managing the associated aging effects for components within the scope of the License Renewal Rule (Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"). A licensee may cite this LR-ISG in its license renewal application (LRA) until the guidance in this LR-ISG is incorporated into the license renewal guidance documents (i.e., GALL Report, SRP-LR).

DISCUSSION

Based on recent industry operating experience (OE) and the staff's review of several LRAs, the staff has determined that the GALL Report and SRP-LR should be revised to incorporate recommendations related to managing loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage of Service Level III (augmented) coatings.

In developing these new recommendations, the staff developed:

- a new GALL Report aging management program (AMP) for Service Level III (augmented) coatings
- three new SRP-LR and GALL Report aging management review (AMR) line items
- a final safety analysis report (FSAR) supplement description for the new AMP
- two new GALL Report definitions

For a description of the term "Service Level III (augmented)," see Section V, below, "Definition of Service Level III (augmented) coating."

I. Background

a. OE indicates that degraded coatings have resulted in unanticipated or accelerated corrosion of the base metal and degraded performance of downstream equipment (e.g., heat exchangers). Based on OE examples, the staff revised the GALL Report and SRP-LR to include recommendations on managing the aging of Service Level III (augmented) coatings applied to the internal surfaces of in-scope components in which loss of the coating could result in accelerated or unanticipated corrosion of the base metal or could prevent an in-scope component (e.g., a component that is in the scope of license renewal) from satisfactorily accomplishing any of its functions identified under 10 CFR 54.4(a)(1), (a)(2), or (a)(3) (e.g., reduction in flow, drop in pressure, reduction in heat transfer). For the purposes of this LR-ISG, the term "coating" includes inorganic (e.g., zinc-based) or organic (e.g., elastomeric or polymeric) coatings, linings (e.g., rubber, cementitious), and concrete surfacers that are designed to adhere to a component to protect its surface. Service Level III (augmented) coatings include coatings used in areas outside the reactor containment whose failure could adversely affect the safety function of a safety-related system, structure or component (SSC), or those applied to the internal surfaces of in-scope components and whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(3) (e.g., fire protection, station blackout).

b. The staff has noted that for AMR steel pipe with elastomer-lined items (such as SRP-LR Table 3.3-1, “Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL Report,” ID 26), many applicants state that the elastomer lining is not credited for aging. The staff recognizes that the corrosion allowance used for the design of a component could have incorporated a general corrosion rate that reflects 40 or 60 years of service. However, if a small portion of the lining degraded and exposed the base material, accelerated corrosion could occur (e.g., where a galvanic couple exists). In addition, the loose coating becomes debris that can result in degraded performance of downstream components. Therefore, when applied to the internal surfaces of in-scope components, these coatings are within the scope of license renewal, whether or not such coatings are “credited” to prevent corrosion of the base material, and the loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage is an applicable aging effect which should be managed if the coating failure could prevent an in-scope component from performing its intended function identified under 10 CFR 54.4(a)(1), (a)(2), or (a)(3).

II. OE examples

a. As described in Information Notice 85-24, “Failures of Protective Coatings in Pipes and Heat Exchangers,” in 1982, a licensee experienced degradation of internal coatings in its spray pond piping and diesel generator heat exchangers that had been in-service for two years. Although this is not newly identified OE, the issue contains many key aspects related to coating degradation. The licensee observed severe blistering, moisture entrapment between layers of the coating, delamination, peeling, and widespread rusting. The degradation occurred as a result of improper practices during installation of the coatings, including improper curing time, restricted availability of air flow leading to improper curing, installation layers that were too thick, and improper surface preparation (e.g., oils on surface, surface too smooth). The failure resulted in flow restrictions to the ultimate heat sink and blockage of the emergency diesel generator governor oil cooler.

Failure to install coatings with the correct installation prerequisites is not always immediately observable. There are three critical stages where failures due to improper installation (e.g., installation techniques, coating not appropriate to application) typically become evident:

i. Immediate failure. Coating failures typically occur as the system is being returned to service.

ii. First time thermal cycling. These failures become evident when a complete thermal cycle occurs resulting in the thermal movement of the substrate. Examples include a tank internal coating after it has been exposed to a winter-summer cycle, and heat-up and cool-down of a heat exchanger. If the coating was not installed properly, the substrate movement can result in a breakdown of the adhesion of the coating to the substrate.

iii. Two to three refueling outage intervals.

Although the root cause of the failure was related to installation practices the failure occurred as time elapsed. Given that the effects might not always be immediately observable, subsequent inspections are necessary to ensure that coating failures are detected prior to an in-scope component's failure to satisfactory accomplish its functions identified under 10 CFR 54.4. As a result, Table 4a, "Inspection Intervals for Service Level III (augmented) Coatings for Tanks, Piping, and Heat Exchangers," of the new GALL Report AMP XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program," recommends that newly installed coatings or coatings that have been repaired or replaced be inspected during the next two refueling outage intervals.

b. During an LRA AMP audit, the staff found that coating degradation, which occurred as a result of weakening of the adhesive bond of the coating to the base metal because of turbulent flow, resulted in the coating eroding away and leaving the base metal subject to wall thinning and leakage. The licensee's corrective actions included revisions to its monitoring program to include more frequent volumetric inspections of the piping system. This OE is described in an NRC Integrated Inspection Report, ADAMS Accession Number ML12045A544.

c. In 1994, a licensee replaced a portion of its cement-lined steel service water piping with piping lined with a common polyvinyl chloride (PVC) polymeric material. The manufacturer stated that the lining material had an expected life of 15 to 20 years. The licensee conducted multiple inspections from 1996 through 2003. An inspection in 1997 showed some bubbles and delamination in the coating material at a flange and an inspection in 2002 found some locations with impaired adhesion to the base metal. In 2011, diminished flow was observed downstream of one of the diesel generator heat exchangers. Inspections revealed that the lining in one piping spool piece was loose or missing in multiple locations. This spool piece had been previously inspected in 1999 with no deficiencies noted. The missing material had clogged a downstream orifice. The licensee sent a sample of the lining to a testing lab where it was determined that cracking was evident in the lining on both the metal and water side and there was a noticeable increase in the hardness of the in-service sample as compared to an unused sample. This OE is described in Request for Additional Information (RAI) B.2.1.11-2, ADAMS Accession Number ML12041A054.

d. During an LRA AMP audit, the staff found that a licensee had experienced multiple instances of coating degradation in in-scope components, resulting in coating debris found in diesel generator intercoolers. As of March 2012, none of the debris has been large enough to result in reduced heat exchanger performance. This OE is described in RAI B2.1.9-3a, ADAMS Accession Number ML12097A064.

e. As described in Information Notice 2008-11, "Service Water System Degradation at Brunswick Steam Electric Plant Unit 1," and an NRC Special Inspection

Report, ADAMS Accession Number ML073200779, a licensee experienced flow reduction over a 14-day period, resulting in the service water room cooler being declared inoperable. The flow reduction occurred because the rubber lining on a butterfly valve body became detached. The licensee had periodically experienced rubber lining and seat failures in upstream control valves. A corrective action document stated, "[t]his has been a historical problem at BNP [Brunswick Nuclear Plant] for the rubber liner in valves to fail due to aging and cracking of the rubber in a chlorinated water environment. This valve is original to the plant and the rubber lined valves in the Service Water system have been replaced with a non-rubber lined valve when the lining has failed."

f. At an international plant, cavitation in saltwater system piping downstream of a flow control valve eroded the pipe coating which resulted in unanticipated corrosion through the pipe wall. Inspection frequencies were increased. This OE is described in a report titled, "Highlights from the International Reporting System for Operating Experience for Events in 2012 and 2011," ADAMS Accession Number ML13063A135.

g. A licensee experienced degradation of the protective concrete lining that allowed brackish water to contact the unprotected carbon steel piping resulting in localized corrosion. The degradation of the concrete lining was likely caused by the high flow velocities and turbulence from the valve located just upstream of the degraded area. This OE is described in a relief request for the temporary repair of a service water pipe, ADAMS Accession Number ML072890132.

III. Industry guidance on degradation of coatings

a. The Electric Power Research Institute (EPRI) has provided the following guidance on the effect of loss of coating integrity in EPRI TR-103403, "Service Water Corrosion and Deposition Sourcebook," which states:

> All of these barrier linings possess some degree of permeability to water and ions; hence their protective capabilities are not perfect. Further, coatings will almost always contain small flaws ("holidays") where local anodic conditions can occur. In some situations, corrosion at these holidays (small anodic areas supported by a large cathode) produces a more severe corrosion problem than if the material had never been coated at all. While the effect of such coating failures on the corrosion of the underlying metal would take time (possibly years), the failed coating itself can have an instant impact on the system. Coatings that fail as sheets or in large pieces can cause blockage of safety-related heat exchangers.

b. EPRI 1010059, "Service Water Piping Guideline," states:

> All coatings exhibit some degree of permeability to water, so they provide a barrier that is effective but less than 100% effective in keeping the environment away from the metallic pressure boundary. Permeability will be a function of the coating type and the coating thickness. Coating life, where life is defined as the time period during which the coating is nearly 100% effective at protecting the metal from corrosion, will typically be less than the life of the

component (less than 40 years). These considerations require that the condition of the coating be examined periodically and that coating repairs or replacements be anticipated during the life of the service water piping.

IV. Industry use of the terms “coating” and “Service Level III coating”

a. During the development of this LR-ISG, the staff reviewed EPRI 1019157, “Guidelines on Nuclear Safety-Related Coatings,” issued December 2009 and Regulatory Guide (RG) 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Plants,” Revision 2, issued October 2010, as well as several ASTM International (formerly known as American Society for Testing and Materials (ASTM)) Standards that are related to coatings and are referenced in RG 1.54. In its review of these documents, the staff recognized that clarification is needed to ensure a common understanding of terms used in this LR-ISG.

b. EPRI 1019157 and RG 1.54 state that Service Level III “coatings are used in areas outside the reactor containment where failure could adversely affect the safety function of a safety-related SSC.” Although this definition of Service Level III coatings sufficiently describes coatings with intended functions that meet the criterion of 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2), it is not completely sufficient in the context of license renewal because it does not address the criterion of 10 CFR 54.4(a)(3) for coatings which, if they degrade, could impact a component’s intended function(s). In order to address this gap, the staff has developed a new term, “Service Level III (augmented) coating,” as described in Section V., below.

c. Section 1.5.1.1, Common Terms Related to Coating Work, in EPRI 1019157 defines paints/coatings/linings as, “[e]ssentially synonymous terms for liquid-applied materials consisting of pigments and fillers bound in a resin matrix that dry or cure to form a thin, continuous protective or decorative film. ‘Linings’ indicates an immersion environment.” ASTM D4538-05, “Standard Terminology Relating to Protective Coating and Lining Work for Power Generation Facilities,” defines a coating system as “polymeric protective film consisting of one or more coats, applied in a predetermined order by prescribed methods.”

   The definition of the term “paints/coatings/linings” as stated in EPRI 1019157 is useful in understanding what is meant by a coating or lining; however, in order to succinctly communicate the scope of paints/coatings/linings covered by this LR-ISG, for purposes of the GALL Report, a new singular term, “coating,” has been added to GALL Report Table IX.B, “Structures and Components,” (see Appendix B of this LR-ISG). The new definition of coating includes the following key aspects:

   i. Coatings include coatings, linings, and other items such as concrete surfacers and rubber or cementitious linings.

   ii. Coatings can be constructed from inorganic (e.g., zinc-based) or organic (e.g., elastomeric or polymeric) materials.

V. Definition of Service Level III (augmented) coating

a. All coatings applied to the internal surfaces of an in-scope component are in the scope of this LR-ISG if its degradation could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(1), (a)(2), or (a)(3). Service Level III (augmented) coatings are those:

i. used in areas outside the reactor containment whose failure could adversely affect the safety function of a safety-related SSC, or

ii. applied to the internal surfaces of in-scope components and whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(3) (e.g., fire protection, station blackout).

b. The staff does not consider a coating to be an SSC, with the exception of one example described below. A coating is applied to a component as part of its original design or later as a modification. In some instances, standard off-the-shelf components are installed with internal coatings even though the licensee's specific environment does not require the protection provided by the coating. However, in most cases, coatings were applied with a function to prevent degradation of the base material. A coating is an integral part of an in-scope component, providing it protection from corrosion whether credited for that protection or not. A coating can be removed from the internal surfaces of a component; however, until such time as it is removed, it is an integral part of the component.

Although the addition of a coating to a component can mitigate the potential effects of corrosion, coatings can also introduce additional aging effects to downstream components. The effects that a coating can have on downstream components are similar to the impact uncoated base material can have on downstream components. For example, general corrosion of uncoated carbon steel piping can result in the release of corrosion products into the system. These corrosion products can have downstream effects such as flow blockage (see the discussion of fire water system flow blockage in LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," where corrosion products led to complete blockage of fire water sprinkler piping) or loss of material due to fouling that leads to corrosion. Similarly, loss of coating integrity can result in downstream flow blockage from debris and unanticipated corrosion.

The concept of coatings being integral to the base material to which it is applied is consistent with current AMR line items in the GALL Report and SRP-LR, as follows:

- SRP-LR item 3.3.1-26, steel (with elastomer lining), steel (with elastomer lining or stainless steel cladding) piping, piping components, and piping elements exposed to treated water being managed for loss of material due to pitting and crevice corrosion (only for steel after lining/cladding degradation).
- SRP-LR item 3.3.1-37, steel (with coating or lining) piping, piping components, and piping elements exposed to raw water being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion; fouling that leads to corrosion; and lining/coating degradation.
- All of the GALL Report items for buried components include the coating or wrapping as integral to the component (i.e., EP-111, AP-198, SP-145).

Because coatings are an integral part of a component, the function(s) of the component dictates whether the component meets the scoping criteria of 10 CFR 54.4(a), and hence whether the coating is considered in the scope of license renewal. More specifically, Service Level III (augmented) coatings are not evaluated as stand-alone components to determine if it meets the scoping criteria of 10 CFR 54.4(a). It is immaterial whether the coating has an intended function identified in the current licensing basis (CLB) because, the CLB intended function of the component dictates whether the component is in-scope and thereby the aging effects of the coating must be evaluated for potential impact on the component and downstream component's intended function(s).

RG 1.54 states that, "[t]he maintenance rule requires the licensee to monitor the effectiveness of maintenance for protective coatings within its scope (as discrete systems or components or as part of any SSC) …." The few examples in the GALL Report for identifying a coating as a component are Service Level I coatings in GALL Report items CP-152 and TP-301. RG 1.54 defines Service Level I coatings as, "[s]ervice Level I coatings are used in areas inside the reactor containment where coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown." There are many coated components within containment that are not in the scope of license renewal (e.g., floors, tanks, supports that do not have intended functions that meet the screening criteria of 10 CFR 54.4(a)). Therefore, in order to efficiently identify all of the applicable coated surfaces in containment, Service Level I coatings were identified as a unique component.

c. The Service Level III coating definition used in EPRI 1019157 and RG 1.54 encompasses components that are within the scope of license renewal under 10 CFR 54.4(a)(1) (defined as "[s]afety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events"), because these functions are safety-related. If the failure of a safety-related coating could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(1), this coating is within the scope of this LR-ISG. Examples include a safety-related coating applied to the inside of a diesel fuel oil storage tank, service water heat exchanger, or pipe.

d. The Service Level III coating definition used in EPRI 1019157 and RG 1.54 encompasses components within the scope of license renewal under 10 CFR 54.4(a)(2) (defined as "[a]ll nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section"). If the failure of a nonsafety-related coating on the inside surface of a safety-related or nonsafety-related piping system could cause a safety-related component to not meet its intended function, these coatings would be in the scope of this LR-ISG. Coating-related degradation could result in a safety-related piping system not meeting its intended function in several ways:

    i. The internal coating in an in-scope pipe could degrade such that the base metal corrodes through-wall and sprays adjacent safety-related switchgear. This example is encompassed by the term leakage boundary (spatial) from SRP-LR Table 2.1-4(b), "Typical 'Passive' Component-Intended Functions," which states, "[n]onsafety-related component that maintains mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs."

ii. An in-scope, internally coated, nonsafety-related system that is connected to a safety-related system through a normally open isolation valve would be in the scope of this LR-ISG. The coatings could become detached because of aging and enter the safety-related system during routine operations, and subsequently clog the system during an accident response, or prevent the isolation valve from fully closing. An example would be a nonsafety-related fire water system that is used as a backup source of water for the auxiliary feedwater (AFW) system in the current licensing basis.

iii. The coatings installed inside a nonsafety-related piping segment which is in-scope because it has a structural integrity (attached) function as defined in SRP-LR Table 2.1-4(b), "[n]onsafety-related component that maintains mechanical and structural integrity to provide structural support to attached safety-related piping and components," would be in the scope of this LR-ISG. If the coatings degraded, internal corrosion could occur and result in the piping segment failing during a seismic event.

e. The Service Level III coating definition is too narrow in that it does not address components within the scope of license renewal under 10 CFR 54.4(a)(3), (defined as "[a]ll systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63)"). Components within the scope of license renewal under 10 CFR 54.4(a)(3) could be in the scope of this LR-ISG even though they are nonsafety-related and might not affect a safety-related function. As stated above, the coatings applied to the interior surface of an in-scope component become an integral part of the in-scope component, providing the component protection from corrosion whether credited for that protection or not. Two examples are as follows:

i. A coating was installed to refurbish plant drains that drain water from a room during a fire event. If the coating degrades and blocks flow in the line, a fire water sprinkler discharge could flood the room and result in an in-scope component's intended function(s) not being maintained. Many plants have designated portions of their plant drain systems as in-scope to ensure that the functions described in 10 CFR 54.4(a)(3) are successfully accomplished. For example, in relation to portions of its plant drain system, an applicant stated, "[i]t also meets 10 CFR 54.4(a)(3) because it is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48)."

ii. A nonsafety-related demineralized water tank is used as a backup source in the current licensing basis for the safety-related suction inventory of the AFW system. The tank is relied on during a station blackout. If the tank or its discharge piping is internally coated, degradation of that coating could result in a reduction of flow to the steam generators or reduction in suction pressure to the AFW pumps.

In summary, Service Level III (augmented) coatings are those:

i. used in areas outside the reactor containment whose failure could adversely affect the safety function of a safety-related SSC, or

ii. applied to the internal surfaces of in-scope components and whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(3) (e.g., fire protection, station blackout).

VI. Basis for not including Service Level II coatings within the scope of this LR-ISG

RG 1.54 states that, "[s]ervice Level II coatings are used in areas where coating failure could impair, but not prevent, normal operating performance. The functions of Service Level II coatings are to provide corrosion protection and decontaminability in those areas outside the reactor containment that are subject to radiation exposure and radionuclide contamination. Service Level II coatings are not safety related." The staff did not include Service Level II coatings within the scope of this LR-ISG because these coatings do not affect the safety function of a safety-related SSC and given the new term "Service Level III (augmented)," are not installed on the internal surfaces of piping, tanks, and heat exchangers. However, if plant-specific OE reveals age-related degradation of a Service Level II coating that could have or would affect a function identified in 10 CFR 54.4(a)(1), the applicant should develop a plant-specific AMP to address aging of the applicable Service Level II coatings.

VII. Summary of changes in this LR-ISG

To address the aging management of Service Level III (augmented) coatings, this LR-ISG implements a new GALL Report AMP XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program." The staff used GALL Report AMP XI.S8, EPRI 1019157, RG 1.54, and ASTM International Standards referenced in RG 1.54 to develop the recommendations contained in the new GALL Report AMP XI.M42. The staff included the Service Level III (augmented) coatings AMP in the mechanical series of AMPs instead of the structural series because the components being age-managed by the program will principally be piping, piping components, heat exchangers, and tanks. Therefore, the AMP is numbered XI.M42 and not XI.S9.

a. A summary of the key recommendations in GALL Report AMP XI.M42 is as follows:

   i. Visual inspections are conducted on all coatings applied to the internal surfaces of in-scope components that could affect a CLB-intended function within the scope of license renewal. The periodicity of the visual inspections is based on an evaluation of the impact of a coating failure (e.g., reduction of flow or drop in pressure, unanticipated or accelerated corrosion, reduction in heat transfer) on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history. However, not-to-exceed inspection intervals have been established in the new AMP that are dependent on the results of previous inspections, if they are newly installed or repaired (defined as two refueling outage intervals), and whether the coating is located in a turbulent environment.

The extent of inspections for all tanks and heat exchangers is all accessible internal surfaces. The extent of inspections for internally coated piping is either a representative 73 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination. The basis for the 73 inspection locations or 50 percent of the pipe length is to provide a close approximation of a 95 percent confidence level that 95 percent of a given population is not experiencing loss of coating integrity.

The staff recognizes that the sampling size recommended in several AMPs (e.g., XI.M32, "One-Time Inspection," XI.M33, "Selective Leaching") is based on a close approximation of a 90 percent confidence level that 90 percent of a given population is not experiencing degradation. However, the staff notes that components within the scope of these programs were generally procured, installed, and tested in accordance with industry consensus documents (e.g., ASTM Standards, ASME Code Section III). However, internal piping coatings, even when installed in accordance with manufacturer's recommendations, did not have the benefit of being procured, installed, and tested in accordance with industry consensus documents that cover the same level of detail as covered in those associated with power piping or nuclear construction codes. Consequently, the staff considers that the representative sample size to manage loss of coating integrity for piping internal coatings should be greater than the representative sample size for other GALL Report AMPs. The staff concluded that a close approximation of a 95 percent confidence level that 95 percent of a given population is not experiencing loss of coating integrity is appropriate.

ii. Fire water storage tanks are not included in the scope of the new AMP. LR-ISG-2012-02 revised GALL Report AMP XI.M27 to recommend that the internal surfaces of fire water storage tanks be inspected to the requirements of National Fire Protection Association (NFPA) 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems." Section 9.2.6, "Interior Inspections," of NFPA 25 covers inspections of coatings for these tanks. The interior surfaces of coated tanks are inspected every 5 years.

iii. A provision was included in the "scope of program" program element of GALL Report AMP XI.M42 to allow the use of alternative AMPs to manage the aging effects of Service Level III (augmented) coatings installed in specific components or systems (e.g., GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," for service water coatings). In order to use this provision, the alternative AMP must include all the recommendations of GALL Report AMP XI.M42 and the updated final safety analysis report (UFSAR) supplement for GALL Report AMP XI.M42, as shown in SRP-LR Table 3.0-1, "FSAR Supplement for Aging Management of Applicable Systems." The "scope of program" program element for each GALL Report AMP that could be used as an alternative AMP was revised to include a discussion of this provision (See Appendix D, "Changes to the 'scope of program' Program Element of Potential Alternative AMPs")

iv. Visual inspections are intended to identify defects such as blistering, cracking, flaking, peeling, delamination, and rusting, as well as physical damage. With the exception of physical damage, Section 10.2 of ASTM D7167-12, “Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant,” describes visual inspection methods for the above defects. For areas not readily accessible for direct inspection, such as pipelines, heat exchangers, and other equipment, consideration is given to the use of remote or robotic inspection tools.

v. For coated surfaces determined to not meet the acceptance criteria due to delamination or blisters, physical testing is performed where physically possible (i.e., sufficient room to conduct testing). The test consists of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54.

vi. The training and qualification of individuals involved in coating inspections is conducted in accordance with ASTM International Standards endorsed in RG 1.54, including staff guidance associated with a particular standard.

vii. If corrosion of the base material is the only potential effect related to coating degradation, external wall thickness measurements can be performed to confirm the corrosion rate of the base metal instead of inspecting the coatings. Corrosion of base material might be the only consideration if Service Level III (augmented) coatings are installed in components in which degradation of the coating cannot result in downstream effects, such as reduction in flow, drop in pressure, or reduction in heat transfer in the system. The basis for this conclusion is to be explained in the LRA. Examples include: (a) a coating installed upstream of a cooling pond where there are no piping obstructions between the coating and the cooling pond and flow circulation in the pond is low enough that it would be expected that the debris would settle and not transport to an inlet pipe, and (b) a coating installed on the internal surfaces of piping system that only has a leakage boundary (spatial) function.

b. New AMR items are included in SRP-LR Sections, Engineered Safety Features Systems (Section 3.2), Auxiliary Systems (Section 3.3), and Steam and Power Conversion Systems (Section 3.4), and in the corresponding GALL Report Tables. The staff did not revise SRP-LR Section 3.1, “Reactor Vessel, Internals, and Reactor Coolant System,” because it is not aware of any instances where coatings have been applied to the internal surfaces of reactor coolant pressure boundary SSCs.

c. The new GALL Report AMP XI.M42 is included in Attachment C.

d. Details for the new SRP-LR and GALL Report items are included in Appendix A and Appendix B.

e. Corresponding changes to the FSAR supplement description are shown in Appendix A, Table 3.0-1.

f. A new material term, “coating,” was added to GALL Report Section IX.C. A new aging effects term, “loss of coating integrity,” was added to GALL Report Section IX.E.

ACTIONS

Applicants should use Appendices A through C in preparing their LRA to be consistent with the GALL Report.

NEWLY IDENTIFIED SYSTEMS, STRUCTURES, AND COMPONENTS UNDER 10 CFR 54.37(b)

The NRC is not proposing to treat the revised recommendations for managing the aging of Service Level III (augmented) coatings as "newly identified" SSCs under 10 CFR 54.37(b). Therefore, any additional action on such materials, which the NRC may impose upon current holders of renewed operating licenses under 10 CFR Part 54, would not fall within the scope of 10 CFR 54.37(b). The NRC would address compliance with the requirements of 10 CFR 50.109, "Backfitting," before it may impose any new aging management requirements on current holders of renewed operating licenses (see discussion below).

BACKFITTING AND ISSUE FINALITY

This LR-ISG contains guidance on one acceptable approach for managing the associated aging effects occurring during the period of extended operation for Service Level III (augmented) coatings which are applied to the internal surfaces of components within the scope of license renewal under 10 CFR Part 54. The staff intends to use the guidance in this LR-ISG when reviewing current and future license renewal applications. Existing holders of renewed operating licenses may follow the guidance in this ISG, but are not required to do so.

<u>Backfitting</u>

Issuance of this LR-ISG does not constitute backfitting as defined in the Backfit Rule for nuclear power plants, 10 CFR 50.109(a)(1), and the NRC staff did not prepare a backfit analysis for issuing this LR-ISG. There are several rationales for this conclusion, depending on the status of the nuclear power plant licensee under 10 CFR Parts 50 and 54.

Licensees currently in the license renewal process - The backfitting provisions in 10 CFR 50.109 do not protect an applicant, as backfitting policy considerations are not applicable to an applicant. Therefore, issuance of this LR-ISG does not constitute backfitting as defined in 10 CFR 50.109(a)(1).

Licensees that already hold a renewed license - This guidance, as proposed, is nonbinding and the draft LR-ISG would not require current holders of renewed licenses to take any action (i.e., programmatic or plant hardware changes for managing the associated aging effects for components within the scope of this LR-ISG). If the draft LR-ISG were finalized as written, then current holders of renewed licenses must treat the information presented in the final LR-ISG information guidance as "operating experience" information, and consider the operating experience as required by their current licensing bases to ensure that relevant AMPs are, and will remain, effective. If, in the future, the NRC decides to take additional action and impose requirements for managing the associated aging effects for components within the scope of this LR-ISG, then the NRC would follow the requirements of the Backfit Rule.

Current 10 CFR *Part 50 operating license holders who have not yet applied for renewed licenses* - The backfitting provisions in 10 CFR 50.109 do not protect any future applicant, as backfitting policy considerations are not applicable to a future applicant. Therefore, issuance of this LR-ISG does not constitute backfitting as defined in 10 CFR 50.109(a)(1).

Issue Finality under 10 CFR *Part 52*

Issuance of this LR-ISG does not constitute a violation or inconsistency with the issue finality provision applicable to standard design certifications, 10 CFR 52.63, or the specific issue finality provisions in each of the currently-approved design certification rules in 10 CFR Part 52, Appendices A through D. The design certifications do not address compliance with the license renewal requirements in 10 CFR Part 54. Therefore, the issue finality provisions applicable to the four currently-approved design certifications do not extend to the nuclear safety issues of license renewal, and the NRC need not address the issue finality provisions when issuing this LR-ISG.

Issuance of this LR-ISG does not constitute a violation or inconsistency with the issue finality provision, 10 CFR 52.98, which is applicable to the two current combined licenses issued under 10 CFR Part 52. The NRC's issuance of those two combined licenses was not based upon any consideration of compliance with the license renewal requirements in 10 CFR Part 54. Furthermore, the issue finality provisions of 10 CFR Part 52 do not extend to the aging management matters covered by 10 CFR Part 54, as evidenced by the requirement in 10 CFR 52.107, "Application for Renewal," stating that applications for renewal of a combined license must be in accordance with 10 CFR Part 54. Therefore, the issue finality provisions applicable to the two current holders of combined licenses do not extend to the subject of license renewal, and the NRC need not address 10 CFR 52.98 when issuing this LR-ISG.

Currently, there are no combined licensees who are seeking license renewal under 10 CFR Part 54. Therefore, the changes and new positions presented in the LR ISG may be made without consideration of the issue finality provisions in 10 CFR Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants." The issue finality provisions in 10 CFR 50.109 do not protect any future applicant, as issue finality policy considerations are not applicable to a future applicant.

CONGRESSIONAL REVIEW ACT

This LR-ISG is a rule as designated in the Congressional Review Act (Title 5 of the United States Code, Part I, Chapter 8 (5 USC, Sec. 801)). However, the Office of Management and Budget has not found it to be a major rule as designated in the Congressional Review Act.

APPENDICES

Appendix A, Mark-up Showing Changes to the SRP-LR

Appendix B, Mark-up Showing Changes to the GALL Report AMR Items and Definitions

Appendix C, GALL Report AMP XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program"

Appendix D, Changes to the "scope of program" Program Element of Potential Alternative AMPs

Appendix E, Resolution of Public Comments

The appendices in this LR-ISG are not shown in crossed out for deleted text and underlined for added text format. The appendices were not annotated in this manner because they consist entirely of new material.

REFERENCES

5 USC, Sec. 801, Congressional Review of Agency Rulemaking, Office of the Law Revision Counsel of the House of Representatives, 2012.

10 CFR Part 50, Domestic Licensing of Production and Utilization Facilities, Office of the Federal Register, National Archives and Records Administration, 2010.

10 CFR Part 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, Office of the Federal Register, National Archives and Records Administration, 2011.

ASTM D4538-05, Standard Terminology Relating to Protective Coating and Lining Work for Power Generation Facilities.

ASTM D7167-12, Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant.

EPRI 1019157, Plant Support Engineering: Guidelines on Nuclear Safety-Related Coatings, December 2009.

EPRI TR-103403, Service Water Corrosion and Deposition Sourcebook, December 1993.

EPRI 1010059, Service Water Piping Guideline, September 2005.

Nuclear Energy Institute, NEI 95-10, Industry Guidelines for Implementing The Requirements of 10 CFR 54 – The License Renewal Rule, Revision 6.

Regulatory Guide 1.54, Service Level I, II, and III Protective Coatings Applied to Nuclear Plants, Revision 2, October 2010.

U.S. Nuclear Regulatory Commission. NUREG-1801, Revision 2, Generic Aging Lessons Learned (GALL) Report, December 2010.

U.S. Nuclear Regulatory Commission. NUREG-1800, Revision 2, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, December 2010.

U.S. Nuclear Regulatory Commission, NRC Information Notice 85-24, Failures of Protective Coatings in Pipes and Heat Exchangers, March 26, 1985.

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APPENDIX A

MARK-UP SHOWING CHANGES TO THE SRP-LR

Table 3.0-1 FSAR Supplement for Aging Management of Applicable Systems				
GALL Chapter	**GALL Program**	**Description of Program**	**Implementation Schedule***	**Applicable GALL Report and SRP-LR Chapter References**
XI.M42	Service Level III (augmented) Coatings Monitoring and Maintenance Program	The program consists of visual inspections of all Service Level III (augmented) coatings applied to the internal surfaces of in-scope components exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, lubricating oil or fuel oil. For coated surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing). The test consists of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants." The training and qualification of individuals involved in coating inspections are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard.	Program is implemented no later than six months before the period of extended operation and inspections begin no later than the last refueling outage before the period of extended operation.	GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP 3.4

APPENDIX A

MARK-UP SHOWING CHANGES TO THE SRP-LR

Table 3.2-1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL Report

ID	Type	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Rev2 Item	Rev1 Item
67	BWR/PWR	Metallic piping, piping components, heat exchangers, tanks with Service Level III (augmented) internal coatings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, or lubricating oil	Loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage	Chapter XI.M42, “Service Level III (augmented) Coatings Monitoring and Maintenance Program”	No	V.A.E-401 V.B.E-401 V.C.E-401 V.D1.E-401 V.D2.E-401	N/A N/A N/A N/A N/A

APPENDIX A

MARK-UP SHOWING CHANGES TO THE SRP-LR

Table 3.2-2 Aging Management Programs Recommended for Aging Management of Engineered Safety Features	
GALL Report Chapter/AMP	**Program Name**
Chapter XI.M42	Service Level III (augmented) Coatings Monitoring and Maintenance Program

Table 3.3-2 Aging Management Programs Recommended for Aging Management of Auxiliary System	
Chapter XI.M42	Service Level III (augmented) Coatings Monitoring and Maintenance Program

Table 3.4-2 Aging Management Programs Recommended for Aging Management of Steam and Power Conversion Systems	
Chapter XI.M42	Service Level III (augmented) Coatings Monitoring and Maintenance Program

APPENDIX A

MARK-UP SHOWING CHANGES TO THE SRP-LR

Table 3.3-1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL Report

ID	Type	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Rev2 Item	Rev1 Item
128	BWR/PWR	Metallic piping, piping components, heat exchangers, tanks with Service Level III (augmented) internal coatings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, lubricating oil, or fuel oil	Loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage	Chapter XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program"	No	VII.A2.A-401 VII.A3.A-401 VII.A4.A-401 VII.C1.A-401 VII.C2.A-401 VII.C3.A-401 VII.D.A-401 VII.E1.A-401 VII.E2.A-401 VII.E3.A-401 VII.E4.A-401 VII.E5.A-401 VII.F1.A-401 VII.F2.A-401 VII.F3.A-401 VII.F4.A-401 VII.G.A-401 VII.H1.A-401 VII.H2.A-401	N/A N/A N/A N/A N/A N/A N/A N/A N/A N/A N/A N/A N/A N/A N/A N/A N/A N/A N/A

Table 3.4-1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL Report

ID	Type	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Rev2 Item	Rev1 Item
62	BWR/PWR	Metallic piping, piping components, heat exchangers, tanks with Service Level III (augmented) internal coatings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, or lubricating oil	Loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage	Chapter XI.M42, “Service Level III (augmented) Coatings Monitoring and Maintenance Program”	No	VIII.A.S-401 VIII.B1.S-401 VIII.B2.S-401 VIII.C.S-401 VIII.D1.S-401 VIII.D2.S-401 VIII.E.S-401 VIII.F.S-401 VIII.G.S-401	N/A N/A N/A N/A N/A N/A N/A N/A N/A

APPENDIX B

MARK-UP SHOWING CHANGES TO THE GALL REPORT AMR ITEMS AND DEFINITIONS

V ENGINEERED SAFETY FEATURES							
Item	**Link**	**Structure and/or Component**	**Material**	**Environment**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)**	**Further Evaluation**
V.A.E-401 V.B.E-401 V.C.E-401 V.D1.E-401 V.D2.E-401		Piping, piping components, heat exchangers, tanks with Service Level III (augmented) internal coatings	Metallic with Service Level III (augmented) internal coating	Closed-cycle cooling water, raw water, treated water, treated borated water, or lubricating oil	Loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage	Chapter XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program"	No

APPENDIX B

MARK-UP SHOWING CHANGES TO THE GALL REPORT AMR ITEMS AND DEFINITIONS

VII AUXILIARY SYSTEMS							
Item	**Link**	**Structure and/or Component**	**Material**	**Environment**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)**	**Further Evaluation**
VII.A2.A-401 VII.A3.A-401 VII.A4.A-401 VII.C1.A-401 VII.C2.A-401 VII.C3.A-401 VII.D.A-401 VII.E1.A-401 VII.E2.A-401 VII.E3.A-401 VII.E4.A-401 VII.E5.A-401 VII.F1.A-401 VII.F2.A-401 VII.F3.A-401 VII.F4.A-401 VII.G.A-401 VII.H1.A-401 VII.H2.A-401		Piping, piping components, heat exchangers, tanks with Service Level III (augmented) internal coatings	Metallic with Service Level III (augmented) internal coating	Closed-cycle cooling water, raw water, treated water, treated borated water, waste water, lubricating oil, fuel oil	Loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage	Chapter XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program"	No

APPENDIX B

MARK-UP SHOWING CHANGES TO THE GALL REPORT AMR ITEMS AND DEFINITIONS

VIII STEAM AND POWER CONVERSION SYSTEMS							
Item	**Link**	**Structure and/or Component**	**Material**	**Environment**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)**	**Further Evaluation**
VIII.A.S-401 VIII.B1.S-401 VIII.B2.S-401 VIII.C.S-401 VIII.D1.S-401 VIII.D2.S-401 VIII.E.S-401 VIII.F.S-401 VIII.G.S-401		Piping, piping components, heat exchangers, tanks with Service Level III (augmented) internal coatings	Metallic with Service Level III (augmented) internal coating	Closed-cycle cooling water, raw water, treated water, treated borated water, or lubricating oil	Loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage	Chapter XI.M42, “Service Level III (augmented) Coatings Monitoring and Maintenance Program”	No

APPENDIX B

MARK-UP SHOWING CHANGES TO THE GALL REPORT AMR ITEMS AND DEFINITIONS

<table>
<tr><td>GALL Report Section</td><td>Term</td><td>Definition as used in this document</td></tr>
<tr><td>IX.C</td><td>Coating</td><td>Coatings include inorganic (e.g., zinc-based) or organic (e.g., elastomeric or polymeric) coatings, linings (e.g., rubber, cementitious), and concrete surfacers designed to adhere to a component to protect its surface. Service Level I and Service Level III (augmented) coatings are included.

Service Level I coatings are used in areas inside the reactor containment where coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown.

Service Level III (augmented) coatings include those:
• used in areas outside the reactor containment whose failure could adversely affect the safety function of a safety-related SSC, or
• applied to the internal surfaces of in-scope components and whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(3) (e.g., fire protection, station blackout).</td></tr>
<tr><td>IX.E</td><td>Flow blockage</td><td>Flow blockage is the reduction of flow or pressure, or both, in a component due to fouling, which can occur from an accumulation of debris such as particulate fouling (e.g., eroded coatings, corrosion products), biofouling, or macro fouling. Flow blockage can result in a reduction of heat transfer or the inability of a system to meet its intended safety function, or both. This definition is consistent with the definition of the term “pressure boundary” as found in SRP-LR Table 2.1-4(b), “Typical ‘Passive’ Component-Intended Functions.”</td></tr>
<tr><td colspan="3">The definition of the term “flow blockage” was added to the GALL Report by LR-ISG-2012-02, “Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation.” It is included here only for information.</td></tr>
</table>

APPENDIX B

MARK-UP SHOWING CHANGES TO THE GALL REPORT AMR ITEMS AND DEFINITIONS

GALL Report Section	Term	Definition as used in this document
IX.E	Loss of Coating Integrity	Loss of coating integrity is the disbondment of a coating from its substrate. For Service Level I and Service Level III (augmented) coatings, loss of coating integrity can be due to a variety of aging mechanisms such as blistering, cracking, flaking, peeling, or physical damage. Where the aging mechanism results in exposure of the base material, unanticipated or accelerated corrosion of the base material can occur. Where the aging mechanism results in the coating not remaining adhered to the substrate, the coating can become debris that could prevent an in-scope component from satisfactorily accomplishing any of its functions identified under 10 CFR 54.4(a)(1), (a)(2), or (a)(3) (e.g., reduction in flow, drop in pressure, reduction in heat transfer).
IX.F	Fouling	Fouling is an accumulation of deposits on the surface of a component or structure. This term includes accumulation and growth of aquatic organisms on a submerged metal surface or the accumulation of deposits (usually inorganic). Biofouling, a subset of fouling, can be caused by either macro-organisms (e.g., barnacles, Asian clams, zebra mussels, or others found in fresh and salt water) or micro-organisms (e.g., algae, microfouling tubercles). Fouling also can be categorized as particulate fouling (e.g., sediment, silt, dust, eroded coatings, and corrosion products), biofouling, or macrofouling (e.g., delaminated coatings, debris). Fouling in a raw water system can occur on the piping, valves, and heat exchangers. Fouling can result in a reduction of heat transfer, flow or pressure, or a loss of material.
The definition of “fouling” was revised by LR-ISG-2012-02. It is included here only for information.		

APPENDIX C

NEW PROGRAM: GALL REPORT AMP XI.M42 SERVICE LEVEL III (AUGMENTED) COATINGS MONITORING AND MAINTENANCE PROGRAM

XI.M42 Service Level III (augmented) Coatings Monitoring and Maintenance Program

Program Description

Proper maintenance of internal Service Level III (augmented) coatings is essential to ensure that the intended functions of in-scope components are met. Service Level III (augmented) coatings include coatings used in areas outside the reactor containment whose failure could adversely affect the safety function of a safety-related SSC, or those applied to the internal surfaces of in-scope components and whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(3) (e.g., fire protection, station blackout).

Degradation of coatings can lead to unanticipated or accelerated corrosion of base materials and downstream effects such as reduction in flow, reduction in pressure or reduction in heat transfer when coatings become debris. The program consists of periodic visual inspections of Service Level III (augmented) coatings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, fuel oil, and lubricating oil. Where the visual inspection of the coated surfaces determines that the coating is deficient or degraded, physical tests, where physically possible, are performed in conjunction with the visual inspection. EPRI Report 1019157, “Guidelines for Inspection and Maintenance of Safety-related Protective Coatings,” provides information on the ASTM standard guidelines and coatings.

Evaluation and Technical Basis

1. Scope of Program: The scope of the program is Service Level III (augmented) coatings installed inside of in-scope components exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, fuel oil, and lubricating oil. The aging effects associated with fire water storage tank internal coatings are managed by GALL Report AMP XI.M27, “Fire Water System,” instead of this AMP.

Coatings are an integral part of an in-scope component. The CLB-intended function(s) of the component that dictates whether the component has an intended function(s) that meets the scoping criteria of 10 CFR 54.4(a). Service Level III (augmented) coatings are not evaluated as stand-alone components to determine whether they meet the scoping criteria of 10 CFR 54.4(a). It is immaterial whether the coating has an intended function identified in the current licensing basis (CLB) because, again, it is the CLB-intended function of the component that dictates whether the component is in-scope and thereby the aging effects of the coating integral to the component must be evaluated for potential impact on the component and downstream component’s intended function(s).

An applicant may elect to manage the aging effects for Service Level III (augmented) coatings in an alternative AMP that is specific to the component or system in which the coatings are installed (e.g., GALL Report AMP XI.M20, “Open-Cycle Cooling Water System,” for service water coatings) as long as the following are met:

- The recommendations of this AMP are incorporated into the alternative program.
- Exceptions or enhancements associated with the recommendations in this AMP are included in the alternative AMP.
- The UFSAR supplement for this AMP as shown in SRP-LR Table 3.0-1, “FSAR Supplement for Aging Management of Applicable Systems,” is included in the application with a reference to the alternative AMP.

2. ***Preventive Actions:*** The program is a condition monitoring program and does not recommend any preventive actions.

3. ***Parameters Monitored/Inspected:*** Visual inspections are intended to identify coatings that do not meet acceptance criteria, such as peeling and delamination. The definition of these terms is included in Section 10.2 of ASTM D7167-12, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant." Physical testing is intended to identify potential delamination of the coating.

4. ***Detection of Aging Effects:*** Baseline Service Level III (augmented) coating inspections occur in the 10-year period prior to the period of extended operation. Subsequent inspections are based on an evaluation of the effect of a coating failure on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history. Subsequent inspection intervals are established by a coating specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 (hereinafter Revision 2 or later). However, inspection intervals should not exceed those in Table 4a, "Inspection Intervals for Service Level III (augmented) Coatings for Tanks, Piping, and Heat Exchangers."

Table 4a. Inspection Intervals for Service Level III (augmented) Coatings for Tanks, Piping, and Heat Exchangers[1, 6]

Inspection Category[2]	Inspection Interval
A	6 years[3]
B[4,5]	4 years
C[5]	Inspections occur during the next 2 refueling outage intervals.

1. Current licensing basis requirements (e.g., Generic Letter 89-13) might require more frequent inspections.
2. Inspection Categories
   A. No peeling, delamination, blisters, or rusting are observed during inspections. Any cracking and flaking has been found acceptable in accordance with the "acceptance criteria" program element of this AMP. No cracking or spalling in cementitious coatings.
   B. Prior inspection results do not meet category A; however, a coating specialist determined that no remediation is required.
   C. Newly installed coatings or coatings that have been repaired or replaced.
3. If the following conditions are met, the inspection interval may be extended to 12 years:
   a. The identical coating material was installed with the same installation requirements in redundant trains (e.g., piping segments, tanks) with the same operating conditions and at least one of the trains is inspected every 6 years.

Table 4a. Inspection Intervals for Service Level III (augmented) Coatings for Tanks, Piping, and Heat Exchangers[1, 6]
b. The coating is not in a location subject to turbulence. Turbulent locations are those where fluid flow is such that the velocity at a given point varies erratically in magnitude and direction and mechanical damage to coatings can occur (e.g., heat exchanger end bells, piping downstream of certain control valves). 4. Specific locations that resulted in subsequent inspections being conducted to Inspection Category B or C are re-inspected as well as new locations. 5. When conducting inspections to Inspection Category B, if two sequential subsequent inspections demonstrate no change in coating condition, subsequent inspections may be conducted at six-year intervals. 6. Internal inspection intervals for diesel fuel oil storage tanks may meet either Table 4a, or if the inspection results meet Inspection Category A, GALL Report AMP XI.M30.

The extent of inspections is based on an evaluation of the effect of a coating failure on the in-scope component's intended function(s), potential problems identified during prior inspections, and known service life history; however, the extent of inspection is not any less than the following for each coating material and environment combination. The coating environment includes both the environment inside the component and the metal to which the coating is attached. Inspection locations are selected based on susceptibility to degradation and consequences of failure.

- Tanks – all accessible internal surfaces
- Heat exchangers – all accessible internal surfaces
- Piping – either inspect a representative 73 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination. The inspection surface includes the entire inside surface of the 1-foot sample. If geometric limitations impede movement of remote or robotic inspection tools, the number of inspection segments is increased in order to cover an equivalent of 73 1-foot axial length sections. For example, if the remote tool can only be maneuvered to view one-third of the inside surface, 219 feet of pipe is inspected.

Coating surfaces captured between interlocking surfaces (e.g., flanges) are not required to be inspected unless the joint has been disassembled to allow access for an internal coating inspection or other reasons. For areas not readily accessible for direct inspection, such as small pipelines, heat exchangers, and other equipment, consideration is given to the use of remote or robotic inspection tools.

The above recommendations for inspection of coatings may be omitted if the degradation of coatings cannot result in downstream effects such as reduction in flow, drop in pressure, or reduction in heat transfer for in-scope components. However, the recommendations for inspections are met if corrosion rates or inspection intervals have been based on the integrity of the coatings. In this case, loss of coating integrity could result in unanticipated or accelerated corrosion rates of the base metal. Alternatively, if corrosion of the base material is the only issue related to coating degradation of the component, external wall thickness measurements can be performed to confirm the acceptability of the corrosion rate of the base metal.

The training and qualification of individuals involved in coating inspections and evaluating degraded conditions is conducted in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with a particular standard.

5. ***Monitoring and Trending:*** A pre-inspection review of the previous two inspections is conducted that includes reviewing the results of inspections and any subsequent repair activities. A coatings specialist prepares the post-inspection report to include: a list and location of all areas evidencing deterioration, a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage, and where possible, photographic documentation indexed to inspection locations. When corrosion of the base material is the only issue related to coating degradation of the component and external wall thickness measurements are used in lieu of internal visual inspections of the coating, the corrosion rate of the base metal is trended.

6. ***Acceptance Criteria:*** Acceptance criteria are as follows:

   a. Indications of peeling and delamination are not acceptable and the coatings are repaired or replaced. For coated surfaces that show evidence of delamination or peeling, physical testing is performed where physically possible (i.e., sufficient room to conduct testing). The test consists of destructive or nondestructive adhesion testing using ASTM International standards endorsed in RG 1.54. A minimum of three sample points adjacent to the defective area are tested.

   b. Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard. The cause of blisters needs to be determined if the blister is not repaired. Physical testing is conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface. If coatings are credited for corrosion prevention, the component's base material in the vicinity of the blister is inspected to determine if unanticipated corrosion has occurred.

   c. Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard.

   d. Minor cracking and spalling of cementitious coatings is acceptable provided there is no evidence that the coating is debonding from the base material.

   e. As applicable, wall thickness measurements meet design minimum wall requirements.

   f. Adhesion testing results meet or exceed the degree of adhesion recommended in engineering documents specific to the coating and substrate.

7. ***Corrective Actions:*** Coatings that do not meet acceptance criteria are repaired or replaced. The site corrective actions program, quality assurance procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the Appendix for GALL, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

8. ***Confirmation Process:*** As discussed in the Appendix for GALL, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** As discussed in the Appendix for GALL, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

10. ***Operating Experience*:** The inspection techniques and training of inspection personnel associated with this program are consistent with industry practice and have been demonstrated effective at detecting loss of coating integrity. Not-to-exceed inspection intervals have been established that are dependent on the results of previous plant-specific inspection results. The following examples describe operating experience pertaining to loss of coating integrity for coatings installed on the internal surfaces of piping systems:

    a. In 1982, a licensee experienced degradation of internal coatings in its spray pond piping system. This issue contains many key aspects related to coating degradation. These include installation details such as improper curing time, restricted availability of air flow leading to improper curing, installation layers that were too thick, and improper surface preparation (e.g., oils on surface, surface too smooth). The aging effects included severe blistering, moisture entrapment between layers of the coating, delamination, peeling, and widespread rusting. The failure to install the coatings to manufacturer recommendations resulted in flow restrictions to the ultimate heat sink and blockage of an emergency diesel generator governor oil cooler.

    b. During an LRA AMP audit, the staff found that coating degradation, which occurred as a result of weakening of the adhesive bond of the coating to the base metal due to turbulent flow, resulted in the coating eroding away and leaving the base metal subject to aggressive erosion/corrosion.

    c. In 1994, a licensee replaced a portion of its cement-lined steel service water piping with piping lined with a common PVC polymeric material. The manufacturer stated that the lining material had an expected life of 15-20 years. An inspection in 1997 showed some bubbles and delamination in the coating material at a flange. A 2002 inspection found some locations that had lack of adhesion to the base metal. In 2011, diminished flow was observed downstream of this line. Inspections revealed that a majority of the lining in one piping segment was loose or missing. The missing material had clogged a downstream orifice. Subsequent inspections in 2011 resulted in no further evidence of delamination; however, localized areas showed bubbles and small waves in the liner material. A sample of the lining was sent to a testing lab where it was determined that cracking was evident on both the base metal and water side of the lining and there was a noticeable increase in the hardness of the in-service sample as compared to an unused sample.

    d. A licensee has experienced multiple instances of coating degradation resulting in coating debris found downstream in heat exchanger end bells. To date, none of the debris has been large enough to result in reduced heat exchanger performance; however, in an out-of-scope system, coating degradation resulted in blocked tubes in a heat exchanger. This licensee also found polymeric coating debris downstream of a valve in its essential cooling water system.

e. A licensee experienced continuing flow reduction over a 14-day period, resulting in the service water room cooler being declared inoperable. The flow reduction occurred due to the rubber coating on a butterfly valve becoming detached.

f. At an international plant, cavitation in the piping system damaged the coating of a piping system which subsequently resulted in unanticipated corrosion through the pipe wall.

g. A licensee experienced degradation of the protective concrete lining which allowed brackish water to contact the unprotected carbon steel piping resulting in localized corrosion. The degradation of the concrete lining was likely caused by the high flow velocities and turbulence from the valve located just upstream of the degraded area.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2009.

ASTM D4538-05, Standard Terminology Relating to Protective Coating and Lining Work for Power Generation Facilities.

ASTM D7167-12, Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant.

EPRI Report 1019157, *Guideline on Nuclear Safety-Related Coatings*, Revision 2, (Formerly TR-109937 and 1003102), Electric Power Research Institute, December 2009.

NRC Regulatory Guide 1.54, Rev. 2, *Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, October 2010.

U.S. Nuclear Regulatory Commission, NRC Information Notice 85-24, Failures of Protective Coatings in Pipes and Heat Exchangers, March 26, 1985.

APPENDIX D

CHANGES TO THE "SCOPE OF PROGRAM" PROGRAM ELEMENT OF POTENTIAL ALTERNATIVE AMPS

The text below will be added to Program Element 1, "scope of program," for the following AMPs as a new paragraph following the existing paragraph(s):

- GALL Report AMP XI.M20, "Open-Cycle Cooling Water System"
- GALL Report AMP XI.M21A, "Closed Treated Water Systems"
- GALL Report AMP XI.M24, "Compressed Air Monitoring"
- GALL Report AMP XI.M27, "Fire Water System"
- GALL Report AMP XI.M29, "Aboveground Metallic Tanks"
- GALL Report AMP XI.M30, "Fuel Oil Chemistry"
- GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"

This program may be used to manage the aging effects for Service Level III (augmented) coatings that are applied to the internal surfaces of components included in the scope of this program as long as the following are met:

- The recommendations of GALL Report AMP XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program," are incorporated into this AMP.
- Exceptions or enhancements associated with the recommendations in GALL Report AMP XI.M42 are included in this AMP.
- The UFSAR supplement for GALL Report AMP XI.M42, as shown in SRP-LR Table 3.0-1, "FSAR Supplement for Aging Management of Applicable Systems," is included in the application with a reference to this AMP.

APPENDIX E

RESOLUTION OF PUBLIC COMMENTS

Note: The Nuclear Energy Institute (NEI) submitted comments related to LR-ISG-2012-02 by letter dated June 14, 2013 (ADAMS Accession No. ML13168A397), which integrated multiple industry comments on the subject LR-ISG. NEI provided three attachments in its letter:

- Attachment 1, “LR-ISG-2012-02 Significant Industry Comments and Considerations”
- Attachment 2, “Detailed Industry Comments”
- Attachment 3, “Supplemental Details”

The text of Attachments 1 and 3 are not included in this Appendix as the specific details and NRC resolution of comments is covered below in the table.

As requested by the staff, NEI provided input related to the potential to split the LR-ISG into multiple parts. The industry requested that the portion of the LR-ISG addressing Service Level III (augmented) coatings be removed from LR-ISG-2012-02, “Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,” and addressed in a new LR-ISG. The industry request stated that this would allow for further discussion on the recommendations associated with Service Level III (augmented) coatings, while progressing with issuance of LR-ISG-2012-02. The staff agreed with this change. Industry comments as originally submitted for the review of draft LR-ISG-2012-02 (i.e., numbered 5, 6, and 74 through 81) related to Service Level III (augmented) coatings are addressed below. The staff’s resolution of these comments is provided for information for those individuals reviewing this draft LR-ISG for comment. It should be noted that in LR-ISG-2012-02, the term “Other” was used in place of Service Level III (augmented).

#	Comment	Staff Resolution
5	If coatings are treated as a non-safety related SSC, it would seem that inclusion of Service Level III coatings or other coatings on the basis that the loss of the coating could "prevent an in-scope component from satisfactorily accomplishing any of its functions identified under 10 CFR 54.4(a)(1), (a)(2), or (a)(3)" would appear to be an expansion of the non-safety affecting safety license renewal scoping criterion. However, if coatings are treated as a part of a "piping component," does this ISG imply all coatings that could prevent satisfactorily accomplishing a 10 CFR 54.4(a)(1), (a)(2), or (a)(3) function are in-scope or only those coatings associated with in-scope piping? For example, if a backup demineralized water tank is not the credited source in a plant's CLB for SBO event, then is the tank in-scope simply because a coating failure could prevent the SBO intended function from being performed? 10 CFR 54.4(a)(2) states that all non-safety related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in Section 54.4(a)(1) should be included within the scope of the Rule. It does not include subject non-safety related (NSR) components that could prevent satisfactorily accomplishment of functions identified under 54.4(a)(2) or (a)(3). As an analogy, a NSR pipe which is located in the same room or space as a functional (a)(2) or (a)(3) equipment failure has a potential to cause spatial interaction that could prevent their accomplishment of an intended function; however, such NSR piping, if located in a space or room that only contains functional (a)(2) or (a)(3) equipment, is not required to be in the scope of license renewal following the guidance in NEI 95-10 Appendix F, while coatings as proposed under this ISG would be in-scope.	The staff does not agree with this comment, although the LR-ISG was revised to clarify the staff’s intent. The staff does not consider a coating to be an SSC. A coating is an integral part of an in-scope component, providing it protection from corrosion, whether credited for that protection or not. The basis for this statement has been included in LR-ISG section V.b. Because coatings are an integral part of a component, it is the function(s) of the component that dictates whether it has an intended function(s) that meets the scoping criteria of 10 CFR 54.4(a). Service Level III (augmented) coatings are not evaluated as stand-alone components to determine whether they meet the scoping criteria of 10 CFR 54.4(a). The staff has clarified the LR-ISG wording to more clearly communicate that the subject coatings are those applied to the inside surfaces of in-scope components. For example, a phrase in GALL Report AMP XI.M42 was revised as follows, “[s]ervice Level IV coatings include those <u>applied to the internal surfaces of in-scope components and</u> whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(3).” Therefore, in response to the example in the first paragraph of the comment, if the backup demineralized water tank is not the credited source in a plant's CLB for a SBO event, the coatings installed inside that tank would not be in-scope.

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#	Comment	Staff Resolution
6	ISG states "Visual inspection will be conducted on all coatings that could affect a license renewal function". Delete the word "all" or revise the statement as follows. "Visual inspection will be conducted on ~~all~~ coatings as noted in the AMP that could affect a license renewal function". This is a significant burden on the plant if 100% visual inspection is required as opposed to sampling methodology that takes into account worst case locations, highest flow, highest risk consequence, etc. Revise this bullet consistent with proposed changes to AMP XI.M42.	The staff agrees with this comment in part. For tanks and heat exchangers, the staff has concluded that all accessible surfaces should be inspected, and therefore the staff has not proposed a change to the LR-ISG for these components. However, for piping, GALL Report AMP XI.M42 was revised to recommend a sample size sufficient to establish reasonable assurance that current licensing basis intended function(s) of internally coated in-scope components would be met during the period of extended operation.
74	AMP XI.M42 Program Description In the 11th line of the program description, the comma should go after the word "degraded" and not "deficient".	The Program Description was editorially corrected as requested.

#	Comment	Staff Resolution
75	AMP XI.M42 Exclude fuel oil tank coatings from the scope of AMP XI.M42. Coatings used in fuel oil tanks (such as epoxies) are inspected during the tank cleaning and inspection recommended by AMP XI.M30. These coatings are not exposed to high fluid velocities, and a search of recent industry OE did not identify any recent fuel oil tank coating/lining degradation that resulted in downstream effects such as reduction of flow, reduction in pressure or reduction of heat transfer. EPRI 1019157 (Guideline on Nuclear Safety Related Coatings) recommends assessment of fuel oil tank coatings every ten years due to the reliability of these coatings. In addition ten years is also the frequency of the diesel fuel oil tank cleaning cycle noted in Regulatory Guide 1.137.	The staff does not agree with this comment, although a new footnote was added to Table 4a as described below. The staff noted the following: • Regulatory Guide 1.137, "Fuel-Oil Systems for Standby Diesel Generators," states, "[a]s a minimum, the fuel oil stored in the supply tanks should be removed, the accumulated sediment removed, the tanks cleaned, and the interior inspected at 10-year intervals." • EPRI 1019157, Table 8-1, "Condition assessment applications and frequency," does recommend that the coatings on each diesel fuel oil storage tank be inspected every ten years. • GALL Report AMP XI.M30, "Fuel Oil Chemistry," recommends that tank internal inspections be conducted at least once during the 10-year period prior to the period of extended operation and once during each 10-year period of the period of extended operation. AMP XI.M30 does not have recommendations related to coating inspections and therefore the staff concludes that fuel oil tank coatings should not be removed from the scope of AMP XI.M42. During AMP audits, the staff has noted degraded internal fuel oil storage tank coatings during its search of plant-specific operating experience. These degraded coatings could continue to degrade to the point where an intended function could be lost. In conjunction with other changes, Table 4a., "Inspection Intervals for Service Level III (augmented) Coatings for Tanks, Piping, and Heat Exchangers," states that for inspection Category A, (i.e., "[n]o peeling, delamination, blisters, or rusting are observed. Any cracking and flaking has been found acceptable in accordance with the 'acceptance criteria' program element of this AMP.)" inspections can occur on six-year intervals. These inspection intervals can be extended to 12 years if inspection Category A is met and if the identical coating material was installed with the same installation requirements in redundant trains (e.g., piping segments, tanks) with the same operating conditions, as long as at least one of the trains is inspected every 6 years. Therefore, if the tank's internal coatings are not degraded and there is a redundant fuel oil storage tank, the LR-ISG recommends an inspection interval that exceeds the 10 years recommended in the Regulatory Guide and EPRI document. However, if degraded coatings are observed, more frequent inspections are warranted. In order to address plants with only one fuel oil storage tank, a new footnote to Table 4a was added to align the internal inspection interval to AMP XI.M30 and Regulatory Guide 1.137 frequency as long as the inspection results meet Inspection Category A criteria.

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#	Comment	Staff Resolution
76	AMP XI.M42 Element 2 In element 2, delete "However, for plants that credit coatings to minimize loss of material, this program is a preventive action." For such cases, the coating is a preventive measure, but the program does not include preventing actions… it remains a condition monitoring program.	The staff agrees with this comment. The statement was deleted.
77	AMP XI.M42 Element 4 Delete the third and fourth paragraph after the notes in element 4. Revise the acceptance criteria to state that peeling or delaminations are repaired or replaced. Additional measures for coatings not meeting acceptance criteria need to be identified in element 6 or 7. Adhesion tests referenced in RG 1.54 are potentially destructive and provide no compensatory considerations/allowances for wetted surface coatings that are in service.	The staff agrees in part with this comment. The paragraph on peeling and laminations was relocated to the "acceptance criteria" program element and integrated into the paragraphs related to peeling or delamination and blistering. The staff does not agree with the comment on adhesion testing. The staff has concluded that it is appropriate to perform testing to demonstrate proper adhesion, when physically possible, because peeling, delamination, and blistering can result in the release of large portions of coating that could significantly impact flow, pressure, and heat transfer in downstream components.
78	AMP XI.M42, Element 4 "Other" coatings do not meet the scoping criteria as defined in 10 CFR 54.4 and should be deleted from this ISG. Due to its size, the discussion for deletion of "other" coatings is available in Attachment 3 Section 1.0.	See the response to Comment No. 5.
79	AMP XI.M42 program description element 4 Recommend the following changes to AMP XI.42:1. In the program description delete the following parenthetical expression in the first sentence of the program description. (as defined in RG 1.54, "Service Level I, II, III Protective Coatings Applied to Nuclear Plants," Revision 2 or latest version). 2. Insert the definition of Service Level III (SL3) coatings as the second sentence of the program description. 3. In element 4 in the second paragraph after Table 4a notes, delete the reference to RG 1.54 and list the applicable ASTM International Standards. The intent of the reference to RG 1.54 in the program description was to point to a definition for SL3 coatings. Including the definition of SL3 coatings would be more appropriate. As written, the program description could be interpreted to mean that maintenance of SL3 coatings that is described in this AMP and that maintenance is consistent with RG 1.54. To avoid misunderstanding or possible AMP exceptions, the ASTM standards that are endorsed for adhesion testing should be identified in the AMP without reference to RG 1.54.	The staff agrees with the first part of this comment regarding inserting the definition of Service Level III coatings into the Program Description and deleting the reference to Regulatory Guide 1.54. The staff does not agree with the change to Program Element 4. Referring to the Regulatory Guide for appropriate ASTM standards related to adhesion testing allows the adoption of future ASTM standards to be used in the program when the Regulatory Guide is updated.

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#	Comment	Staff Resolution
80	AMP XI.M42 Element 4 Provide a sample population for coating inspections. A 100% inspection of all internally coated piping on a two year frequency for plants with a large population of coated components can be a large undertaking. In addition, remote technology might not be readily available for long lengths of internally coated buried pipe or drain piping embedded in concrete. A 100% inspection is neither warranted (at least for some coatings) nor practical. Some buried fire protection piping is cement lined, and performs very well over very long time frames. However, inspection is extraordinarily onerous, unlikely to identify degradation, but may actually increase the potential for degradation, where excavation is necessary to gain access to the piping internal surfaces.	The staff agrees with this comment. Based on the staff's evaluation of OE, the "detection of aging effects" program element was revised to include inspection intervals based on inspection results, most which exceed two years. In addition, the program element extent of inspection was revised for piping segments to be sampling based.
81	App. H Element 4 Delete the fourth paragraph after the notes in element 4 about determining corrosion rates and performing external wall thickness measurements. External wall thickness measurements should not be required by the coatings program. Loss of material on the internal surfaces of mechanical fluid systems within the scope of license renewal is managed by other AMPs noted in GALL. Unless identified by the CLB, corrosion rates and inspection intervals for loss of material should not be included in a coatings AMP.	The staff does not agree with this comment. The provision addresses alternatives to coating inspections. In some cases, as defined by the alternative, wall thickness measurements are appropriate. The applicant does not have to implement the wall thickness measurements if it conducts the coatings inspections.