TURKEY POINT NUCLEAR GENERATING UNITS 3 AND 4 (TURKEY POINT)
SUBSEQUENT LICENSE RENEWAL APPLICATION (SLRA)
REQUESTS FOR ADDITIONAL INFORMATION (RAIS)
SAFETY - SET 1

1. No Aging Effects – Mechanical Components

Regulatory Basis:

Section 54.21(a)(3) of Title 10 of the *Code of Federal Regulation* (10 CFR) requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR § 54.29(a)) is that actions have been identified and have been or will be taken with respect to the managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB). As described in the SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing NUREG-2191, Rev. 0, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," dated July 2017. In order to complete its review and enable making a finding under 10 CFR § 54.29(a), the staff requires additional information in regard to the matters described below.

RAI # 3.1.2.2.15-1

Background:

SLRA Section 3.1.2.2.15, associated with SLRA Table 3.1.1, items 3.1.1-105 and 3.1.1-115, states that:

> There are no reactor coolant system stainless steel or steel piping or piping components, within the scope of subsequent license renewal, exposed to concrete at Turkey Point. Where reactor coolant system piping is required to penetrate concrete, penetration sleeves are used. This is addressed further in Section 3.5.

NUREG-2192, Rev. 0, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants" (SRP-SLR), dated July 2017 (SRP-SLR), Section 3.1.2.2.15 states that there are three conditions associated with determining that there are no aging effects for steel piping exposed to concrete:

> (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater.

SLRA Section 3.3.2.2.9 documents that, "[t]he concrete at Turkey Point is designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards."

SRP-SLR Section 3.1.2.2.15 states that there is one condition associated with determining that there are no aging effects for stainless steel piping exposed to concrete, that being, the piping is not potentially exposed to groundwater.

Issue:

For steel piping the response to SLRA Section 3.3.2.2.9 does not provide the results of a search of plant-specific OE demonstrating that there are no instances where degradation of the concrete that could lead to penetration of water to the metal surface occurred. However, SLRA Table 3.3-1, aging management review (AMR) item 3.31-112 states, "A review of OE [operating experience] for Turkey Point indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface…"

For both stainless steel and steel piping, the response to SLRA Section 3.3.2.2.9 does not state whether the piping could be exposed to groundwater.

There does not appear to be any further discussion of reactor coolant piping penetrating concrete through penetration sleeves. The discussions related to sleeves in Section 3.5 are associated with containment penetrations and the associated time limiting aging analyses.

Request:

Address criterion (b) and (c) for steel piping, noting that criterion (b) addresses any type of water penetrating through the concrete and criterion and (c) specifically addresses groundwater. State whether the stainless steel piping could be exposed to groundwater.

RAI # 3.3.2.1.4-1

Background:

SLRA AMR items 3.3.1-114 and 3.4.1-054 state that copper alloy piping and piping components exposed to air, condensation, or gas have no aging effects requiring management.

Several SLRA Table 2 AMR items, associated with AMR items 3.3.1-114 and 3.4.1-054, cite copper alloy greater than 15 percent zinc components exposed to air-dry, air-indoor controlled, air-indoor uncontrolled, air-outdoor, condensation, and gas as having no aging effects requiring management.

For these copper alloy greater than 15 percent zinc components: (a) one of these AMR items (SLRA Table 3.3.2-4), associated with gas as the environment, plant-specific note 2 states that the piping component is wetted; and (b) for two of these AMR items (SLRA Table 3.3.2-16), the component is identified as heat exchanger tubes.

GALL-SLR AMR items S-454 and S-455 recommend that cracking due to stress corrosion cracking (SCC) be managed for copper alloy greater than 15 percent zinc piping, piping components, and tanks exposed to air or condensation.

Issue:

SRP-SLR AMR items 3.3.1-114 and 3.4.1-054 are only applicable to copper alloy components, not copper alloy greater than 15 percent zinc components. No basis was provided for why cracking is not an applicable aging effect for copper alloy greater than 15 percent zinc component exposed to air-dry, air-indoor controlled, air-indoor uncontrolled, air-outdoor, or condensation.

Although the GALL-SLR Report does not address copper alloy greater than 15 percent zinc components exposed to gas, it would not be expected that cracking would occur in this environment due to the unlikely presence of ammonia-based compounds in the gas. However, the staff lacks sufficient information to come to this conclusion due to the potential for the piping component to be wetted.

It is unclear how cracking will be managed for heat exchanger tubes due to the inaccessibility of the internal and external surfaces for inspection types cited in the SLRA aging management programs (AMPs) (e.g., Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, External Surfaces Monitoring of Mechanical Components program).

Request:

a) State the basis for why cracking is not an applicable aging effect for copper alloy greater than 15 percent zinc components exposed to air-dry, air-indoor controlled, air-indoor uncontrolled, air-outdoor, or condensation.
b) State the basis for why the source of the moisture that wets the surface of the piping component exposed to gas in SLRA Table 3.3.2-4 will not induce cracking.

If cracking needs to be managed for the heat exchanger tubes, state the inspection method(s) that will be used and the applicable AMP.

RAI 3.3.2.2.9-1

Background:

SLRA Section 3.3.2.2.9 states:

> The stainless steel components are above groundwater and, therefore, do not require management as detailed above. A review of OE [operating experience] for Turkey Point indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting, and crevice corrosion of steel piping and tanks exposed to concrete is an aging effect that requires management.

> Consistent with the recommendation of GALL-SLR, the Buried and Underground Piping and Tanks AMP is used to manage loss of material in steel piping exposed to concrete. This AMP provides for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability.

SLRA Table 3.3-1, AMR item 3.3.1-202 states, "[c]onsistent with NUREG-2191. A review of Turkey Point OE [operating experience] confirms no degradation of concrete that would allow exposure of embedded portions of stainless steel piping or piping components to groundwater; there are no aging effects to manage."

SLRA Table 3.3-1, AMR item 3.3.1-112 states that it is not used. It also states, "[a] review of OE [operating experience] for Turkey Point indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting, and crevice corrosion of steel piping and tanks exposed to concrete is an aging effect that requires management."

Issue:

Depending on where the stainless steel components are located, rainwater could penetrate degraded concrete and come in contact with the stainless steel components as it proceeds through the soil to the water table.

The statements in SLRA Section 3.3.2.2.9, SLRA Table 3.3-1, AMR item 3.3.1-112, and SLRA Table 3.3-1, AMR item 3.3.1-202 appear to be inconsistent in regard to the review of plant-specific operating experience associated with degraded concrete.

SLRA Table 3.3-1, AMR item 3.3.1-112 states that it is not used and SLRA Section 3.3.2.2.9 states that the Buried and Underground Piping and Tanks AMP will be used to manage loss of material in steel piping exposed to concrete. However, a review of the SLRA Table 2s associated with SLRA Section 3.3, reveals that there are no carbon steel AMR items exposed to concrete. It is unclear how loss of material steel components exposed to concrete will be managed by the Buried and Underground Piping and Tanks program when there are no corresponding Table 2 items.

Request:

1. Describe the location of the stainless steel components embedded in concrete (e.g., inside a building). State whether the concrete surrounding the stainless steel components is susceptible to penetration by rainwater as it proceeds through the soil to the water table.

2. Clarify the possible inconsistency between SLRA Section 3.3.2.2.9 and SLRA Table 3.3-1, AMR item 3.3.1-112, regarding plant-specific operating experience associated with degraded concrete. If the basis of the statements is that there are instances of plant-specific operating experience revealing that concrete degradation has occurred in the vicinity of carbon steel embedded in concrete but not stainless steel embedded in concrete, state the basis of why concrete degradation will not occur in the future for stainless steel components embedded in concrete.

3. State which AMR items will be used to manage loss of material for steel piping exposed to concrete.

2. SS Nickel Alloy Aluminum Alloy Further Evaluations

Regulatory Basis:

Section 54.21(a)(3) of 10 CFR requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR § 54.29(a)) is that actions have been identified and have been or will be taken with respect to the managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB). As described in the SRP-LR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL Report. In order to complete its review and enable making a finding under 10 CFR § 54.29(a), the staff requires additional information in regard to the matters described below.

RAI 3.2.2.2.2-1

Background:

Table 3.2.2.2.2-1, below, is a compilation of several SLRA Table 2 entries including the SLRA Table 2 number, system, component type, intended function, material, environment, aging effect requiring management (AERM), SLRA aging management program (AMP), and SLRA Table 1 number.

Issue:

For the SLRA Table 2 entries in the Table 3.2.2.2.2-1, below, the staff lacks sufficient information to conclude that the cited AMP will be capable of detecting aging effects as follows. For the:

1. Heat exchanger internals (SLRA Table 3.3.2-9), the extent of accessible internal surfaces of the heat exchanger available for inspection is not known.
2. Heat exchanger fins (SLRA Tables 3.3.2-12, 3.3.2-14, and 3.3.2-16), it is not clear how the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components will be effective at detecting loss of material and cracking in the heat exchanger fins exposed to an external air environment unless the heat exchanger is located within ducting.
3. Heat exchanger head/tubesheet (SLRA Table 3.2.2-6) and heat exchanger tubesheet (SLRA Table 3.2.2-5), it is not clear whether the internal side of the tubes are exposed to the air-indoor uncontrolled environment and treated water/treated borated water/treated borated water greater than 140 degrees is on the shell side of the heat exchanger tubes

or vice versa. If the shell side of the tubes are exposed to the air-indoor uncontrolled environment, it is not clear how the External Surfaces Monitoring of Mechanical Components program will be effective at detecting loss of material and cracking.

4. Heat exchanger housing (SLRA Table 3.3.2-16), the extent of accessible internal surfaces of the heat exchanger available for inspection is not known.
5. Heat exchanger tubes (SLRA Tables 3.3.2-10 and 3.3.2-11), it is not clear how the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program: (a) will detect cracking or loss of material on the external surfaces of the tubes unless the heat exchanger is located within ducting, and (b) will detect aging effects on heat exchanger tubes within the tube bundle and for those surfaces of the outer tubes that are not directly exposed to view. SLRA Section B.2.3.25, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," states that the program will use visual inspections and when appropriate, surface examinations. Absent inspection techniques such as eddy current, the staff is not aware of visual or surface examination techniques that will detect loss of material or cracking (to anything more than a limited extent) in heat exchanger tubes.
6. Strainer element (SLRA Table 3.2.2-5), it is not clear how the External Surfaces Monitoring of Mechanical Components program will detect loss of material and cracking on strainer elements versus the strainer body.

<u>Request</u>:

1. State the extent of the internal surfaces of the heat exchanger that will be accessible for internal inspections and the basis for why the extent of inspections will be adequate to detect cracking and loss of material for stainless steel heat exchangers exposed to outdoor air (internal).
2. State the basis for why the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is adequate to detect aging effects on the external surfaces of the heat exchanger fins.
3. Clarify the configuration of the heat exchangers (i.e., state which fluid flows through the internal side of the tube and the shell side of the tube). If the shell side of the tubes are exposed to the air-indoor uncontrolled environment, state how the External Surfaces Monitoring of Mechanical Components will be effective at detecting loss of material and cracking on the heat exchanger head and tube sheet.
4. State the extent of the internal surfaces of the heat exchanger housing that will be accessible for internal inspections and the basis for why the extent of inspections will be adequate to detect cracking and loss of material of stainless steel heat exchanger housings exposed to outdoor air (internal).
5. State what inspection techniques will be used to detect loss of material and cracking in the heat exchanger tubes and the basis for the effectiveness of the technique when heat exchanger tubes are inspected as part of the representative sample.
6. State the basis for why the External Surfaces Monitoring of Mechanical Components program is adequate to detect aging effects on the external surfaces of the strainer elements.

Table 3.2.2.2.2-1								
SLRA Table 2	**System**	**Component Type**	**Intended Function**	**Material**	**Environment**	**AERM**	**SLRA AMP**	**LRA Table 1**
3.3.2-9	Plant Air	Heat exchanger	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 004
3.3.2-12	Control Building Ventilation	Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 242
3.3.2-14	Turbine Building Ventilation	Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 242
3.3.2-16	Emergency Diesel Generator Cooling Water	Heat exchanger (fins)	Heat transfer	Aluminum	Air – outdoor (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 242
3.3.2-12	Control Building Ventilation	Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 254
3.3.2-14	Turbine Building Ventilation	Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 254
3.3.2-16	Emergency Diesel Generator Cooling Water	Heat exchanger (fins)	Heat transfer	Aluminum	Air – outdoor (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 254
3.2.2-6	Containment Post Accident Monitoring and Control	Heat exchanger (head/ tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	3.2-1, 004
3.2.2-6	Containment Post Accident Monitoring and Control	Heat exchanger (head/ tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	3.2-1, 007

Table 3.2.2.2.2-1								
SLRA Table 2	**System**	**Component Type**	**Intended Function**	**Material**	**Environment**	**AERM**	**SLRA AMP**	**LRA Table 1**
3.3.2-16	Emergency Diesel Generator Cooling Water	Heat exchanger (housing)	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 004
3.3.2-16	Emergency Diesel Generator Cooling Water	Heat exchanger (housing)	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 006
3.3.2-11	Auxiliary Building and Electrical Equipment Room Ventilation	Heat exchanger (tubes)	Leakage Boundary (Spatial)	Stainless steel	Condensation (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 004
3.3.2-10	Normal Containment Ventilation	Heat exchanger (tubes)	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 004
3.3.2-11	Auxiliary Building and Electrical Equipment Room Ventilation	Heat exchanger (tubes)	Leakage Boundary (Spatial)	Stainless steel	Condensation (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 241
3.3.2-10	Normal Containment Ventilation	Heat exchanger (tubes)	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 241
3.2.2-5	Residual Heat Removal	Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	3.2-1, 004

Table 3.2.2.2.2-1								
SLRA Table 2	**System**	**Component Type**	**Intended Function**	**Material**	**Environment**	**AERM**	**SLRA AMP**	**LRA Table 1**
3.2.2-5	Residual Heat Removal	Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	3.2-1, 007
3.2.2-5	Residual Heat Removal	Strainer element	Filter	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	3.2-1, 004
3.2.2-5	Residual Heat Removal	Strainer element	Filter	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	3.2-1, 007

RAI 3.3.2.2.3-1

Background:

SLRA Table 3.3-1, items 3.3.1-146 and 3.3.1-246 states that, "[t]he stainless steel underground piping in the Auxiliary Systems is managed using other line items."

Issue:

Based on a search of the SLRA auxiliary system Table 2s, no stainless steel piping or piping components are identified as being exposed to an underground environment. It is not clear to the staff whether there are missing stainless steel items in the auxiliary system Table 2s, or the statement associated with items 3.3.1-146 and 3.3.1-246 is in error.

Request:

State whether the statement associated with items 3.3.1-146 and 3.3.1-246 is in error or identify the AMR items that are missing from the auxiliary system Table 2s.

3. Internal Coatings / Lining

Regulatory Basis:

Section 54.21(a)(3) of 10 CFR requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR § 54.29(a)) is that actions have been identified and have been or will be taken with respect to the managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB). As described in the SRP-LR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL Report. In order to complete its review and enable making a finding under 10 CFR § 54.29(a), the staff requires additional information in regard to the matters described below.

RAI B.2.3.29-1

Background:

SLRA Section B.2.3.29 states that in regard to:

1. The scope of the program:

   This AMP is a condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, treated borated water, waste water, lubricating oil or fuel oil that can lead to loss of material of base materials and downstream effects such as reduction in

flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris.

2. The detection of aging effects, "[f]or cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces."
3. Acceptance criteria, "[a]ctive peeling and delamination are not acceptable." It also states, "[t]here are no active and/or significant indications of peeling or delamination."

SLRA Section 17.2.22.9 states:

4. Similarly to item 1, above, the UFSAR uses the term "and" in lieu of "or" when stating the scope of the program associated with terms of the potential aging effects.
5. Similarly to item 3, above, the UFSAR uses the term "active" to describe acceptance criteria in relation to peeling and delamination.

Issue:

1. The scope of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program is not consistent with the "scope of program" program element of AMP XI.M42 because the term "and" implies that both the component's intended function and a downstream component's intended function must be impacted by loss of coating integrity for the coating to be within the scope of the program. AMP XI.M42 recommends that the criteria for inclusion are either of the impacts.
2. GALL-SLR Report AMP XI.M42 recommends that, "[f]or cementitious coatings/linings inspectors should have a minimum of 5 years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of 1 year of experience."
3. The acceptance criteria for GALL-SLR Report AMP XI.M42 recommends that, "[t]here are no indications of peeling or delamination."
4. GALL-SLR Report Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs," recommends that the term "or" is used when describing aging effects associated with the program (i.e., "loss of material of base materials or downstream effects such as…").
5. GALL-SLR Report Table XI-01, recommends that any indications of peeling or delamination are not acceptable.

Request:

1. State the basis for using the term "and."
2. State the basis for why the statement in SLRA Section B.2.3.29 regarding cementitious coating inspector qualifications is consistent with GALL-SLR AMP XI.M42.
3. State the basis for why allowing degraded coatings that do not exhibit active or significant indications of peeling or delamination is consistent with GALL-SLR AMP XI.M42.

4. State the basis for why SLRA Section 17.2.2.29 states "and" instead of "or" when stating the scope of the program associated with terms of the potential aging effects.
5. State the basis for why SLRA Section 17.2.2.29 uses the term "active" in relation to acceptance criteria for peeling or delamination.

RAI B.2.3.29-2

Background:

During the audit, the staff reviewed the following plant-specific procedures:

- SPEC-C-004, "Engineering Maintenance Specification Form." This procedure states that coating inspectors can be qualified to NACE Level II, ANSI N18.1-1971, or possess equivalent knowledge as determined by a Nuclear Coatings Specialist.
- SPEC-M-086, "Specification Intake Cooling Water System Piping Inspections Turkey Point Units 3 and 4." This procedure states that: (a) the inspections of the internal coatings for piping in the intake circulating water system will be conducted every 72 months with an 18 month grace period; and (b) degraded rubber linings installed on valves requires an engineering evaluation. The specification does not have any provisions for additional inspections when inspection results do not meet acceptance criteria (e.g., cement lining debonding from the pipe).

Issue:

GALL-SLR AMP XI.M42 recommends that coatings inspectors be qualified in accordance with ASTM International standards endorsed in Regulatory Guide 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," including staff limitations associated with a particular standard. It also recommends specific aspects of cementitious coating inspectors (e.g., experience, education). The staff is aware of the requirements for qualifying to NACE Level II and ANSI N18.1-1971. However, using the term, "possess equivalent knowledge as determined by a Nuclear Coatings Specialist," is not consistent with the GALL Report and lacks the detail the staff needs to evaluate this portion of the aging management program.

GALL-SLR AMP XI.M42 recommends that inspections occur at 6-year intervals if inspection results are acceptable and 4-year intervals if for example, peeling, delamination, blisters, or rusting are observed during inspections. The 72-month inspection interval is only consistent with the GALL-SLR Report AMP XI.M42 if degraded coatings as defined in the AMP are not detected. The 18 month grace period is not consistent with the GALL-SLR Report unless the multiple train provisions of GALL-SLR AMP XI.M42 are met.

GALL-SLR AMP XI.M42 recommends that indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist. Using engineering staff without this specific qualification is not consistent with GALL-SLR AMP XI.M42.

GALL-SLR AMP XI.M42 recommends a specific minimum threshold for additional inspections when inspection results do not meet acceptance criteria. The specification is not consistent with GALL-SLR AMP XI.M42 because it does not have any provisions for additional inspections when inspection results do not meet acceptance criteria.

Request

State the basis for:

1. Using a Nuclear Coatings Specialist to determine an appropriate level of qualification for coatings inspectors.
2. The periodicity of internal coating inspections for the intake cooling water coatings.
3. For using engineering staff to conduct evaluations of degraded coating conditions.
4. Not specifying a minimum set of additional inspections when degraded coatings that don't meet acceptance criteria are identified.

RAI B.2.3.29-3

Background:

During the audit, the staff reviewed plant-specific procedures 3-PMM-022.4 and 4-PMM-022.4, "Unit 3 (Unit 4) Diesel Fuel Oil Storage Tank Cleaning." These procedures are used in part to inspect internal coatings on the fuel oil storage tanks.

Issue:

Although the scope of program of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program includes components exposed to fuel oil, there are no Table 2 AMR items for managing loss of coating integrity for components exposed to fuel oil. Based on a review of the Section 3.3 Table 2s, the Fuel Oil Chemistry and One-Time Inspection programs are the only programs cited for components exposed to fuel oil. In addition, based on the staff's review of the Fuel Oil Chemistry program, 3-PMM-022.4, and 4-PMM-022.4, there do not appear to be sufficient exceptions and enhancements to demonstrate consistency with GALL-SLR AMP XI.M42.

GALL-SLR AMP XI.M42 states that applicants may elect to manage loss of coating integrity with other programs (e.g., Fuel Oil Chemistry) as long as: (a) the recommendations of AMP XI.M42 are incorporated into the alternative program; (b) exceptions or enhancements associated with the recommendations in AMP XI.M42 are included in the alternative program; and (c) the FSAR supplement for AMP XI.M42 as shown in the GALL-SLR Report Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs," is included in the application with a reference to the alternative AMP.

Request:

1. State the basis for why the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program and/or Fuel Oil Chemistry program are consistent with GALL-SLR Report AMP XI.M42 in regard to managing aging effects for internally coated components exposed to fuel oil.

2. State which AMR items will be used to manage loss of coating integrity for internally coated fuel oil components.

RAI 3.2.2.1.2-1

Background:

SLRA Table 3.1.2-1 states that loss of coating integrity will be managed for the pressurizer surge tank by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. The AMR item cites Table 3.2-1, item 3.2.1-072.

UFSAR Table 4.1-3, "Pressurizer and Pressurizer Relief Tank Design Data," states that the pressurizer relief tank has a normal water temperature of 120 degrees F and a design temperature of 340 degrees F. UFSAR Section 4.2.1 states that: (a) "steam safety valves and power-operated relief valves are connected to the pressurizer and discharge to the pressurizer relief tank, where the discharged steam is condensed and cooled by mixing with water;" (b) "[s]team is discharged under the water level to condense and cool by mixing with the water," and (c) "[t]he tank is equipped with a spray, and a drain to the Waste Disposal System, which are operated to cool the tank following a discharge."

Issue:

Although the UFSAR states that the tank has a normal temperature of 120 degrees F, the staff does not know what the internal coatings are constructed of and the maximum temperature rating of the coatings. In addition, the staff does not know whether there are operational controls that would limit the time that the coatings would be exposed to an elevated temperature.

GALL-SLR Report AMP XI.M42 was not written for coatings exposed to elevated temperatures.

Request:

State the coating material type and if possible manufacturer, and the coatings maximum design rating.

Describe any operational controls that would minimize the exposure time to higher temperatures.

RAI B.2.3.21-1

Background:

SLRA Tables 3.2.2-2, 3.2.2-4, 3.3.2-16, and 3.3.2-18 cite internally coated cast iron heat exchanger shells and non-internally coated cast iron valve bodies, pump casings, and heat exchanger channel heads exposed to treated water. There are AMR items to manage loss of coating integrity (for internally coated cast iron heat exchanger shells) and loss of material; however, there are no AMR items to manage loss of material due to selective leaching by either the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program or the Selective Leaching program.

Issue:

Cast iron components are susceptible to loss of material due to selective leaching. Consistent with the GALL-SLR Report, loss of material due to selective leaching can be managed by either the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (when the components are internally coated) or the Selective Leaching program.

Request:

State the basis for not managing loss of material due to selective leaching for cast iron heat exchanger shells and channel heads, valve bodies, and pump casings exposed to treated water.

4. Fire Water System

Regulatory Basis:

Section 54.21(a)(3) of 10 CFR requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR Section 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the subsequent period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR Section 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB). In order to complete its review and enable making a finding under 10 CFR Section 54.29(a), the staff requires additional information in regard to the matters described below.

RAI B.2.3.16-1

Background:

1. SLRA Section B.2.3.16 cites an enhancement, Enhancement No. 4, to the Fire Water System Program as follows:

   > Update AMP [aging management program] inspection/testing procedure(s) and develop new procedures to state that testing and visual inspections are performed in accordance with [GALL-SLR Report AMP] Table XI.M27-1 from NUREG-2191 [Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report]. This table, “Fire Water System Inspection and Testing Recommendations,” is based on NFPA [National Fire Protection Association] 25 [Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems] (Reference B.3.131), 2011 edition. Unless recommended otherwise, external visual inspections are to be conducted on an RFO [refueling outage] interval.

The program basis document, reviewed during the in-office audit, cites a list of procedures and corresponding Table XI.M27-1 tests or inspections. It does not provide a description of the required changes, nor does SLRA Section B.2.3.16.

SLRA Section B.2.3.16, Enhancement No. 4 states, "[update inspection/testing procedures] to state that testing and visual inspections are performed in accordance with Table XI.M27-1…"

2. Procedure 0-OSP-016.30, "Fire Main Post Indicator Valve (PIV) Leak/Flow Path Valve Surveillance Test and System Flush," does not include a step to verify that the hydrant barrel drains in 60 minutes.

3. The fire water system program basis document states that procedure 0-ADM-016, "Fire Protection Program," addresses the ability to maintain the required system pressures.

4. Procedure 4-SMM-016.02A, "Spray/Sprinkler System Insp. (EDG 4A Preaction Deluge Valve 4-10-1112 Partial Flow Test, Zone 138)," allows removal and cleaning of obstructed spray sprinklers.

5. Procedure 0-SFP-106.5, "Fire Protection Equipment Surveillance," states that the acceptance criteria for the inspection of internals for the raw water tanks is no signs of age-related degradation which could compromise the integrity of the for protection system.

6. The fire water system program basis document states that procedure PI-AA-104-1000, "Condition Reporting," addresses corrective actions associated with: (a) conducting evaluations to determine if deposits need to be removed to determine if loss of material has occurred; and (b) conducting a flush in accordance with the guidance in NFPA 25 Appendix D.5, "Flushing Procedures," when loose fouling products that could cause flow blockage in sprinklers is detected.

<u>Issue</u>:

1. Enhancement No. 4, along with the additional information provided in the program basis document, lacks sufficient detail for the staff to have reasonable assurance that all plant-specific procedure change actions will be identified in relation to fire water system inspection and test procedures conducted during the subsequent period of extended operation. For example, Section 6.0, "Implementing Documents," in the program basis document states the following in relation to procedure changes associated with internal tank inspections:

   > Perform a fire water storage tank interior inspection every five years that includes inspections for signs of pitting, spalling, rot, waste material and debris, and aquatic growth. Also, revise existing procedures to perform a non-destructive examination to determine wall thickness whenever degradation is identified during internal tank inspections.

This description of changes to internal tank inspections lacks details related to other tests and inspections recommended in Table XI.M27-1 (NFPA 25 Section 9.2.7, “Tests During Interior Inspections”) when signs of interior pitting, corrosion, or failure of coatings are detected during internal tank inspections. Examples include vacuum box testing and various coating inspections techniques that are beyond those recommended in AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks;” however, recommended in AMP XI.M27, “Fire Water System.”

Some inspections cited in Table XI.M27-1 utilize techniques other than visual methods (e.g., NFPA 25, “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” Section 9.2.7 (3) ultrasonic thickness measurements of fire water storage tank bottoms). Flushes are recommended in addition to tests and visual inspections.

2. NFPA-25, “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” Section 7.3.2.4, “Hydrants,” states that full drainage of dry barrel hydrants should take no longer than 60 minutes. Meeting this section of NFPA-25 is recommended by GALL-SLR Report AMP XI.M27, Table XI.M27-1, “Fire Water System Inspection and Testing Recommendations.” Verifying the drain time ensures that potential accumulation of debris will not prevent the drainage of the barrel, which can ensure that the hydrant will not freeze and result in a loss of intended function.

3. GALL-SLR Report AMP XI.M27 recommends that:

   > The water-based fire protection systems are normally maintained at required operating pressure and monitored in such a way that loss of system pressure is immediately detected and corrected when acceptance criteria are exceeded. Continuous system pressure monitoring or equivalent methods (e.g., number of jockey fire pump starts or run time) are conducted.

   Based on a review of 0-ADM-016, there are no surveillance activities that address routine monitoring of the system pressure such that an adverse pressure trend is detected promptly and corrected.

4. The staff recognizes that removal and cleaning of deluge nozzles is a normal acceptable practice. However, removal and cleaning of sprinklers is not allowed by NFPA 25 Section 5.2.1, “Sprinklers,” due to the potential for undetected damage to the sprinkler during the cleaning process. Meeting this section of NFPA-25 is recommended by GALL-SLR Report AMP XI.M27, Table XI.M27-1. Based on the staff’s review of 4-SMM-016.02A, it would appear that the subject “spray sprinklers” are actually deluge nozzles; however, the staff cannot confirm that this is the case across all of the plant-specific procedures.

5. GALL-SLR Report AMP XI.M27 recommends that the acceptance criterion for loss of material is based on minimum design wall thickness. The acceptance criteria in 0-SFP-106.5 lacks sufficient clarity for the staff to complete its evaluation.

6. GALL-SLR Report AMP XI.M27 recommends that: (a) an evaluation be conducted to determine if deposits need to be removed to determine if loss of material has occurred; and (b) a flush be conducted in accordance with the guidance in NFPA 25 Appendix D.5, "Flushing Procedures," when loose fouling products that could cause flow blockage in sprinklers is detected.

Request:

1. Respond to the following:
   a. For existing procedures that need to be updated, provide a description of the specific changes necessary for the fire water system inspections and tests to be consistent with GALL-SLR Report AMP XI.M27 Table XI.M27-1. Alternatively, state and justify any exceptions that are deemed necessary.
   b. For new procedures that need to be developed (e.g., sprinkler testing, water storage tank inspections, main drain tests, obstruction inspections), provide a summary of the changes sufficient to demonstrate that the procedure will be consistent with the inspections and tests described in XI.M27 Table XI.M27-1. For example, see Enhancement No. 8 related to bottom surface inspections of tanks. Alternatively, state and justify any exceptions that are deemed necessary.
   c. State the basis for why Enhancement No. 4 states that only changes to tests and visual inspections will be consistent with Table XI.M27-1.

2. State the basis for why procedure 0-OSP-016.30 is not consistent with GALL-SLR Report AMP XI.M27 in regard to verifying that hydrant barrels drain in 60 minutes.

3. State the basis for why procedure 0-ADM-016 is not consistent with the GALL-SLR Report AMP XI.M27 in regard to routine monitoring of the system pressure such that an adverse pressure trend is detected promptly and corrected.

4. State whether the "spray sprinklers" cited in plant-specific inspection procedures where removal and cleaning is allowed are actually deluge nozzles. If not, state the basis for allowing removal and cleaning of the "spray sprinklers."

5. State the basis for not using minimum design wall thickness as the acceptance criterion when evaluating loss of material.

6. State the basis for why procedure PI-AA-104-1000 is not consistent with GALL-SLR Report AMP XI.M27 in regard to corrective actions associated with: (a) conducting evaluations to determine if deposits need to be removed to determine if loss of material has occurred; and (b) conducting a flush in accordance with the guidance in NFPA 25 Appendix D.5, "Flushing Procedures," when loose fouling products that could cause flow blockage in sprinklers is detected.

RAI B.2.3.16-2

Background:

Many spray or sprinkler system inspection and test procedures (e.g., 4-SMM-016.02A) state that the supply line to the deluge valve should be flushed at normal operating velocity long enough to clear pipe of any scale or foreign materials prior to conducting the test.

During its review of the results of these inspection and test procedures conducted between 2013 to 2017, the staff noted that 16 deluge tests were conducted without any flow blockage of the nozzles being noted; however, there were 5 tests where one or more nozzles were clogged,

Issue:

The staff recognizes that nozzle blockage can occur during testing and a limited number of blocked nozzles might not result in a loss of intended function for the deluge system. However, there are no parameters recorded (e.g., duration of flush, collection and weighing the amount of debris) during the flush. The number of clogged nozzles cannot be used to trend results due to the preconditioning during the flush. As a result, there is no means to trend the test results, as recommended by GALL-SLR Report AMP XI.M27, to determine if an adverse trend is occurring, which could necessitate corrective actions more extensive than cleaning individual nozzles.

Request:

State how the spray and sprinkler system inspection and test procedures will be enhanced to enable trending of data.

RAI B.2.3.16-3

Background:

During the audit, the staff reviewed two 2002 reports associated with the inspection of raw water tank Nos. 1 and 2. These reports stated that: (a) the drainage around the tanks is not adequate to prevent water from coming up over the concrete base and deteriorating the tank base; and b) the base seal will not prevent water from deteriorating the underside of the tank bottom plates.

Issue:

As a result of the potential for water to accumulate under the raw water tanks, the staff has determined that loss of material due to pitting and crevice corrosion could occur on the tank bottom. AMP XI.M29 (the recommended AMP for inspection of the bottom surface exposed to soil or concrete of fire water storage tanks) does not include specific recommendations for the quantity of data points or location of the bottom thickness measurements. However, given the

potential for water intrusion under the tank, the staff requires this information to complete its evaluation.

It should be noted that the low-frequency electromagnetic testing (LFET) technique can be capable of scanning the entire bottom of the tank in order to detect discrete locations where augmented bottom thickness measurements should be conducted. The staff's evaluation of the use of this technique is documented in NUREG-2172, "Safety Evaluation Report Related to the License Renewal of Callaway Plant, Unit 1," Section 3.0.3.2.8.

Request:

1. State the quantity and location of data points for the periodic bottom thickness measurements of the raw water tanks. In addition, state the basis for why the quantity and location of data points will be sufficient to detect loss of material due to pitting or crevice corrosion.

2. If the LFET technique will be used, state the criteria for followup discrete tank thickness measurements.

If other scanning techniques will be used, state the basis for the effectiveness of these techniques in detecting loss of material due to pitting or crevice corrosion and the criteria for followup discrete tank thickness measurements.

RAI B.2.3.16-4

Background:

Procedure FP-AA-1006, "Implementation of the NFPA 805 [Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants] Monitoring Program," describes the plant-specific requirements for implementing NFPA-805.

Issue:

The staff noted that procedure FP-AA-1006 does not cite EPRI Report 1006756, "Fire Protection Equipment Surveillance Optimization and Maintenance Guide." EPRI Report 1006756, Section 11.2, "Data Collection and Evaluation," includes industry-standard guidance for selecting the number of data points to be used in potentially adjusting test and inspection frequencies. Citing EPRI Report 1006756 is not required for subsequent license renewal; however, absent citing a similar standard or enhancing the procedure to incorporate the critical guidance, the staff cannot complete its evaluation. As established by the staff in NUREG-2172, "Safety Evaluation Report Related to the License Renewal of Callaway Plant, Unit 1," Section 3.0.3.2.7, "Fire Water System," the staff requires additional information to complete its evaluation.

Request:

State: (a) the earliest (i.e., number of years prior to the subsequent period of extended operation) data that would be used for modifying test and inspection frequencies; (b) the minimum sample size to modify test and inspection frequencies; and (c) whether performance data would be used to modify fire water storage tank inspections/tests, underground flow tests, and inspections of normally dry but periodically wetted piping that will not drain due to its configuration.

RAI 3.3.2.1.2-1

Background:

SLRA Table 3.3.1, item 3.3.1-064, addresses steel and copper alloy piping and piping components exposed to raw water, treated water, and raw water (potable) which will be managed for loss of material and flow blockage. During its review of components associated with item number 3.3.1-064 for which the applicant cited generic note C, the staff noted that the SLRA credits the Fire Water System program to manage the aging effects for steel, gray cast iron, and copper alloy greater than 15 percent zinc heat exchanger tubes, shell, tubesheet, and channel heads, as shown in the below chart.

Component Type	Material	Environment	AERM
Heat exchanger (tubes)	Copper alloy >15% Zn	Raw water (int)	Loss of material; flow blockage
Heat exchanger (shell)	Gray cast iron	Treated water (int)	Loss of material; flow blockage
Heat exchanger (tubesheet)	Copper alloy >15% Zn	Treated water (ext)	Loss of material; flow blockage
Heat exchanger (tubesheet)	Copper alloy >15% Zn	Raw water (int)	Loss of material
Heat exchanger (tubes)	Copper alloy >15% Zn	Treated water (ext)	Loss of material
Heat exchanger (channel head)	Copper alloy >15% Zn	Raw water (int)	Loss of material; flow blockage
Heat exchanger (shell)	Carbon steel	Treated water (int)	Loss of material

Issue:

The staff lacks sufficient information to conclude which Fire Water System program inspections or tests will be conducted sufficient to detect loss of material and flow blockage for these components.

Request:

State which Fire Water System program inspections or tests will be conducted sufficient to detect loss of material and flow blockage for these components.

RAI 3.3.2.1.3-1

Background:

SLRA Table 3.3.1, item 3.3.1-042 addresses copper alloy, titanium, or stainless steel heat exchanger tubes exposed to raw water, raw water (potable), or treated water, which will be managed for reduction of heat transfer due to fouling. For the AMR item that cites generic note E, the SLRA credits the Fire Water System Program to manage the aging effect for copper alloy greater than 15 percent heat exchanger tubes.

Issue:

During the in-office audit, the staff was told that there are two diesel engine fire pump heat exchangers associated with several of the SLRA Table 3.3.2-15 AMR items, these being cooling water and a lubricating oil heat exchanger. It was also stated that reduction of heat transfer would be managed by observing heat exchanger performance during the periodic tests of the pump. The staff requires that the information documented in this issue be verified or corrected on the docket.

Request:

Verify that the information as stated in the above issue is correct or state the basis for how the inspections or tests of the Fire Water System program will be effective at managing reduction of heat transfer due to fouling.

RAI 3.3.2.2.7-1

Background:

SLRA Section 3.3.2.2.7, “Loss of Material Due to Recurring Internal Corrosion,” states that there have been no corrosion issues that meet the criteria of recurring internal corrosion.

Issue:

During the Operating Experience Audit, the staff identified several corrective action (CA) entries that might be associated with loss of material due to recurring internal corrosion. During the audit each corrective action entry was discussed and plausible explanations were provided for virtually all examples as to why the cause was not internal corrosion (e.g., external corrosion, leakage past threads, packing leaks). The staff requires that the information be placed on the docket.

Note: in the below request, LR-ISG-2012-02, “Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,” is cited as the basis for loss of material due to recurring internal corrosion. The recommendations associated with loss of material due to recurring internal corrosion were incorporated into the GALL-SLR Report with no significant changes. As a result, NUREG-2221, “Technical Bases for Changes in the Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG–2192,” does not contain the basis for SRP-SLR Section 3.3.2.2.7.

Request:

State the basis for why the following corrective action entries are not examples of internal corrosion as described in LR-ISG-2012-02.

CA Entry	Title	Date
00405413	Leak in weld on 10-inch fire main piping.	04/26/2007
00440984	Small leak in the 1-inch inspector test drain line on the first floor of the nuclear maintenance building in the area of the fire system riser.	05/02/2007
00440545	Through wall leakage in the fire main header.	05/03/2007
00507320	An approximately 2-inch diameter fire line is corroded and leaking at the screwed fitting near a sprinkler head above No. 3 waterbox inlet piping, upstream of drain valve 3-10-1311.	09/12/2007
00462447	Fire water system pipe leak at the raw water storage tank (RWST) in a 2-inch pipe at threaded connection. No visible signs of extensive external corrosion.	01/26/2009
01618249	There is a leak at the connection between the pipe and elbow just downstream of valve 10-619. The leak is a slow drip when in standby and continuous spray when the electric driven fir pump is running.	02/09/2011
01800862	Fire suppression system piping is leaking at a piping union west and above the U3 4A low pressure feed water heater.	09/07/2012
01824738	The 4-10-1301 sprinkler valve just south of the cable spreading room on the mezzanine deck is leaking directly on top of the secondary response center. This is causing mild flooding in the room.	11/17/2012
01824931	A 1-inch pipe with a spray nozzle is broken off of the fire protection loop around the lube oil tank at U4.	11/18/2012
01871471	Water is leaking onto the floor in the response center. The water is coming from the overhead and running down inside the wall, possibly from the fire sprinkler system.	05/02/2013
01877303	Valve 3-10-1303 is leaking externally at a rate of approximately 30 drops per minute (dpm).	05/25/2013
01887603	Action request associated with removing an approximate 3-foot section of 3-inch pipe and replacing it with new pipe. The work area is located in the heating, ventilation, and air conditioning room located on the east side of the building.	07/08/2013

CA Entry	Title	Date
01950652	Through-wall leak on the fire water jockey pump recirculation line. The leak is shooting a 10 to 15 foot stream of water into the air.	03/22/2014
01990890	The deluge fire system just west of the U4 lube oil reservoir has a pin hole leak coming from the joint elbow above valve 4-10-1600. The leak is a constant spray, not drops.	09/12/2014
02021813	Piping near valve 4-10-1600, alarm test valve for U4 turbine building sprinklers, is leaking by a previously installed patch and spraying approximately 1 gallon per minute (gpm). This action request is also linked to 01990890.	01/29/2015
02065087	Valve 4-10-1303, U4 turbine building east sprinkler system sectional isolation valve for the 18-foot elevation sprinklers is leaking at a rate of 200 DPM.	08/05/2015
02124480	Water was noted to be leaking through the lighting fixture in document control. It has been determined that the pipe that is leaking is a fire sprinkler pipe.	04/11/2016
02238434	Repeat leak in recirc. line of diesel driven fire pump	11/30/2017
02235611	Leak in recirc. line of diesel driven fire pump	11/09/2007

5. Reactor Coolant Pump Flywheel

Regulatory Basis:

10 CFR Section 54.21(c)(1) requires an applicant to provide a list of time-limited aging analyses (TLAAs) and demonstrate that (i) the analyses remain valid for the period of extended operation; (ii) the analyses have been projected to the end of the period of extended operation; or (iii) the effects of aging on the intended functions will be adequately managed for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR § 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB). The SRP-SLR provides the acceptance criteria for an applicant to demonstrate compliance with 10 CFR 54.21(c)(1). In order to complete its review and enable making a finding under 10 CFR § 54.29(a), the staff requires additional information in regard to the matters described below.

RAI 4.3.5-1

Background:

The Turkey Point SLR referenced PWROG-17011-NP, Revision 0 report, “Update for Subsequent License Renewal: WCAP-14535A, ‘Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,’ and WCAP-15666-A, ‘Extension of Reactor Coolant Pump Motor Flywheel Examination’,” dated May 2018 to support the TLAA for the Reactor Coolant Pump Flywheel. The PWROG-17011-NP, Revision 0 report provides the technical and regulatory basis for continuing the 20-year inservice inspection interval approved for reactor coolant pump motor flywheels for the 60 year period of license renewal in WCAP-15666-A into the 80 year period of subsequent license renewal.

Issue:

1. Section 3.4.3 of PWROG-17011-NP, Revision 0 provides descriptions and frequencies of the initiating events for the different conditions listed in Table 3-5. For the second condition, the description is, “The initiating event frequency for a plant trip or non-LOCA transient is estimated as 1 event/year (plants on average experience 1 plant trip per year).” This referencing of a non-LOCA transient does not appear in Tables 3-7 and 3-8 of PWROG-17011-NP, Revision 0 for condition 2. Further, it appears contradictory to the description in Table 3-5 of PWROG-17011-NP, Revision 0 and in Tables 3-12 and 3-13 in WCAP-15666-A, which references a LOCA event: “Failure of the RCP motor flywheel given a plant transient or LOCA event with NO loss of electric power to the RCP.”

2. Tables 3-7 to 3-9 of PWROG-17011-NP, Revision 0 show that the event frequency for the fourth condition is 1.4E-8/year. In WCAP-15666-A, the corresponding event frequency is 2.8E-8/year based on a maximum LOCA frequency (LOCAs with greater than 5000 gpm blowdown) of 2E-6/year and the probability of loss of station power following a LOCA of 1.4E-2/year. The staff previously approved the value for the fourth condition in WCAP-15666-A. The new event frequency is only half of this previously approved value. The staff needs confirmation of the correct value to determine the change in CDF and LERF to verify within the acceptable range in Regulatory Guide 1.174.

Request:

1. Please provide clarification for the apparent inconsistencies between Tables 3-5, 3-7, 3-8, 3-12, and 3-13 regarding LOCA events vs. non-LOCA events.

2. Please justify the difference in the event frequency for the fourth condition between PWROG-17011-NP and WCAP-15666-A.