FPL

L-2019-071
10 CFR 54.17

April 10, 2019

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555-0001

Re: Florida Power & Light Company
Turkey Point Units 3 and 4
Docket Nos. 50-250 and 50-251
Turkey Point Units 3 and 4 Subsequent License Renewal Application
Safety Review Requests for Additional Information (RAI) Set 10 Response

References:

1. FPL Letter L-2018-004 to NRC dated January 30, 2018, Turkey Point Units 3 and 4 Subsequent License Renewal Application (ADAMS Accession No. ML18037A812)
2. FPL Letter L-2018-082 to NRC dated April 10, 2018, Turkey Point Units 3 and 4 Subsequent License Renewal Application – Revision 1 (ADAMS Accession No. ML18113A134)
3. NRC RAI E-Mail to FPL dated March 28, 2019 – Requests for Additional Information for the Safety Review of the Turkey Point Subsequent License Renewal Application – Set 10 (EPID No. L-2018-RNW-0002) (ADAMS Accession Nos. ML19087A209 and ML19087A211)
4. FPL Letter L-2019-037 to NRC dated March 6, 2019, Turkey Point Units 3 and 4 Subsequent License Renewal Application Safety Review Requests for Additional Information (RAI) Set 9 Responses (ADAMS Accession No. ML19070A113)

Florida Power & Light Company (FPL) submitted a subsequent license renewal application (SLRA) for Turkey Point Units 3 and 4 to the NRC on January 30, 2018 (Reference 1) and SLRA Revision 1 on April 10, 2018 (Reference 2).

The purpose of this letter is to provide, as attachments to this letter, the response to the safety review Set 10 RAI No. B.2.3.28-1 issued by the NRC on March 28, 2019 (Reference 3), and a supplemental response for the Open-Cycle Cooling Water (OCCW) Aging Management Program (AMP). The Set 10 RAI response augments the response submitted by FPL on March 6, 2019 (Attachment 1 of Reference 4). The attachments identify revisions amending the SLRA.

If you have any questions, or need additional information, please contact me at 561-691-2294.

A084
NRR

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 10, 2019.

Sincerely,

William Maher
Senior Licensing Director
Florida Power & Light Company

WDM/RFO

Attachments:

1. FPL Response to NRC RAI No. B.2.3.28-1b
2. FPL Supplemental Response for OCCW AMP

cc:

Senior Resident Inspector, USNRC, Turkey Point Nuclear
Regional Administrator, USNRC, Region II
Project Manager, USNRC, Turkey Point Nuclear
Plant Project Manager, USNRC, SLRA
Plant Project Manager, USNRC, SLRA Environmental
Ms. Cindy Becker, Florida Department of Health

NRC RAI Letter Nos. ML19087A209 and ML19087A211 Dated March 28, 2019

1. Buried and Underground Piping and Tanks, GALL AMP XI.M41

RAI B.2.3.28-1b

Regulatory Basis:

Section 54.21(a)(3) of Title 10 of the *Code of Federal Regulations* (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 subsequent 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 10 CFR 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 SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the 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.

Background:

By letter dated February 6, 2019, (ADAMS Accession No. ML19037A398) the staff issued follow-up RAI B.2.3.28-1a requesting that a basis be provided for why Preventive Action Category F is appropriate for buried steel piping during the 10-year period prior to the subsequent period of extended operation (SPEO). The basis for issuing this RAI was that: (a) operating experience (OE) at Turkey Point has indicated several instances of leaks/significant degradation of buried steel piping; and (b) Preventive Action Category F is limited to instances where plant-specific OE identifies only a few (i.e., as opposed to several) instances of leaks/significant degradation. The staff's assertion that there have been several instances of leaks/significant degradation of buried steel piping due to external corrosion is based on the following:

- SLRA Section B.2.3.28, "Buried and Underground Piping and Tanks," states:

> Turkey Point has experienced a number of pipe leaks and/or breaks in buried piping. Most of these pipe breaks have been in the piping for the fire water and service water systems. These breaks have been documented in the corrective action program (CAP). A review of the documentation in the CAP indicates that typically they have been caused by localized corrosion.

- During the audit the staff noted that: (a) several leaks and locations of localized external corrosion have occurred in buried service water and fire water system piping; (b) an action report (AR) from 2008 documents that corrosion of buried carbon steel piping is a known problem at the station; and (c) the Structures Monitoring program basis report documents that groundwater/soil at Turkey Point is aggressive with chlorides greater than 500 parts per million (ppm), which indicates an aggressive groundwater/soil classification.

Follow-up RAI B.2.3.28-1 was responded to by letter dated March 6, 2019, (ADAMS Accession No. ML19070A113). Each of the ARs that were cited by the staff in the OE audit report (ADAMS Accession No. ML18183A445) were addressed. For several of the ARs which identified leaks, the response states that the buried piping is not within the scope of subsequent license renewal (SLR) and is therefore not related to the Buried and Underground Piping and Tanks program. The overall conclusion stated in the response was that: (a) there has not been significant degradation and only one minor leak was identified; and (b) no additional inspections beyond those currently planned are required for buried steel piping during the 10-year period prior to the SPEO.

<u>Issue:</u>

The response to follow-up RAI B.2.3.28-1a focused on addressing each of the ARs that were cited by the staff in the OE audit report. The staff has two issues with the response:

1. The staff does not agree with the claim that leaks/degradation in out-of-scope buried piping are not relevant to the Buried and Underground Piping and Tanks program. In-scope piping would be just as susceptible to degradation as out-of-scope piping unless a technical justification is provided for why the two are not representative of each other (e.g., similar material composition, degradation mechanisms, coatings, environmental conditions, age of installation, operational history of cathodic protection if installed). GALL-SLR Report Aging Management Report (AMP) XI.M41 states:

    > If cathodic protection is not provided for any reason, the applicant reviews the most recent 10 years of plant-specific operating experience (OE) to determine if degraded conditions that would not have met the acceptance criteria of this AMP have occurred. This search includes components that are not in-scope for license renewal if, when compared to in-scope piping, they are similar materials and coating systems and are buried in a similar soil environment.

    Although cathodic protection will be installed at least 7 years prior to the SPEO, AMP XI.M41 clearly establishes the purpose of using plant-specific operating experience related to buried components that are not in-scope.

2. The response addressed each of the ARs listed in the OE audit report; however, this listing of ARs was not intended to be an exhaustive list documenting all instances of buried piping leaks/degradation at Turkey Point. The staff's review of operating experience spans approximately 10 years, not the entire life of the plant. The staff also notes that corrosion of buried carbon steel piping was known to be an issue in 2008 (approximately 10 years ago). Therefore, there could be examples of buried steel piping leaks/degradation that were not included in the OE audit report.

Request:

State the basis for why additional inspections, beyond those recommended for Preventive Action Category F, are not appropriate for buried steel piping during the 10-year period prior to the SPEO.

FPL Response:

This response augments the response in Attachment 1 of Ref. 4. The number of inspections planned during the 10-year period prior to the SPEO conforms to the guidance for Preventive Action Category F in NUREG-2191, Table XI.M41-2. This initial plan for SLR is justified by consideration of current LR programs, a more in-depth (holistic) review of operating experience, and documented soil conditions. Each consideration is further discussed below.

Current LR and SLR Program Inspection Plans

The buried steel piping systems included in the scope of the PTN Buried and Underground Piping and Tanks AMP for SLR are intake cooling water (ICW), fire protection (FP) and plant air (PA). Per the piping design specifications, the buried piping materials for these systems are as follows:

- ICW – Cast iron piping, cement lined (double thickness), coated
- FP – Cast iron piping, some small bore carbon steel piping, wrapped and coated
- PA – Carbon steel, galvanized, wrapped and coated

For current license renewal, aging management for these systems is performed by the Intake Cooling Water Inspection Program, the Fire Protection Program, and the Systems and Structures Monitoring Program, respectively. To address NEI 09-014, Rev. 4 (Ref. 1), PTN more recently implemented the Turkey Point Nuclear Station Underground Piping and Tank Integrity Program, which includes periodic external inspections of buried piping. Activities under these programs will continue to be performed throughout the balance of the current period of extended operation (PEO) in conjunction with the pre-SPEO inspections for SLR described below.

The PTN plan for SLR is to follow the guidance in NUREG-2191, Table XI.M41-2, Preventive Action Category F, and perform 11 buried steel piping inspections of a combination of ICW, FP and PA. These inspections will begin no earlier than 10 years and no later than six months prior to the SPEO. Consistent with the requirements of

XI.M41, piping inspection locations will be selected based on risk (i.e., susceptibility to degradation and consequences of failure). Plant specific OE can also be used as an input for selecting inspection locations. PTN is also committed to installing a cathodic protection system at least seven years prior to the SPEO, which will ultimately reduce the number of required inspections (Ref. 2). However, the cathodic protection system is not credited in establishing the number of steel piping inspections to be performed prior to the SPEO. There are also provisions in element 7, Corrective Actions, of the PTN Buried and Underground Piping and Tanks AMP to expand the number of inspections based on the extent of degradation found consistent with XI.M41 requirements.

Therefore, based on current inspection plans, there is reasonable assurance that systems within the scope of the PTN Buried and Underground Piping and Tanks AMP will continue to perform their intended functions.

Review of OE

To ensure a thorough assessment of OE as it relates to buried piping, a more in-depth (holistic) review of OE has been performed, including the OE summarized by the NRC in the OE audit report (Ref. 3), and the OE assessed by FPL in support of the SLRA including over 200 ARs, seven buried piping inspection self-assessments, and twenty-four buried piping system health reports.

This review included the Turkey Point Nuclear Station Underground Piping and Tank Integrity Program (available on the ePortal), which identifies the internal and external piping inspection history from 2004 to 2016 and future inspection plans.

Based on the above, 15 ARs of relevance were identified. These are further discussed below:

- Four ARs (01931234, 02066294, 02071661, 02105634) were for service (domestic) water piping leaks located outside the plant protected area. These four ARs were reporting leakage from the same ~15 foot section of service water piping located in a paved area between the nuclear entrance building and the FPL fitness center. The ARs did not document any coating or wrap on the piping. This OE is not directly comparable to the buried piping in the scope of the PTN Buried and Underground Piping and Tanks AMP for the following reasons:

  - With exception to a limited amount of small bore carbon steel piping in the fire water system, the carbon steel service water piping is a different material than the steel piping (e.g., cast iron, galvanized carbon steel) in the scope of the PTN Buried and Underground Piping and Tanks AMP.
  - The design and installation of piping outside of the protected area are not covered by the design and installation specifications for piping installed on the main plant island (power block) for Units 3 and 4.

- The PTN specifications for fill indicate that all areas containing foundations for the main plant island (power block) for Units 3 and 4 are compacted to 95 percent or greater meaning smaller rock size and a better environment for buried piping. Fill for tanks, plant and access roads within the protected area are compacted to 85 percent or less. There are no specific criteria for fill for areas outside the protected area, so compaction would be expected to be much less than that for the main plant island (power block).
- There are no specific license renewal commitments to manage aging of the buried portions of the service water system. Thus, the system is not monitored or inspected on a regular basis.

- One AR (00529702) was associated with fire protection piping for PTN fossil Units 1 and 2, which are no longer in operation and outside of the protected area. The design and installation of piping for the fossil units are not covered by and typically less rigorous than the design and installation specifications for piping installed on the nuclear units, and the pipe material, presence of coatings, and fill conditions are unknown.

- Five ARs (ARs in parentheses) were not related to aging and/or buried piping as follows:

  - A fire main break caused by construction excavation activities (00461305).
  - A service water leak in the stairwell of the central storage facility (02053141).
  - A drawing issue associated with a valve installed in a section of buried service water piping (01940055).
  - A question raised regarding coating requirements on new stainless steel piping that was planned to be encased in concrete (02055286).
  - A leak in a service water valve supplying administrative buildings on the South side of the plant site (00460508).

- Five ARs (ARs in parentheses) represented applicable OE to the PTN Buried and Underground Piping and Tanks AMP as follows:

  - Two for external inspections of buried ICW piping indicating it was in good condition (01955813, 02014369).
  - One for corrosion of fire protection piping (00485197).
  - One for a pin-hole leak on a fire hydrant (00464785).
  - Although not in the scope of SLR, one for corrosion of service water piping located near the plant cafeteria (00462055).

The review of these five ARs indicates there are three ARs that are related to corrosion of buried piping. These ARs, which were discussed in Ref. 4, are summarized below for convenience:

- In January 2009 (AR 00485197), fire protection piping was found corroded during excavation for a construction activity. Although the external surface of the piping was corroded, the lowest wall thickness measurement was still well above the minimum wall thickness required for the service conditions. The cause was attributed to damage to the protective pipe wrap either due to past excavations or limited fill cover (<18"). The piping was cleaned, coated and backfilled.

- In October 2009 (AR 00464785), a pin-hole leak on a cast iron fire hydrant lower barrel (extension casing) was discovered after excavation to address bubbling paint above ground and at the air/ground interface. The functionality assessment indicated that although there was reduced margin, the fire hydrant was considered "Functional". The pin-hole leak was due to a localized corrosion cell. The leak location was repaired, coated and backfilled.

- In January 2009 (AR 00462055), external corrosion was found on four areas of buried service water piping between the cafeteria and the nuclear entrance building within the PA. Although the external surface of the piping was corroded, the lowest wall thickness measurement was greater than that required to maintain pressure integrity. The piping was cleaned, coated and backfilled.

SLRA, Section B.2.3.28, Buried and Underground Piping and Tanks, page B-233, makes the following statement:

> "In addition, PTN has experienced a number of pipe leaks and/or breaks in buried piping. Most of these pipe breaks have been in the piping for the fire water and service water systems. These breaks have been documented in the CAP. A review of the documentation in the CAP indicates that typically they have been caused by localized corrosion. These breaks have been repaired and the piping returned to service."

Based on the OE review summarized above, this statement is revised. There has only been one pipe break, and that was due to construction excavation activities. Additionally, only one minor (pin-hole) leak has occurred that is directly applicable to external corrosion of buried piping within the scope of SLR. Accordingly, the statement in SLRA Section B.2.3.28 is revised as noted below in the SLRA associated changes.

<u>Buried Piping Soil Classification</u>

The RAI above indicates that per the Structures Monitoring AMP the groundwater/soil at PTN meets an aggressive classification. However, this is for groundwater/soil below groundwater level and none of the piping within the scope of the PTN Buried and Underground Piping and Tanks AMP is installed below groundwater level. Additionally, soil resistivity and pH testing performed per the Turkey Point Nuclear Station Underground Piping and Tank Integrity Program, with average values of 11,671 ohm-cm and 8.92 respectively, concluded that the soil condition above groundwater at PTN is moderately corrosive to non-corrosive.

Conclusion:

Therefore, plant specific OE (one instance of a leak in the fire water system (AR 00464785) and no significant degradation of buried piping in the scope of SLR (see ICW and other inspection results above)) supports the applicability of Preventative Action Category F in Table XI.M41-2 of NUREG-2191. Accordingly, PTN's current plan to perform 11 buried steel piping inspections (determined using the guidance of Table XI.M41-2, Preventive Action Category F) prior to the SPEO, in conjunction with other inspections being performed for current LR, are appropriate and justified.

References:

1. NEI 09-14, Rev. 4, Guideline for the Management of Underground Piping and Tank Integrity, December 2014

2. FPL Letter L-2018-166 to NRC dated October 16, 2018, Turkey Point Units 3 and 4 Subsequent License Renewal Application, Safety Review Requests for Additional Information (RAI) Set 3 Responses (ADAMS Accession No. ML18296A024)

3. NRC letter dated July 23, 2018 entitled, Turkey Point Nuclear Generating Units 3 and 4 - Report for the Operating Experience Review Audit Regarding the Subsequent License Renewal Application Review (EPID No. L-2018-RNW-0002), transmitting "Audit Report Operating Experience Review Audit Regarding the Turkey Point Nuclear Generating Units 3 and 4, Subsequent License Renewal Application" (ADAMS Accession No. ML18183A445)

4. FPL Letter L-2019-037 to NRC dated March 6, 2019 Turkey Point Units 3 and 4 Subsequent License Renewal Application, Safety Review Requests for Additional Information (RAI) Set 9 Responses (ADAMS Accession No. ML19070A113).

Associated SLRA Revisions:

SLRA Section B.2.3.28 is amended as indicated by the following text deletion (strikethrough) and text addition (red underlined font) revisions.

Revise SLRA Section B.2.3.28 on page B-223 as follows:

~~In addition, PTN has experienced a number of pipe leaks and/or breaks in buried piping. Most of these pipe breaks have been in the piping for the fire water and service water systems. These breaks have been documented in the CAP. A review of the documentation in the CAP indicates that typically they have been~~ **Only one minor (pin-hole) leak has occurred on buried piping in the scope of SLR**. **This pin-hole leak was** caused by **a** localized corrosion **cell**. ~~These breaks have been~~ **The leak was** repaired and the piping returned to service.

Associated Enclosures:

None

Open Cycle Cooling Water (OCCW) System, GALL AMP XI.M20

Issue:

Turkey Point's SLRA states that the Open-Cycle Cooling Water (OCCW) System AMP will be used to manage loss of coating integrity for internal coatings of intake cooling water (ICW) system piping. NUREG-2191 AMP XI.M20, "Open-Cycle Cooling Water System" states that if the OCCW system program manages loss of coating integrity for internal coatings or linings, the program includes the guidance provided in the 'scope of program' program element in NUREG-2191 AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks." This program element identifies three criteria for when an applicant elects to manage the aging effects for internal coatings/linings in an alternative AMP that is specific to the component or system in which the coatings/linings are installed. The staff identified inconsistencies with the first and third recommendations, which state that the recommendations of this AMP (XI.M42) are incorporated into the alternative program (OCCW) and that the FSAR supplement for this AMP (XI.M42) is included in the application with a reference to the alternative AMP (OCCW).

Regarding the first recommendation, Section B.2.3.11 of the SLRA includes enhancements to meet the recommendations of AMP XI.M42. However, the staff identified inconsistencies with several items. For example, for the 'detection of aging effects' program element, the inspection interval is specified to not exceed five years, while Table XI.M42-1 defines Inspection Categories A and B to be 6 and 4 years, respectively, based on the criteria listed in the table. It also appears that the recommendations of the 'monitoring and trending' and 'corrective actions' program elements of AMP XI.M42 are not addressed.

Regarding the third recommendation, SLRA Section 17.2.2.29 does not appear to include a reference to the OCCW System AMP.

Request:

The staff needs additional information to confirm that the portion of the applicant's OCCW System program used to manage loss of coating integrity is consistent with the recommendations in AMP XI.M20 and AMP XI.M42.

FPL Response:

FPL inadvertently omitted the necessary enhancements to Elements 4, 5 and 7 of the PTN Open-Cycle Cooling Water (OCCW) System AMP in SLRA Section B.2.3.11 and Commitment 15 of SLRA Table 17-3 required to manage loss of coating integrity of ICW system piping consistent with the requirements of NUREG-2191 AMP XI.M42. In addition, the UFSAR update included in SLRA Section 17.2.2.29 (Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks) inadvertently omitted a reference to the OCCW AMP.

PTN SLRA Sections 17.2.2.29 and B.2.3.11 and Commitment 15 of Table 17-3 are updated to address these inconsistencies in the PTN Open-Cycle Cooling Water

System and Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMPs.

This supplemental response also supersedes the response to Request #2 of RAI B.2.3.29-2 and the associated SLRA markups for Section B.2.3.11 and Commitment 15 of Table 17-3 which is provided in Attachment 7 of Reference 1.

References:

1. FPL Letter L-2018-152 to NRC dated August 31, 2018, Turkey Point Units 3 and 4 Subsequent License Renewal Application Safety Review Requests for Additional Information (RAI) Set 1 Responses (ADAMS Accession Number ML18248A257)

Associated SLRA Revisions:

SLRA Sections 17.2.2.29 and B.2.3.11 and Table 17-3 are amended as indicated by the following text deletion (strikethrough) and text addition (red underlined font) revisions.

Revise the first paragraph of SLRA Section 17.2.2.29 as follows:

The PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP, although some of its activities and inspections were formerly a portion of the PTN Periodic Surveillance and Preventative Maintenance Program, the PTN Intake Cooling Water Inspection Program, the PTN Field Erected Tanks Internal Inspection Program, and other site-specific programs. 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. **Note that the applicable elements of this AMP are included in the Open-Cycle Cooling Water (OCCW) System AMP (Section 17.2.2.11) to manage loss of coating integrity for internal coatings of intake cooling water (ICW) system piping.**

Update the Enhancements table of SLRA Section B.2.3.11 to revise Element 4 and add new Elements 5 and 7 as follows:

Element Affected	Enhancement
4. Detection of Aging Effects	~~The inspection interval for ICW piping internal inspections, as delineated in the pertinent testing specification SPEC-M- 086, should not exceed five years. .~~ ~~**Pending coating inspection results, specific locations may require coatings inspections every four years in accordance with NUREG-2191 Section XI.M42 Table XI.M42-1.**~~ ~~In addition, changes to piping internal inspection intervals are to be established by a coating specialist qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54 (Reference B.3.20).~~ **ICW piping internal inspections are based on an evaluation of the effect of a coating/lining failure on the in-scope component's intended function, potential problems identified during prior**

Element Affected	Enhancement
	inspections, and known service life history. Inspection intervals are established by a coating specialist qualified in accordance with RG 1.54 [Reference B.3.20]. However, inspection intervals should not exceed those specified in GALL SLR Table XI.M42-1. The extent of the ICW piping internal inspection is not any less than the following for each coating/lining material and environment combination. The coating/lining environment includes both the environment inside the piping and the metal to which the coating/lining is attached. Since PTN is a two-unit site, a representative sample of fifty-five (55) 1-foot axial length circumferential segments of piping are inspected per unit. The inspection surface includes the entire inside surface of the 1-foot segment. If geometric limitations impede the inspection of the entire circumferential segment, the number of inspection segments is increased in order to cover an equivalent of fifty-five (55) 1-foot axial length circumferential segments. Where documentation exists that manufacturer recommendations and industry consensus documents (i.e., those recommended in RG 1.54, or earlier versions of those standards) were complied with during installation, the extent of piping inspections may be reduced to nineteen (19) 1-foot axial length circumferential segments of piping of each coating/lining material and environment combination at each unit. Reduction of the number of required ICW piping internal inspections is acceptable for PTN Units 3 and 4 as the ICW systems on each unit are essentially identical (Section 2.3.3.1). Similar ICW system operating conditions (flowrate, pressure, temperature, cooling water source, etc.) for PTN Unit 3 and 4 will continue to provide representative inspection results for each unit. Coating/lining surfaces captured between interlocking surfaces (e.g., flange faces) are not required to be inspected unless the joint has been disassembled to allow access for an internal coating/lining inspection or other reasons. For areas not readily accessible for direct inspection, consideration is given to the use of remote or robotic inspection tools. For cementitious ICW piping coatings within the scope of the program, inspectors should have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings/linings, or a degree in the civil/structural discipline and a minimum of one year of experience.
5. Monitoring and Trending	A pre-inspection review of the previous two ICW piping inspections is conducted, when available, that includes reviewing the results of the inspections and any subsequent repair activities. A coatings specialist prepares the post-inspection report to include: a list and location of 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.

Element Affected	Enhancement
	Where practical, degradation is projected until the next scheduled inspection. Results are evaluated against the acceptance criteria to confirm that the sampling bases will maintain the component's intended functions throughout the SPEO based on the projected rate and extent of degradation.
7. Corrective Actions	ICW piping coatings/linings that do not meet acceptance criteria are repaired, replaced, or removed. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material. As an alternative, internal coatings exhibiting indications of peeling and delamination may be returned to service if: (a) physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal; (b) the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered); (c) adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of 3 sample points adjacent to the defective area; (d) an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component; and (e) follow-up visual inspections of the degraded coating are conducted within 2 years from detection of the degraded condition, with a reinspection within an additional 2 years, or until the degraded coating is repaired or replaced. If the ICW piping base metal has been exposed or it is beneath a blister, the component's base material in the vicinity of the degraded coating/lining is examined to determine if the minimum wall thickness is met and will be met until the next inspection. When a blister does not meet the acceptance criteria, and it is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain in service should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister. Additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the site's corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria. The timing of

Element Affected	Enhancement
	the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, in all cases, the additional inspections are completed within the interval in which the original inspection was conducted, or if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections. Additional samples are inspected for any recurring degradation to provide reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections include inspections at both PTN units with the same piping material, environment, and aging effect combination.

Update the Commitment 15 of SLRA Table 17-3 as follows:

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
15	Open-Cycle Cooling Water System (17.2.2.11)	XI.M20	Continue the existing PTN Open-Cycle Cooling Water System AMP, including enhancement to: a) Delineate within the pertinent testing specification the descriptions of the specific aging mechanisms associated with coatings/linings (blistering, cracking, flaking, peeling, delamination, and rusting); b) ~~Ensure that the inspection frequency for ICW piping internal inspections delineated in the pertinent testing specification should not exceed 5 years. .~~ ~~**Pending coating inspection results, specific locations may require coatings inspections every four years in accordance with NUREG-2191 Section XI.M42 Table XI.M42-1.**~~ ~~In addition, changes to piping internal inspection intervals are to be established by a coating specialist qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54.~~ **ICW piping internal inspections are based on an evaluation of the effect of a coating/lining failure on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history. Inspection intervals are established by a coating specialist qualified in accordance with RG 1.54 [Reference B.3.20). However, inspection intervals should not exceed those specified in GALL SLR Table XI.M42-1.** **The extent of the ICW piping internal inspections is not any less than the following for each coating/lining material and environment combination. The coating/lining environment includes both the environment inside the piping**	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			and the metal to which the coating/lining is attached. Since PTN is a two-unit site, a representative sample of fifty-five (55) 1-foot axial length circumferential segments of piping are inspected per unit. The inspection surface includes the entire inside surface of the 1-foot segment. If geometric limitations impede the inspection of the entire circumferential segment, the number of inspection segments is increased in order to cover an equivalent of fifty-five (55) 1-foot axial length circumferential segments. Where documentation exists that manufacturer recommendations and industry consensus documents (i.e., those recommended in RG 1.54, or earlier versions of those standards) were complied with during installation, the extent of piping inspections may be reduced to nineteen (19) 1-foot axial length circumferential segments of piping of each coating/lining material and environment combination at each unit. Reduction of the number of required ICW piping internal inspections is acceptable for PTN Units 3 and 4 as the ICW systems on each unit are essentially identical (Section 2.3.3.1). ICW system operating conditions (flowrate, pressure, temperature, cooling water source, etc.) for PTN Unit 3 and 4 will continue to provide representative inspection results for each unit. Coating/lining surfaces captured between interlocking surfaces (e.g., flange faces) are not required to be inspected unless the joint has been disassembled to allow access for an internal coating/lining inspection or other reasons. For	

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			areas not readily accessible for direct inspection, consideration is given to the use of remote or robotic inspection tools. For cementitious ICW piping coatings within the scope of the program, 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. c) **A pre-inspection review of the previous two ICW piping inspections is conducted, when available, that includes reviewing the results of the inspections and any subsequent repair activities. A coatings specialist prepares the post-inspection report to include: a list and location of 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.** **Where practical, degradation is projected until the next scheduled inspection. Results are evaluated against the acceptance criteria to confirm that the sampling bases will maintain the component's intended functions throughout the SPEO based on the projected rate and extent of degradation.** ~~c)~~**d)** Ensure the pertinent testing specification coating acceptance criteria include the following:	

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• There are no indications of peeling or delamination. • Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size or frequency should not be increasing between inspections (e.g., ASTM D714-02, "Standard Test Method for Evaluating Degree of Blistering of Paints"). • 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 limitations associated with use of a particular standard. • Minor cracking and spalling of cementitious coatings/ linings is acceptable provided there is no evidence that the coating/lining is debonding from the base material. • As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements. • Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in site-specific design requirements specific to the coating/lining and substrate. **e) Ensure ICW piping coatings/linings that do not meet acceptance criteria are repaired, replaced, or removed. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that**	

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			the extent of repaired or replaced coatings/linings encompasses sound coating/lining material. As an alternative, internal coatings exhibiting indications of peeling and delamination may be returned to service if: (a) physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal; (b) the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered); (c) adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of 3 sample points adjacent to the defective area; (d) an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component; and (e) follow-up visual inspections of the degraded coating are conducted within 2 years from detection of the degraded condition, with a reinspection within an additional 2 years, or until the degraded coating is repaired or replaced. If the ICW piping base metal has been exposed or it is beneath a blister, the component's base material in the vicinity of the degraded coating/lining is examined to determine if the minimum wall thickness is met and will be met until the next inspection. When a blister does not meet the acceptance criteria, and it is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM	

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			International standards endorsed in RG 1.54. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain in service should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister. Additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the site's corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, in all cases, the additional inspections are completed within the interval in which the original inspection was conducted, or if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections. Additional samples are inspected for any recurring degradation to provide	

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			reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections include inspections at both PTN units with the same piping material, environment, and aging effect combination.	

Associated Enclosures:

None