ATTACHMENTS 7P, 8P, 9P AND 10P CONTAIN INFORMATION REQUESTED TO BE WITHHELD FROM PUBLIC DISCLOSURE UNDER 10 CFR 2.390

FPL.

L-2018-166
10 CFR 54.17
10 CFR 2.390

October 16, 2018

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
<u>Safety Review Requests for Additional Information (RAI) Set 3 Responses</u>

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 September 17, 2018, Requests for Additional Information for the Safety Review of the Turkey Point Subsequent License Renewal Application – Set 3 (EPID No. L-2018-RNW-0002) (ADAMS Accession Nos. ML18243A006 and ML18243A007)

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, public and certain non-public (proprietary) responses to the safety review RAIs issued by the NRC on September 17, 2018 (Reference 3). Each RAI response and its corresponding attachment and associated information enclosure are indexed on page 3 of this letter. The attachments identify changes that will be made in a future revision of the SLRA (if applicable).

Attachments 7P, 8P, 9P and 10P have been placed after Attachment 36 of this submittal and contain proprietary information (enclosed within brackets and/or marked 'Withhold from Public Disclosure Under 10 CFR 3.390') that FPL requests be withheld from public disclosure under 10 CFR 2.390(a)(4). The withholding request applications for this proprietary information are enclosed with Attachments 7, 7P, 8, and 8P.

A084
NRR

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

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

Executed on October 16, 2018.

Sincerely,

William Maher
Senior Licensing Director
Florida Power & Light Company

WDM/RFO

Attachments: 40 RAI Responses (refer to Letter Attachment Index)

Enclosures: 6 RAI Response Enclosures (refer to Letter Enclosures Index)

Enclosure 1

Westinghouse Letter CAW-18-4822 dated October 10, 2018, Application for Withholding Proprietary Information from Public Disclosure

Westinghouse Affidavit CAW-18-4822

Proprietary Information Notice and Copyright Notice

WCAP-15355 Revision 0, "A Demonstration of Applicability of SME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4" (Proprietary)

Enclosed are:

1. WCAP-15355 Revision 0, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4" (Proprietary)

2. WCAP-15355-NP Revision 0, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4" (Non-Proprietary)

Also enclosed are the Westinghouse Application for Withholding Proprietary Information from Public Disclosure CAW-18-4822, accompanying Affidavit, Proprietary Information Notice, and Copyright Notice.

As Item 1 contains information proprietary to Westinghouse Electric Company LLC ("Westinghouse"), it is supported by an Affidavit signed by Westinghouse, the owner of the information. The Affidavit sets forth the basis on which the information may be withheld from public disclosure by the Nuclear Regulatory Commission ("Commission") and addresses with specificity the considerations listed in paragraph (b)(4) of Section 2.390 of the Commission's regulations.

Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations.

Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse Affidavit should reference CAW-18-4822 and should be addressed to Camille Zozula, Manager, Facilities and Infrastructure Licensing, Westinghouse Electric Company, 1000 Westinghouse Drive, Building 2 Suite 256, Cranberry Township, Pennsylvania 16066.

Westinghouse

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CAW-18-4822

October 10, 2018

APPLICATION FOR WITHHOLDING PROPRIETARY INFORMATION FROM PUBLIC DISCLOSURE

Subject: WCAP-15355 Revision 0, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4" (Proprietary)

The Application for Withholding Proprietary Information from Public Disclosure is submitted by Westinghouse Electric Company LLC ("Westinghouse"), pursuant to the provisions of paragraph (b)(1) of Section 2.390 of the Nuclear Regulatory Commission's ("Commission's") regulations. It contains commercial strategic information proprietary to Westinghouse and customarily held in confidence.

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-18-4822 signed by the owner of the proprietary information, Westinghouse. The Affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying Affidavit by Florida Power & Light Company.

Correspondence with respect to the proprietary aspects of the Application for Withholding or the Westinghouse Affidavit should reference CAW-18-4822, and should be addressed to Camille Zozula, Manager, Facilities and Infrastructure Licensing, Westinghouse Electric Company, 1000 Westinghouse Drive, Building 2 Suite 256, Cranberry Township, Pennsylvania 16066.

Paul A. Russ

Paul A. Russ, Director
Licensing and Regulatory Affairs

Enclosures:
1. Affidavit CAW-18-4822
2. Proprietary Information Notice and Copyright Notice
3. WCAP-15355 Revision 0, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4" (Proprietary)

CAW-18-4822

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF BUTLER:

I, Paul A. Russ, am authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC ("Westinghouse") and declare that the averments of fact set forth in this Affidavit are true and correct to the best of my knowledge, information, and belief.

Executed on: 10/10/18

Paul A. Russ

Paul A. Russ, Director
Licensing and Regulatory Affairs

(1) I am Director, Licensing and Regulatory Affairs, Westinghouse Electric Company LLC ("Westinghouse"), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Nuclear Regulatory Commission's ("Commission's") regulations and in conjunction with the Westinghouse Application for Withholding Proprietary Information from Public Disclosure accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitute Westinghouse policy and provide the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of

Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage (e.g., by optimization or improved marketability).

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

(iii) There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iv) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, is to be received in confidence by the Commission.

(v) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(vi) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in WCAP-15355, Revision 0, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4" (Proprietary), for submittal to the Commission, being transmitted by Florida Power & Light Company letter. The proprietary information as submitted by Westinghouse is that associated with NRC approval of PWROG-17033-P, "Update for Subsequent License Renewal: WCAP-13045, 'Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems'," and may be used only for that purpose.

(a) This information is part of that which will enable Westinghouse to provide a technical justification for acceptability of the structural integrity of the pump casings for Turkey Point Units 3 and 4 in support of their subsequent license renewal program.

(b) Further, this information has substantial commercial value as follows:

(i) Westinghouse plans to sell the use of similar information to its customers for the purpose of supporting other subsequent license renewal programs.

(ii) Westinghouse can sell support and defense of industry guidelines and acceptance criteria for plant-specific applications.

(iii) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar technical evaluation justifications and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and non-proprietary versions of a document, furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the Affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

COPYRIGHT NOTICE

The reports transmitted herewith each bear a Westinghouse copyright notice. The NRC is permitted to make the number of copies of the information contained in these reports which are necessary for its internal use in connection with generic and plant-specific reviews and approvals as well as the issuance, denial, amendment, transfer, renewal, modification, suspension, revocation, or violation of a license, permit, order, or regulation subject to the requirements of 10 CFR 2.390 regarding restrictions on public disclosure to the extent such information has been identified as proprietary by Westinghouse, copyright protection notwithstanding. With respect to the non-proprietary versions of these reports, the NRC is permitted to make the number of copies beyond those necessary for its internal use which are necessary in order to have one copy available for public viewing in the appropriate docket files in the public document room in Washington, DC and in local public document rooms as may be required by NRC regulations if the number of copies submitted is insufficient for this purpose. Copies made by the NRC must include the copyright notice in all instances and the proprietary notice if the original was identified as proprietary.

Enclosure

Westinghouse Letter CAW-18-4821 dated October 11, 2018, Application for Withholding Proprietary Information from Public Disclosure

Westinghouse Affidavit CAW-18-4821

Proprietary Information Notice and Copyright Notice

LTR-SDA-18-078 P-Attachment, Rev. 0, "Turkey Point Subsequent License Renewal Application RAI Responses" (Proprietary)

Enclosed are the attachments to LTR-SDA-18-078:

1) Turkey Point Subsequent License Renewal Application RAI Responses (Proprietary), October 5, 2018 (LTR-SDA-18-078 P-Attachment)

2) Turkey Point Subsequent License Renewal Application RAI Responses (Non-Proprietary, October 5, 2018 (LTR-SDA-18-078 NP-Attachment)

Also enclosed are Westinghouse Application for Withholding Proprietary Information from Public Disclosure (CAW-18-4821), accompanying Affidavit, Proprietary Information Notice, and Copyright Notice.

As Item 1 contains information proprietary to Westinghouse Electric Company LLC ("Westinghouse"), it is supported by an Affidavit signed by Westinghouse, the owner of the information. The Affidavit sets forth the basis on which the information may be withheld from public disclosure by the Nuclear Regulatory Commission ("Commission") and addresses with specificity the considerations listed in paragraph (b)(4) of Section 2.390 of the Commissioner's regulations.

Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations.

Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse Affidavit should reference CAW-18-4821 and should be addressed to Camille Zozula, Manager, Facilities and Infrastructure Licensing, Westinghouse Electric Company, 1000 Westinghouse Drive, Cranberry Township, Pennsylvania, 16066.

Westinghouse Non-Proprietary Class 3

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CAW-18-4821

October 11, 2018

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: LTR-SDA-18-078 P-Attachment, Rev. 0, "Turkey Point Subsequent License Renewal Application RAI Responses" (Proprietary)

The Application for Withholding Proprietary Information from Public Disclosure is submitted by Westinghouse Electric Company LLC ("Westinghouse"), pursuant to the provisions of paragraph (b)(1) of Section 2.390 of the Nuclear Regulatory Commission's ("Commission's") regulations. It contains commercial strategic information proprietary to Westinghouse and customarily held in confidence.

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Accordingly, this letter authorizes the utilization of the accompanying Affidavit by Florida Power & Light Company.

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Paul A. Russ, Director
Licensing and Regulatory Affairs

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CAW-18-4821

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF BUTLER:

I, Paul A. Russ, am authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC ("Westinghouse") and declare that the averments of fact set forth in this Affidavit are true and correct to the best of my knowledge, information, and belief.

Executed on: 10/11/18

Paul A. Russ, Director
Licensing and Regulatory Affairs

(1) I am Director, Licensing and Regulatory Affairs, Westinghouse Electric Company LLC ("Westinghouse"), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

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Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage (e.g., by optimization or improved marketability).

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

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(iv) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, is to be received in confidence by the Commission.

(v) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(vi) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in LTR-SDA-18-078 P-Attachment, "Turkey Point Subsequent License Renewal Application RAI Responses" (Proprietary), for submittal to the Commission, being transmitted by Florida Power & Light Company letter. The proprietary information as submitted by Westinghouse is that associated with Westinghouse's request for NRC approval of LTR-SDA-18-078 P-Attachment, and may be used only for that purpose.

(a) This information is part of that which will enable Westinghouse to provide a technical justification for acceptability of RCP components for Turkey Point Units 3 and 4 in support of their subsequent license renewal program.

(b) Further, this information has substantial commercial value as follows:

(i) Westinghouse plans to sell the use of similar information to its customers for the purpose of supporting other subsequent license renewal programs.

(ii) Westinghouse can sell support and defense of industry guidelines and acceptance criteria for plant-specific applications.

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Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar technical evaluation justifications and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

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In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the Affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

COPYRIGHT NOTICE

ATTACHMENTS 7P, 8P, 9P AND 10P CONTAIN INFORMATION REQUESTED TO BE WITHHELD FROM PUBLIC DISCLOSURE UNDER 10 CFR 2.390

LETTER ATTACHMENT INDEX			
Attachment	**NRC RAI**	**Attachment**	**NRC RAI**
1	B.2.2.1-1	19	B.2.3.2-2
2	B.2.3.17-1	20	B.2.3.2-3
3	B.2.3.40-1	21	B.2.3.2-4
4	B.2.3.20-1	22	B.2.3.43-1
5	B.2.3.20-2	23	B.2.3.44-1
6	3.4.2.1.2-1	24	B.2.2.4-1
7, 7P	4.7.5-1	25	B.2.3.28-1
8, 8P	4.7.5-2	26	B.2.3.28-2
9, 9P	4.7.5-3	27	B.2.3.28-3
10, 10P	4.7.5-4	28	B.2.3.28-4
11	4.7.5-5	29	4.7.2-1
12	4.7.5-6	30	B.2.3.25-1
13	4.7.5-7	31	B.2.3.25-2
14	4.7.5-8	32	3.3.2.10-1
15	B.2.3.21-2	33	B.2.2.2-1
16	B.2.3.21-3	34	B.2.3.11-1
17	B.2.3.21-4	35	B.2.3.27-1
18	B.2.3.2-1	36	B.2.3.27-2

LETTER ENCLOSURES INDEX			
Attachment	**Enclosure**	**Attachment**	**Enclosure**
7, 7P	1	8, 8P	1
7, 7P	2		

cc: w/o Attachments 7P, 8P, 9P and 10P

Senior Resident Inspector, USNRC, Turkey Point Plant
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. ML18243A006 and ML18243A007 dated September 17, 2018

1. Fatigue Monitoring Program, GALL AMP X.M1

Regulatory Basis:

Title 10 of the Code of Federal Regulation (10 CFR) Section 54.21(a)(3) states for each structure and component subject to an aging management review per § 54.21(a)(1), the applicant shall demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current license basis (CLB) for the subsequent period of extended operation (SPEO).

RAI B.2.2.1-1

Background:

The subsequent license renewal application (SLRA) Section B.2.2.1 and the applicant's program basis document states that the Fatigue Monitoring Program implementing procedure will identify the ten (10) components and the specific projected cycles utilized in their environmentally assisted fatigue cumulative usage factor (CUF_{en}) analyses (i.e., of 80-year projected cycles instead of the design cycles to achieve a CUF_{en} value less than 1.0).

SLRA Section 4.3.3, including supporting fatigue calculations, indicate that nine (9) components that required refined CUF_{en} analyses used 80-year projected cycles instead of the design cycles to achieve a CUF_{en} value less than 1.0. During its review of the applicant's refined CUF_{en} calculations, the staff noted that two (2) additional components (i.e., the pressurizer spray nozzle and pressurizer heater well) may have used 80-year projected cycles in the refined CUF_{en} calculations.

SLRA Section B.2.2.1 includes an enhancement to the "parameters monitored or inspected" program element to update the aging management program (AMP) governing procedure to identify and require monitoring of the 80-year plant design cycles, or projected cycles that are utilized as inputs to component CUF_{en} calculations, as applicable.

Issue:

The staff noted a discrepancy between SLRA Sections B.2.2.1 and 4.3.3, and the applicant's CUF_{en} calculations; thus, it is not clear whether the implementing procedure for the Fatigue Monitoring Program will incorporate the appropriate components and cycle limits from the refined CUF_{en} analyses in order to manage environmentally-assisted fatigue during the SPEO.

Request:

- Please confirm the number and identity of the components for which the 80 year projected cycles were used in the CUF_{en} analysis.
- Please confirm that the implementing procedures for the Fatigue Monitoring Program will be updated to require monitoring of cycle limits for the components for which the CUF_{en} analysis relies on projected cycles.

FPL Response:

- The total number of components that utilized 80-year projected cycles in the associated Time Limited Aging Analyses (TLAAs) included in Section 4.3.3 of the PTN SLRA is eleven (11). This includes nine (9) components that required refined CUF_{en} analyses and two (2) additional components (i.e., the pressurizer spray nozzle and pressurizer heater well) that required a finite element fatigue calculation using the methodology of Subarticle NB-3200 of Section III of the ASME code. These 11 components and the type of analysis that was used to determine the component CUF_{en} value is included in Table 1.
- Table 2 provides a listing of the 80-year projected cycles utilized in the component CUF_{en} analyses. These PTN Unit 3 and 4 80-year projected cycle values will be the cycle limits specified in the implementing procedures for the Fatigue Monitoring Program. The 80-year projected cycles are consistent with the values specific in PTN SLRA Tables 4.3-2 and 4.3-3.

Table 1

Component	**Type of CUF_{en} Analysis**
Reactor Vessel Flange	Refined analysis
Reactor Vessel Shell at Core Support Pads	Refined analysis
CRDM Housing J-Weld	Refined analysis
CRDM Housing Bi-metallic Weld	Refined analysis
CRDM Latch Housing	Refined analysis
CRDM Lower Joint	Refined analysis
Steam Generator Divider Plate	Refined analysis
Steam Generator Tubes	Refined analysis
Pressurizer Spray Nozzle	Finite element analysis
Pressurizer Upper Head	Refined analysis
Pressurizer Heater Well	Finite element analysis

Table 2

Transient Name	Design Cycles	Projected Cycles for 80 Years	
		Unit 3	Unit 4
Reactor Coolant System			
Plant heatup	200	164	181
Plant cooldown	200	164	181
Loss of load cycles	80	28	27
Plant loading at 5%	14,500	533	484
Plant unloading at 5%	14,500	440	451
Step load increase of 10%	2000	79	82
Step load decrease of 10%	2000	164	107
Step load decrease of 50%	200	82	51
Reactor trip cycles	400	272	292
Hydrostatic pressure test at 2485 psig pressure and 400°F	5	2	2
Loss-of-offsite AC electrical power	40	10	19
Loss of flow in one reactor coolant loop	80	26	21
Inadvertent auxiliary spray	10	1	1

References:

None

Associated SLRA Revisions:

The following changes to SLRA Section 4.3.3 and paragraph 5 of SLRA Section B.2.2.1 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Section 4.3.3, pages 4.3-22 and 4.3-23 to update the final CUF_{en} summaries for the "CRDM Housing Bi-metallic Weld" and "Pressurizer Spray Nozzle" as follows:

<u>CRDM Housing Bi-metallic Weld</u>

A revised CUF_{en} was calculated by performing a more refined analysis and crediting 80-year projected design cycles ~~for plant heatup, cooldown, and reactor trips~~ **<u>as presented in Reference 4.3.6.21.</u>**

<u>Pressurizer Spray Nozzle</u>

A revised CUFen was calculated by performing a finite element fatigue calculation using the methodology of Subarticle NB-3200 of Section III of the ASME Code and projected design cycles for plant heatup**<u>,</u>** ~~and~~ cooldown**<u>, and inadvertent auxiliary spray.</u>**

Revise SLRA Section B.2.2.1 as follows:

The resultant CUF_{en} Screening values for all in-scope components are included in Table 4.3.3-2. As indicated in Table 4.3.3-2, the resultant CUF_{en} Screening value for ~~eleven (11)~~ **<u>twelve (12)</u>** components exceeded 1.0 and required additional analysis. As discussed in SLRA Section 4.3.3, ~~ten (10)~~ **<u>eleven (11)</u>** of these component locations utilized 80-year projected cycles instead of the design cycles to achieve a CUF_{en} value less than 1.0. A finite element fatigue calculation was performed for the remaining component to achieve a CUF_{en} value less than 1.0. Therefore, all resultant CUF_{en} values are below the acceptance criteria of 1.0 with the exception of the pressurizer surge line welds. This exception is consistent with the results of the EAF evaluation performed for the PTN PEO. Consistent with the PEO, a flaw tolerance evaluation and inspection program for the pressurizer surge line welds is included in the Pressurizer Surge Line Fatigue AMP to ensure aging effects are managed during the SPEO. The PTN Fatigue Monitoring AMP implementing procedure will identify the ~~10~~ **<u>11</u>** components and the specific projected cycles utilized in their CUF_{en} analyses. The PTN Fatigue Monitoring AMP also relies on the PTN SLR Water Chemistry AMP to provide monitoring of appropriate environmental parameters utilized in calculating environmental fatigue multipliers (F_{en} values).

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

2. Atmospheric Metallic Tanks, GALL AMP XI.M29

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 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. 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.2.3.17-1

Background:

The design basis document for the component cooling water (CCW) system states:

- There is an overhead surge tank and static head tank serving two independent headers.
- A passive failure is defined as a 50 gpm leak resulting from a packing or seal failure. This requirement is cited as an original design basis.
- The passive failure occurs in the long term portion of recovery of an accident.
- The emergency containment coolers are supplied by the CCW system.
- The demineralized water storage system and primary water system provide normal, non-safety related makeup water for operational purposes.

UFSAR Section 9.3.3 "System Evaluation, Availability and Reliability, Leakage Provisions, Component Cooling Loop," states:

> The component which is leaking can be located by sequential isolation or inspection of equipment in the loop. If the leak is in one of the component cooling water heat exchangers, the leaking heat exchanger would be isolated and repaired. During normal operation, the leaking heat exchanger could be left in service with leakage up to the capacity of the makeup line to the system from the primary water storage tank. By manual transfer, emergency power is available for primary water pump operation.

> If a design basis leak (defined as a 50 gpm leak) were to occur coincident with a design basis LOCA, the installed automatic valves in the supply and return lines to the RCP isolate rapidly, such that the inventory remaining in the CCW head tank would be sufficient to ensure continued CCW system operability under all design basis conditions.

UFSAR page 9.3-10 states:

> The CCW head tank has been designed and installed to provide sufficient static head, such that component cooling water temperatures up to 270°F will not initiate steam void formation. The required NPSH [net positive suction head] for one pump at 15,000 gpm is approximately 46 ft. with the installed CCW head tank; the available NPSH is 123.8 ft when the maximum post accident suction temperature is 182.5°F. Therefore, sufficient NPSH is available. Installation of the CCW head tank increases available static head by a nominal 29 psig. That added NPSH will ensure that pump performance will remain unaffected by establishing added margin during elevated temperature operation.

Drawing No. 5613-M-3030, Sheet 1, "Component Cooling Water System," cites a normal volume of 125 gallons in the CCW head tank and a 2000 gallon capacity in the CCW surge tank.

10 CFR 54.4(a)(2) states that all nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of 10 CFR 54.4 should be in scope.

SRP-SLR Section 2.1.3.1.1 states:

> The scoping criterion under 10 CFR 54.4(a)(2), in general, is intended to identify those nonsafety-related SSCs that support safety-related functions. More specifically, this scoping criterion requires an applicant to identify all nonsafety- related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(1). Section III.c(iii) of the SOC [Statements of Consideration] (60 FR 22467) clarifies the NRC's intent for this requirement in the following statement:
>
> > The inclusion of nonsafety-related systems, structures, and components whose failure could prevent other systems, structures, and components from accomplishing a safety function is intended to provide protection against safety function failure in cases where the safety-related structure or component is not itself impaired by age-related degradation but is vulnerable to failure from the failure of another structure or component that may be so impaired.

> Therefore, to satisfy the scoping criterion under 10 CFR 54.4(a)(2), the applicant must identify those nonsafety-related SSCs (including certain second-, third-, or fourth-level support systems) whose failures are considered in the CLB and could prevent the satisfactory accomplishment of a safety-related function identified under 10 CFR 54.4(a)(1). In order to identify such systems, the applicant should consider those failures identified in: (1) the documentation that makes up its CLB, (2) plant-specific operating experience (OE), and (3) industry-wide OE that is specifically applicable to its facility. The applicant need not consider hypothetical failures that are not part of the CLB, have not been previously experienced, or are not applicable to its facility.

NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants," Section A.1.2.1, "Applicable Aging Effects," states, "[h]owever, leakage from bolted connections should not be considered as abnormal events. Although bolted connections are not supposed to leak, experience shows that leaks do occur..." Although this portion of the NUREG-2192 is quoted from a portion that addresses identification of aging effects, it clearly states industry operating experience related to the fact that leaks occur in systems.

NEI 17-01, Section 3.1.2 states, "[a]n applicant should rely on the plant's CLB, actual plant-specific experience, industry wide operating experience, as appropriate, and existing plant-specific engineering evaluations to determine the appropriate SSCs in this category."

Issue:

The staff believes that failure of the makeup water source to the overhead surge tank might prevent the CCW system from meeting its intended function(s).

Based on a review of the UFSAR and the CCW design basis document, the current licensing basis for the CCW includes a passive failure equivalent to a 50 gpm leak resulting from a packing or seal failure occurring in the long term portion of recovery of an accident. In order for the staff to conclude that there is reasonable assurance that the intended functions of the CCW system will be met in the subsequent period of extended operation, it must be concluded that either: (a) aging effects are managed for a source of makeup water (i.e., tank, piping) to the CCW surge tank and static head tank or (b) the CCW surge tank and static head tank have sufficient inventory to sufficiently mitigate the effects of the leakage.

The staff requires further information in regard to the following:

a) Based on a review of SLRA Section 2 and the referenced piping and instrument drawings, it appears that aging effects are not managed for any of the sources of makeup water to the CCW surge tank and static head tank. The UFSAR states that the isolation of the supply and return lines to the reactor coolant pump would not challenge the available inventory in the surge tank and static head tank. However, the SLRA does not contain enough information for the staff to reach a similar conclusion for potential normal leakage in other portions of the CCW system. Even though CCW systems are designed to minimize leakage, no system is leak tight. As evidenced by industry experience, leakage occurs in systems. Normal long term leakage from the CCW system (e.g., packing, flanges, seal leakage, boundary valve leakage) could challenge the available volume in the surge tank during the long term portion of recovery of an accident. As such, long term normal leakage should be considered in regard to determining the scope of components for subsequent license renewal.

b) Given long term leakage and leakage during the sequential isolation operations, it is not clear that the water level in the surge tank and static head tank will be sufficient to meet NPSH or other requirements (e.g., minimum elevation for the CCW head tank to maintain system static pressure above the maximum anticipated saturation pressure post-accident).

c) It is not clear that the CCW supply lines to components in post LOCA high radiation areas would be accessible for isolation in the recovery phase (e.g., RHR pump seal coolers, containment spray pump coolers, safety injection pump coolers, emergency containment coolers).

d) During the audit, it was stated that there are plant-specific off normal operating procedures for conducting the sequential isolation. However, it is not known whether these off normal procedures have had a timed walk through to ensure that isolation of the limiting component is possible prior to the surge tank not meeting the required minimum level.

<u>Request:</u>

1. If there is a flow path from the primary water system, or other suitable inventory source where aging effects will be managed for the tank, piping, piping components, etc., state the flow path and applicable Table 2 AMR items.

2. Alternatively, state the following:

   a. The plant-specific normal long-term leakage rate from the CCW system. State the length of the long term portion of recovery subsequent to a loss of coolant accident. Given plant-specific and industry operating experience, state the expected normal leakage from boundary isolation valves post-LOCA.

   b. The minimum level in the CCW surge tank necessary to support the intended functions of the CCW system including factors such as NPSH and maintaining system static head requirements.

c. Whether the isolation valves necessary to conduct the sequential isolation of CCW components will be accessible during the recovery subsequent to a loss of coolant accident.

d. The maximum time the sequential isolation process could take to perform

FPL Response:

PTN has chosen to address Request 1 above by including the flow path from the PTN Unit 3 and 4 primary water storage tanks (PWSTs) to their respective CCW surge tank in the scope of SLR. This primary water makeup (PWM) system flowpath meets the scoping criterion of 10 CFR 54.4(a)(2) as the flowpath provides a long-term nonsafety-related make-up function that supports safety-related functions of the CCW system. Note that the normal operating water level within the PWSTs contains sufficient water for this SLR function. The aging effects for this PWM flow path will be managed during the SPEO as indicated by the associated SLRA revisions provided below.

Accordingly, Request 2 above does not need to be addressed.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Sections 2.1.5.2.1, 2.3.3.2, 2.3.3.4, 2.3.3.5, 3.3.2.1.5, 3.3.2.2.3, 3.3.2.2.4, 17.2.2.17, B.2.3.17 and Tables 2.3.3.5, 3.3-1,3.3.2-5, and 17-3 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLR Section 2.1.5.2.1 "Nonsafety-Related SSCs Required to Functionally Support Safety-Related SSCs" to add the additional nonsafety-related SSCs as being within the scope of SLR per 10 CFR 54.4(a)(2):

- **The primary water makeup system provides long-term make-up to the Unit 3 and 4 component cooling water (CCW) system surge tanks.**

Revise SLR Section 2.3.3.2 "Boundary" to add the following text after the second paragraph:

The following CCW boundary drawings have been updated as they have been impacted by the addition of the flowpath from the PWM system to the CCW surge tanks discussed in SLRA Section 2.3.3.5.

Turkey Point Unit 3

5613-M-3030, Sheet 1

Turkey Point Unit 4

5614-M-3030, Sheet 1

Revise SLR Section 2.3.3.4 "Boundary" to add the following text after the second paragraph:

The following CVCS boundary drawing has been updated as it has been impacted by the addition of the flowpath from the PWM system to the CCW surge tanks discussed in SLRA Section 2.3.3.5.

Turkey Point Common

5610-M-3046, Sheet 1

Revise SLR Section 2.3.3.5 "Boundary" to add the following text after the second paragraph:

The PWM system SLR boundary drawings have been modified to include the flow path from the PTN Unit 3 and 4 primary water storage tanks (PWSTs) to their respective CCW surge tank. This PWM system flowpath meets the scoping criterion of 10 CFR 54.4(a)(2) as the flowpath provides a long-term nonsafety-related make-up function that supports safety-related functions of the CCW system. The following PWM boundary drawings have been updated to reflect this flowpath.

Turkey Point Unit 3

5613-M-3020, Sheet 1

5613-M-3020, Sheet 2

Turkey Point Unit 4

5614-M-3020, Sheet 1

5614-M-3020, Sheet 2

Revise SLRA Table 2.3.3-5 to add 2 additional rows as follows:

Component Type	Component Intended Function(s)
Pump casing	**Pressure boundary**
Tank	**Pressure boundary**

Revise SLRA Section 3.3.2.1.5 "Materials", "Environments", "Aging Effect Requiring Management", and "Aging Management Programs" as follows:

The materials of construction for the Primary Water Makeup components are:

- Carbon steel
- **Coating**
- Stainless steel

The Primary Water Makeup components are exposed to the following environments:

- Air with borated water leakage
- Air – indoor uncontrolled
- **Air – outdoor**
- Treated water
- **Underground**

The following aging effects associated with the Primary Water Makeup components require management:

- Cracking
- **Loss of coating or lining integrity**
- Loss of material
- Loss of preload

The following AMPs manage the aging effects for the Primary Water Makeup components:

- Bolting Integrity
- Boric Acid Corrosion
- **Buried and Underground Piping and Tanks**
- External Surfaces Monitoring of Mechanical Components
- **Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks**
- One-Time Inspection
- **Outdoor and Large Atmospheric Metallic Storage Tanks**
- Water Chemistry

Revise the last two (2) paragraphs of SLR Section 3.3.2.2.3 as follows:

Auxiliary Systems contain stainless steel bolting, piping, piping components, ducting, ducting components, heat exchanger components, and tanks exposed to both controlled and uncontrolled indoor air as well as outdoor air **and underground**

environments. A review of Turkey Point OE confirms halides are present in both the indoor and outdoor environments at Turkey Point. As such, stainless steel components exposed to indoor and outdoor air **and underground environments** in Auxiliary Systems are susceptible to cracking due to SCC and require management with an appropriate program.

Consistent with the recommendation of GALL-SLR, cracking of these components will be managed by the Bolting Integrity, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, **Buried and Underground Piping and Tanks,** and the External Surfaces Monitoring of Mechanical Components program for components exposed to air internally or externally, respectively. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Bolting Integrity, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, **Buried and Underground Piping and Tanks,** and External Surfaces Monitoring of Mechanical Components AMPs are described in Appendix B.

Revise the last two (2) paragraphs of SLR Section 3.3.2.2.4 as follows:

Auxiliary Systems contain stainless steel piping, piping components, ducting, ducting components, heat exchanger components, and tanks exposed to both controlled and uncontrolled indoor air as well as outdoor air **and underground environments**. A review of Turkey Point OE confirms halides are present in both the indoor and outdoor environments at Turkey Point. As such, all stainless steel components exposed to uncontrolled indoor and outdoor air in the Auxiliary Systems are susceptible to loss of material due to pitting and crevice corrosion and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, loss of material in these components will be managed via the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**, Buried and Underground Piping and Tanks,** and the External Surfaces Monitoring of Mechanical Components AMP for components exposed to air internally or externally, respectively. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of ~~cracking~~ **loss of material due to pitting and crevice corrosion** will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping**, Buried and Underground Piping and Tanks,** and Ducting Components and External Surfaces Monitoring of Mechanical Components AMPs are described in Appendix B.

Revise SLRA Table 3.3-1 as follows. Note that Table 3.3-1 item numbers 3.3-1, 146 and 3.3-1, 246 were revised as part of the response to NRC RAI No. 3.3.2.2.3-1 contained in Attachment 5 to FPL letter number L-2018-152, dated August 31, 2018 (ML18248A257). The revisions to these two (2) table items below supersede those contained in the previous response to NRC RAI No. 3.3.2.2.3-1.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 137	Steel, stainless steel, aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water, raw water, waste water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	~~Not applicable.~~ ~~There are no tanks that fall within the scope of Outdoor and Large Atmospheric Metallic Storage Tanks AMP that are exposed to treated water, raw water, or waste water in the Auxiliary Systems.~~ **Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material in steel tanks exposed to treated water.**

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 146	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	~~Not used.~~ ~~The stainless steel underground piping in the Auxiliary Systems is managed using other line items.~~ **Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP will be used to manage cracking of stainless steel underground piping.**
3.3-1, 246	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	~~Not used.~~ ~~The stainless steel underground piping in the Auxiliary Systems is managed using other line items.~~ There are no underground nickel alloy piping, piping, components, or tanks in the Auxiliary Systems. **Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP will be used to manage loss of material of stainless steel underground piping.**

Revise SLRA Table 3.3.2-5 as follows:

Table 3.3.2-5: Primary Water Makeup - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Underground	Cracking	Buried and Underground Piping and Tanks	VII.I.A-714b	3.3-1, 146	A
Piping	Pressure boundary	Stainless steel	Underground	Loss of material	Buried and Underground Piping and Tanks	VII.I.A-775b	3.3-1, 246	A
Pump casing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Pump casing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Pump casing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A

Table 3.3.2-5: Primary Water Makeup - Summary of Aging Management Evaluation								
Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VII.H1.A-401	3.3-1, 128	A
Tank	Pressure boundary	Carbon steel	Concrete	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VII.H1.A-401	3.3-1, 128	A
Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VII.H1.A-413	3.3-1, 137	A
Tank	Pressure boundary	Coating	Treated water (int)	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	VII.H2.A-416	3.3-1, 138	A
Tank	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VII.H1.A-401	3.3-1, 128	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A

Table 3.3.2-5: Primary Water Makeup - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A

Revise the first paragraph of SLRA Appendix A, Section 17.2.2.17 as follows:

The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP is an existing condition monitoring AMP that manages loss of material. One-time inspections were performed by the PTN Field Erected Tanks Internal Inspection Program for original license renewal. Other plant documents control inspections or activities of the various outdoor storage tanks in the scope of the AMP. The condensate storage tanks (CSTs), common demineralized water storage tank (DWST), refueling water storage tanks (RWSTs), ~~and~~ Unit 3 emergency diesel generator (EDG) fuel oil storage tank (FOST)**, and the primary water storage tanks (PWSTs)** comprise the scope of this AMP.

Revise the first and third paragraphs and the "Enhancements" portion of SLRA Section B.2.3.17 as follows:

The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP is an existing condition monitoring AMP that was formerly the PTN Field Erected Tanks Internal Inspection Program. The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP manages the effects of loss of material on the outside and inside surfaces of metallic aboveground tanks that are located outdoors and constructed on concrete. One-time inspections were performed in accordance with PTN Field Erected Tanks Internal Inspection Program for the original license renewal between 2010 and 2012. As explained below, one-time inspections performed by the PTN Field Erected Tanks Internal Inspection Program for original license renewal will be converted to periodic inspections performed at 10-year intervals starting 10 years prior to the SPEO as part of the PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP. The Unit 3 and Unit 4 condensate storage tanks (CSTs), common demineralized water storage tank (DWST), Unit 3 and Unit 4 refueling water storage tanks (RWSTs)~~, and the~~ Unit 3 EDG fuel oil storage tank (FOST)**, and the Unit 3 and 4 primary water storage tanks (PWSTs)** are included in the scope of this AMP. Tanks supplying water to the fire water system are not within the scope of this program.

The material of construction for each tank is steel. Each tank has an external protective coating. ~~None of the tanks are insulated and therefore, the accessible external surface of each tank shell is managed under the External Surface Monitoring of Mechanical Components AMP (Section B.2.3.23).~~ Each of the tanks is coated on the interior surface. The coated interior surfaces are inspected in accordance with the requirements of the PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.29). Each tank is constructed with a concrete foundation. The concrete foundations are managed by the Structures Monitoring AMP (Section B.2.3.35). The tank design does not specify the use of sealant or caulking for the tank-to-concrete interface. The contents of the CSTs, DWST**,** **PWSTs** and RWSTs are treated water controlled under the Water Chemistry AMP

(Section B.2.3.2). The contents of the EDG FOST is fuel oil controlled under the Fuel Oil Chemistry AMP (Section B.2.3.18).

Enhancements

One-time inspections performed by the PTN Field Erected Tanks Internal Inspection program for original license renewal will be converted to periodic inspections in focused areas performed at 10-year intervals starting no earlier than 10 years prior to the SPEO. Inspections or tests that are required to be completed prior to the SPEO are completed no later than 6 months prior to SPEO or no later than the last RFO prior to SPEO. Scope will be expanded to include the Unit 3 EDG FOST and actions clarified when a tank does not meet acceptance criteria.

Element Affected	Enhancement
1. Scope 6. Acceptance Criteria	Include U3 EDG FOST **and the Unit 3 and 4 PWSTs** in the scope of the program (including design corrosion allowance which is the same as for the CSTs).
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending	Convert one-time inspections for original license renewal to the following periodic inspections: a. Visual examination of tank internal surfaces.* b. Tank bottom thickness measurements.* * These additional inspections will be conducted each 10-year interval starting 10 years prior to entering the SPEO.
7. Corrective Actions	Clarify that increased inspections address each tank in a material environment combination in the same inspection interval, including tanks from both units, IF only one tank is inspected and does not meet acceptance criteria, which requires corrective action.

Revise Commitment 21 of SLRA Appendix A Table 17-3 as follows:

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
21	Outdoor and Large Atmospheric Metallic Storage Tanks (17.2.2.17)	XI.M29	Continue the existing PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP, including enhancement to: a) Add the U3 EDG FOST **and the Unit 3 and 4 PWSTs** and associated acceptance criteria to the scope of the AMP; b) b) Convert one-time inspections for original license renewal to the following periodic inspections, with the associated frequencies and acceptance criteria – • Visual examination of tank internal surfaces • Tank bottom thickness measurements Note: These additional inspections will be conducted each 10-year interval starting 10 years prior to entering the SPEO. c) Clarify that increased inspections address each tank in a material environment combination in the same inspection interval, including tanks from both units, IF only one tank is inspected and does not meet acceptance criteria, which requires corrective action.	This AMP is implemented and inspections or tests begin no earlier than 10 years prior to the SPEO. Inspections or tests that are required to be completed prior to the SPEO are completed no later than 6 months prior to SPEO or no later than the last RFO prior to SPEO. The corresponding dates are as follows: PTN3: 7/19/2022 - 1/19/2032 PTN4: 4/10/2023 - 10/10/2032

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

3. Inaccessible Medium Voltage Cables, GALL AMP XI.E3A

Regulatory Basis:

Section 54.21(a)(3) of 10 CFR requires the 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. As described in SRP-SLR, an applicant may demonstrate compliance with 10 CFR. Section 54.21(a) (3) and Section 54.21(d) by referencing the NUREG-2191, Rev. 0, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," dated July 2017., when the evaluation of the matter in the GALL-SLR Report applies to the plant. Section 54.21(d) of 10 CFR requires an FSAR supplement to include a summary description of the programs and activities for managing the effects of aging.

RAI B.2.3.40-1

Background:

SLRA Appendix A Section 17.2.2.40, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements," states that inaccessible medium-voltage cables designed for continuous wetting or submergence are also included in this AMP for a one-time inspection and test. However, it does not state that "the need for additional tests and inspections is determined by the test/inspection results as well as industry and plant-specific operating experience."

SRP-SLR Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs," for AMP XI.E3A recommends that the UFSAR supplement includes a statement about the need for additional test and inspection. Specifically, it states, "submarine or other cables designed for continuous wetting or submergence are also included in this AMP as a one-time inspection and test with additional periodic tests and inspections determined by one-time inspection results and industry and plant-specific operating experience."

Issue:

The licensing basis for this program for the period of extended operation will not be consistent with the staff-issued guidance documents if the UFSAR supplement does not include the need for additional test and inspection determined by one-time inspection results and industry and plant-specific operating experience.

The staff cannot complete its review of the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements UFSAR supplement without additional information or reviewing the changes to SLRA

Supplement A Section 17.2.2.40 necessary to address the need for additional tests/inspections.

Request:

State the basis for why SLRA Appendix A Section 17.2.2.40 does not cite the need for additional test for submarine or other cables design for continuous wetting or submergence. Alternatively, what are the changes that will be incorporated into SLRA Appendix A Section 17.2.2.40 to include these requirements?

FPL Response:

SLRA Appendix A Section 17.2.2.40 will be revised to state that additional periodic tests and inspections will be determined based on the one-time inspection results and industry and plant-specific operating experience as described in the GALL-SLR Report AMP XI.E3A.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Appendix A Section 17.2.2.40 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Appendix A Section 17.2.2.40 "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements" as follows:

In-scope inaccessible medium-voltage power cables exposed to significant moisture are tested to determine the condition of the electrical insulation. One or more tests may be required based on cable application, construction, and electrical insulation material to determine the age degradation of the cable. The first tests for license renewal are to be completed no later than 6 months prior to the SPEO with subsequent tests performed at least once every six years thereafter. ~~Inaccessible medium voltage cables designed for continuous wetting or submergence are also included in this AMP for a one time inspection and test.~~ **Submarine or other cables designed for continuous wetting or submergence are also included in this AMP as a one-time inspection and test with additional periodic tests and inspections determined by the one-time test/inspection results as well as industry and plant-specific operating experience.**

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

4. One-Time Inspection, GALL AMP XI.M32

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 SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL-SLR 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.2.3.20-1

Background:

Section 54.21(d) of 10 CFR states, "[t]he UFSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging…"

SLRA Section 17.2.2.20, "One –Time Inspection," does not state that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

GALL-SLR Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs," states that the XI.M32, "One-Time Inspection" program will consist of a one-time inspection to verify that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

Issue:

The licensing basis for this program for the period of extended operation will not be consistent with staff-issued guidance documents if the UFSAR supplement does not include the long-term loss of material for steel components exposed to environments that do not include corrosion inhibitors.

The staff cannot complete its review of the AMP UFSAR supplement without additional information to address the long-term loss of material will for steel components exposed to environments that do not include corrosion inhibitors.

Request:

State the basis for why SLRA Section 17.2.2.20 does not cite that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

Alternatively, what are the changes that will be incorporated into SLRA Section 17.2.2.20 to include these requirements?

FPL Response:

The scope of this AMP will include managing long term loss of material due to general corrosion in steel components that are not in an environment that includes a corrosion inhibitor. SLRA Section 17.2.2.20 is revised to state that the One-Time Inspection AMP will manage the long-term loss of material aging effect.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Section 17.2.20 paragraph 1 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

The PTN One-Time Inspection AMP is a new AMP that consists of a one-time inspection of selected components to accomplish the following:

(a) Verify the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the SPEO. The aging effects evaluated are loss of material, cracking, ~~and~~ fouling~~.~~**, and long-term loss of material for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.**

(b) Confirm the insignificance of an aging effect for situations in which additional confirmation is appropriate using inspections that verify unacceptable degradation is not occurring.

(c) Trigger additional actions that ensure the intended functions of affected components are maintained during the SPEO.

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI B.2.3.20-2

Background:

SLRA Table 3.2.2-2, states that carbon steel piping exposed internally to treated borated water will be managed for loss of material by the Water Chemistry and One - Time Inspection programs.

The "scope of program" program element of GALL-SLR AMP XI.M32 states the following:

1. The program cannot be used for structures or components with known age-related degradation mechanisms as determined based on a review of plant-specific and industry OE for the prior operating period.

Periodic inspections are proposed in these cases for structures or components with known age- related degradation.

During the audit, the staff reviewed AR 01638881, which states, "[t]here is a long history of Containment Spray carbon steel piping corrosion at PTN [Turkey Point]." Additionally, the AR states that the Containment Spray System Piping Inspection program was developed to perform ultrasonic testing (UT) with a 54 month frequency. The staff also noted that the AR states "corrosion product buildup can occur within the Containment Spray headers have been documented in several AR..." the AR goes on to state that most of the corrosion is considered to be general boric acid corrosion and there is also a buildup of bimetallic weld transition from carbon to stainless steel.

Issue:

It is not clear to the staff how the One-Time Inspection program will be sufficient for managing age-related degradation of carbon steel piping in the containment spray system, when a history of loss of material is apparent. The One-Time Inspection program states that the program cannot be used for structures or components with known age-related degradation mechanisms as determined based on a review of plant-specific and industry OE for the prior operating period. The program states that periodic inspections are proposed in these cases.

Request:

State the basis for using the One-Time Inspection program for carbon steel piping in the containment spray system. Alternatively, provide the following:

1. Provide a periodic inspection program that will be used to monitor the loss of material for carbon steel.
2. Provide the inspection frequency that will be used to monitor wall thinning for carbon steel piping in the containment spray system.

3. Provide how bimetallic corrosion (galvanic corrosion) will be managed for the weld transition from carbon to stainless steel.

FPL Response:

The carbon steel piping in the containment spray system is located inside containment and is partially filled with stagnant borated water, due to leakage through MOV-3/4-880A/B, up to a maximum water elevation of the refueling water storage tank of 65 feet. The most susceptible locations to loss of material due to generic, pitting, crevice, galvanic, or boric acid corrosion are inspected using ultrasonic thickness measurements in accordance with the existing containment spray system piping inspection AMP. The inspections consider the most susceptible locations due to the bimetallic (galvanic) couplings on the stainless steel elbows to carbon steel pipe (on the replaced elbows) and the carbon steel elbows to the stainless steel pipe (near the containment penetration). The existing program calculates loss of material rates based on the UT measurements and either increases or decreases frequencies of inspections or replaces carbon steel pipe with stainless steel pipe as necessary. The frequency of these inspections were initially set to occur every outage, but the current inspection frequency is every five outages based on an evaluation of the observed loss of material rates and past replacement of limiting carbon steel elbows with stainless steel elbows.

These program activities will continue throughout the subsequent period of extended operation under the internal surfaces of miscellaneous piping and ducting AMP. The internal surfaces of miscellaneous piping and ducting AMP was chosen to subsume these inspections so that the related program elements will govern performing the inspections, monitoring and trending the results, and the proper corrective actions if insufficient results are obtained. In addition, opportunistic inspections will be required if the piping is opened up for other reasons. This AMP is clarified to include the program activities associated with the existing containment spray system piping inspection program. The SLRA is updated to reflect that the inspection of internal surfaces of miscellaneous piping and ducting AMP will manage loss of material for the carbon steel containment spray piping.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.2-1, Table 3.2.2-2, Section 17.2.2.25 and Section B.2.3.25 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Table 3.2-1 Item 90 as follows:

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 090	Steel components exposed to treated water, treated borated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The One-Time Inspection AMP will be used to manage long-term loss of material in the ~~steel containment spray piping and the~~ pressurizer relief tank exposed to treated borated water. The pressurizer relief tank is coated~~and the containment spray piping is normally empty~~.

Revise SLRA Table 3.2.2-2 as follows:

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure Boundary	Carbon steel	Treated borated water (int)	Long-term loss of material	~~One Time Inspection~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	~~V.A.E 434~~ -	~~3.2 1, 090~~ -	~~A~~ H, 1

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure Boundary	Carbon steel	Treated borated water (int)	Loss of material	~~Water Chemistry One Time Inspection~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	-	-	H, 1

Revise SLRA Table 3.2.2-2 plant specific notes as follows:

Plant-Specific Notes for Table 3.2.2-2

1. Aging effect for this component, material, and environment combination is not in NUREG-2191. This line item is specific to the carbon steel piping header for containment spray. This portion of piping is normally drained but is flooded during system testing. The ~~Water Chemistry and One Time Inspection~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components** AMP~~s are~~ **is** used to manage **loss of material and long-term loss of material.** ~~this aging effect as these AMPs are used to manage loss of material in other portions of the treated borated water s~~

Add the following paragraph to the end of SLRA Section 17.2.2.25 on page A-32 as follows:

This AMP is also used to manage loss of material and long-term loss of material for the carbon steel containment spray headers that are exposed to treated borated water. This AMP periodically uses ultrasonic thickness measurements to determine which portions of carbon steel piping should be inspected more frequently or replaced with stainless steel to ensure containment spray system intended function.

Add the following paragraph to the end of SLRA Section B.2.3.25 on page B-205 as follows:

This AMP is also used to manage loss of material for the carbon steel containment spray headers that are exposed to treated borated water. This AMP periodically uses ultrasonic thickness measurements to determine which portions of carbon steel piping should be inspected more frequently or replaced with stainless steel to ensure containment spray system intended function. The current inspection frequency is no less frequent than every five refueling outages but may be increased or decreased depending on future inspection results and the trended loss of material rates.

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI 3.4.2.1.2-1

Background:

SLRA Table 3.4-1, item 3.4.1-81, addresses steel components exposed to treated water and raw water for long-term loss of material due to general corrosion. The applicant also states that this item is not applicable and there are no components exposed to raw water in the Steam and Power Conversion Systems.

SRP-SLR Table 3.4-1, item 3.4.1-81 addresses steel components exposed to treated water and raw water for long-term loss of material due to general corrosion.

Issue:

The staff reviewed the SLRA and confirmed that there are no components in the Steam and Power Conversion Systems that are exposed to raw water. However, SLRA Table 3.4.1, item 3.4.1-81 also addresses steel components exposed to treated water. It is not clear to the staff how the applicant will manage steel components exposed to treated water for long term loss of material due to general corrosion in the Steam and Power Conversion Systems.

Request:

State the basis for why SLRA Table 3.4-1, item 3.4.1-81 does not include steel components exposed to treated water for long term loss of material. Alternatively, provide additional information on how steel components exposed to treated water will be managed for long term loss of material due to general corrosion.

FPL Response:

The steam and power conversion systems are treated with corrosion inhibitors and are therefore not susceptible to long-term loss of material. SLRA Table 3.4-1 item 81 is revised to clarify that the steam and power conversion systems are not susceptible to long-term loss of material.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.4-1, Item 081 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Table 3.4-1: Summary of Aging Management Evaluation for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 081	Steel components exposed to treated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no components exposed to raw water in the Steam and Power Conversion Systems. **The Steam and Power Conversion Systems treated water contains corrosion inhibitors so long-term loss of material is not an applicable aging effect.**

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

5. Reactor Coolant Pump Integrity Analysis, GALL TLAA 4.7

Regulatory Basis:

Section 54.21 (c) 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 (CLB) 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 the managing the effects of aging during the subsequent period of extended operation (SPEO) 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 subsequent renewed license will continue to be conducted in accordance with the CLB. As described in SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL-SLR 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 4.7.5-1

Background:

The regulation in 10 CFR 54.21(c)(1)(ii) states that, for a specific time limited aging analyses (TLAA) that is dispositioned in accordance with this regulation, the applicant must demonstrate that the analysis has been projected to the end of the SPEO. Subsequent license renewal application (SLRA) Section 4.7.5, "Code Case N-481 Reactor Coolant Pump Integrity Analysis," identifies the examination reactor coolant pump (RCP) casing in the current licensing basis as a TLAA item.

In 2000, the applicant submitted for NRC review and approval the 60-year license renewal application. As part of that application, the applicant performed a reactor coolant pump (RCP) integrity analysis for Turkey Point Units 3 and 4 as documented in Westinghouse topical reports, WCAP-13045 and WCAP-15355. To demonstrate continued compliance during SPEO, the Pressurized Water Reactor Owner's Group (PWROG) re-evaluated WCAP-13045 associated with the application of Code Case N-481 to the RCP casing during the SPEO as documented in PWROG-17033, Revision 0. The applicant submitted the topical report PWROG-17033, Revision 0 as part of the SLRA.

Issue:

The applicant referenced following three reports in Section 4.7.5 of the SLRA.

1. WCAP-13045, Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems.

2. WCAP-15355, A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4, and
3. PWROG-17033-P/NP, Revision 0, entitled "Update for Subsequent License Renewal: WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems", October 2017.

By letter dated June 14, 2018, Pressurized Water Reactor Owners Group (PWROG) submitted, for NRC review and approval, topical report PWROG-17033-P & NP, Revision 1, under the NRC's topical report review process for generic use.

Request:

a. Submit WCAP-15355 for staff review so that the staff can verify how Code Case N-481 is applicable to the examination of the pump casing.
b. Discuss any technical changes between Revision 0 and Revision 1 and their impact to Revision 0 of PWROG-17033.

FPL Response:

a. WCAP-15355-NP, Revision 0, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4" (Non-Proprietary), is included as Enclosure 2 to this RAI response.

   It should be noted that the NRC staff had previously reviewed WCAP-15355, in the year 2012, for the Turkey Point Units 3 and 4 pump casing report for the extended power uprate (EPU), and concluded that the report is acceptable for EPU conditions (which post-dates the 60 year license renewal program as well). See NRC safety evaluation and acceptance of WCAP-15355 for Turkey Point EPU in "Turkey Point Units 3 and 4 – Issuance of Amendments Regarding Extended Power Uprate (TAC NOS. ME4907 and ME 4908)," dated June 2012, ML11293A365.

b. The subject topical report supports Turkey Point Units 3 and 4 subsequent license renewal application (80 year design life) to satisfy the requirements of 10 CFR 54.21(c)(1) evaluations of time-limited aging analyses.

   Revision 0 of this report was issued by the Owners Group prior to December 2017 and was included as an attachment (along with other reports) to FPL's Subsequent License Renewal Application for Turkey Point Units 3 and 4. Subsequent to FPL's submittal, the PWROG determined that a final licensing review should be performed on the attached reports to ensure clarity of information. The PWROG reports were revised based on the licensing comments and then issued to the NRC for review and acceptance for referencing in regulatory actions.

No new analysis was performed during the revision process for these documents. In Revision 1 of PWROG-17033, the "Purpose and Background" sections were expanded to provide past examples of NRC approval of Code Case N-481 evaluations based on WCAP-13045. Between Revision 0 and Revision 1 of these documents, the methodology, inputs, reported numerical results, margins to criteria allowable values, and conclusions remain unchanged.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

Enclosure 1. Westinghouse Letter CAW-18-4822 dated October 10, 2018, Application for Withholding Proprietary Information from Public Disclosure

Enclosure 2, WCAP-15355-NP, Revision 0, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4" (Non-Proprietary)

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI 4.7.5-2

Issue:

Page 1-2 of PWROG-17033-P/NP, Revision 0, states that Westinghouse has several models for the RCP. There are eight different models of RCPs in Westinghouse type pressurized water reactors (PWRs), Models 63, 70, 93, 93A, 93A-1, 93D, 100A, and 100D.

Request:

a. Discuss the material, casing wall thickness, and model number of RCP casing at Turkey Point.

b. Discuss whether the pump drawings in Section 3 of WCAP-13045 are consistent with or representative of the actual pumps installed at Turkey Point.

FPL Response:

a. Based on plant specific information and evaluation performed in WCAP-15355, the Turkey Point Units 3 and 4 RCP casings are Westinghouse Model 93 design. The RCP casings are made from SA-351 CF8 cast stainless steel. The wall thickness varies between [ ][a,c,e] (see Table 5-1 in WCAP-15355) at the locations of the postulated flaws.

b. The pump casing drawing, portrayed in Figure 3-3 in Section 3 of WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems", is representative of the Model 93 pump casings installed at Turkey Point Units 3 and 4. Thus, the Model 93 pump design drawing as shown in Figure 2-1 of WCAP-15355 (consistent to the drawing in Figure 3-3 of WCAP-13045) is used in the plant specific Code Case N-481 evaluations (WCAP-15355).

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

Enclosure. Westinghouse Letter CAW-18-4821 dated October 11, 2018, Application for Withholding Proprietary Information from Public Disclosure

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI 4.7.5-3

Issue:

As shown in WCAP-13045, the applicant postulated a flaw of ¼ T depth (T is the wall thickness of the RCP casing) having an aspect ratio of 6 to 1 in accordance with Code Case N-481. The locations of the flaws are identified in Section 9 of WCAP-13045. The NRC staff notes that the applied loading to analyze the postulated flaw are generic in nature. Tables 11-2 to 11-9 of WCAP-13045 provided the generic Japp values (the applied J-integral) for various flaws under various loading conditions for various pump models.

Request:

a. Confirm that the locations of the postulated flaws in WCAP-13045 represent the high stress areas of the pump casing at Turkey Point.

b. Discuss whether the J_{app} values in WCAP-13045 bound the J_{app} values from the RCPs at Turkey Point.

c. Discuss which flaw identification number (potential proprietary information) in Tables 11-2 to 11-5 represents the worst (limiting) case in pump casing at Turkey Point.

d. The staff notes that the postulated 1/4T flaw in the pump casing satisfies the crack stability criteria; however, discuss the depth of a flaw in the pump casing that would not satisfy the crack stability criteria.

FPL Response:

a. As discussed in the response to RAI 4.7.5-2(a), the primary loop pump casing of Turkey Point Units 3 and 4 are Westinghouse Model 93 design fabricated from SA-351 CF8 cast stainless steel. Therefore, the locations of the postulated flaws shown in Figure 9-1 of WCAP-13045, which is for Model 93 pump design, represent the high stress areas of the pump casing for Turkey Point. Furthermore, Figure 5-1 of WCAP-15355 shows the flaw evaluation locations for Turkey Point at the high stress regions. These flaw locations as shown in Figure 5-1 of WCAP-15355 are the same locations evaluated in Figure 9-1 of WCAP-13045, and therefore, these locations are the high stress areas of the pump casing at Turkey Point.

b. The pump casing evaluations in WCAP-13045 are a generic integrity evaluation applicable to all Westinghouse design pump casings which demonstrates compliance to ASME Code Case N-481. WCAP-13045 provides enveloping or bounding criteria whereby a specific plant, such as Turkey Point, need only show that the pump casings of interest fall under the umbrella established in WCAP-

13045. The loads used in the WCAP-13045 analysis were selected to be conservative for a majority of the plants.

For Turkey Point, the plant specific loads were not adequately covered by the umbrella loads considered in WCAP-13045; thus, the J_{app} values of WCAP-13045 do not completely bound Turkey Point. Therefore, a plant specific flaw evaluation (stability evaluation) was performed for Turkey Point in WCAP-15355.

In WCAP-15355, the J_{app} values have been recalculated using Turkey Point specific loads and material properties. As discussed in Section 5.4 of WCAP-15355, the plant specific evaluations continue to meet the stability criteria. It should be noted that since the work performed in WCAP-15355 in the year 2000, Turkey Point Units 3 and 4 has implemented EPU (extended power uprate). A review of the changes in the operating parameters (temperature or pressure) and loads due to the EPU demonstrate that the uprate has an insignificant impact on the stability evaluations in WCAP-15355 (as mentioned in response to RAI 4.7.5-1(a), the NRC has accepted WCAP-15355 for EPU conditions in 2012). There have been no other plant modifications that would impact the evaluations in WCAP-15355. Therefore, the plant specific J_{app} values considered in WCAP-15355 are still applicable for the primary loop pump casings of Turkey Point Units 3 and 4.

c. As discussed in the response to RAI 4.7.5-3(b), the stability results presented in WCAP-13045 were re-evaluated for Turkey Point Units 3 and 4 using Turkey Point specific loads and material properties. These plant specific stability results are provided in Table 5-2 of WCAP-15355. Per Table 5-2 of WCAP-15355 for Turkey Point, the most limiting flaw location is at [ ][a,c,e]. However, even for this most limiting flaw scenario, the stability margins are met, as J_{app} is less than the J_{max}, and the T_{app} is below T_{mat}.

d. As described in the response to RAI 4.7.5-3(c), the flaw identification number [ ][a,c,e] is determined to be the most limiting flaw location, which still meets the stability criteria with sufficient margins (per Table 5-2 of WCAP-15355). However, as noted at the end of Section 4.2 of WCAP-15355, there is more margin available in the stability analysis since the fracture toughness values used in Table 5-2 of WCAP-15355 are per WCAP-13045, which are very conservative. An alternative method based on NUREG/CR-4513 Revision 1, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems," was used to recalculate the fully aged toughness values using the actual chemistry of Turkey Point Units 3 and 4 pump casings (see end of Section 4.2 of WCAP-15355).

Based on NUREG/CR-4513 Rev. 1, the calculated fracture toughness values specific for Turkey Point pump casings are [ ][a,c,e]. These values are higher than the conservative fracture toughness values used in Table 5-2 of WCAP-15355, which are [ ][a,c,e]. Thus, additional margin is available for the stability criteria if the industry and NRC-approved methodology is used from NUREG/CR-4513, Rev. 1.

Note that subsequent to the work performed in WCAP-15355, the correlations in NUREG/CR-4513, Rev. 1 have been updated in May 2016 as documented in NUREG/CR-4513 Revision 2. A comparison of the fracture toughness correlations for CF8 materials shows that there is a minor change in the equation to calculate the fracture toughness (specifically the "n" term in the equation, $J = C\Delta a^n$). With the use of the latest correlations in NUREG/CR-4513, Rev. 2, the fracture toughness allowable values [ ][a,c,e] continue to be larger than the fracture toughness values used in Table 5-2 of WCAP-15355. Thus, there is additional margin available in the stability analysis for Turkey Point Units 3 and 4 pump casings than that shown in Table 5-2 of WCAP-15355, based on NUREG/CR-4513, Rev. 2.

It should be noted that the Japp values exponentially increase with increasing flaw sizes; thus, on a generic basis for Turkey Point, the stability criteria can be met for flaw depths larger than 1/4T (25% of thickness), such as approximately in the flaw depth range of [ ][a,c,e] of the wall thickness based at the different flaw locations. Postulated flaws larger than the range mentioned above would have difficulty in satisfying the crack stability criteria, unless other parameters can be re-assessed (i.e. refinement in loads, stresses, material properties, etc.). However, for Turkey Point, as discussed in WCAP-15355, the stability criteria are met per the guidance of Code Case of N-481 for postulated flaw depth of 1/4T.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

(Refer to) Attachment 8 Enclosure. Westinghouse Letter CAW-18-4821 dated October 11, 2018, Application for Withholding Proprietary Information from Public Disclosure

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI 4.7.5-4

Issue:

Second paragraph on Page 3-2 of PWROG-17033 stated that

> "…The transient stresses used in the fatigue crack growth are generic and encompass the various pump designs; furthermore, these stresses have not changed for the subsequent license renewal period (80 years). The number of predicted cycles for 80 years of service are assumed to be bounded by the transient cycles considered in Table 12-2 of WCAP-13045; moreover, the transient definitions are also not expected to change over the 80-year design life…"

However, it is not clear that the generic stresses used in WCAP-13045 bound the transient stresses in pump casing at Turkey Point. Also, it is not clear that the number of transient cycles used in the fatigue growth calculations in WCAP-13045 bound the transient cycles that are predicted in the Turkey Point SLRA.

Fourth paragraph on Page 3-2 of PWROG-17033 stated that a flaw of depth 0.3 inches is the maximum acceptable flaw size for the pump casing.

Request:

a. Demonstrate that the stresses used in WCAP-13045 bound the stresses at the Turkey Point pump casing in the fatigue crack growth calculations.

b. Discuss whether the number of transient cycles used in the fatigue growth calculations bound the transient cycles that are predicted for the 80 years of SPEO in the Turkey Point SLRA.

c. Discuss the length of the postulate flaw, orientation of the flaw, and the direction of its growth (e.g., crack grows radially, axially or circumferentially; or into the wall thickness) in the fatigue crack growth calculations.

FPL Response:

a. The Turkey Point Units 3 and 4 plant specific report WCAP-15355, Section 6.0, "Fatigue Crack Growth Assessment" states that postulated cracks subjected to various cyclic conditions were considered for the fatigue growth analysis of Model 93 pump casings. The highest stress location was considered for the fatigue crack growth, which is the region at flaw location [ ]^{a,c,e}. As discussed in Section 6.1, the stresses representative of this location are shown in Figure 8-8 of WCAP-13045, which is for the Model 93 design that is present at Turkey Point Units 3 and 4.

As discussed in the responses to RAI 4.7.5-2(a), the material, geometry and model number of the RCP casing at Turkey Point is the same as that analyzed in WCAP-13045; therefore, due to the similarities in the geometrical and material parameters, the stresses used in the FCG evaluation are also the same from the model considered in WCAP-13045 to the Turkey Point pump design.

Furthermore, Section 3 (Tables 3-1 and 3-2) of WCAP-15355, shows a comparison of the normal and faulted loads between Turkey Point and WCAP-13045. Based on Table 3-2, the faulted loads (forces and moments) based on WCAP-13045 are larger (bounding) than the Turkey Point loads. The normal moments based on Table 3-1, which are from WCAP-13045, are larger (bounding) than the Turkey Point moments; however, the generic normal force (per Table 3-1) is slightly lower than the Turkey Point force. However, fatigue crack growth (FCG) evaluations are based on stress which is a combination of forces and moments. Therefore, the slight difference in force is accounted for by the bounding moments considered in the generic analysis from WCAP-13045. Thus, the piping stresses in WCAP-13045 are bounding for Turkey Point Units 3 and 4. Note that the loads and moments in Tables 3-1 and 3-2 are for normal operating steady state stresses (deadweight, pressure, and thermal expansion piping loads, etc.), which are considered in the FCG analysis; however the FCG analysis is also based on transient stress ranges. As discussed in Section 6 of WCAP-15355, the generic transients considered in the FCG evaluation of WCAP-13045 were reviewed against the actual plant operating transient severity and frequency. Based on the review, it was concluded that the typical design transient and cycles use in WCAP-13045 can also be applied for Turkey Pont Units 3 and 4. It should be noted that the EPU conditions do not impact the loads and transient as previously mentioned in the response to RAI 4.7.5-3(b).

As an additional measure of conservatism, the fatigue crack growth analysis performed in PWROG-17033 doubled the number of transient cycles used in the WCAP-13045 to account for the increase in plants life from 60 to 80 years of operation to demonstrate that the fatigue crack growth analysis performed in WCAP-13045 remains valid, which also demonstrates that the fatigue crack growth analysis for Turkey Point Units 3 and 4 in WCAP-15355, Section 6 remains valid.

Thus, based on the above discussions, the FCG evaluation considered for Model 93 pump design in WCAP-13045 are acceptable and representative for Turkey Point Pump casings.

b. The number of transient cycles considered in the fatigue crack growth evaluation is presented in Table 12-2 of WCAP-13045. The design transients and cycles for Turkey Point Units 3 and 4 are provided in Tables 4.3-2 and 4.3-3 of the Turkey Point SLRA, ML18113A146, in which the number of design cycles bound the projected 80 year transient cycles in all cases. Comparing these tables to Table 12-2 of WCAP-13045 demonstrates that the number of transient cycles considered in the fatigue crack growth evaluations in WCAP-13045 bound the number of design cycles for Turkey Point Units 3 and 4. [

]a,c,e.

As discussed in the response to RAI 4.7.5-4(a), for additional conservatism, the fatigue crack growth analysis performed in PWROG-17033 doubled the number of transient cycles used in WCAP-13045 to account for 80 years of operation to demonstrate that the fatigue crack growth analysis performed in WCAP-13045 remains valid, which also demonstrates that the fatigue crack growth analysis for plant specific assessments such as Turkey Point Units 3 and 4 in WCAP 15355, Section 6 remains valid.

c. For the Model 93 (Turkey Point) pump casing, the fatigue crack growth evaluation which produced the most limiting results were for postulated flaws at the [
]a,c,e. For the Model 93A pump casing, the limiting fatigue crack growth results were for a postulated flaw oriented in the [

]a,c,e.

The FCG analysis for postulated flaw depths (flaw length is based on the aspect ratio flaw length/flaw depth, of 6:1) into the pump casing wall thickness is provided in Table 12-3 of WCAP-13045 for Model 93 pump design. The smallest postulated flaw depth evaluated in WCAP-13045 and PWROG-17033 is based on an initial depth of 0.3". Other initial flaw depths were also considered, as shown in Table 12-3, for sensitivity analyses to demonstrate that the growth due to FCG is small. Therefore, the postulated flaw depths used in the FCG are equal to and well in excess of the maximum acceptable flaw size (flaw depth of 0.3") in the Acceptance Standards in Table IWB-3518-2 (for pressure retaining welds in pump casings) up to the 2007 Edition of the ASME Section XI code. The flaw depth of 0.3" is still the maximum acceptable flaw size in the Acceptance Standards Table IWB-3519.2-2 (for pump casings) in later editions of the ASME Section XI Code. Therefore, the flaw depth of 0.3" and the other larger postulated flaw size cases in WCAP-13045 were provided as sensitivity studies to demonstrate that the flaws do not grow significantly over time.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

(Refer to) Attachment 8 Enclosure. Westinghouse Letter CAW-18-4821 dated October 11, 2018, Application for Withholding Proprietary Information from Public Disclosure

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI 4.7.5-5

Issue:

The applicant performs visual examinations of the pump casing in accordance with Code Case N-481. Code Case N-481(a) requires a VT-2 visual examination of the exterior of all pumps during the hydrostatic pressure test required by Table IWB-2500-1, Category B-P.

Code Case N-481(b) requires a VT-1 visual examination of the external surfaces of the weld of one pump casing. Code Case N-481(c) requires a VT-3 visual examination of the internal surfaces whenever a pump is disassembled for maintenance.

Request:

a. Discuss any degradation in the pump casing that need to be addressed in the SPEO.
b. Discuss defense-in-depth measures and/or aging management programs that are in place to alert the operators to take corrective actions should leakage or cracking occur at the pump casing during the SPEO.

FPL Response:

a. Consistent with the requirements of Code Case N-481, the external surfaces of the PTN Unit 3 and 4 reactor cooling pump (RCP) casings have received VT-1 visual examinations during the applicable refueling outages. No recordable indications were identified during these inspections.

   In addition, partial VT-3 visual examinations of the internal surfaces of the Unit 3 and 4 RCP C casings were performed during refueling outages when the pumps were disassembled. These were partial examinations of accessible portions of the internal surfaces of the pump casings with the pump diffuser in place. No recordable indications were identified during these inspections.

   Based on these inspection results to date, no pump casing degradation needs to be addressed during the SPEO at this time.

   Note that the examination requirements of Code Case N-481 were incorporated into the 2000 Addenda of the ASME Section XI Code. In addition, the external surfaces examination of the RCP casings was deleted from the 2008 Addenda of the Code.

b. Defense-in-depth measures that are in place to alert operators to take corrective actions should leakage occur in containment are described in the "Containment" section writeup of Section 2.1.5.2.3 of Revision 1 of the PTN SLRA. In addition, PTN Technical Specification (TS) 3/4.4.6 includes the operability requirements for the reactor coolant leakage detection systems and TS 3.4.6.2 provides the operational leakage limits for the reactor coolant system (RCS). PTN plant operating procedures provide the methodology to be used when performing RCS leak rate calculations.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI 4.7.5-6

Issue:

The WCAP-13045 report is referenced in SLRA Section 4.7.5 (crack stability analysis for RCP casings) and PWROG-17033-P, Revision 0 report that was submitted as part of the SLRA. The WCAP-13045 report is a technical basis document of PWROG-17033-P, Revision 0. Section 11.1 of WCAP-13045 addresses the crack stability analysis results for postulated flaws in the Model 93 pump casings made with CF8M cast austenitic stainless (CASS). Specifically, the stability analysis in the WCAP-13045 report indicates that postulated flaw 5-93 is subject to the loss of load transient (upset condition) and is identified as the highest stressed location.

WCAP-13045 also indicates that on a plant-specific basis, a yield strength level slightly greater than 20 ksi is sufficient to confirm the flaw stability at flaw location 5-93. The WCAP report further indicates that such a yield strength level (greater than 20 ksi) will ensure that the stability criteria regarding the fracture toughness and tearing modulus are met (i.e., applied J-integral < J_{max} of the material, and applied tearing modulus T < T_{max} of the material).

In contrast, the SLRA (specifically, Table 2 of PWROG-17033, Revision 0) uses a yield strength level less than 20 ksi to calculate the fracture toughness properties of the CF8M material in the crack stability analysis. In addition, the SLRA does not clearly address whether postulated flaw 5-93 meets the crack stability criteria for 80 years of operation when the crack stability analysis uses the updated fracture toughness properties such as those in NUREG-4513, Revision 2.

Request:

Describe how the applicant's crack stability analysis confirms the stability of postulated flaw 5-93 (CF8M material at the highest stressed location) taking into account the plant-specific yield strength of the material and actual loading conditions.

FPL Response:

The RCP casings at Turkey Point Units 3 and 4 are Westinghouse Model 93 design fabricated from SA-351 CF8 cast stainless steel. The discussion on evaluation of postulated flaws with assumptions on certain yield strengths in WCAP-13045 (Tables 11-2 through 11-4) are for SA-351 CF8M materials not CF8 materials. Furthermore, the Turkey Point crack stability analysis was completed on a plant specific basis in Section 4, "Material Characterization," and Section 5, "Stability Evaluations," of WCAP-15355. It was determined that, as described in the response of RAI 4.7.5-3(b), the stability results (J_{app}) were required to be recalculated based on Turkey Point specific material properties and loads as shown in Table 5-2 of WCAP-15355. Also, as described in response to RAI 4.7.5-3(d), the plant specific evaluation in WCAP-15355 demonstrated that there are additional margins available if NUREG/CR-4513 fracture toughness were to be used in the stability criteria in lieu of the conservative fracture toughness values of WCAP-13045.

Further discussion on yield strength as it pertains to the stability evaluation is provided in the response to RAI 4.7.5-8, as well.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI 4.7.5-7

Issue:

Page 2-4 of PWROG-17033 stated that "...the fracture toughness correlations used for the full aged condition is applicable for plants operating at and beyond 15 EFPY (Effective Full Power Years) for the CF8M materials..."

Request:

Provide the exact EFPY for Turkey Point Units 3 and 4 as of January 1, 2018.

FPL Response:

The Effective Full Power Years (EFPY) through December 31, 2017 for Turkey Point Units 3 and 4 are 33.69 EFPY and 33.74 EFPY, respectively.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI 4.7.5-8

Issue:

Section 11.2 of WCAP-13045 discusses the crack stability analyses for Model 93 pump casings. In the discussions, there is a postulated flaw that exceeded the stability criteria under certain assumptions on yield stress and operating conditions.

Request:

Discuss whether the pump casing at Turkey Point would have a postulated flaw with the yield stresses of the Turkey Point pump casing that would exceed the crack stability criteria as the case discussed in Section 11.2 of WCAP-13045. If the crack stability criteria will be exceeded, discuss how this issue can be resolved.

FPL Response:

The crack stability analysis results for Model 93 pump casings is provided in Tables 11-2 through 11-5 of WCAP-13045. The discussion of evaluation of postulated flaws with assumptions on certain yield strengths that would exceed crack stability criteria pertains to Tables 11-2 through 11-4 (WCAP-13045), which is for SA-351 CF8M materials not CF8 materials. Turkey Point Units 3 and 4 pump casings are fabricated based on CF8 material in lieu of CF8M materials. For CF8 material, as discussed in Section 11.2 of WCAP-13045, the stability criteria are met for all conditions, as shown in Table 11-5 of WCAP-13045.

Thus, the discussion of a postulated flaw that exceeded the stability criteria under assumptions on yield and operating conditions is not directly applicable for Turkey Point. The material property consideration for Turkey Point is also discussed in Sections 4 and 5 of WCAP-15355. Furthermore, the J-integral stability results are recalculated in WCAP-15355 as discussed in the responses of RAI 4.7.5-3 and meet the stability criteria based on a plant specific evaluation for Turkey Point CF8 pump casings.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

6. Selective Leaching, GALL AMP XI.M33

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 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.2.3.21-2

Background:

SLRA Table 3.3.2-15 states that gray cast iron valve bodies and fire hydrants exposed to soil will be managed for loss of material using the Buried and Underground Piping and Tanks program. The components are not being managed for loss of material due to selective leaching.

The "scope of program" program element of GALL-SLR AMP XI.M33, "Selective Leaching," states that gray cast iron components exposed to soil are susceptible to selective leaching.

Issue:

It is unclear to the staff why the gray cast iron valve bodies and fire hydrants are not being managed for loss of material due to selective leaching.

Request:

State the basis for not managing the gray cast iron valve bodies and fire hydrants for loss of material due to selective leaching. Alternatively, state the changes to the SLRA necessary to address loss of material due to selective leaching for the gray cast iron valve bodies and fire hydrants.

FPL Response:

Gray cast iron valve bodies and fire hydrants exposed to soil are subject to loss of material due to selective leaching and this aging effect is managed by the Selective

Leaching AMP as described in SLRA B.2.3.21 and SLRA 17.2.2.21. This aging effect will be managed by the Selective Leaching AMP. SLRA Table 3.3.2-15 is revised to include rows for gray cast iron valve bodies and fire hydrants exposed to soil with loss of material managed by the Selective Leaching AMP.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.3.2-15 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Table 3.3.2-15: Fire Protection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Fire hydrant	Pressure Boundary	Gray cast iron	Soil (ext)	Loss of material	Selective Leaching	VII.G.A-02	3.3-1, 072	A
Valve body	Pressure Boundary	Gray cast iron	Soil (ext)	Loss of material	Selective Leaching	VII.G.A-02	3.3-1, 072	A

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI B.2.3.21-3

Background:

The "detection of aging effects" program element of GALL-SLR AMP XI.M33, "Selective Leaching," states the following:

a. One-time inspections are only conducted for components exposed to closed-cycle cooling water (CCCW) or treated water when no plant-specific operating experience (OE) of selective leaching exists in these environments.

b. Opportunistic and periodic inspections are conducted for components exposed to raw water, waste water, or soil, and for components in CCCW or treated water where plant-specific OE includes selective leaching in these environments.

SLRA Section B.2.3.21 states "[t]o date, PTN site-specific OE has not revealed selective leaching in components exposed to treated water. Those components are only subject to a one-time inspection unless that inspection identifies selective leaching."

During its audit, the staff noted that during the license renewal "C" auxiliary feedwater (AFW) lubricating oil cooler inspection, selective leaching was found on the gray cast iron bonnet end bells and divider plates. In addition, the staff noted that the AFW lubricating oil cooler uses demineralized water.

SLRA Table 3.0-1, "Service Environments for Mechanical Aging Management Reviews," states that "[t]reated water is demineralized water and is the base water for all clean systems."

Issue:

During its audit, the staff noted that selective leaching was identified on components exposed to a treated water environment. Based on this observation, it is unclear to the staff why one-time inspections are appropriate for components susceptible to selective leaching exposed to a treated water environment.

Request:

State the basis for why one-time inspections are appropriate for components susceptible to selective leaching exposed to a treated water environment.

FPL Response:

One-time inspections are appropriate for copper alloy > 8% aluminum and copper alloy > 15% Zn components susceptible to selective leaching exposed to a treated water environment as there has been no OE of leaching of these materials in that environment. As stated in the response to RAI B.2.3.21-1, the Selective Leaching AMP will use periodic and opportunistic inspections to manage loss of material due to selective leaching in gray cast iron and cast iron components. SLRA Section B.2.3.21 is revised to clarify that only copper alloy >8% aluminum and copper alloy >15% zinc components in treated water environments have not experienced selective leaching at PTN and that there are no copper alloy >8% aluminum or copper alloy >15% zinc components exposed to soil at PTN.

References:

FPL Letter L-2018-152 dated August 31, 2018, Safety Review Requests for Additional Information (RAI) Set 1 Responses

Associated SLRA Revisions:

The following changes to SLRA Section 17.2.21 and Section B.2.3.21 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Section 17.2.21 paragraph 2 as follows:

This AMP includes a one-time inspection for components exposed to a treated water environment when site-specific OE has not revealed selective leaching in these environments. To date, no site-specific OE at PTN has revealed selective leaching **in copper alloy >8% aluminum and copper alloy >15% zinc components**, therefore, a one-time inspection is required. The AMP also includes periodic inspections for components that are exposed to raw water, waste water, lubricating oil, or soil environments **and cast iron / gray cast iron components exposed to treated water.** ~~and~~ **The AMP also includes** opportunistic inspections whenever components are opened, or whenever buried or submerged surfaces are exposed**.**~~, and these periodic~~ **Periodic** inspections are conducted at an interval of no greater than every 10 years during the SPEO.

Revise SLRA Section B.2.3.21 Paragraph 3 as follows (includes the markup to bullet 8 from the response to RAI B.2.3.21-1):

To date, PTN site-specific OE has not revealed selective leaching in **copper alloy >8% aluminum and copper alloy >15% zinc** components exposed to treated water. Those components are only subject to a one-time inspection unless that inspection identifies selective leaching. For components in other environments, periodic inspections will be performed every 10 years and opportunistic inspections will be performed when possible. The populations requiring examination and their type of required inspections for PTN 3 and 4 are:

- Copper alloy > 8 percent aluminum exposed to raw water (Periodic and Opportunistic)
- Copper alloy > 8 percent aluminum exposed to treated water (One-Time)

- ~~Copper alloy > 8 percent aluminum exposed to soil (Periodic and Opportunistic)~~
- Copper alloy > 15 percent zinc and raw water (Periodic and Opportunistic)
- Copper alloy > 15 percent zinc and treated water (One-Time)
- ~~Copper alloy > 15 percent zinc exposed to soil (Periodic and Opportunistic)~~
- Gray cast iron exposed to raw water (Periodic and Opportunistic)
- Gray cast iron **and cast iron** exposed to treated water (~~One-Time~~ **Periodic and Opportunistic**)
- Gray cast iron and waste water (Periodic and Opportunistic)
- Gray cast iron and lubricating oil (Periodic and Opportunistic)
- Gray cast iron exposed to soil (Periodic and Opportunistic)
- Ductile iron exposed to raw water (Periodic and Opportunistic)

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI B.2.3.21-4

Background:

The "corrective actions" program element of GALL-SLR AMP XI.M33, "Selective Leaching," states "[t]he program includes a process to evaluate difficult-to-access surfaces (e.g., heat exchanger shell interiors, exterior of heat exchanger tubes) if unacceptable inspection findings occur within the same material and environment population."

SLRA Section B.2.3.21, "Selective Leaching," does not include the statement above regarding difficult-to-access surfaces.

SLRA Tables 3.2.2-1, 3.2.2-2, 3.2.2-4, 3.3.2-2, 3.3.2-4, 3.3.2-8, 3.3.2-10, 3.3.2-15, 3.3.2-16, and 3.4.2-3 states that heat exchanger components will be managed for loss of material due to selective leaching using the Selective Leaching program.

Issue:

It is unclear to the staff why SLRA Section B.2.3.21 does not address a process to evaluate difficult-to-access surfaces given that the program manages heat exchanger components.

Request:

State the basis for why SLRA Section B.2.3.21 does not address a process to evaluate difficult-to-access surfaces if unacceptable inspection findings occur within the same material and environment population.

FPL Response:

With the exception of the treated water environment associated with the CCW heat exchangers tubes and upper bearing oil cooler heat exchanger for each RCP, all of the heat exchangers with difficult to access surfaces have corresponding components with the same material and environment combination such that inspection results for surfaces that are not difficult to access can be evaluated before needing to inspect susceptible heat exchangers surfaces. The susceptibility of the heat exchangers to selective leaching is similar to that of other components with the same material and environment combinations. If acceptance criteria are not met and there are not a sufficient number of components that are not difficult to access to meet the additional inspection population criteria, then heat exchanger surfaces most susceptible to selective leaching will be made available for inspection. SLRA Section B.2.3.21 is revised to include the process for evaluating difficult to access surfaces.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Section B.2.3.21 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Add the following paragraph after the second paragraph in SLRA Section B.2.3.21 on Page B-181 as follows:

Heat exchangers within the scope of the program contain surfaces that may be difficult to access. If acceptance criteria are not met and there are not a sufficient number of components that are not difficult to access to meet the additional inspection population criteria, then heat exchangers surfaces most susceptible to selective leaching will be made available for inspection. If a heat exchanger will need to be made available for inspection, the work order will contain the specific instructions for the extent of disassembly, inspection, and reassembly as necessary.

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

7. Water Chemistry, GALL AMP XI.M2

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 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 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.2.3.2-1

Background:

In its SLRA, Section B.2.3.2, "Water Chemistry," the applicant claimed consistency with the GALL-SLR Report for the AMP XI.M2, "Water Chemistry." The GALL-SLR Report recommends the monitoring and control of reactor water chemistry in accordance the Electric Power Research Institute (EPRI) PWR Primary Water Chemistry Guidelines, Revision 7. Additionally, the "Monitoring and Trending," program element, states that "Chemistry parameter data are recorded, evaluated, and trended in accordance with the EPRI Water Chemistry Guidelines."

During the In-Office audit, the staff reviewed the procedure 0-ADM-651, "Nuclear Chemistry Parameters Manual," Revision 12, to evaluate whether the applicant is consistent with the GALL-SLR Report recommendations for the "Water Chemistry" AMP. The staff reviewed Section 5.3, "Reactor Coolant System Action Level Responses," which describes applicant actions when water chemistry parameters exceed certain values. In its procedure, the applicant states that formal technical reviews are "recommended" for prolonged abnormal water chemistry conditions.

Issue:

The EPRI PWR Primary Water Chemistry Guidelines, Revision 7, state that technical reviews are necessary for prolonged abnormal water chemistry conditions. It is not clear to the staff why formal technical reviews of prolonged abnormal water chemistry conditions are not required.

Request:

Justify why technical reviews of prolonged abnormal water chemistry conditions are 'recommended by procedure,' instead of 'necessary' as identified in the EPRI guidelines.

FPL Response:

Revision 12 of PTN procedure 0-ADM-651, "Nuclear Chemistry Parameters Manual," Section 5.3, outlines the Action Level Responses for the reactor coolant system chemistry parameters. 0-ADM-651 states "it is recommended" that a formal technical review be performed for prolonged abnormal water chemistry conditions where Revision 7 of the EPRI PWR Primary Water Chemistry Guidelines states a formal technical review is required to be performed in response to prolonged abnormal water chemistry conditions. As such, Element 5 of the SLRA Section B.2.3.2 Water Chemistry AMP requires enhancement to be consistent with NUREG-2191 AMP XI.M2. The PTN SLRA Appendix A Table 17-3 and Section B.2.3.2 are updated to reflect the needed enhancements as well as the commitment associated with these enhancements.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Appendix A Table 17-3 and Section B.2.3.2 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Appendix A Table 17-3 as follows:

Table 17-3

List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
6	Water Chemistry (17.2.2.2)	XI.M2	Continue the existing PTN Water Chemistry AMP~~.~~**, including enhancement to:** **a) Align the PTN action level responses in 0-ADM-651 with the recommended action level responses provided in EPRI 3002000505, PWR Primary Water Chemistry Guidelines, Rev.7 to specify prolonged abnormal values require a formal technical review.**	~~Ongoing~~**No later than 6 months prior to the SPEO, i.e.:** **PTN3: 1/19/2032** **PTN4: 10/10/2032**

Revise SLRA Section B.2.3.2 as follows:

NUREG-2191 Consistency

The PTN Water Chemistry AMP will be consistent**, with enhancements,** with the 10 elements of NUREG-2191, Section XI.M2, "Water Chemistry."

Exceptions to NUREG-2191

None

Enhancements

~~None~~

The PTN Water Chemistry AMP will be enhanced for alignment with NUREG-2191, as discussed below. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element	**Enhancement**
5. Monitoring and Trending	**Align the PTN action level responses in in the implementing procedure with the recommended action level responses provided in EPRI 3002000505, PWR Primary Water Chemistry Guidelines, Rev.7 to specify prolonged abnormal values require a formal technical review.**

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI B.2.3.2-2

Background:

In its SLRA, Section B.2.3.2, "Water Chemistry," the applicant claimed consistency with the GALL-SLR Report for the AMP XI.M2, "Water Chemistry." The GALL-SLR Report recommends taking corrective actions for abnormal chemistry conditions as established in the EPRI PWR Primary Water Chemistry Guidelines, Revision 7. The "Corrective Actions," program element, states that "...corrective actions are taken to bring the parameter back within the acceptable range...."

During the In-Office audit, the staff reviewed the procedure 0-ADM-651, "Nuclear Chemistry Parameters Manual," Revision 12, Section 5.7 "Secondary Systems – Power Operation," to evaluate whether the applicant is consistent with the recommendations for the Water Chemistry AMP in the GALL-SLR Report.

Issue:

The EPRI PWR Secondary Water Chemistry Guidelines recommend the applicant develop a site-specific action for Action Level 2 oxygen levels in the secondary water. During its review of the procedure the NRC staff noted that no plant specific action is specified for Action Level 2 oxygen levels in the secondary water.

Request:

Justify why a site-specific action for Action Level 2 oxygen levels in the secondary water is not included in 0-ADM-651.

FPL Response:

Revision 12 of 0-ADM-651, "Nuclear Chemistry Parameters Manual," Table 5-6 has a note which states, "A plant-specific action that allows the oxygen source to be identified and corrected while minimizing the risk to steam generator integrity shall be developed. Reduction to ≤ 50% power may not be a proper response to this Action Level 2 situation." The intent of this note is to initiate in-situ planning to reduce risk to the steam generator integrity based on the specific plant conditions surrounding the event. Dissolved oxygen is closely monitored and it is expected that several actions will have been taken prior to reaching an Action Level 2 value. As such, the Action Level 2 response will be dependent upon the prior actions taken, and the unique circumstances of the event. Therefore, no changes are required to be made as the response for Action Level 2 oxygen levels is considered to be consistent with the guidance.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI B.2.3.2-3

Background:

In its SLRA, Section B.2.3.2, "Water Chemistry," the applicant claimed consistency with the GALL-SLR Report for the AMP XI.M2, "Water Chemistry." The GALL-SLR Report recommends adherence to the parameter limits established in the EPRI PWR Primary Water Chemistry Guidelines, Revision 7.

During the In-Office audit, the staff reviewed procedure 0-ADM-651, "Nuclear Chemistry Parameters Manual", Revision 12, Section 5.2.3, "Power Operation (Reactor Critical)," which describes the Mode 1 normal chemistry values. In addition, Updated Final Safety Analysis Report (UFSAR) Table 4.2-2, "Reactor Coolant Water Chemistry Specification," also specifies Mode 1 normal chemistry values.

Issue:

The values recommended by the EPRI PWR Primary Water Chemistry Guidelines for chlorides, fluorides, sulfates, and conductivity during power operations do not appear to be consistent between procedure 0-ADM-651, and the UFSAR. It should be clear which values are used as the controlling parameters during power operations in order to ensure consistency with the GALL-SLR.

Request:

State the basis for the apparent discrepancies between the water chemistry parameter values for chlorides, fluorides, sulfates, and conductivity during power operations in the UFSAR and procedure 0-ADM-651.

FPL Response:

Revision 12 of PTN procedure 0-ADM-651, "Nuclear Chemistry Parameters Manual," is the controlling document for primary water chemistry parameter values and it is consistent with the chloride, fluoride, sulfate, and conductivity Action Level values specified for power operation in Revision 7 of the EPRI PWR Primary Water Chemistry Guidelines. The inconsistency between the PTN controlling chemistry procedure and the UFSAR will be addressed through the PTN corrective action program.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI B.2.3.2-4

Background:

The GALL-SLR Report recommends the use of AMP XI.M21A, "Closed Treated Water Systems," to manage aging effects for components in closed, treated water systems. The GALL-SLR Report AMP XI.M2, "Water Chemistry," relies on the monitoring and control of reactor water chemistry to control impurities in primary and secondary water consistent with the guidance found in the EPRI PWR Primary and Secondary Water Chemistry Guidelines.

The emergency diesel generator (EDG) cooling water systems are not part of the primary, or secondary water systems. Instead, as noted in document FPLCORP020-REPT-010, "Turkey Point Units 3 and 4 Subsequent License Renewal Screening Results Emergency Diesel Generator Cooling Water System," Revision 1, Section 2.2.1, "System Intended Functions," one of the safety related functions of the EDG cooling water systems is to "Function independently from other cooling water systems...." In addition, the EPRI Closed-Cooling Water Systems Guidelines provide guidance, and recommendations for monitoring and controlling cooling water in EDG cooling jackets.

SLRA Table 3.3.2-16, "Emergency Diesel Generator Cooling water – Summary of Aging Management Evaluation," states that loss of material for stainless steel piping, and valve body, in a treated water environment will be managed using the "Water Chemistry," AMP described in Section B.2.3.2 of the SLRA. Additionally, these AMR items reference Table 3.3.1. Item 3.3-1, 085.

Issue:

1. It is not clear to the staff how the applicant's "Water Chemistry" AMP will be effective to monitor and mitigate the loss of material in the EDG cooling water system.
2. It is not clear to the staff why Table 1 Item 3.3.1, 085, is referenced under a Table 3.3.2-16 item which covers stainless steel piping. Table 1 Item 3.3.1, 085 covers elastomer piping.

Request:

1. State the basis for why the "Water Chemistry" AMP will be an effective program for monitoring and mitigating the loss of material in the EDG cooling water system.
2. Provide the basis for referencing Table 1 Item 3.3-1, 085, for Table 3.3.2-16 items which cover stainless steel piping.

FPL Response:

The stainless steel piping and valve body components in the PTN emergency diesel generator cooling water system, exposed to an internal environment of treated water, are subject to loss of material and are managed by the Closed Treated Water Systems AMP. Table 3.3.2-16 of the SLRA is updated to reflect the appropriate aging management program, NUREG-2191 item, and Table 1 item for the stainless steel piping and valve body components.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.3.2-16 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Table 3.3.2-16: Emergency Diesel Generator Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	~~Water Chemistry~~ ~~One Time Inspection~~ **Closed Treated Water Systems**	~~VIII.D1.Sp-87~~ **VII.C2.A-52**	~~3.3-1, 085~~ **3.3-1, 049**	~~A~~**B**
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	~~Water Chemistry~~ ~~One Time Inspection~~ **Closed Treated Water Systems**	~~VIII.D1.Sp-87~~ **VII.C2.A-52**	~~3.3-1, 085~~ **3.3-1, 049**	~~A~~**B**

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

8. Electrical Cable Connections Not Subject to 10 CFR 50.49 Requirements, GALL AMP XI.E6

Regulatory Basis:

Section 54.21(a)(1) of 10 CFR requires the applicant to identify and list those structures and components subject to an aging management review. Section 54.21(a)(3) of 10 CFR requires the applicant to demonstrate that the effects of aging for structures and components within the scope of license renewal and subject to an AMR pursuant to 10 CFR 54.21(a)(1) 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. As described in SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL-SLR Report, and when evaluation of the matter in the GALL-SLR Report applies to the plant.

RAI B.2.3.43-1

Background:

SLRA Section B.2.3.43 describes the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Requirements Program as consistent with GALL-SLR Report AMP XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The staff reviewed the applicant's basis document FLCORP 020-REPT-114, "Aging Management Program Basis Document - Electrical Cable Connections Not Subject to 10 CFR 50.49 Requirements" that describes the ten elements of the proposed program and concludes that there is consistency with the corresponding elements of the GALL-SLR Report AMP XI.E6.

The "monitoring and trending" element of the GALL-SLR Report AMP XI.E6 states in part "... condition monitoring inspections or test results that are trendable provide additional information on the rate of electrical connection degradation." The staff noted that the applicant's proposed program element "monitoring and trending" does not include trending when inspections or test results are trendable.

The applicant's program basis document FLCORP 020-REPT-114 identifies various types of connections used at PTN that will be included in the sampling population for inspection and testing. During the operating experience review of the applicant's corrective actions data base, the NRC staff noted that split bolt connections are utilized at PTN. However, FLCORP 020-REPT-114 does not mention split bolt connections to be included in the sampling basis as a category of connection to be tested.

Issue:

1. It is not clear to the NRC staff that the applicant's proposed program element "monitoring and trending" is consistent with the corresponding program element in the GALL-SLR Report AMP XI.E6.
2. It is not clear to the NRC staff whether all applicable in-scope connection types utilized at PTN will be considered in the sampling population of the electrical connection to be inspected or tested.

Request:

1. Justify why the "trending and monitoring" element of the proposed program B.2.3.43, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Requirements" does not include trending when the results of condition monitoring or tests are trendable as described in the GALL-SLR Report AMP XI.E6, or update the appropriate implementing documents to include trending when the results of condition monitoring or test are trendable.
2. Clarify whether split bolt connections used at PTN are included in the connection types in the sampling population of the proposed program B.2.3.43, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Requirements," or update the appropriate implementing documents to include these connections.

FPL Response:

1. Consistent with the GALL-SLR Report AMP XI.E6, PTN intends to implement the proposed program as a one-time test wherein a representative sample of cable connections within the scope of SLR are to be tested on a one-time test basis to confirm the absence of age-related degradation of the cable connection. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. The one-time test results, if successful, would provide only one data point whereby trending would be rendered academic. If one-time test results lead to periodic testing, condition monitoring inspections or test results will be trended to provide additional information on the rate of electrical connection degradation as directed under the PTN corrective action program in accordance with the FPL quality assurance (QA) program (10 CFR Part 50, Appendix B). The GALL-SLR Report AMP XI.E6 also includes an alternative to measurement testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc. In the alternate method, the applicant may use a visual inspection of insulation materials to detect surface anomalies. When this alternative visual inspection is used to check cable connections, the first inspection is completed prior to the SPEO and at least every 5 years thereafter. The alternate method allows for trending because it is a periodic inspection and multiple condition monitoring data points would be accumulated during the SPEO for trending purposes. However, PTN does not intend to

implement the alternate method.

2. PTN utilizes split bolt connectors on ground cable repairs and temporary power cable connections (e.g. for outage work). Split bolt connections in these applications are not within the scope of subsequent license renewal because they do not perform or support a system level function per 10 CFR 54.4. PTN does not utilize split bolt connectors as a cable splice for electrical circuits within the scope of subsequent license renewal. All cable splices for electrical circuits are made in accordance with approved plant procedures and predominately incorporate Raychem products. Therefore, split bolt connections are not within the scope of the proposed program B.2.3.43 "Electrical Cable Connections Not Subject to 10 CFR 50.49 Requirements" and are not specified as a connection type in the sampling population.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

9. High-Voltage Insulator, GALL AMP XI.E7

Regulatory Basis:

Section 54.21(a)(1) of 10 CFR requires the applicant to identify and list those structures and components subject to an aging management review. Section 54.21(a)(3) of 10 CFR requires the applicant to demonstrate that the effects of aging for structures and components within the scope of license renewal and subject to an AMR pursuant to 10 CFR 54.21(a)(1) 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. As described in SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL-SLR Report, and when evaluation of the matter in the GALL-SLR Report applies to the plant.

RAI B.2.3.44-1

Background:

SLRA Section B.2.3.44 describes the new High-Voltage Insulators program as consistent with GALL-SLR Report AMP XI.E7, "High-Voltage Insulators." This section states that PTN utilizes polymer insulators made of silicon rubber. However, SLRA Table 3.6.1 and Table 3.6.2-1 describe PTN high-voltage insulators as porcelain type rather than insulators made of polymers. The GALL-SLR evaluated porcelain type insulators, but polymer insulators have not been addressed in this document. Presence of material and component types not previously addressed in the GALL-SLR report constitutes a site-specific material/environment combination that should be addressed in the SLRA. However, the applicant's SLRA Tables 3.6.1 and 3.6.2-1 do not mention this site-specific component type (polymer insulators).

Polymer High-voltage insulators are typically composed of material such as fiberglass, silicone rubber (SIR), ethylene propylene rubber (EPR), epoxy, silicone gel, sealants, ductile iron, aluminum, aluminum alloys, steel, steel alloys, malleable iron, and galvanized metals. Exposure to air-outdoor can cause degradation and aging effects that can result in reduced insulation resistance due to deposits and surface contamination, reduced insulation resistance due to polymer degradation as well as loss of material caused by wind blowing on transmission conductors, all of which may require aging management. This component material/environment combination has not previously been evaluated in GALL-SLR and is considered a site-specific condition to be evaluated by the applicant.

Polymer high-voltage insulators have been shown to have unique failure modes with little advance indications. Surface buildup of contamination can be worse for SIR (compared to porcelain insulators) due to absorption by silicone oil, especially in late stages of service life.

Typical aging degradation and mechanisms for polymer high-voltage insulators include (but not limited to) the following:

- Deposits and buildup of surface contamination causing reduced insulation resistance, arcing and flashover
- Polymer degradation caused by thermal degradation of organic material, radiolysis and photolysis of UV sensitive material, oxidation, and moisture intrusion
- Stress corrosion cracking (SCC) of glass fibers due to sheath degradation
- Swelling of SIR layer due to chemical contamination
- Sheath wetting caused by chemicals absorbed by oil from SIR compound
- Brittle fracture of rods resulting from discharge activity, flashunder, and flashover
- Chalking and crazing of insulator surfaces resulting in contamination, arcing, and flashover
- Water penetration through the sheath followed by electrical failure
- Bonding failure at rod and sheathing interface
- Water ingress through end fittings causing flashunder, corrosion and fracture of glass fibers

Additionally, aggressive environment due to presence of and excrements from birds and rodents containing chemicals such as uric acid, phosphates, and ammonia can accelerate degradation.

Issue:

The applicant's SLRA does not include a discussion of site-specific material/environment combination relating to polymer high-voltage insulators installed at PTN for in-scope SBO recovery path transmission lines and switchyard components.

Request:

Justify why the actual material used for high-voltage insulators is not listed in the SLRA, or revise the SLRA to include polymer high-voltage insulator material/environment combination. Provide a discussion of industry operating experience, surface buildup of contaminations, applicable aging, degradations, aging mechanisms, aging effects, aging studies, and any site-specific aging management programs to address relevant AERMs to ensure the aging effects of these components composed of the particular constituent material exposed to the PTN site environment will be adequately managed.

FPL Response:

Porcelain high-voltage (H-V) insulators are used in the PTN Unit 4 station blackout (SBO) recovery path. Polymer H-V insulators are used in the PTN Unit 3 SBO recovery path. The polymer H-V insulators are suspension type insulators used in the string bus connecting the 240KV transmission lines from the Unit 3 240kV switchyard to the high side bushings of Start-up Transformer (SUT) No. 3. As stated in SLRA section 2.5.1.4, Drawing 5610-E-1, sheet 1 (Reference 2.5.3.6 of the SLRA), depicts the electrical interconnection between Turkey Point Unit 3 and the offsite transmission network. The highlighted portions of SLR drawing 5610-E-1, sheet 1 identifies the PTN Unit 3 restoration power path used for offsite power following a SBO event. The polymer H-V insulators used in the PTN Unit 3 SBO recovery path are manufactured by NGK-Locke. Polymer insulators are not addressed in the GALL-SLR (NUREG-2191).

Operating Experience

The Electrical Power Research Institute (EPRI) document 1007752 provides an industry history of polymer insulator development. This EPRI document refers to EPRI's non-ceramic insulator (NCI) failure database. The NCI database includes, but is not limited to, polymer, polymeric, and composite insulators. The database includes detailed information on individual failures and is updated as failures are reported. Information on failures since the 1970s is included in the database. As of September 2002, EPRI had entered information on 161 failures. An additional 46 international failures were added from an IEEE Task Force Report. The total identified number of failures worldwide is a little more than 200. In addition to failure information, some manufacturers also provided information on the number of units sold. Based on this information the average failure rate for all the manufacturers that provided sales information was 1 per 65,500 units sold. Except for one manufacturer that experienced no failures, the individual manufacturer failure rates varied from 1 per 65,000 to 1 per 31,000 units sold.

As of the end of December 2017, EPRI's polymer insulator database indicates that there have been approximately 300 total failures reported. This is an increase of approximately 100 total failures from the 2002 total of slightly more than 200, which is approximately seven failures per year on average worldwide.

As of June 2015, NGK-Locke (NGK) had supplied 4 million polymer insulators (suspension, tension, and line post) in the US and around the world since 1993. NGK polymer insulators were included in the 2002 EPRI survey of American utilities that utilized polymer insulators. In 2011, NGK had indicated a failure rate of less than 0.0005%/yr. The NGK polymer insulators used in the PTN Unit 3 SBO recovery path were installed in December 2012 and have experienced no recorded failures since their installation.

The extensive operating experience in transmission and distribution systems demonstrates that polymer insulators are reliable replacements for porcelain insulators and consistently operate with a long service life with little or no maintenance.

Surface Buildup of Contamination

Contamination flashovers account for less than 5% of polymer insulator failures. Laboratory tests and field installation experience have shown that polymer insulators exhibit resistance to contamination flashovers that is superior to that of ceramic insulators. One of the specific advantages of polymer insulators over ceramic insulators is the superior contamination performance. This is attributed both to the difference in the wettability of the surface materials and the differences in geometry. The contamination performance of polymer insulators is dependent on both the design of the insulator and the material from which the insulator is made. Materials with long-term water repellant characteristics provide better contamination performance than those without such characteristics. Flashovers caused by contamination generally occur during drizzle, fog, or high humidity conditions due to a reduction in the surface electrical resistance.

Hydrophobicity is the surface property that causes a water drop to form a bead. The sheds and coverings of the PTN Unit 3 polymer H-V insulators are silicone rubber (SR). The surface wetting properties of the silicone rubber material of the PTN's polymer insulators are highly hydrophobic. Water contacting hydrophobic surfaces tends to form into beads. Silicone rubber is naturally hydrophobic, has excellent resistance to UV, and minimizes leakage currents on the surface of the insulator, all of which help polymer insulators perform well in contaminated environments. Silicone rubbers are characterized by having a low surface energy that results in highly hydrophobic surfaces. This property prevents the insulator surface from becoming completely wet, thereby suppressing leakage currents under contaminated conditions. Water deposited on the surface of the rubber cannot dissolve the encapsulated contamination to create a conductive film. The lightweight silicone chains in the rubber surface material impregnate the contaminant layer, making it hydrophobic as well which is what gives the silicone rubber superior contamination performance. Washing a silicone rubber housing will temporarily wash off the surface silicone oil along with the contamination. The silicone oil will replenish itself by the migration of low molecular weight silicone oil from the bulk material migrating to the surface, but the contamination performance of the rubber is reduced until it does. NGK states that the surface and hydrophobicity will be recovered within approximately 24 hours. The only case where washing becomes necessary is when an enormous amount of bird excrement has accumulated on the insulators. As a result, contaminant flashovers are unlikely. Consequently, silicone rubber insulators can withstand high levels of contamination.

The PTN Unit 3 polymer H-V insulators manufactured by NGK use a compression molding to give shape to the silicone rubber covering and to form the silicone rubber covering onto the fiberglass reinforced plastic (FRP) rod. The stacked sheds or watersheds are also made of silicone rubber. The Si-O molecular bonds (inorganic backbone of silicone) are very stable in the NGK silicone rubber formulation. The Si-O bond is stronger than the amount of energy provided by UV radiation found in sunlight, making the silicone resistant to UV degradation. In addition to providing protection against ultraviolet radiation, electrical aging, and corona effect, silicone exhibits hydrophobic properties, which provide excellent recovery characteristics to control leakage currents in highly polluted or coastal environments. The NGK silicone rubber formulation has_ consistently outperformed EPR formulations in its hydrophobicity, its hydrophobicity recovery rate, and its electrical properties in contaminated environments. The PTN Unit 3 insulators are designed with a standard type shed profile (designated SS-for a medium contamination environment) using an alternating shed pattern to increase the leakage current distance. There are no industries within the 0-5 mile radius of PTN, with approximately one-half of the total area within the 0-5 mile radius being formed by the coastal waters in Biscayne Bay. PTN is located on a shallow bay and is not subject to a harsh salt environment primarily due to the lack of wave action. Additionally, periodic rainfall tends to wash away any salt deposits from the polymer H-V insulator surfaces. Therefore, the rate of contamination buildup on the polymer H-V insulators is not significant. These NGK polymer insulators have superior design characteristics to the porcelain insulators they replaced and provided better protection against contamination buildup due to hydrophobic material properties, and insulator design configuration.

Aging Studies

A number of accelerated aging tests have been conducted worldwide to evaluate the long-term performance of polymer insulators. These tests are designed to simulate specific environments around which an aging cycle is developed. The design of the aging cycle is dependent on the primary aging mechanism under consideration. For example, if a highly contaminated environment is being considered, a higher number of pollution events may be included in the cycle. In the case of an aging test simulating a low-contamination environment, the number, or duration, of wetting events may be increased. Another important consideration when designing an aging cycle is to include rest periods where silicone rubber-based insulators are able to recover their hydrophobicity.

EPRI performed accelerated aging tests on 230 kV polymer high-voltage insulators from 2001 to 2005 to evaluate the long-term performance of composite component applications on transmission systems. The accelerated aging chamber had a computer-controlled environmental system simulating a defined climate by varying temperature, clean fog, salt fog, clean rain, UV radiation, and humidity. The environment selected for the accelerated aging test is a warm temperate climate similar to that of the southeastern United States, and Louisiana is included in the EPRI area for the southeastern United States. Polymer insulators from four manufacturers including NGK were used in the EPRI accelerated aging tests. The aging chamber simulated 28.3 years for these tests of 230 kV polymer high-voltage insulators. One failure was noted out of 41 units at 25 years of aged service, but this was not an NGK-manufactured insulator. Investigators compared the polymer insulators test results to analysis of service-aged polymer insulators and concluded the results of each were reasonable. The NGK polymer H-V insulators installed on the PTN Unit 3 SBO recovery path are specifically designed and manufactured to minimize the likelihood of failure modes identified by aging studies and operating experience with polymer insulators.

SLRA Polymer Insulator Materials

NGK polymer H-V suspension insulators have three main components: the fiberglass reinforced plastic (FRP) rod, the silicone rubber housing, and metal end-fittings. The PTN Unit 3 polymer H-V insulators and connection hardware have the following materials: silicone rubber, fiberglass, aluminum alloy, stainless steel, galvanized metal (galvanized ductile iron, galvanized forged steel).

Need for Site Specific Aging Management Program

As shown in the following table, the aging effects for polymer high-voltage insulators are similar to porcelain high-voltage insulators with some variations. The aging effects of reduced insulation resistance due to deposits or surface contamination, and loss of material due to mechanical wear caused by wind blowing on transmission conductors are the same as porcelain high-voltage insulators. Polymer H-V insulators have the additional aging effect of reduced insulation resistance due to polymer degradation (e.g. due to thermal or thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation induced oxidation, moisture intrusion).

Material	**Stressor or Mechanism**	**Potential Aging Effects**
Silicone Rubber	Deposits or surface contamination	Reduced insulation resistance
Metal	Mechanical wear (caused by wind blowing on transmission conductors)	Loss of material
Silicone Rubber	Polymer degradation (e.g. due to thermal / thermoxidative degradation of organics, radiolysis and photolysis (UV sensitive materials only) of organics, radiation induced oxidation, moisture intrusion)	Reduced insulation resistance

<u>Deposits and Surface Contamination</u>

Similar to porcelain high-voltage insulators, various airborne contaminates such as dust, salt, fog, or industrial effluent can contaminate the polymer H-V insulator surface leading to reduced insulation resistance. The buildup of surface contamination is gradual and, in most cases, removed by rainfall. As discussed previously, the silicone rubber of the polymer H-V insulator is superior to porcelain due to its hydrophobic properties. Excessive surface contaminants can lead to insulator flashover and failure. Although the rate of contamination buildup on the polymer H-V insulators is not significant, PTN will implement a Polymer High-Voltage Insulators program, to manage surface contamination.

In addition, polymer insulators may experience the following aging degradation effects resulting from deposits and surface contamination. The PTN Polymer High-Voltage Insulators program will also manage these as well.

- Swelling of silicone rubber layer due to chemical contamination

  Hydrophobicity is a property of the housing that causes excellent insulator contamination performance. On silicone surfaces, contamination becomes encapsulated so that the insulator may accumulate some contamination. Periodic rainfall tends to wash away any chemical contamination from the polymer H-V insulator surfaces.

- Sheath wetting caused by chemicals absorbed by oil from silicone rubber compound

  Silicone rubbers are characterized by having a low surface energy that results in highly hydrophobic surfaces. This property prevents the insulator surface from becoming completely wet.

- Chalking and crazing of insulator surfaces resulting in contamination, arcing, and flashover

  Hydrophobicity is the surface property that causes a water drop to form a bead. The silicone rubbers used in insulators are highly hydrophobic. This property limits contamination caused flashovers by preventing the formation of a conductive water film on the insulator surface. Silicone insulators have more hydrophobicity than all the other types of insulators including EPR polymers. They also keep their hydrophobic properties over a long period of time, unlike EPR that gets chalky (white with age) and loses what little hydrophobicity it had when new. The PTN Unit 3 insulators are made of silicone rubber not EPR.

- Aggressive environments due to excrements from birds and rodents containing chemicals such as uric acid, phosphates, and ammonia

  Damage to polymer insulators from rodents could possibly occur during storage or transportation, but not while in service. The PTN unit 3 polymer H-V insulators are located on take-off structures far away from rodents. Birds of many species frequently roost on transmission and distribution structures or in substations. Birds can contaminate insulators with their droppings. Usually insulators can perform satisfactorily with a small amount of bird dropping contamination. If the bird species is the type that flock or if a few but very large birds roost, enough contaminate may be deposited on insulators to cause arcing and flashover. Because of their hydrophobicity, washing polymer insulators isn't a routine practice. The only case where washing would become necessary is when an enormous amount of bird excrement has accumulated on the insulators.

Loss of Material

Like porcelain high-voltage insulators, loss of metallic material can occur due to mechanical wear caused by oscillating movement of insulators due to wind. Surface corrosion in metallic parts may appear due to contamination or where galvanized or other protective coatings are worn. Additionally, airborne contamination, such as salt, can cause surface corrosion in metallic parts leading to loss of material. Excessive loss of material can lead to insulator flashover and failure. Although polymer H-V insulator wear is not significant enough to cause a loss of intended function, PTN will implement a Polymer High-Voltage Insulators program, to manage mechanical wear of metallic parts.

Reduced Insulation Resistance Due to Polymer Degradation

The polymer material for the PTN polymer H-V insulators is silicone rubber. Similar to aging effects discussions for electrical cables, silicone rubber is subject to reduced insulation resistance due to polymer degradation from thermal/thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation induced oxidation; and moisture intrusion. Silicone rubbers are characterized by having a low surface energy that results in highly hydrophobic surfaces, which inhibits moisture accumulation on the insulator surface. The NGK silicone formulation Si-O molecular bonds (inorganic backbone of silicone) are very stable. The Si-O bond is stronger than the energy provided by UV found in sunlight, making the silicone resistant to UV degradation. The environment does not support radiation induced oxidation. Silicone rubbers are very resistant to thermal and thermoxidative degradation, based on an 80-year service limiting temperature of 268.9°F (131.6°C). Although this evaluation has shown that polymer high-voltage insulators at PTN are aptly suited for their service environment, PTN will implement a Polymer High-Voltage Insulators program, to manage reduced insulation resistance due polymer degradation.

In addition, polymer insulators may experience the following aging degradation effects resulting from polymer degradation. The PTN Polymer High-Voltage Insulators program will manage these as well.

- Stress corrosion cracking (SCC) of glass fibers due to sheath degradation

The FRP rod provides mechanical strength. It is the load bearing member. It also provides electrical insulation. The silicone rubber housing has two functions; 1) it acts as a barrier to protect the rod from sunlight and moisture that can cause deterioration. In this function it is sometimes called the insulator sheath or simply the covering; 2) it also is formed into weather sheds to give greater leakage distance for contamination performance. The shed shape that gives the best contamination performance depends on the type of contamination and local wetting conditions. A shed with a deep conical shape may better shield its underside from rain and perform well in rain conditions. However, it will be prone to contamination build up under the cone that is difficult to be clean and have poor performance in fog or dew.

Alternating the shed diameters is effective for preventing ice bridging and water bridging on insulators in a vertical position. The PTN Unit 3 insulators are designed with a standard type shed profile (designated SS-for a medium contamination environment) using an alternating shed pattern to increase the leakage current distance.

- Brittle fracture of rods resulting from discharge activity, flashunder, and flashover

The electric fields can be stronger on polymer insulators at the energized ends and their polymeric rubber is more easily damaged by corona than is porcelain. Strong electric field gradients can cause ionization of gas molecules found in air. These ions can go into solution to create acids that attack the polymeric rubber. The acids attack the rubber resulting in corona cutting. Corona cutting may result in an exposed rod and consequently a separation due to brittle fracture or erosion of the rod. The ionization process also creates high frequency energy, heat, and light. This can cause premature failure of the polymer insulator. The installation of grading rings, sometimes called corona rings, on the ends of insulators can reduce the electric field gradients in these areas and prevent ionization. Also see discussion of last 2 bullet items below.

- Water penetration through the sheath followed by electrical failure

Silicone rubbers are characterized by having a low surface energy that results in highly hydrophobic surfaces. This property prevents the insulator surface from becoming completely wet.

Corona can cause the depletion of surface silicone by electrochemical mechanisms in which the long polymer chains are broken up and the small chains leave the surface through evaporation. Grading rings (sometimes called corona rings) not only protect from corona, but also improve contamination performance of polymer insulators. The PTN Unit 3 insulators are designed with 8-inch grading rings to promote a uniform electric field distribution across the insulators to mitigate sheath degradation.

- Bonding failure at rod and sheathing interface

  NGK uses compression molding to give shape to the silicone rubber covering and to form the silicone rubber covering onto the FRP rod. The correct combination of heat, pressure, and time results in an insulator with rubber completely bonded to the rod, as well as all rubber pieces bonded together. Insulators with one continuous polymer housing bonded to the core provides a superior design compared to injection molding which uses a bonding agent to the help ensure adhesion of the fiberglass rod to the rubber. Metal end fittings are then compressed onto the fiberglass rod. NGK uses a patented multiple step, controlled pressure crimping process to attach end fittings to the FRP rod. To ensure customer do not receive a polymer insulator with a cracked rod. NGK acoustically monitors each compression during the crimping process.

- Water ingress through end fittings causing flashunder, corrosion and fracture of glass fibers

  Brittle fracture is a separation of the fiberglass rod. The failure site has one or more smooth flat surfaces perpendicular to the axis of the rod. These surfaces resemble cuts. Other surfaces in the failure area are the result of normal fracture due to high mechanical stress. Brittle fracture is caused by an acid attack of the glass fibers in the rod. The acid attack creates the perpendicular cuts. Although there are competing explanations on the brittle fracture mechanism, all explanations involve water contacting the fiberglass rod. Poor end-fitting sealing has been the primary initiating cause of brittle fractures in the United States.

  Because of several instances of brittle fracture failures that were initiated by water intrusion, end fitting seals have been improved through re-design. By the mid-1990s, significant improvements had been made by the polymer manufacturers and today's products are much superior in preventing this failure to those of only a decade ago. The first generation of polymer insulators in the United States had some electrical and mechanical failures because of poor material and design although some of the first generation successfully remain in service today. Silicone was introduced in the early 80s and has become the most popular rubber to use at transmission voltages due to its contamination performance and UV resistance. Currently there are variations in the housing and rod material used by manufacturers, but crimping is the process used to attach metal end fittings.

  Fiberglass reinforced plastic (FRP) rods are composed of many, very small diameter glass filaments in a resin matrix. The resin matrix holds the glass filaments together so that they collectively act together and maintains the shape of the rod. Resins that have been used are epoxy, vinyl ester, and polyesters. FRP rods made with polyester resin are less expensive. The more expensive epoxy resin rods have higher shear strength and fatigue resistance. The rods used in the polymer H-V insulators at PTN Unit 3 use only epoxy resin rods.

To prevent water from contacting the fiberglass rod, good sealing of end-fittings and bonding of rubber to the rod is required. NGK uses compression molding to give shape to the silicone rubber covering and to form the silicone rubber covering onto the FRP rod. The correct combination of heat, pressure, and time results in an insulator with rubber completely bonded to the rod, as well as all rubber pieces bonded together. Insulators with one continuous polymer housing bonded to the core provides a superior design compared to injection molding which uses a bonding agent to the help ensure adhesion of the fiberglass rod to the rubber. Metal end fittings are then compressed onto the fiberglass rod. NGK uses a patented multiple step, controlled pressure crimping process to attach end fittings to the FRP rod. To ensure customer do not receive a polymer insulator with a cracked rod. NGK acoustically monitors each compression during the crimping process.

From this evaluation, FPL concludes the polymer high-voltage insulators used in the PTN Unit 3 station blackout recovery path have aging effects requiring management. A site-specific, polymer high-voltage insulator aging management program will be developed for the SPEO.

References:

NGK-Locke Polymer Insulators, Inc. Polymer Insulator Application Guide 2011

NGK-Locke Polymer Insulators, Inc. Polymer Suspension Insulators 69kVto 765kV, Catalog 011

EPRI 1007752, Polymer Insulator Survey 2002: Utility Field Experience and In-Service Failures

Associated SLRA Revisions:

The following changes to SLRA Section 3.6.2.1 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Section 3.6.2.1 “Materials” as follows:

Materials

Electrical commodities subject to aging management review are constructed of the following materials.

- Aluminum <u>and aluminum alloy</u>
- Copper
- Cement

- Fiberglass
- Galvanized metals
- Insulation material – various organic polymers
- Porcelain
- Silicone Rubber
- Steel and steel alloys
- Stainless steel
- Various metals used for bus and electrical connections

Revise SLRA Section 3.6.2.1 "Aging Management Programs" as follows:

Aging Management Programs

The following aging management programs will manage the effects of aging on electrical commodities.

- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.38)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits (B.2.3.39)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.40)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.41)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.42)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.43)
- High-Voltage Insulators (B.2.3.44)
- **Polymer High-Voltage Insulators (B.2.4.2)**
- Boric Acid Corrosion (B.2.3.4)

Revise SLRA Table 3.6.2-1 as follows:

Table 3.6.2-1: Electrical Commodities — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
High-voltage electrical insulators (porcelain)	Insulate (electrical)	Porcelain; malleable iron; aluminum; galvanized steel;cement	Air – outdoor	Loss of material	High-Voltage Insulators	VI.A.LP-32	3.6-1, 002	A
High-voltage electrical Insulators (porcelain)	Insulate (electrical)	Porcelain; malleable iron; aluminum; galvanized steel; cement	Air – outdoor	Reduced electrical insulation resistance	High-Voltage Insulators	VI.A.LP-28	3.6-1, 003	A
High-voltage electrical insulators (polymer)	Insulate (electrical)	Silicone rubber, fiberglass, aluminum alloy, stainless steel, galvanized metals	Air – outdoor	Loss of material	Polymer High-Voltage Insulators	N/A – PTN Site-Specific Program	--	F
High-voltage electrical insulators (polymer)	Insulate (electrical)	Silicone rubber, fiberglass, aluminum alloy, stainless steel, galvanized metals	Air – outdoor	Reduced electrical insulation resistance	Polymer High-Voltage Insulators	N/A – PTN Site-Specific Program	--	F

Revise Notes for SLRA Table 3.6.2-1 as follows:

Notes for Table 3.6.2-1

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

F. Material not in NUREG-2191 for this component.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

Revise SLRA Section B.2.3.44 "Program Description" as follows:

The PTN High-Voltage Insulators AMP is a new AMP for SLR. The purpose of the PTN High- Voltage Insulators AMP is to provide reasonable assurance that the intended functions of high- voltage insulators within the scope of the program are maintained consistent with the CLB through the SPEO. This AMP was developed specifically to adequately manage porcelain high-voltage insulators susceptible to aging degradation due to local environmental conditions.

The scope of this AMP is limited to ~~those~~ the PTN Unit 4 porcelain high-voltage insulators in the power path utilized for restoration of off-site power following a Station Blackout event. This is a condition monitoring program. Periodic visual inspections along with periodic insulator coating and cleaning will be performed to manage high-voltage insulator aging effects throughout the SPEO.

Revise SLRA Section 17.2.2.44, "High-Voltage Insulators" as follows:

The PTN High-Voltage Insulators AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of high-voltage insulators within the scope of SLR are maintained consistent with the CLB through the SPEO. This AMP was developed specifically to age manage porcelain high-voltage insulators susceptible to aging degradation due to local environmental conditions. Periodic visual inspections along with periodic insulator coating and cleaning are performed to manage high-voltage insulator aging effects throughout the SPEO.

The scope of this AMP is limited to the PTN Unit 4 porcelain high-voltage insulators in the power path utilized for restoration of off-site power following a Station Blackout event. This is a condition monitoring program. The high-voltage insulators within the scope of this AMP are visually inspected to detect reduced insulation resistance aging effects, including cracks, foreign debris, salt, dust, and industrial effluent contamination. Metallic parts are visually inspected to detect loss of material due to mechanical wear or corrosion. Visual inspections may be supplemented with infrared thermography inspections to detect high-voltage insulator reduced insulation resistance.

Revise 17.2.3, "Site-Specific Aging Management Programs" as follows:

17.2.3.2Polymer High-Voltage Insulators

The PTN Polymer High-Voltage Insulators AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of polymer high-voltage insulators within the scope of SLR are maintained consistent with the CLB through the SPEO. This AMP was developed specifically to age manage polymer high-voltage insulators susceptible to aging degradation due to local environmental conditions. Periodic visual inspections are performed to manage polymer high-voltage insulator aging effects throughout the SPEO.

The scope of this AMP is limited to the PTN Unit 3 polymer high-voltage insulators in the power path utilized for restoration of off-site power following a Station Blackout event. This is a condition monitoring program. The polymer high-voltage insulators within the scope of this AMP are visually inspected to detect reduced insulation resistance aging effects, foreign debris, salt, dust, and industrial effluent contamination. Metallic parts are visually inspected to detect loss of material due to mechanical wear or corrosion. Visual inspections may be supplemented with infrared thermography inspections and corona scans to detect polymer high-voltage insulator reduced insulation resistance.

Revise SLRA Table 17-1 "List of PTN Aging Management Programs" as follows:

NUREG-2191 Section	**Aging Management Program**	**Existing AMP or New AMP**
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section 17.2.2.41)	New
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section 17.2.2.42)	New
XI.E4	Metal Enclosed Bus Not Applicable (PTN U3 and U4 do not have any components within this program scope.)	N/A
XI.E5	Fuse Holders Not Applicable (PTN U3 and U4 do not have any components within this program scope.)	N/A
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements (Section 17.2.2.43)	New
XI.E7	High-Voltage Insulators (Section 17.2.2.44)	New
N/A – PTN Site- Specific Program	Pressurizer Surge Line Fatigue (Section 17.2.3.1)	Existing
N/A – PTN Site- Specific Program	Polymer High-Voltage Insulators (Section 17.2.3.2)	New

Revise SLRA Table 17-3 "List of SLR Commitments and Implementation Schedule" as follows:

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
53	Containment Structure and Internal Structural Components Aging Management Review	N/A	Follow the ongoing industry efforts that are clarifying the effects of irradiation on concrete and corresponding aging management recommendations, including: a) Ensure their applicability to the PTN Unit 3 and Unit 4 primary shield wall and associated reactor vessel supports; b) Update design calculations, as appropriate, and; c) Develop an informed site-specific program, if needed.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
54	Nonsafety-related SSCs that are not Directly Connected to Safety-Related SSCs but have the Potential to Affect Safety-Related SSCs Through Spatial Interactions Screening Document	N/A	Minimize the potential for indoor abandoned equipment outside containment to leak or spray on safety-related equipment by performing the following: a) Update plant procedures to require the periodic venting and draining of indoor abandoned equipment located outside containment that is directly connected to in-service systems; b) Verify that abandoned equipment that is no longer directly connected to in-service systems is vented and drained.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
55	**Polymer High-Voltage Insulators (17.2.3.2)**	**N/A**	**Implement the new site-specific Polymer High-Voltage Insulators AMP.**	**No later than 6 months prior to the SPEO, i.e.:** **PTN3: 1/19/2032 PTN4: 10/10/2032** **Required pre-SPEO inspections that require plant outage are completed no later than the last RFO prior to the SPEO.**

Revise SLRA Section B.2.4 "Site-Specific Aging Management Programs" as follows:

B.2.4.2 Polymer High-Voltage Insulators

Program Description

The PTN Polymer High-Voltage Insulators AMP is a new site-specific AMP for SLR. The purpose of the PTN Polymer High-Voltage Insulators AMP is to provide reasonable assurance that the intended functions of polymer high-voltage insulators within the scope of the program are maintained consistent with the CLB through the SPEO. This site-specific AMP was developed specifically to adequately manage polymer high-voltage insulators susceptible to aging degradation due to local environmental conditions.

The scope of this site-specific AMP is limited to those polymer high-voltage insulators in the PTN Unit 3 power path utilized for restoration of off-site power following a Station Blackout event. This is a condition monitoring program. Periodic visual inspections will be performed to manage polymer high-voltage insulator aging effects throughout the SPEO.

Visual inspection provides reasonable assurance that the applicable aging effects are identified, and polymer high-voltage insulator age degradation is managed. Insulation materials used in polymer high-voltage insulators may degrade when installed in a harmful environment. The insulation and metallic elements of polymer high-voltage insulators are made of silicone rubber, fiberglass, aluminum alloy, stainless steel, and galvanized metals. Loss of metallic material can occur due to mechanical wear caused by oscillating movement of insulators due to wind. Surface corrosion in metallic parts may appear due to contamination or where galvanized or other protective coatings are worn. Additionally, airborne contamination, such as salt, can cause surface corrosion in metallic parts and various airborne contaminates such as dust, salt, fog, or industrial effluent can contaminate the insulator surface leading to reduced insulation resistance. Excessive surface contaminants or loss of material can lead to insulator flashover and failure.

The polymer high-voltage insulators within the scope of this site-specific AMP are visually inspected to detect reduced insulation resistance aging effects including, foreign debris, salt, dust, and industrial effluent contamination. Metallic parts are visually inspected to detect loss of material due to mechanical wear or corrosion. Visual inspections may be supplemented with infrared thermography inspections and corona scans to detect polymer high-voltage insulator reduced insulation resistance.

The polymer high-voltage insulators within the scope of this site-specific AMP are to be visually inspected at a frequency, determined prior to the SPEO, based on industry and site-specific OE. The first inspections for SLR are to be completed no later than six months prior to entering the SPEO or no later than the last RFO prior to the SPEO.

To meet the acceptance criterion for visual inspections, the polymer high-voltage insulator surfaces must be free from signs of swelling, discoloration, chalking and crazing, and unacceptable accumulation of foreign material, such as significant salt or dust buildup as well as other contaminants. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. Metallic parts shall be free from significant loss of materials due to pitting, fatigue, crevice, and general corrosion.

Scope of Program: Element 1

This site-specific AMP applies to polymer high-voltage insulators within the scope of SLR susceptible to airborne contaminants including dust, salt, fog, industrial effluent or loss of material.

The scope of this site-specific AMP is limited to the PTN Unit 3 polymer high-voltage insulators in the power path utilized for restoration of off-site power following a Station Blackout (SBO) event.

Preventive Actions: Element 2

This is a condition monitoring program. Periodic visual inspections will be performed to manage polymer high-voltage insulator aging effects throughout the SPEO.

Parameters Monitored or Inspected: Element 3

The polymer high-voltage insulators within the scope of this site-specific AMP will be visually inspected at a frequency based on industry and plant-specific OE. Polymer high-voltage insulator surfaces will be visually inspected to detect reduced insulation resistance aging effects including foreign debris, salt, dust, etc. Metallic parts of the insulator will be visually inspected to detect loss of material due to mechanical wear or corrosion.

Detection of Aging Effects: Element 4

The polymer high-voltage insulators within the scope of this site-specific AMP are visually inspected to detect reduced insulation resistance aging effects including foreign debris, salt, dust, and industrial effluent contamination. Metallic parts are visually inspected to detect loss of material due to mechanical wear or corrosion. Visual inspections may be supplemented with infrared thermography inspections

and corona scans to detect polymer high-voltage insulator reduced insulation resistance. The first inspection for SLR will be completed prior to the SPEO.

Monitoring and Trending: Element 5

Trending actions are not required as part of this site-specific AMP.

Acceptance Criteria: Element 6

An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function.

Acceptance criterion for visual inspection is that polymer high-voltage insulator surfaces are free from signs of swelling, discoloration, chalking and crazing, and unacceptable accumulation of foreign material such as significant salt or dust buildup as well as other contaminants. Metallic parts shall be free from significant loss of materials due to pitting, fatigue, crevice, and general corrosion.

If thermography is used, acceptance criteria will be based on temperature rise above a reference temperature for the application. The reference temperature will be ambient temperature or a baseline temperature based on data from the same type of high-voltage insulator being inspected. If a corona scan is performed, acceptance criteria will be based on the location and amount of corona or aching activity.

Corrective Actions: Element 7

See Section B.1.3 for discussion on how Corrective Actions: Element 7 is addressed by this site-specific AMP

Confirmation Process: Element 8

See Section B.1.3 for discussion on how Confirmation Process: Element 8 is addressed by this site-specific AMP.

Administrative Controls: Element 9

See Section B.1.3 for discussion on how Administrative Controls: Element 9 is addressed by this site-specific AMP.

Operating Experience: Element 10

Industry Operating Experience

NRC issued information notice IN 93-95, "Storm-Related Loss of Offsite Power Events due to Salt Buildup on Switchyard Insulators." The IN discussed salt contamination build up on insulators which caused arcing across switchyard insulators causing a plant power outage. This situation occurred at Crystal River Unit 3, Brunswick Units 1 and 2 and Pilgrim Station. The recommendations of this

IN suggested the use of room temperature vulcanized silicon rubber coatings on insulators. FPL response to NRC Guidance on Scoping of Equipment Relied on to Meet the Requirements of the Station Blackout Rule for License Renewal in letter no. L-2002-071 dated April 19, 2002 explained that "PTN Units 3 and 4 are located on a shallow bay and are not subject to a harsh salt environment primarily due to the lack of wave action. Additionally, periodic rainfall tends to wash away any salt deposits from surfaces. Consequently, the rate of contamination buildup on the insulators is not significant. Therefore, surface contamination of the PTN Units 3 and 4 insulators is not an aging effect requiring management for the period of extended operation."

Site-Specific Operating Experience

Currently, PTN Unit 3 utilizes polymer insulators made of silicon rubber that do not require normal cleaning. The silicon rubber exudes silicone oil that encapsulates the contaminants on the surface of the rubber. Water deposited on the surface of the rubber cannot dissolve the encapsulated contamination to create a conductive film which is what gives the silicone rubber superior contamination performance. Washing a silicone rubber housing will wash off the silicone oil along with the contamination. The silicone oil will replenish itself, but the contamination performance of the rubber is reduced until it does. The only case where washing becomes necessary is when an enormous amount of bird excrement has accumulated on the insulators. Utilizing the silicon rubber type insulators is in alignment with the recommendations cited in IN 93-95.

In addition, PTN maintenance staff regularly inspects and clean the switchyard insulators when required. Maintenance staff reviews weather conditions and other factors to determine when the insulators will be cleaned. PTN also has an equipment life cycle equipment management plan which includes inspections and cleaning of designated single point vulnerable (SPV) insulators every 10 years as well.

The PTN Polymer High-Voltage Insulators AMP is a new program for PTN to be implemented prior to the SPEO. Therefore, there is no existing site-specific OE to validate the effectiveness of this program at PTN; however, there is OE relevant to components within the scope of the PTN Polymer High-Voltage Insulators AMP.

The road along the west and south side of the PTN Switchyard was required to be moved to support EPU in the switchyard in 2012. During discussion of impacts of an AR associated with dirty motor filters on the 3B heater drain pump, it was determined there may be negative impacts on the switchyard insulators and main, auxiliary, C-Bus and Start Up transformers due to road dust accumulation on insulators. Site Area Operations was enlisted to evaluate the impact of the

nearby road work on switchyard insulators. External OE advised that these types of construction sites have contaminated switchyard equipment insulation resulting in flash over. This was due to wind shift blowing dust over the switchyard resulting in contamination build up on the insulation. To minimize this effect on the switchyard equipment and transformer bushings at PTN during EPU, a wetting mechanism was utilized on the road. The road contractor utilized a water tanker and wetted the road during base preparation and completed asphalt installation on January 28, 2012; therefore, there was no further danger of dust impact. A swipe test was performed on the test bell insulator, which showed minimal surface contamination confirming that the road wetting technique during construction was effective.

Although the Polymer High-Voltage Insulators AMP is a new program, this example demonstrates when potential damage to high-voltage insulators has previously been identified, PTN has taken the appropriate measures to prevent loss of intended function. The polymer high-voltage insulators within the scope of this new site-specific AMP are to be visually inspected at a frequency, determined prior to the SPEO, based on based on industry and site-specific OE. Site-specific OE, similar to this, will be used in the development of the inspection frequency of this new AMP. Additionally, this new site-specific AMP will be informed and enhanced

NUREG-2191 Consistency

The Polymer High-Voltage Insulators AMP is consistent with the ten elements of an aging management program described in NUREG-2192, Branch Technical Position A.1.2.3.

Conclusion

The PTN Polymer High-Voltage Insulators AMP is a new site-specific program that will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of this site-specific AMP will be maintained consistent with the CLB during the SPEO.

Revise SLRA Table B-1 "List of PTN Aging Management Programs" as follows:

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
XI.S3	B.2.3.32	ASME Section XI, Subsection IWF	Existing
XI.S4	B.2.3.33	10 CFR Part 50, Appendix J	Existing
XI.S5	B.2.3.34	Masonry Walls	Existing

XI.S6	B.2.3.35	Structures Monitoring	Existing
XI.S7	B.2.3.36	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Existing
XI.S8	B.2.3.37	Protective Coating Monitoring and Maintenance	Existing
XI.E1	B.2.3.38	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	Existing
XI.E2	B.2.3.39	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits	New
XI.E3A	B.2.3.40	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E3B	B.2.3.41	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E3C	B.2.3.42	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E4	N/A	Metal Enclosed Bus Not Applicable (PTN U3 and U4 do not have any components within this program scope.)	N/A
XI.E5	N/A	Fuse Holders Not Applicable (PTN U3 and U4 do not have any components within this program scope.)	N/A
XI.E6	B.2.3.43	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E7	B.2.3.44	High-Voltage Insulators	New
N/A – PTN	B.2.4.1	Pressurizer Surge Line Fatigue	Existing

Site-Specific Program			
N/A – PTN Site-Specific Program	B.2.4.2	Polymer High-Voltage Insulators	New

Revise SLRA Table B-2 "Aging Management Programs" as follows:

PTN Aging Management Program	Section	NUREG-2191 Section
External Surfaces Monitoring of Mechanical Components	B.2.3.23	XI.M36
Fatigue Monitoring	B.2.2.1	X.M1
Fire Protection	B.2.3.15	XI.M26
Fire Water System	B.2.3.16	XI.M27
Flow-Accelerated Corrosion	B.2.3.8	XI.M17
Flux Thimble Tube Inspection	B.2.3.24	XI.M37
Fuel Oil Chemistry	B.2.3.18	XI.M30
High-Voltage Insulators	B.2.3.44	XI.E7
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.3.25	XI.M38
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B.2.3.13	XI.M23
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.2.3.36	XI.S7
Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B.2.3.29	XI.M42
Lubricating Oil Analysis	B.2.3.26	XI.M39

Masonry Walls	B.2.3.34	XI.S5
Monitoring of Neutron-Absorbing Materials other than Boraflex	B.2.3.27	XI.M40
Neutron Fluence Monitoring	B.2.2.2	X.M2
One-Time Inspection	B.2.3.20	XI.M32
Open-Cycle Cooling Water System	B.2.3.11	XI.M20
Outdoor and Large Atmospheric Metallic Storage Tanks	B.2.3.17	XI.M29
Polymer High-Voltage Insulators	**B.2.4.2**	**N/A** **PTN Site-Specific**
Pressurizer Surge Line Fatigue	B.2.4.1	N/A PTN Site-Specific
Protective Coating Monitoring and Maintenance	B.2.3.37	XI.S8
Reactor Vessel Internals	B.2.3.7	XI.M16A
Reactor Head Closure Stud Bolting	B.2.3.3	XI.M3
Reactor Vessel Material Surveillance	B.2.3.19	XI.M31

Revise SLRA Table B-3 "Correlation with NUREG-2191 Aging Management Programs" as follows:

NUREG-2191 Section	NUREG-2191 Aging Management Program	PTN Aging Management Program
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.41)
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Low- Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.42)

XI.E4	Metal-Enclosed Bus	Not Applicable (PTN U3 and U4 do not have any components within the XI.E4 AMP scope.)
XI.E5	Fuse Holders	Not Applicable (PTN U3 and U4 do not have any components within the XI.E5 AMP scope.)
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.43)
XI.E7	High-Voltage Insulators	High-Voltage Insulators (Section B.2.3.44)
N/A	PTN Site-Specific Program	Pressurizer Surge Line Fatigue (Section B.2.4.1)
N/A	**PTN Site-Specific Program**	**Polymer High-Voltage Insulators (Section B.2.4.2)**

Revise SLRA Table B-4 "PTN Aging Management Program Consistency with NUREG-2191" as follows:

PTN Aging Management Program	Section	PTN Site-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.43	No	XI.E6	New	No
High-Voltage Insulators	B.2.3.44	No	XI.E7	New	No
Pressurizer Surge Line Fatigue	B.2.4.1	Yes	N/A	N/A	N/A
Polymer High-Voltage Insulators	**B.2.4.2**	**Yes**	**N/A**	**N/A**	**N/A**

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

10. Environmental Qualification of Electric Equipment, GALL AMP X.E1

Regulatory Basis:

Section 54.21(a)(1) of 10 CFR requires the applicant to identify and list those structures and components subject to an aging management review. Section 54.21(a)(3) of 10 CFR requires the applicant to demonstrate that the effects of aging for structures and components within the scope of license renewal and subject to an AMR pursuant to 10 CFR 54.21(a)(1) 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. As described in SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL-SLR Report, and when evaluation of the matter in the GALL-SLR Report applies to the plant.

RAI B.2.2.4-1

Background:

SLRA Section B.2.2.4 describes the Environmental Qualification of Electric Equipment program as consistent with the GALL-SLR Report AMP X.E1, "Environmental Qualification of Electric Equipment." The staff reviewed the applicant's basis document FLCORP 020-REPT-109, "Aging Management Program Basis Document – Environmental Qualification of Electric Equipment" that describes the ten elements of the proposed program and claims consistency with each corresponding element of the GALL- SLR Report AMP X.E1.

The applicant's program basis document FLCORP 020-REPT-109, does not mention adverse localized environments (ALE) in the following program elements: "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "corrective actions." These program elements, as described in the GALL-SLR Report AMP X.E1, include discussions of ALE as an essential consideration of the program during the subsequent period of extended operation.

An adverse localized environment is an environment that exceeds the most limiting qualified condition for temperature or radiation for the component material. ALE may increase the rate of aging or have an adverse effect on the basis for equipment qualification. Environmentally qualified electrical equipment may degrade more rapidly than expected when exposed to ALE.

Issue:

It is not clear to the NRC staff that the applicant's proposed program elements "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "corrective actions" are consistent with the corresponding program elements in the GALL-SLR Report AMP X.E1, without considering ALE.

Request:

Justify why the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "corrective actions" elements of the proposed program B.2.2.4, "Environmental Qualification of Electric Equipment program," do not include discussions of adverse localized environments as described in the GALL-SLR Report AMP XI.E1, or update the basis document to include ALE considerations.

FPL Response:

The AMP basis document "Aging Management Program Basis Document – Environmental Qualification of Electric Equipment" program elements: "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "corrective actions" will be updated to include discussions of adverse localized environments (ALE) as described in the GALL-SLR Report AMP X.E1.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Section B.2.2.4 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Section B.2.2.4 "Program Description" as follows:

The preventive actions associated with this AMP include the identification of qualified life and specific maintenance/installation requirements to maintain the component within the qualification basis. This AMP provides EQ-related surveillance and maintenance requirements for EQ equipment, and monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life. Although 10 CFR 50.49 does not require monitoring and trending of EQ equipment, this AMP does provide surveillance and maintenance requirements for the EQ equipment, verifies that the required activities are performed, and tracks and maintains the service life of qualified components. Implementation of this AMP is a coordinated effort from a variety of departments within the PTN and fleet organization to ensure the continued environmental integrity of specified equipment to remain operable when exposed to a harsh environment. Surveillance and maintenance is performed on all equipment on the EQ list to ensure the equipment remains qualified. The PTN EQ of Electric Equipment AMP will also provide for visual inspection of accessible, passive EQ equipment at least once every 10 years (see Enhancement statement, below). This inspection is performed to view the EQ equipment, and also to identify any adverse localized plant environments. **An adverse localized environment is an environment that exceeds the most limiting qualified condition for temperature or radiation for the**

component material. An adverse localized environment may increase the rate of aging or have an adverse effect on the basis for equipment qualification. EQ electrical equipment may degrade more rapidly than expected when exposed to an adverse localized environment.

Revise SLRA Section B.2.2.4 "Enhancements" as follows:

Element Affected	Enhancement
4. Detection of Aging Effects	Visual inspection of accessible, passive EQ equipment **for adverse localized environments that could impact qualified life** will be performed at least once every 10 years with the first periodic visual inspection being performed prior to the SPEO.

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

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

Regulatory Basis:

10 CFR § 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 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 § 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 GALL-SLR 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.2.3.28-1

Background:

SLRA Section B.2.3.28 states the following:

a) Preventive Action Category F (i.e., inspection quantity of the smaller of 10 percent of the piping length or six inspections) has been selected for monitoring steel piping exposed to soil during the initial monitoring period because the cathodic protection system will not be operational during that time period.

b) Two inspections will be conducted for cementitious piping exposed to soil during each 10 year inspection period.

c) 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.

GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," states the following:

a) Cathodic protection is a recommended preventive action for steel and reinforced concrete piping exposed to soil.

b) Additional inspections, beyond those in Table XI.M41-2, "Inspection of Buried and Underground Piping and Tanks," may be appropriate if exceptions are taken to program element 2, "preventive actions," or in response to plant specific operating experience (OpE).

During the audit the staff noted the following:

a) Leaks and localized external corrosion in buried service water and fire water system piping.

b) Corrosion of reinforcement is an applicable aging mechanism for concrete piping exposed to soil.

Issue:

The staff notes that the inspection quantities identified in SLRA Section B.2.3.28 for steel and reinforced concrete piping during the 10 year period prior to the SPEO are based on recommendations provided in GALL-SLR Report AMP XI.M41 Table XI.M41-2. However, it is unclear to the staff why GALL-SLR Report recommended inspection quantities are appropriate for steel and reinforced concrete piping during the 10 year period prior to the subsequent SPEO based on the following:

a) Additional inspections beyond those recommended in the GALL-SLR Report AMP XI.M41 may be appropriate if exceptions are taken to the "preventive actions" program element. Cathodic protection is a recommended preventive action for steel and reinforced concrete piping; however, cathodic protection will not be provided for steel and reinforced concrete piping during the 10 year period prior to the subsequent SPEO.

b) Additional inspections beyond those recommended in the GALL-SLR Report AMP XI.M41 may be appropriate in response to plant specific OpE. As stated in the SLRA and by the staff during the audit, leakage (due to a combination of external and internal degradation) has occurred in buried steel piping within the scope of license renewal.

Request:

State the basis for why the inspection quantities in GALL-SLR Report Table XI.M41 2 are appropriate for the 10 year period prior to the subsequent SPEO for steel and reinforced concrete piping.

FPL Response:

Although the Buried and Underground Piping and Tanks AMP is a new AMP for SLR, there are existing activities performed at PTN on buried and underground piping. These inspection activities are associated with the NEI 09-14 industry initiative and produced the operating experience referred to in the background section above. Inspections and repairs will continue throughout the period prior to the SPEO and additional inspections or repairs will be performed as necessary to ensure operability of systems with buried and underground piping. These inspections will continue to produce OE that will inform the SLR Buried and Underground Piping and Tanks AMP until the SLR AMP is fully implemented.

FPL commits to installing cathodic protection for buried steel and cementitious piping for systems within the scope of license renewal no later than 7 years prior to the SPEO. The intent is to meet the GALL-SLR Table XI.M41-2 preventive action category C requirements such that the required number of inspections during the first inspection period would be four total inspections for buried steel piping. These four inspections include the two inspections for fire water system piping required because fire main testing will not be performed.

However, PTN has conservatively classified itself under preventive action category F until adequate cathodic protection surveys can be performed after installation. Eleven inspections for steel piping will be planned for the first inspection period (10 years prior to the SPEO until the SPEO) and if a different set of preventive action categories are met and sufficient positive OE is obtained from the existing Underground Piping and Tank Integrity Program, then the required number of inspections will be adjusted as necessary. Two required inspections for cementitious piping is based on GALL-SLR Table XI.M41-2; this number is justified by a lack of OE showing degradation in cementitious piping at PTN.

SLRA commitment 32, SLRA Section 17.2.2.28, and SLRA Section B.2.3.28 are adjusted to reflect the commitment to install cathodic protection no later than 7 years prior to the SPEO.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 17-3, Section 17.2.2.28 and Section B.2.3.28 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Table 17-3 Item 32 as follows:

Table 17-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
32	Buried and Underground Piping and Tanks (17.2.2.28)	XI.M41	Implement the new PTN Buried and Underground Piping and Tanks AMP. Install cathodic protection systems and perform effectiveness reviews in accordance with Table XI.M41-2 in NUREG-2191, Section XI.M41.	Implement AMP and start inspections no earlier than 10 years prior to the SPEO. **Install cathodic protection systems no later than 7 years prior to the SPEO.** Complete pre-SPEO inspections no later than 6 months or the last RFO prior to SPEO. Corresponding dates are as follows: PTN3: 7/19/2022 - 1/19/2032 PTN4: 4/10/2023 - 10/10/2032

Revise SLRA Section 17.2.2.28 page A-33 paragraph 4 as follows:

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria, such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the SPEO, an increase in the sample size is conducted. Direct visual inspection are performed on the external surfaces, protective coatings, wrappings, quality of backfill and wall thickness measurements using NDE techniques. Additional inspections are performed on steel piping in lieu of fire main testing. The fire water system jockey pump activity (or a similar parameter) will be monitored for unusual trends. The table below provides additional information related to inspections. Preventative Action Category F has been **initially** selected for monitoring steel piping (which includes cast iron piping) during the initial monitoring period ~~since the cathodic protection system will not be operational during that time period~~. **Based on the cathodic protection survey results and OE gathered prior to the SPEO, the preventive action category and number of inspections may be changed depending on which set of preventive actions listed GALL-SLR Table XI.M41-2 are satisfied at the time.** The **currently planned** number of inspections for each 10-year inspection period, commencing 10 years prior to the start of SPEO, are based on the inspection quantities noted in Table XI.M41-2, adjusted for a 2-Unit plant site **as shown in the table below**.

Revise SLRA Section B.2.3.28 page B-219 paragraph 3 under "Preventive measures" as follows:

PTN currently does not have a cathodic protection system for buried and underground piping. The original plant design assumed that based on the use of the limerock fill around the buried piping the groundwater would migrate to the water table and not be retained in the vicinity of the piping. Due to the high permeability of the limerock, corrosion was not expected to be a significant influence. In accordance with the requirements of GALL-SLR Report AMP XI.M41 a cathodic protection system will be installed prior to SPEO. **Because of operating experience related to past corrosion of buried pipe at PTN, a cathodic protection system will be installed in accordance with the requirements of GALL-SLR Report AMP XI.M41 at least 7 years prior to the SPEO. Once cathodic protection is installed for steel piping, annual cathodic protection surveys are conducted so that adequate effectiveness can be demonstrated during the first inspection period. For steel components, the acceptance criteria for the effectiveness of the cathodic protection is -850 mV relative to a copper/copper sulfate reference electrode, instant off.**

Revise SLRA Section B.2.3.28 page B-220 paragraphs 2 and 3 as follows:

Additional inspections are performed on steel piping in lieu of fire main testing. The fire water system jockey pump activity (or a similar parameter) will be monitored for unusual trends. ~~The table below provides additional information related to inspections.~~

Preven~~ta~~tive Action Category F has been **initially** selected for monitoring steel piping (which includes cast iron piping) during the initial monitoring period ~~since the cathodic protection system will not be operational during that time period~~. **Based on the cathodic protection survey results and OE gathered prior to the SPEO, the preventive action category and number of inspections may be changed depending on which set of preventive actions listed GALL-SLR Table XI.M41-2 are satisfied at the time.** The **currently planned** number of inspections for each 10-year inspection period, commencing 10 years prior to the start of SPEO, are based on the inspection quantities noted in Table XI.M41-2, adjusted for a 2-Unit plant site **as shown in the table below**.

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI B.2.3.28-2

Background:

SLRA Tables 3.3.2-1, 3.3.2-9, and 3.3.2-15 state that steel piping, fire hydrants, bolting, and valve bodies exposed to soil will be managed for loss of material using the Buried and Underground Piping and Tanks program. In addition, SLRA Tables 3.3.2-9, 3.3.2-12, and 3.4.2-2 state loss of material will be managed for stainless steel piping exposed to soil using the Buried and Underground Piping and Tanks program. Stress corrosion cracking is not addressed as an applicable aging effect.

SRP SLR items 3.3.1-144 and 3.4.1-72 state that steel and stainless steel components exposed to soil are susceptible to stress corrosion cracking (steel in carbonate/bicarbonate environment only).

GALL-SLR Report AMP XI.M41 states that steel components can experience stress corrosion cracking when exposed to a carbonate/bicarbonate environment depending on cathodic polarization level, temperature, and pH. This is based on the staff's review of NACE SP0169 2013, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," Figure 2, "SCC [stress corrosion cracking] Range of Pipe Steel in Carbonate/Bicarbonate Environments."

During its review of soil corrosivity testing during the audit, the staff could not determine if the carbonate/bicarbonate environment is applicable at Turkey Point.

Issue:

a) The SLRA does not address stress corrosion cracking of stainless steel exposed to soil.
b) The SLRA does not address stress corrosion cracking of steel exposed to soil, which can occur in a carbonate/bicarbonate environment depending on cathodic polarization level, temperature, and pH. Based on the staff's review of soil corrosivity testing during the audit, it is unclear why stress corrosion cracking is not an aging effect requiring management for steel piping exposed to soil.

Request:

State the basis for why stress corrosion cracking is not an aging effect requiring management for steel and stainless steel piping exposed to soil.

FPL Response:

Stainless steel piping exposed to soil is susceptible to stress corrosion cracking. Based on 2010 soil testing results, the pH of the soil may indicate the presence of a carbonate/bicarbonate environment; thus, steel piping exposed to soil is also assumed to be susceptible to stress corrosion cracking. As stated in SLRA Section B.2.3.28, the

Buried and Underground Piping and Tanks AMP manages the cracking aging effect for components exposed to soil. SLRA Tables 3.3.2-1, 3.3.2-9, and 3.3.2-15 are revised to include rows associated with steel components exposed to a soil environment that are susceptible to stress corrosion cracking. SLRA Tables 3.3.2-9, 3.3.2-12, and 3.4.2-2 are revised to include rows associated with stainless steel components in a soil environment susceptible to stress corrosion cracking. The associated SLRA Table 1 items 3.3-1, 144 and 3.4-1, 072 are also updated to reflect the revised Table 2 items.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Tables 3.3-1, 3.4-1, 3.3.2-1, 3.3.2-9, 3.3.2-12, 3.3.2-15, and 3.4.2-2 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Table 3.3-1 item 144 as follows:

Table 3.3-1: Summary of Aging Management Evaluation for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 144	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP is used to manage cracking in stainless steel piping exposed to concrete **and soil, carbon steel exposed to soil, and gray cast iron exposed to soil**.

Revise SLRA Table 3.4-1 item 072 as follows:

Table 3.4-1: Summary of Aging Management Evaluation for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 072	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	~~Not used.~~ ~~The components exposed to soil or concrete in the Steam and Power Conversion Systems are addressed under item numbers 3.4-1, 030 and 3.4-1, 047.~~ **Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP is used to manage cracking in stainless steel piping exposed to soil.**

Add the following rows to SLRA Table 3.3.2-1:

Table 3.3.2-1: Intake Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	**Pressure boundary**	**Carbon steel**	**Soil (ext)**	**Cracking**	**Buried and Underground Piping and Tanks**	**VII.I.A-425**	**3.3-1, 144**	**C**
Piping	**Pressure boundary**	**Carbon steel**	**Soil (ext)**	**Cracking**	**Buried and Underground Piping and Tanks**	**VII.I.A-425**	**3.3-1, 144**	**A**
Piping	**Pressure boundary**	**Gray cast iron**	**Soil (ext)**	**Cracking**	**Buried and Underground Piping and Tanks**	**VII.I.A-425**	**3.3-1, 144**	**A**

Add the following row to SLRA Table 3.3.2-9:

Table 3.3.2-9: Plant Air – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks	VII.I.A-425	3.3-1, 144	A
Piping	Pressure boundary	Stainless steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks	VII.I.A-425	3.3-1, 144	A

Add the following row to SLRA Table 3.3.2-12:

Table 3.3.2-12: Control Building Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks	VII.I.A-425	3.3-1, 144	A

Add the following rows to SLRA Table 3.3.2-15:

Table 3.3.2-15: Fire Protection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Fire hydrant	Pressure boundary	Gray cast iron	Soil (ext)	Cracking	Buried and Underground Piping and Tanks	VII.I.A-425	3.3-1, 144	A
Piping	Pressure boundary	Carbon steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks	VII.I.A-425	3.3-1, 144	A
Piping	Pressure boundary	Gray cast iron	Soil (ext)	Cracking	Buried and Underground Piping and Tanks	VII.I.A-425	3.3-1, 144	A
Valve body	Pressure boundary	Gray cast iron	Soil (ext)	Cracking	Buried and Underground Piping and Tanks	VII.I.A-425	3.3-1, 144	A

Add the following row to SLRA Table 3.4.2-2:

Table 3.4.2-2: Feedwater and Blowdown – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Stainless steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks	VIII.H.S-420	3.4-1, 072	A

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI B.2.3.28-3

Background:

SLRA Sections B.2.3.28 and 17.2.2.28 state that the Buried and Underground Piping and Tanks program will (a) conduct two inspections for stainless steel during each 10 year inspection period; and (b) inspection quantities are adjusted for a two unit site.

SLRA Tables 3.2.2 4, 3.3.2 8, 3.3.2 9, 3.3.2 12, and 3.4.2 2 state that aging effects for buried and underground stainless steel piping and piping components will be managed using the Buried and Underground Piping and Tanks program.

For two-unit sites, GALL-SLR Report AMP XI.M41 recommends two inspections for stainless steel in a buried environment and two inspections for stainless steel in an underground environment (i.e., four total inspections) during each 10 year inspection period.

Issue:

It is unclear to the staff why the Buried and Underground Piping and Tanks program will conduct only two inspections, as opposed to four inspections, for stainless steel during each 10 year inspection period.

Request:

State the basis for why the Buried and Underground Piping and Tanks program will only conduct two inspections for stainless steel piping during each 10 year inspection period.

FPL Response:

The Buried and Underground Piping and Tanks program will conduct four inspections for stainless steel piping during each 10 year inspection period. Two inspections will take place for stainless steel in the underground environment and two inspections will take place for stainless steel in the buried environment. SLRA Section 17.2.2.28 is updated to clarify the number of inspections that will be performed for stainless steel piping.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Section 17.2.2.28 and B.2.3-28 are made as indicated by text deletion (strikethrough) and text addition (red underlined font).

The table on SLRA pages A-33 and B-220 is revised as follows:

Material	Parameter(s) Monitored	No. of Inspections	Notes
Steel (Category F)	Loss of Material	11	GALL-SLR Report AMP XI.M41 Table XI.M41-2 quantity increased by 2 in lieu of fire main flow testing
Stainless Steel	Loss of Material Cracking	2 (underground environment) 2 (buried environment)	
Cementitious	Loss of Material Cracking	2	

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 Dated September 17, 2018

RAI B.2.3.28-4

Background:

Section 54.21(d) of 10 CFR states, "[t]he UFSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging…"

SLRA Section 17.2.2.28, "Buried and Underground Piping and Tanks," does not state the following:

a. Annual cathodic protection surveys are conducted.

b. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured.

c. If a reduction in the number of inspections recommended in GALL-SLR Report, AMP XI.M41, Table XI.M41-2 is claimed based on a lack of soil corrosivity as determined by soil testing, then soil testing is conducted once in each 10-year period starting 10 years prior to the subsequent period of extended operation.

GALL SLR Table XI 01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs," for AMP XI.M41 recommends that the UFSAR supplement includes the three statements listed in the paragraph above.

Issue:

The licensing basis for this program for the period of extended operation will not be consistent with staff issued guidance documents if the UFSAR supplement does not include the three statements listed in the Background section above.

The staff cannot complete its review of the Buried and Underground Piping and Tanks UFSAR supplement without additional information to address these three gaps.

Request:

State the basis for why SLRA Section 17.2.2.28 does not cite the three statements listed in the Background section above

FPL Response:

The Buried and Underground Piping and Tanks AMP is consistent with GALL-SLR AMP XI.M41. Statements are added to SLRA Section 17.2.2.28 to be consistent with the recommendations of GALL SLR Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs." Changes are also made to

SLRA Section B.2.3.28 to reflect this response, but these changes are included in the response to RAI B.2.3.28-1 included above.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Section 17.2.2.28 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Section 17.2.2.28 as follows:

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria, such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the SPEO, an increase in the sample size is conducted. Direct visual inspection are performed on the external surfaces, protective coatings, wrappings, quality of backfill and wall thickness measurements using NDE techniques.

Additional inspections are performed on steel piping in lieu of fire main testing. The fire water system jockey pump activity (or a similar parameter) will be monitored for unusual trends. The table below provides additional information related to inspections. Preventative Action Category F has been selected for monitoring steel piping (which includes cast iron piping) during the initial monitoring period since the cathodic protection system will not be operational during that time period. The number of inspections for each 10-year inspection period, commencing 10 years prior to the start of SPEO, are based on the inspection quantities noted in Table XI.M41-2, adjusted for a 2-Unit plant site. **Once cathodic protection is installed for steel piping, annual cathodic protection surveys are conducted. For steel components, the acceptance criteria for the effectiveness of the cathodic protection is -850 mV relative to a copper/copper sulfate reference electrode, instant off. A reduction in the number of inspections based on a lack of soil corrosivity is not taken so soil testing is not conducted.**

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

12. Emergency Containment Cooler Tube Wear, GALL TLAA 4.7

Regulatory Basis:

For time-limited aging analyses, 10 CFR 54.21(c)(1)(iii) requires an applicant to demonstrate that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. As provided in 10 CFR 54.29(a), a renewed license may be issued if the staff finds that actions have been identified, which either have been or will be taken, with respect to time limited aging analyses identified to require review under 10 CFR 54.21(c). In order to complete its review and to enable formulation of a finding under 10 CFR 54.29(a), the staff requires additional information as described below.

RAI 4.7.2-1

Background:

SLRA Section 4.7.2, Emergency Containment Cooler [ECC] Tube Wear includes a discussion about conducting an inspection for minimum tube wall thickness in 2011. The measured wall thickness was found to be 0.039 inches and based on an initial tube wall thickness of 0.049 inches, the calculated wear rate was 0.000263 inches per year using 38 years of operation. The ultrasonic testing (UT) wall thickness values for the 1.125-inch diameter tubes are listed in the "UT Matrix" and show wall thickness values between 0.054 inches and 0.039 inches. Although these results concluded that the calculated wear rates would be acceptable for the subsequent period of extended operation, the SLRA states that a one-time inspection will be performed to confirm the acceptability of the projected wear rates because tube wall loss has been observed.

PTN-ENG-LRAM-00-00065, "Emergency Containment Cooler Inspection – License Renewal Basis Document," includes a sketch as part of Attachment 9.1, "Unit 4 ECC Tubes Inspection Report dated 04/04/11," showing that inspection locations A through E, on both the North Side and South Side headers, are either on 90° elbows or 180° returns on the cooler. The staff notes that based on information in Vendor Manual V000060, "Installation, Operation, & Maintenance Instructions Emergency Containment Filter Equipment and Cooling," the 8-inch schedule 40 "North Side" header appears to be the supply side of the water to the tubes and the "South Side" header appears to be the return side of the water from the tubes. In its discussion of erosion, EPRI 1007820, Closed Cooling Water Chemistry Guideline," April 2004, Section B.1.2 "Localized Corrosion," states, "Copper alloy heat exchanger tubes are often subject to erosion conditions, especially at the inlet end where turbulence is greatest."

The "Ultrasonic Thickness Calibration Data Sheet" in Attachment 9.1, includes the statement (in regards to the UT measurement of the calibration block) that, "the instrument shall read ±0.005 inches from the actual thickness measured."

The staff also notes that the "acceptance criteria" discussion in PTN-ENG-LRAM-00-0065 states the minimum allowable wall thickness value of 0.011 inches "includes a 10% margin typically used in wear applications (such as the Flow Accelerated Corrosion program)."

Issue:

The staff identified the following potential nonconservatisms with the initial methodology used to show that the projected wear rates for the ECC heat exchanger tubes are acceptable:

1) Sample Location. Wall thickness measurements were only taken at 90° or 180° fittings. Based on the information from EPRI 1007820, it is not clear to the staff how the sample selection criteria determined that the inlet portion of the tubing coming off of the supply header was not one of the most susceptible locations. The flow in the supply header past the first sets of tubing take-offs will induce significantly more turbulence in the inlet portion of the tubing than the last sets of tubing take-offs. The outlet portion of the tubing in the return header would not be susceptible to this aspect.

2) Wear Rate Calculation Methodology. The UT measurements show that some of the locations have thicknesses greater than the nominal 0.049 inch tubing wall thickness. Consequently, basing the wear rate on the difference between the nominal value and measured value potentially, significantly underestimates the wear rate. It was not clear to the staff why the wear rate calculation did not use initial wall thicknesses values greater than the nominal value based on the actual measurements.

3) Wear Rate Projection Methodology. The wear rate is calculated based on an assumed amount of yearly operation during surveillance testing. The calculation for the initial license renewal appropriately determined the remaining wall thickness at year 60, assuming the amount of system surveillance testing done during the initial 38 years of operation will be comparable to the amount of surveillance testing to be done in the remaining 22 years. However, it was not clear to the staff how the calculation accounted for the additional wear that would occur due to high flow rates during design basis accident conditions.

4) Wall Thickness Measurement Uncertainty. Based on the small tube diameter, thin wall, unique configuration of the tubes, and the statement on the UT calibration sheet, it is not clear to the staff whether some measurement uncertainty should be considered in the wear rate calculation.

5) Safety Factor Application. The acceptance criteria states that it includes a 10 percent margin typically used in wear applications such as the Flow-Accelerated Corrosion program. (The allowable wall thickness of 0.011 inches,

includes the calculated minimum wall thickness of 0.010 inches plus an additional 10 percent.) As stated in GALL-SLR Report AMP XI.M17, "Flow-Accelerated Corrosion, a conservative safety factor is applied to the predicted wear rate determination to account for uncertainties in the wear rate calculations and UT measurements. Applying a safety factor to the calculated minimum wall thickness instead of the calculated wear rate potentially underestimates the applied margin, depending on the magnitudes of the minimum wall thicknesses and the wear rates. For the specific situation of the ECC tubes, the applied margin of 0.001 inch would only be conservative as long as the calculated wear rate is determined to be less than 0.000319 inches per year (neglecting the wear rate projection methodology question above). Using the worst case wear rate based on the thickest and the thinnest readings, the calculated wear rate is 0.000395 inches per year. Consequently, it is not clear to the staff that applying the 10 percent margin to the acceptance criteria, instead of to the wear rate, is consistent with typical wear applications such as for the Flow-Accelerated Corrosion program.

Request:

In order to determine whether the same approach used for the initial license renewal can be used for the subsequent license renewal activities:

1) Provide information to show that the wall thickness measurements were taken at the most susceptible locations. Include a discussion explaining how the inlet portions tubes that are subjected to significant turbulence were determined to be less susceptible than the locations on the outlet side of the heat exchanger.

2) Provide information to show that the use of nominal wall thickness values in the wear rate calculation bounds the potential wear rates of the heat exchanger components.

3) Provide information to show that the projection of the tube wall thinning only needs to account for material lost during periodic surveillances and testing through the end of the extended period of operation and that no additional consideration needs to be included for wall thinning that will occur during high flow conditions as part of an accident response.

4) Provide information to show that wall thickness data consider UT measurement uncertainty or that consideration of UT measurement uncertainty is not needed in order provide reasonable assurance that wall thinning due to tube erosion is acceptable.

5) Provide information to show that the application of a 10 percent margin to the acceptance criteria instead of the wear rate is consistent with other wear applications such as flow-accelerated corrosion.

FPL Response:

FPL reviewed the inspection data relative to emergency containment cooler (ECC) tube thickness and wear and a condition report was entered into the PTN corrective action program to evaluate the ECC ultrasonic test (UT) tube thickness measurement data. FPL determined that although there is a potential data duplication error, the acceptance criteria and projected acceptability of the results to the end the period of extended operation are unaffected. Based on the current calculation of the wear rate, the screening criteria thickness of 0.035" may be reached in 2024. Therefore, an ultrasonic thickness measurement inspection is currently scheduled prior to 2024.

Even though the tubes are not expected to wear below the screening criteria (0.035") or the minimum wall thickness without margin (0.010") prior to 2024, a work order was written to re-perform the ultrasonic thickness measurements of the limiting locations of the 4B emergency containment cooler during the next refueling outage in 2019. The 4B emergency containment cooler has been determined to be the most limiting cooler with respect to loss of material. Both the inlet and outlet bends will be inspected. Due to the data duplication error in the previous (2011) results and potential to reach the screening criteria thickness prior to the end of the PEO, the performance of this inspection and evaluation of the data will serve as a baseline for future inspections in the SPEO and will consider the following:

1) Based on an engineering evaluation of the specific geometry of the emergency containment coolers and the way the tube bends were formed and statements made in the EPRI1007820 guidance document, the inlet bends were determined to be the most limiting location in terms of wear rate. Sufficient inspection data will be taken to confirm that the inlet bends are the most limiting locations.

2) The wear rate will be calculated based on either the highest measured wall thickness from the 2011 data or the nominal thickness of 0.049", whichever is higher. Going forward, the wear rate will be calculated based on which location is experiencing the highest wear rate.

3) The wear rate calculated will consider past operating history and the effects of any parameter change (i.e., flow rate or increased operation time) that may affect future wear rate calculations. The safety factors added to the wear rate will be established to bound any off-normal or DBA condition to ensure that the ECCs will perform their SLR intended function. Sufficient ECC tube thickness data points will be acquired to establish the projected wear rate.

4) The calculated wear rate will consider instrument uncertainty.

5) A margin of 10% will be applied to the wear rate consistent with the PTN FAC program.

To ensure that the intended function of the ECCs will be maintained throughout the SPEO, FPL commits to an ECC tube thickness inspection frequency of no greater than every 10 years to ensure that measured and projected wear rates remain acceptable. The wear rate will be recalculated and adjusted as necessary after each inspection to ensure that the emergency containment coolers can perform their SLR intended function. The SLRA is revised to remove the calculation of the wear rate based on the 2011 data as compared to the nominal thickness and add the requirement for performing periodic inspections. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be revised to reflect follow-up inspections and the recalculation of the tube wear rate for the ECCs.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Section 4.7.2, Section 17.3.7.2, Section 17.2.2.25, and Section B.2.3.25 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise the "TLAA Evaluation" section contained in SLRA Section 4.7.2 as follows:

To ensure ECC cooler coil reliability, an inspection for minimum tube wall thickness was conducted in 2011 prior to the initial period of extended operation.

~~The actual measured all was 0.039". Therefore, based on an initial tube wall thickness of 0.049", the calculated wear rate is (0.049-0.039)/ 38 years = 0.000263 in/yr. The expected material loss is calculated by multiplying the erosion rate (0.000263 in/yr) by the remaining years of service from the one time inspection activity (4/04/2011) to the end of the SPEO (42 years). The expected material loss value is then added to the minimum allowable wall thickness value of 0.011 inches which includes a 10% margin typically used in wear applications. Based on the above, the acceptance criterion for SLR was determined to be 0.022 inches. The results concluded that the calculated tube wear rates would be acceptable for the SPEO. However, since~~

Since tube wall loss has been observed, **periodic inspections** ~~a one time inspection~~ to confirm the projected tube wear rates are acceptable for the SPEO will be performed. **During each inspection, tube wall loss rate will be measured and the evaluation will ensure that the tube wall thickness will meet the acceptance criteria until at least the next scheduled inspection.**

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The ~~One Time Inspection~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components** program described in Section B.2.3.~~20~~**25** will ensure that the aging effect of emergency containment cooler tube wear will be adequately managed for the SPEO.

Revise SLRA Section 17.3.7.2 paragraphs 4 and 5 as follows:

To ensure emergency containment cooler coil reliability, an inspection for minimum tube wall thickness was conducted in 2011 prior to the initial PEO. Results concluded that the calculated tube wear rates would be acceptable for the PEO. However, since cooler tube wall loss has been observed, ~~an~~ **periodic** inspection**s** of the emergency containment cooler coils to confirm updated tube wear rates would be acceptable for the revised 80-year plant life will be performed.

The PTN ~~One Time Inspection~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components** AMP will ensure that the aging effect of emergency containment cooler tube wear will be adequately managed for the SPEO. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

Add the following paragraph before the last paragraph in Section 17.2.2.25 on page A-32:

The PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will also perform periodic ultrasonic thickness measurements of the limiting locations of the limiting emergency containment cooler tubes every 10 years or as determined by the calculated wear rate, whichever is more frequent. Based on the data collected during the inspections, the wear rates will be used to ensure the coolers can perform their intended function throughout the SPEO.

Add the following paragraph before the last paragraph in the program description portion of SLRA Section B.2.3.25 on page B-205:

The PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will also perform periodic ultrasonic thickness measurements of the limiting locations of the limiting emergency containment cooler tubes every 10 years or as determined by the calculated wear rate, whichever is more frequent. The calculation should consider the following:

1) **The wear rate will be calculated based on the previous data collected and will be applied to the limiting location.**
2) **The wear rate calculated will consider past operating history and consider the effects of any additional thinning that may have occurred during increased usage during off-normal conditions.**
3) **The calculated wear rate will consider instrument uncertainty.**

4) **The calculated wear rate will include a 10% safety factor.**

The wear rate should be projected until the next 10 year inspection and inspection frequencies will be adjusted as necessary to ensure adequate the emergency containment coolers can perform their intended function. The AMP will be updated to reflect the latest wear rate.

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

13. Inspection of Internal Surfaces in Misc Piping and Ducting Components, GALL AMP XI.M38

Regulatory Basis:

10 CFR § 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 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 § 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 GALL-SLR 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.2.3.25-1

Background:

The following components do not include flow blockage due to fouling as an aging effect requiring management (AERM):

a) Gray cast iron drains exposed to waste water in SLRA Table 3.3.2-8.

b) Elastomeric expansion joints exposed to raw water in SLRA Table 3.3.2-15.

The GALL-SLR Report Section IX.C, "Use of Terms for Materials," definition for steel states "[i]n some environments, carbon steel, alloy steel, gray cast iron, ductile iron, malleable iron, and high-strength low-alloy steel are vulnerable to general, pitting, and crevice corrosion, even though the rate of loss of material may vary amongst material types. Consequently, these metal types are generally grouped under the broad term "steel.""

SRP-SLR Table 3.3-1, items 85 and 91, state that elastomeric and steel (inclusive of gray cast iron) piping and piping components exposed to raw water and waste water should be managed for flow blockage due to fouling.

Issue:

It is unclear to the staff why flow blockage due to fouling is not being managed for the gray cast iron drains exposed to waste water and the elastomeric expansion joints exposed to raw water.

Request:

State the basis for not managing flow blockage due to fouling for the gray cast iron drains exposed to waste water and the elastomeric expansion joints exposed to raw water.

FPL Response:

For the gray cast iron drains exposed to waste water and the elastomeric expansion joints exposed to raw water, flow blockage due to fouling is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Aging Management Program (XI.M38 AMP). This is generically described in SLRA Sections B.2.3.25 and 17.2.2.25, which state that this AMP manages the aging effects of flow blockage (i.e., fouling-induced flow blockage) and that this AMP performs visual inspection and, when appropriate, surface examinations of internal surfaces of components exposed to any water-filled systems not managed by another AMP (which includes these cast iron drains associated with the waste disposal system and elastomeric expansion joints associated with the fire protection system).

SLRA Table 3.3.2-8 and Table 3.3.2-15 are clarified accordingly by adding "Flow blockage" as an aging effect requiring management for the respective line items associated with Table 3.3-1, items 85 and 91. These changes are shown in the "Associated SLRA Revisions" section below.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.3.2-8 and Table 3.3.2-15 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Table 3.3.2-8 as follows:

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Drain	Pressure boundary	Gray cast iron	Waste water (int)	Loss of material **Flow blockage**	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-281	3.3-1, 091	A

Revise SLRA Table 3.3.2-15 as follows:

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Expansion joint	Pressure boundary	Elastomer	Raw water (int)	Hardening or loss of strength **Flow blockage**	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-75	3.3-1, 085	A

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI B.2.3.25-2

Background:

Section 54.21(d) of 10 CFR states, "[t]he UFSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging..."

SLRA Section 17.2.2.25, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," states that this program ***may*** also perform surface examinations or ASME Code Section XI VT-1 examinations to detect and manage cracking due to stress corrosion cracking in aluminum and stainless steel components exposed to aqueous solutions and air environments containing halides. In addition, SLRA Section 17.2.2.25 does not state that opportunistic inspections continue in each period despite meeting the sampling limit.

GALL-SLR Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs," for AMP XI.M38 recommends that the UFSAR supplement include a statement that (a) surface examinations or ASME Code Section XI VT-1 examinations are conducted to detect cracking of stainless steel and aluminum components; and (b) opportunistic inspections continue in each period despite meeting the sampling limit.

Issue:

The licensing basis for this program for the subsequent period of extended operation will not be consistent with staff-issued guidance documents if the UFSAR supplement does not include a statement that (a) surface examinations or ASME Code Section XI VT-1 examinations are (as opposed to may) conducted to detect cracking of stainless steel and aluminum components; and (b) opportunistic inspections continue in each period despite meeting the sampling limit.

The staff cannot complete its review of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components UFSAR supplement without additional information to address the two gaps noted above.

Request:

State the basis for why SLRA Section 17.2.2.25 does not cite the two gaps noted in the Issue section above.

FPL Response:

As described in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Aging Management Program (AMP) basis document, the AMP consists of visual inspections and, when appropriate, surface examinations or ASME Code Section XI VT-1 examinations to detect and manage internal cracking due to SCC in aluminum and stainless steel components exposed to aqueous solutions and the air environments which may contain halides.

In addition, SLRA Section B.2.3.25 indicates that "Opportunistic inspections continue in each period despite meeting the sample limit."

The Updated Final Safety Analysis Report (UFSAR) supplement for this AMP (Section 17.2.2.5) and SLRA Section B.2.3.25 are clarified accordingly. These changes are shown in the "Associated SLRA Revisions" section below.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Sections 17.2.2.25 and B.2.3.25 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Section 17.2.2.25 paragraph 2 as follows:

This AMP consists of visual inspections and, when appropriate, surface examinations of specific SSCs with accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to potentially aggressive environments. These environments include air, air with borated water leakage, condensation, gas, diesel exhaust, fuel oil, lubricating oil, and any water-filled systems not managed by another AMP. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this AMP. This AMP ~~may~~ also ~~perform~~**performs** surface examinations or ASME Code Section XI VT-1 examinations to detect and manage cracking due to SCC in aluminum and SS components exposed to aqueous solutions and air environments containing halides.

Revise SLRA Section 17.2.2.25 paragraph 4 as follows:

Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service and the severity of operating conditions. **Opportunistic inspections continue in each period despite meeting the sampling limit.** For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this AMP.

Revise SLRA Section B.2.3.25 paragraph 3 as follows:

This AMP ~~is~~ also **uses visual inspections and, when appropriate, surface examinations or ASME Code Section XI VT-1 examinations to detect and** ~~used to~~ manage internal cracking due to SCC in aluminum and stainless steel components exposed to aqueous solutions and the air environments which **may** contain halides.

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

14. Closed Treated Water System, GALL AMP XI.M21A

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 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. As described in SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL-SLR Report. In order to complete its review and enable the formulation of a finding under 10 CFR 54.29(a), the staff requires additional information in regard to the matters described below.

RAI 3.3.2.10-1

Background:

SLRA Table 3.3.2-10, "Normal Containment Ventilation," identifies several AMR items for heat exchanger tubes made from copper alloy with greater than 15 percent zinc. Enercon Report FPLCORP020-REPT-033, "Subsequent License Renewal Aging Management Review,

Containment Ventilation Systems," also shows the same materials of construction for the normal containment cooler heat exchanger tubes and cites design document V000968. Vendor Manual V000968, Revision 2, "Installation, Operation, & Maintenance for Normal Containment Coolers," includes an Aerofin Coil Data Sheet that specifies the tube material as "90/10 CuNi." In addition, the data sheet includes various fin parameters and specifies a fin material as copper. The staff notes that SLRA Table 3.3.2-10 does not contain any AMR items associated with heat exchanger fins.

Issue:

The material specified in SLRA Table 3.3.2-10 for the normal containment cooler heat exchanger tube AMR item does not correspond to the material shown in the associated vendor manual. In addition, the table does not include an AMR item for the heat exchanger fins specified in the vendor manual.

Request:

Provide information to reconcile the differences in heat exchanger tube material and component type between SLRA Table 3.3.2-10 and Vendor Manual V000968 for the normal containment coolers.

FPL Response:

The heat exchanger tube material used in the normal containment coolers is "copper alloy" and not "copper alloy >15% zn". SLRA Table 3.3.2-10 is revised to change the heat exchanger tubes from "copper alloy >15% zn" to "copper alloy". This copper alloy is not subject to selective leaching. Therefore, this row is deleted.

"Copper alloy" "Heat exchanger (fins)" are added to Table 3.3.2-10. These "Heat exchanger (fins)" are in a "Condensation (ext)" environment. Table 3.3-1 is revised to include condensation as an environment in the discussion of item 3.3-1, 096a. Table 2.3.3-10 is revised to include the component type "Heat exchanger (fins)" with a "Heat transfer" function.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Tables 3.3.2-10, 3.3-1, and 2.3.3-10 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Table 3.3.2-10 as follows. Note that Table 3.3.2-10 was revised as part of the response to NRC RAI No. 3.3.2.1.4-1 contained in Attachment 2 to FPL letter number L-2018-152, dated August 31, 2018 (ML18248A257). The revisions to Table 3.3.2-10 items below supersede those contained in the previous response to NRC RAI No. 3.3.2.1.4-1. Additionally, the changes made to Table 3.3.2-10 below supersedes the discussion of copper alloy > 15% Zn heat exchanger tubes in the normal containment coolers in NRC RAI No. 3.2.2.2.2-11 contained in Attachment 4 to FPL letter number L-2018-152, dated August 31, 2018 (ML18248A257).

Table 3.3.2-10: Normal Containment Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (tubes)	Heat transfer	Copper alloy ~~≥15% Zn~~	Condensation (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F3.A-565	3.3-1, 161	A
Heat exchanger (tubes)	Heat transfer	Copper alloy ~~≥15% Zn~~	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems	VII.F3.AP-205	3.3-1, 050	B
Heat Exchanger (tubes)	Pressure boundary	Copper alloy ~~≥15% Zn~~	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F3.AP-203	3.3-1, 046	B
~~Heat exchanger (tubes)~~	~~Pressure boundary~~	~~Copper alloy >15% Zn~~	~~Treated water (int)~~	~~Loss of material~~	~~Selective Leaching~~	~~VII.F3.AP-65~~	~~3.3-1, 072~~	~~A~~
Heat exchanger (fins)	**Heat transfer**	**Copper alloy**	**Condensation (ext)**	**Reduction of heat transfer**	**Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	**VII.F3.A-419**	**3.3-1, 096a**	**A**

Revise SLRA Table 3.3-1 item 096a as follows:

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 096a	Steel, aluminum, copper alloy, stainless steel, titanium heat exchanger tubes internal to components exposed to air, condensation (external)	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is used to manage reduction of heat transfer in aluminum and copper heat exchanger tubes exposed to air **and heat exchanger fins exposed to condensation**.

Revise SLRA Table 2.3.3-10 as follows:

Component Type	Component Intended Function(s)
Heat Exchanger (fins)	**Heat transfer**

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

15. Neutron Fluence Monitoring Program, GALL AMP X.M2

Regulatory Basis:

The NRC staff is evaluating Appendix B.2.2.2 of the SLRA to determine its consistency with NUREG-2192, "Generic Aging Lessons Learned for Subsequent License Renewal Report" (GALL-SLR) Aging Management Program (AMP) X.M2, "Neutron Fluence Monitoring." The program provides an acceptable basis for managing aging effects attributable to neutron irradiation in accordance with requirements in 10 CFR 54.21(c)(1)(iii).

RAI B.2.2.2-1

Background:

In Appendix B.2.2.2 of its subsequent license renewal application (SLRA), Florida Power and Light, the applicant, describes a neutron fluence monitoring program. The applicant states that the program "is an existing program that ensures the continued validity of the neutron fluence analyses and neutron fluence-based TLAA and related analyses involving time-dependent neutron irradiation through monitoring and periodic updates."

Issue:

The NRC staff is unable to determine that the applicant's treatment of fluence for reactor vessel internals (RVI) components is consistent with the scope of GALL-SLR Report AMP X.M.2. Whereas, in GALL-SLR Report AMP X.M.2, RVI fluence estimates are considered within the scope of the program, and subject to the remaining program elements, the applicant defers to GALL-SLR XI.M16a for the determination of RVI fluence estimates. In Appendix C.2.2 of the SLRA, which describes aging management of RVI components, the applicant determined fluence using methods that were not described in adequate detail, and the NRC staff was unable to determine whether the fluence estimates for the RVI components were adherent to Regulatory Guide (RG) 1.190, :Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence ," or otherwise acceptable, and subject to additional justification, as appropriate, as noted in GALL-SLR Report AMP X.M.2. In addition, as described above, the applicant provided no enhancements to ensure that additional justification for fluence estimates for the RVI components, if determined using RG 1.190-adherent methods, would be provided in concert with any generic industry initiatives.

Request:

Please provide justification for the treatment of fluence estimates for RVI components within Appendix B.2.2.2, "Neutron Fluence Monitoring Program" of the SLRA. Additionally, as appropriate, identify whether fluence estimates for RVI components are excluded from the program, or clarify whether the program and enhancements, as proposed, include RVI component fluence estimates.

FPL Response:

The RVI fluence estimates used for the Turkey Point SLRA were determined for the Electric Power Research Institute (EPRI) Materials Reliability Program 191 (MRP-191) representative three-loop Westinghouse pressurized water reactor (PWR) using the three-dimensional fluence rate synthesis methodology described in WCAP-14040-A. The WCAP-14040-A methodology adheres to the guidance of Regulatory Guide 1.190. The RVI fluence estimates are considered part of the Turkey Point Neutron Fluence Monitoring Program.

An evaluation performed in support of the SLRA demonstrated that the RVI fluence estimates determined for the MRP-191 representative three-loop PWR are applicable to Turkey Point Units 3 and 4. In particular, this evaluation demonstrated that for an 80-year period of operation, the RVI fluence estimates determined for the MRP-191 representative three-loop PWR bound the plant-specific ones determined for Turkey Point. Note that as part of this evaluation, plant-specific RVI fluence estimates for Turkey Point were determined using the three-dimensional fluence rate synthesis methodology described in WCAP-14040-A.

The RVI fluence estimates determined for the MRP-191 representative three-loop PWR and used for the SLRA will continue to bound the plant-specific ones determined for Turkey Point provided the MRP-191 core loading/core design applicability criteria are met on a cycle-specific basis. These applicability criteria are the same as the MRP-227 core loading/core design applicability criteria.

The MRP-191 core loading/core design applicability criteria are confirmed for each core reload design as part of the core reload design process. The cycle-specific checks of the core loading/core design applicability criteria are included in the Neutron Fluence Monitoring Program. These periodic checks ensure that plant and core operating conditions remain bounded by the assumptions of the MRP-191 representative 3-loop PWR.

References:

None

Associated SLRA Revisions:

None

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

16. Open Cycle Cooling Water System, GALL AMP XI.M20

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 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. As described in the SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL-SLR 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.2.3.11-1

Background:

The recommendations in Aging Management Program XI.M20, "Open-Cycle Cooling Water System" (OCCW) in Generic Aging Lessons Learned for Subsequent License Renewal (GALL- SLR) Report state that the scope of program addresses piping and piping components exposed to raw water in the OCCW system. Enercon Report FPLCORP020-REPT-082, Aging Management Program Basis Document – Open-Cycle Cooling Water System," Revision 1 shows that the only implementing document associated with piping inspections is SPEC-M-086, "Intake Cooling Water System Piping Inspection."

Issue:

The staff noted that SPEC-M-086 describes the scope of the inspection procedure to include selected piping with nominal diameters of 24 inches or larger and did not specify inspection requirements for piping with diameters less than 24 inches. Drawing 5614-M-3019, Revision 28, "Intake Cooling Water System," appears to include in-scope OCCW piping with diameters less than 24 inches.

Request:

Discuss how the applicable aging effects (e.g., loss of material, flow blockage) for in-scope OCCW piping with diameters less than 24 inches are managed by the OCCW program. Describe the inspections that are performed on in-scope OCCW piping with diameters less than 24 inches and cite any relevant procedures that address inspections of this piping.

FPL Response:

Consistent with Element 4, "Detection of Aging Effects", of NUREG-2191 AMP XI.M20, the inspection scope, methods, and frequencies of the program are in accordance with PTN's docketed response to NRC Generic Letter (GL) 89-13. As such, SPEC-M-086 appropriately identifies that the scope of the intake cooling water (ICW) system internal piping inspections is limited to 24 inch diameter and larger piping. Additionally, SPEC-M-086 defines the inspection boundaries being limited to the following:

- Piping from the ICW pump discharge check valves to the component cooling water (CCW) basket strainers
- Piping from the ICW pump discharge check valves to the turbine plant cooling water (TPCW) baskets strainers

Per the current scope of SPEC-M-086, the PTN SLRA credits the Open-Cycle Cooling Water (OCCW) System AMP to manage the aging effects of this same scope of 24-inch diameter and larger ICW piping. The aging effects of ICW piping outside the boundaries of the current inspection scope included in SPEC-M-086 and exposed to an internal environment of raw water are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP and the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP if the component is coated. For SLR, these same two AMPs will be credited with managing the aging effects of ICW piping components less than 24 inches in diameter that are directly connected to the 24 inch and larger ICW piping that is in the scope of the OCCW System AMP.

As discussed in Sections B.2.3.25 and B.2.3.29 of Revision 1 to PTN SLRA, both the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP and the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP are new programs that require the development of new governing procedures for program implementation. The development of the governing procedures for these AMPs is included in PTN SLRA Appendix A, Table 17-3, Commitment numbers 29 and 33. For areas not readily accessible for direct inspection, a component with a like material and environment will be inspected as a representative sample. If the results of the inspection of a like material and environment component requires inspection of not readily accessible components to evaluate the extent of condition, remote or robotic inspection tools may be considered.

Several AMR line items from Table 3.3.2-1 of PTNs SLRA are updated to reflect the limited scope of PTNs Open-Cycle Cooling Water System AMP.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.3.2-1 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	**Pressure boundary**	**Ductile iron**	**Raw water (int)**	**Wall thinning - erosion**	**Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	**VII.C1.A-409**	**3.3-1, 126**	**E, 4**
Flow element	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	~~VII.C1.A-54~~ **VII.C1.A-727**	~~3.3-1, 040~~ **3.3-1, 134**	A
Flow element	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flow element	Throttle	Stainless steel	Raw water (int)	Loss of material Flow blockage	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	~~VII.C1.A-54~~ **VII.C1.A-727**	~~3.3-1, 040~~ **3.3-1, 134**	A
Flow element	Throttle	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~4
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~4
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~4

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (~~T~~**tubesheet**)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
Nozzle	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
Nozzle	Pressure boundary	Nickel alloy	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
Orifice	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	**Pressure boundary**	**Gray cast iron**	**Raw water (int)**	**Wall thinning - erosion**	**Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	**VII.C1.A-409**	**3.3-1, 126**	**E, 4**
Piping	**Pressure boundary**	**Coating**	**Raw water (int)**	**Loss of coating or lining integrity**	**Open-Cycle Cooling Water System**	**VII.C1.A-416**	**3.3-1, 138**	**E, 3**
Piping	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
Piping	Pressure boundary	Ductile iron	Raw water (int)	Loss of material Flow blockage	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	~~VII.C1.AP-194~~ **VII.C1.A-727**	~~3.3-1, 037~~ **3.3-1, 134**	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Ductile iron	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
Piping **≥ 24 inch diameter**	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping **≥ 24 inch diameter**	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.AP-194	3.3-1, 037	A
Piping	Pressure boundary	Nickel alloy	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
~~Piping~~	~~Pressure boundary~~	~~Stainless steel~~	~~Raw water (int)~~	~~Loss of material~~ ~~Flow blockage~~	~~Open-Cycle Cooling Water System~~	~~VII.C1.A-54~~	~~3.3-1, 040~~	~~A~~
Piping and piping components	Structural integrity (attached)	Ductile iron	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
Pump casing	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~4
Pump casing	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~4
~~Strainer body~~	~~Pressure boundary~~	~~Carbon steel~~	~~Raw water (int)~~	~~Loss of material~~ ~~Flow blockage~~	~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components~~	~~VII.C1.A-727~~	~~3.3-1, 134~~	~~A~~
Thermowell	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~4

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Nickel alloy	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
Tubing	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
~~Tubing~~	~~Pressure boundary~~	~~Stainless steel~~	~~Raw water (int)~~	~~Loss of material~~ ~~Flow blockage~~	~~Open-Cycle Cooling Water System~~	~~VII.C1.A-54~~	~~3.3-1, 040~~	~~A~~
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning - erosion	~~Open-Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	**Pressure boundary**	**Gray cast iron**	**Raw water (int)**	**Wall thinning - erosion**	**Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	**VII.C1.A-409**	**3.3-1, 126**	**E, 4**
Valve body	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
Valve body	Pressure boundary	Ductile iron	Raw water (int)	Wall thinning **- erosion**	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**
Valve body	Pressure boundary	Nickel alloy	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	~~Open Cycle Cooling Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.C1.A-409	3.3-1, 126	E, ~~1~~**4**

Notes for Table 3.3.2-1

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.3.2-1

1. The Open-Cycle Cooling Water System AMP is enhanced to manage the wall thinning due to erosion aging effect.
2. These pump casings have a raw water external environment and loss of material is managed by the External Surfaces Monitoring of Mechanical Components AMP.

3. **The Open-Cycle Cooling Water System AMP is enhanced to manage the loss of coating or lining integrity aging effect.**

4. **The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage the wall thinning due to erosion aging effect.**

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

17. Monitoring of Neutron-Absorbing Materials Other Than Boraflex, GALL AMP XI.M40

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 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 CLB. As described in SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL-SLR 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.2.3.27-1

Background:

SLRA, Section B.2.3.27, "Monitoring of Neutron-Absorbing Materials other than Boraflex," states that the program is consistent with GALL-SLR Report AMP XI.M40, "Monitoring of Neutron- Absorbing Materials other than Boraflex." In plant-specific procedure 0-OSP-034.3, "Metamic Insert Surveillance," Revision 1, as well as in FPLCORP020-REPT-098, "Aging Management Program Basis Document – Monitoring of Neutron-Absorbing Materials [NAM] Other Than Boraflex," Revision 1, the test frequency for the Metamic inserts is described. The testing frequency provided in 0-OSP-034.3 describes the testing intervals that extend for 30 years after the installation of the Metamic NAM. An enhancement is provided in the SLRA to revise procedure 0-OSP-034.3 to state that the maximum interval between each inspection of an insert, and coupon test, does not exceed 10 years regardless of operating experience.

Issue:

Procedure 0-OSP-034.3 provides defined test intervals for the Metamic coupons that only extend for 30 years after the installation of the Metamic NAM. This would indicate that the test intervals end during the subsequent period of extended operation (SPEO) as the Metamic NAM was previously installed as described in the license amendments issued July 17, 2007 (Agencywide Document Access and Management System

(ADAMS) No. ML071800198) In addition, the proposed enhancement to this AMP doesn't clarify whether the tests will continue past the initial 30 year inspections.

Request:

State whether Metamic coupon, and insert, testing will continue throughout the SPEO and will not end after the 30 years currently described in the procedure.

FPL Response:

The PTN Monitoring of Neutron-Absorbing Materials Other than Boraflex AMP will continue to inspect Metamic coupons throughout the SPEO. The PTN SLRA Appendix A Table 17-3 Commitment 31, Section B.2.3.27, and the AMP implementing procedures are updated to clarify the inspection schedule.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Appendix A Table 17-3 Commitment 31 and Section B.2.3.27 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Appendix A Table 17-3 as follows:

Table 17-3 List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
31	Monitoring of Neutron Absorbing Materials other than Boraflex (17.2.2.27)	XI.M40	Continue the existing (previously only credited for Metamic® inserts) PTN Monitoring of Neutron-Absorbing Materials other than Boraflex AMP, including enhancement to: a) Inspect and test Metamic® inserts**, throughout the SPEO,** on a frequency dependent on the condition of the neutron-absorbing material and determined and justified with PTN specific OE. For each Metamic® insert, the maximum interval between each inspection and between each coupon test is not to exceed 10 years, regardless of OE;	Complete the initial Boral® testing and inspections no later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Revise SLRA Section B.2.3.2 as follows:

Enhancements

The PTN Monitoring of Neutron-Absorbing Materials other than Boraflex AMP will be enhanced as follows, for alignment with NUREG-2191 AMP XI.M40. Implementation of this AMP with the following enhancements and inspections will be completed no later than six months prior to entering the SPEO.

Element	Enhancement
4. Detection of Aging Effects	Update the governing AMP procedure and the Metamic® insert surveillance procedure to state that the frequency of the Metamic® insert inspection and testing**, throughout the SPEO,** depends on the condition of the neutron-absorbing material and is determined and justified with PTN-specific OE, and for each Metamic® insert, the maximum interval between each inspection and between each coupon test is not to exceed 10 years, regardless of OE.

Associated Enclosures:

None

NRC RAI Letter Nos. ML18243A006 and ML18243A007 dated September 17, 2018

RAI B.2.3.27-2

Background:

The Turkey Point UFSAR, Section 16.2.17, "Metamic Insert Surveillance Program," Revision 28, contains a description of the Metamic Insert Surveillance Program. This description includes items such as: criteria for the surveillance testing; test requirements; test frequency; acceptance criteria; and corrective actions, documentation and reporting based on test results. In addition, procedure 0-OSP-034.3, "Metamic Insert Surveillance," Revision 1, contains a similar description of requirements for the program, and also references UFSAR Section 16.2.17 for these requirements. Surveillance Requirement (SR) 4.9.14.2 in Technical Specification (TS) 3/4.9.14, "Spent Fuel Storage," also references UFSAR Section 16.2 for the surveillance program requirements.

Issue:

The staff reviewed the proposed UFSAR supplement, and it appeared that significant details of the program would be removed from the UFSAR. It is unclear whether these changes will impact the implementing procedure for the Metamic insert surveillance program.

Request:

Clarify whether the Metamic insert surveillance program, TS 3/4.9.14, or SR 4.9.14.2, will be impacted by the proposed changes to the UFSAR.

FPL Response:

The proposed changes to the SLRA UFSAR supplement Section 17.2.2.27 do not impact TS 3/4.9.14 or SR 4.9.14.2. The level of detail provided in the proposed UFSAR supplement is consistent with level of detail provided in NUREG-2191 Table XI-01. The implementing documents maintain sufficient detail to be consistent with NUREG-2191.

However, based on breakout session discussions with the NRC, the UFSAR supplement for the Monitoring of Neutron Absorbing Materials other than Boraflex AMP will be revised to align with the level of detail in the current PTN UFSAR Section 16.2.

References:

None

Associated SLRA Revisions:

The following changes to SLRA UFSAR supplement Section 17.2.2.27 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

17.2.2.27 Monitoring of Neutron-Absorbing Materials other than Boraflex

The PTN Monitoring of Neutron-Absorbing Materials other than Boraflex AMP, formerly the PTN Metamic® Insert Surveillance Program, is an existing condition monitoring program that is implemented to ensure that degradation of the neutron-absorbing material used in spent fuel pools, that could compromise the criticality analysis, will be detected. This AMP relies on periodic inspection, testing, monitoring, and analysis of the criticality design to ensure that the required 5 percent subcriticality margin is maintained during the SPEO. ~~This AMP consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearance, dimensional measurements, weight, geometric changes (e.g., formation of blisters, pits, and bulges), and boron areal density as observed from coupons or in situ.~~

~~This AMP addresses the aging management of the PTN spent fuel pools' credited neutron absorbing materials, which include Metamic® inserts and Boral® panels.~~ **Surveillance testing is only applicable to those inserts and coupons installed in the "lead unit" unless a condition is identified that warrants testing of the inserts on the "non-lead unit." The frequency inspection and testing depends on the condition of the neutron-absorbing material and is determined and justified with PTN-specific operating experience (OE), the maximum interval between each inspection and between each inspection or test is not to exceed 10 years, regardless of operating experience (OE).**

The Metamic® insert surveillance procedure selects the Metamic® inserts that are to be inspected based on the following:

- **Results from site receipt and pre-installation inspections (i.e. inserts shall be selected if they have more pre-existing conditions).**
- **Experience gained during installation (i.e. select inserts that experienced higher insertion or removal forces).**
- **Post-installation spatial distribution of inserts in Region II racks and within the individual storage rack modules (i.e. selecting inserts surrounded by fuel assemblies and located in areas not adjacent to pit walls).**
- **Spatial variations in cooling water flow within the Spent Fuel Pool, specifically considering the effects of the Spent Fuel Pool Cooling System suction and discharge piping.**
- **Storage arrangements and the characteristics of fuel assemblies proximate to each insert, especially heat generation rates.**

- **Noteworthy or unique aspects of Turkey Point fuel pool-related operating experience during the in-service interval, such as atypical water chemistry or impact by a foreign object.**
- **Relevant operating experience from other plants.**

The Metamic® insert surveillance procedure then performs visual inspections, weight testing, dimensional measurements, and neutron attenuation testing. Visual inspections on the selected Metamic® inserts monitor for anomalies such as cracking, corrosion, pitting, voids, discoloration, and other surface defects. Weight testing on the selected number of Metamic® inserts determines if the inserts are still within their nominal weight range. The selected Metamic® insert panels also have their length, width, and height measured to ensure the dimensions remain within their nominal. Neutron attenuation testing is performed on the selected number of Metamic® coupons, which determines if any significant change in the boron-10 areal density occurred.

Boral® panels are monitored for loss of material and changes in dimension that could result in loss of neutron-absorbing capability of the Boral® panels. The parameters monitored are associated with the physical condition of the Boral® panels and include *in-situ* gap formation, geometric changes (such as blisters, pits, and bulges) as observed from coupons or *in situ*, and decreased boron-10 areal density, etc. The parameters monitored are directly related to determination of the loss of material or loss of neutron absorption capability of the Boral® panels.

The observations and measurements from the periodic inspections and coupon testing are compared to baseline information or prior measurements and analyses for trending analysis, projecting future degradation, and projecting the future subcriticality margin of the spent fuel pool (SFP). This trending of inspection and coupon testing measurements, for the purpose of projecting future Metamic® insert or Boral® panel degradation and SFP subcriticality margins, must use an adequate representation of the entire population and consider differences in each insert or panel's exposure conditions and differences in the spent fuel racks.

To ensure that the 5 percent subcriticality margin in the SFP is maintained within the criticality analysis, the Metamic® inserts are subject to the following acceptance criteria:

A. Visual inspections of Metamic® inserts did NOT identify indications of corrosion/damage, bubbling, blistering, corrosion pitting, cracking, flaking, or other surface based defects.

B. Dimensional measurements of Metamic® inserts determined:

• Length to be within of +/- 1.0 inches of initial factory acceptance measurements.

• Width to be within of +/- 0.5 inches of initial factory acceptance measurements.

• Thickness to be within of +0.010 I -0.004 inches of initial factory acceptance measurements.

C. Weight measurements of Metamic® inserts determined weight to be within +/- 10 percent of the initial factory acceptance measurements.

D. Neutron attenuation testing of Metamic® coupon did NOT identify a significant decrease in areal density.

1) 'Significant' is defined as any unexpected decrease in areal density from the As-Fabricated condition outside the statistical inaccuracies of the testing methodology.

2) Technical Specifications (TS) specify that the minimum certified boron-10 areal density shall be greater than or equal to 0.015 grams of boron-10/cm2

E. The Metamic® insert surveillance procedure does not specify any functional criteria.

To ensure that the 5 percent subcriticality margin in the SFP is maintained within the criticality analysis, the Boral® panels are subject to the following acceptance criteria:

A. The Boral® panels' boron-10 areal density must remain greater than or equal to 0.0204 grams/cm2.

B. The gap between the cask area rack and the adjacent Region I and Region II racks must remain greater than or equal to 2 inches.

C. The cask area racks' center-to-center lattice spacing is required to be as follows:

- North-south direction nominal value of 10.7 +/- 0.04 inches
- East-west direction nominal value of 10.1 inches +/- 0.04 inches

D. The Boral® panels' dimensions must remain within the manufacturer's recommended tolerances.

Any Metamic® insert or neutron attenuation testing coupon, which does not meet acceptance criteria, is to be documented in an action request (AR). That Metamic® insert is removed from service and additional surveillance is performed

on an additional 5 Metamic® inserts, and if any of those fail then the shift manager and licensing manager are notified.

Corrective actions are initiated if the results from measurements and analysis of the Boral® panels indicate that the 5 percent subcriticality margin cannot be maintained because of current or projected future degradation of the neutron-absorbing material. When required, to maintain the subcriticality margin, the possible corrective actions consist of providing additional neutron-absorbing capacity with an alternate material or applying other options which are available.

This AMP consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearance, dimensional measurements, weight, geometric changes (e.g., formation of blisters, pits, and bulges), and boron areal density as observed from coupons or in situ. This AMP addresses the aging management of the PTN spent fuel pools' credited neutron absorbing materials, which include Metamic® inserts and Boral® panels.

Associated Enclosures:

None