VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

April 29, 2021

10 CFR 50
10 CFR 51
10 CFR 54

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555-0001

Serial No.: 21-134
NRA/DEA: R1
Docket Nos.: 50-338/339
License Nos.: NPF-4/7

VIRGINIA ELECTRIC AND POWER COMPANY
NORTH ANNA POWER STATION (NAPS) UNITS 1 AND 2
SUBSEQUENT LICENSE RENEWAL APPLICATION (SLRA)
RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION
SAFETY REVIEW - SET 2
AND FLOW-ACCELERATED CORROSION PROGRAM
ENHANCEMENT COMPLETION

By letter dated August 24, 2020 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML20246G697), Virginia Electric and Power Company (Dominion Energy Virginia or Dominion) submitted an application for the subsequent license renewal of Renewed Facility Operating License Nos. NPF-4 and NPF-7 for North Anna Power Station (NAPS) Units 1 and 2, respectively. The US Nuclear Regulatory Commission (NRC) has been reviewing the NAPS SLRA and has identified areas where additional information is needed to complete their review. In an email from Lois M James (NRC) to Daniel G. Stoddard (Dominion), the NRC staff transmitted specific requests for additional information (RAIs) to support completion of the Safety Review.

Dominion's response to the NRC RAIs are provided in Enclosure 1.

Enclosure 2 discusses the completion of an enhancement to the Flow-Accelerated Corrosion program and the associated SLRA changes that are included in Enclosure 3.

Enclosure 3 provides mark-ups of affected SLRA sections and/or tables associated with RAI Set 2 and Enclosure 2. It is noted that a change to one commitment (Item #8) is provided in Table A4.0-1.

If there are any questions regarding this submittal or if additional information is needed, please contact Mr. Paul Aitken at (804) 273-2818.

Sincerely,

Mark D. Sartain
Vice President - Nuclear Engineering and Fleet Support

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Mark D. Sartain, who is Vice President - Nuclear Engineering and Fleet Support of Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 29th day of April, 2021.

My Commission Expires: 12/31/24

Notary Public

Commitments made in this letter: None

Enclosures:

1. Response to NRC Request for Additional Information NAPS SLRA Safety Review Set 2
2. Flow-Accelerated Corrosion Program Enhancement Completion
3. SLRA Mark-ups Set 2 RAIs

CRAIG D SLY
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Enclosure 1

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION
NAPS SLRA SAFETY REVIEW - SET 2

Virginia Electric and Power Company
(Dominion Energy Virginia)
North Anna Power Station Units 1 and 2

Response to NRC Request for Additional Information
NAPS SLRA Safety Review - Set 2

North Anna Power Station, Units 1 and 2
Subsequent License Renewal Application

By letters dated August 24, 2020, (Agencywide Documents Access and Management System Accession No. ML20246G703), Dominion Energy submitted an application for subsequent license renewal of Renewed Facility Operating License Nos. NPF-4 and NPF-7 for the North Anna Power Station, Unit Nos. 1 and 2 (North Anna) to the U.S. Nuclear Regulatory Commission (NRC) pursuant to Section 103 of the Atomic Energy Act of 1954, as amended, and part 54 of title 10 of the Code of Federal Regulations, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

The NRC is reviewing the subsequent license renewal application and has provided specific requests for additional information (RAIs) to support completion of the Safety Review. Dominion Energy Virginia's response to the NRC RAIs is provided below.

1. SLRA Section 2.3.3.7, Service Water

Regulatory Basis:

Title 10 of the Code of Federal Regulations (10 CFR) 54.4(a) "Scope" reads in part:

(a) Plant systems, structures, and components within the scope of this part are--

(1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions--

(i) The integrity of the reactor coolant pressure boundary;

(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable. ...

In addition, 10 CFR 54.21(a) "Contents of application--technical information" reads in part:

Each application must contain the following information:

(a) An integrated plant assessment (IPA). The IPA must--

(1) For those systems, structures, and components within the scope of this part, as delineated in § 54.4, identify and list those structures and components subject to an aging management review. Structures and components

subject to an aging management review shall encompass those structures and components--

(i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. ...

Subsequent License Renewal Application (SLRA) Section 2.1.4.2 "Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)" states in part:

For a nonsafety-related piping system that is directly connected to and provides structural support for a safety-related piping system; the nonsafety-related piping and supports shall be included within the scope of subsequent license renewal up to (1) the analytical boundary defined in the CLB seismic analysis for the safety-related piping or, (2) if the seismic boundary is not clearly defined in the CLB information, up to and including the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions. The location of the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions is identified using the guidance presented in NEI 95-10, Appendix F, Section 4 (as referenced in NEI 17-01).

RAI 2.3.3.7-1

Guidance

NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR)": Section 2.1.3.1.2 "Nonsafety-Related"

Background

Sheet 2 "Subsequent License Renewal Service Water System North Anna Power Station Unit 1" of SLRA Drawing No. 11715-SLRM-078L, Coordinate A-5, displays Level Indicator SW-LI-203. In addition, this drawing displays Calgon Chemical Feeders (Coordinate B-5) and Pump 2-SW-P-22 (Coordinate B-4) all designated as F.4.a "Base Mounted Components" to connote a "structural" function.

Issue

The staff notes that neither Table 2.3.3-7 "Service Water" nor Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation contains:

a) a line item for neither the component type "Level Indicator" or "Sight Glass"
b) a line item for the Calgon Chemical Feeder with a "Structural Integrity" intended function
c) a line item for Pump 2-SW-P-22 with a "Structural Integrity" intended function

NRC Request

Please identify where the SLRA addresses the aging management review (AMR) for these components as depicted on the subject SLRA Drawing. If not addressed elsewhere, provide a justification for not including these "Component Type" and their associated "Environment" in the aging management program.

Dominion Response

The "Sight glass" component (2-SW-LI-203) is in scope and subject to aging management review. SLRA Tables 2.3.3-7 and 3.3.2-7 are updated to include this component type.

Additionally, while determining the material for 2-SW-LI-203, the materials for two other components on drawing 11715-SLRM-078L, Sh. 2 were determined to be misidentified. The "Pump casing (chemical addition makeup)" and "Tank (polymer storage)" in SLRA Section 3.3.2.1.7 and Table 3.3.2-7 are updated to address aging management for the correct materials.

The Calgon Chemical Feeders and 2-SW-P-22 are subject to AMR and are addressed in SLRA Tables 2.3.3-7 and 3.3.2-7 as component type "Tank (chemical mixing chamber)" and "Pump casing (chemical addition)", respectively. The leakage boundary (LB) intended function assigned to these components includes the structural integrity function, where applicable, as defined in SLRA Table 2.1-1.

Based on the above, SLRA . SLRA Tables 2.3.3-7 and 3.3.2-7 and Section 3.3.2.1.7 are revised, as shown in Enclosure 3.

2. SLRA Section 2.3.3.8, Bearing Cooling

Regulatory Basis:

Paragraph 54.4(a) of 10 CFR "Scope" reads in part:

(a) Plant systems, structures, and components within the scope of this part are--

(1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions--

(i) The integrity of the reactor coolant pressure boundary;

(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable. ...

In addition, 10 CFR 54.21(a) "Contents of application--technical information" reads in part:

Each application must contain the following information:

(a) An integrated plant assessment (IPA). The IPA must--

(1) For those systems, structures, and components within the scope of this part, as delineated in § 54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components--

(i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. ...

SLRA Section 2.1.4.2 "Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)" states in part:

For a nonsafety-related piping system that is directly connected to and provides structural support for a safety-related piping system; the nonsafety-related piping and supports shall be included within the scope of subsequent license renewal up to (1) the analytical boundary defined in the CLB seismic analysis for the safety-related piping or, (2) if the seismic boundary is not clearly defined in the CLB information, up to and including the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions. The location of the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions is identified using the guidance presented in NEI 95-10, Appendix F, Section 4 (as referenced in NEI 17-01).

RAI 2.3.3.8-1

<u>Guidance</u>

SRP-SLR Section 2.1.3.1.2 "Nonsafety-Related"

<u>Background</u>

Sheet 1 "Subsequent License Renewal Service Water System North Anna Power Station Unit 1" of SLRA Drawing No. 11715-SLRB-040D Coordinates B-3 and E-7 displays "BC" Safety Related piping and valves within the Safety Related Turbine Building.

<u>Issue</u>

The staff notes that there are no "structural" identifiers on the drawing to ensure that the structural integrity of the NSR piping "anchors" are managed for aging effects consistent with the SLRA Section 2.1.4.2 excerpt cited above during the period of extended operations. In particular, the subject SLRA drawing does not display seismically qualified equivalent supports for the two interfaces of these (a)(1)/(a)(2) system piping components.

NRC Request

Please provide a justification for not including a seismically qualified equivalent anchor for the interfaces of these (a)(1)/(a)(2) system piping components.

Dominion Response

BC system piping on SLRA drawing 11715-SLRB-040D, Sh. 1, grids B-3 and E-7 transitions to SLRA drawing 11715-SLRM-080A, Sh. 1, grids L-2 and L-4. Equivalent anchor notations (F.4.4) are indicated on SLRA drawing 11715-SLRM-080A, Sh. 1, grids L-2 and L-4 for this nonsafety-related attached BC system piping. Additionally, while not specifically labeled as such, the central station air conditioner units on 11715-SLRM-080A, Sh. 1, grids K-2 and L-2 are base mounted components that also serve as structural integrity endpoints.

3. SLRA Section 2.3.3.14, Instrument Air System

Regulatory Basis:

Paragraph 54.4(a) of 10 CFR "Scope" reads in part:

(a) Plant systems, structures, and components within the scope of this part are--

(1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions--

(i) The integrity of the reactor coolant pressure boundary;

(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable. ...

In addition, 10 CFR 54.21(a) "Contents of application--technical information" reads in part:

Each application must contain the following information:

(a) An integrated plant assessment (IPA). The IPA must--

(1) For those systems, structures, and components within the scope of this part, as delineated in § 54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components--

(i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. ...

SLRA Section 2.1.4.2 "Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)" states in part:

> *For a nonsafety-related piping system that is directly connected to and provides structural support for a safety-related piping system; the nonsafety-related piping and supports shall be included within the scope of subsequent license renewal up to (1) the analytical boundary defined in the CLB seismic analysis for the safety-related piping or, if the seismic boundary is not clearly defined in the CLB information, up to and including the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions. The location of the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions is identified using the guidance presented in NEI 95-10, Appendix F, Section 4 (as referenced in NEI 17-01).*

RAI 2.3.3.14-1

Guidance

SRP-SLR Section 2.1.3.1.2 "Nonsafety-Related"

Background

Sheet 2 "Subsequent License Renewal Instrument Air System North Anna Power Station Unit 2" of SLRA Drawing No. 12050-SLRM-082C Coordinates F-7 and F-8 displays 3" NSR piping on either side of the Containment Penetration 112 as not being structurally supported.

Issue

The staff notes that there are no "structural" identifiers on the drawing to ensure that the structural integrity of the NSR piping "anchors" are managed for aging effects consistent with the SLRA Section 2.1.4.2 excerpt cited above during the period of extended operations. In particular, the subject SLRA drawing does not display seismically qualified equivalent supports for the two interfaces of these (a)(1)/(a)(2) system piping components.

NRC Request

Please provide a justification for not including a seismically qualified equivalent anchor for the interfaces of these (a)(1)/(a)(2) system piping components.

Dominion Response

The piping depicted on SLRA drawing 12050-SLRM-082C, Sh. 2, grids F-7 and F-8, consists of safety-related containment penetration piping (highlighted in blue) with dead-ended sections of nonsafety-related piping attached both inside and outside containment.

All of the attached nonsafety-related piping is highlighted orange [for leakage boundary or structural integrity (a)(2) function], is within the scope of subsequent license renewal, and subject to aging management review.

Anchor notations do not identify specific component supports that must be included within scope, but identify the endpoint of piping that must be included within scope to ensure adequate support of attached safety-related piping. Anchor notations are provided for some safety/nonsafety transitions to show that beyond the notation point, it is not necessary to include piping within scope for the structural support function. As noted in NEI 95-10, Appendix F.4 (referenced in NEI 17-01), "An alternative to specifically identifying a seismic anchor or series of equivalent anchors that support the SR/NS piping interface is to include enough of the NS piping run to ensure these anchors are included and thereby ensure the piping and anchor intended functions are maintained."

Since all of the attached nonsafety-related piping is within scope, the specific location of the anchors is not depicted (there is no more attached piping that could be added to scope to encompass them). The anchors/supports are addressed as structural commodities in SLRA Section 2.4.1.38.

4. SLRA Section 2.3.3.15 Service Air

Regulatory Basis:

Paragraph 54.4(a) of 10 CFR "Scope" reads in part:

(a) Plant systems, structures, and components within the scope of this part are--

(1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions--

(i) The integrity of the reactor coolant pressure boundary;

(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable. ...

In addition, 10 CFR 54.21(a) "Contents of application--technical information" reads in part:

Each application must contain the following information:

(a) An integrated plant assessment (IPA). The IPA must--

(1) For those systems, structures, and components within the scope of this part, as delineated in § 54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components--

(i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. ...

SLRA Section 2.1.4.2 "Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)" states in part:

For a nonsafety-related piping system that is directly connected to and provides structural support for a safety-related piping system; the nonsafety-related piping and supports shall be included within the scope of subsequent license renewal up to (1) the analytical boundary defined in the CLB seismic analysis for the safety-related piping or, (2) if the seismic boundary is not clearly defined in the CLB information, up to and including the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions. The location of the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions is identified using the guidance presented in NEI 95-10, Appendix F, Section 4 (as referenced in NEI 17-01).

RAI 2.3.3.15-1

Guidance

SRP-SLR Section 2.1.3.1.2 "Nonsafety-Related" Background

Unit 1 - Sheet 1 "Subsequent License Renewal Service Air System North Anna Power Station Unit 1" of SLRA Drawing No. 11715-SLRM-082F displays at Coordinate C-7, a 2" NSR line inside containment connected to SR piping at Containment Penetration 42.

Unit 2 - Sheet 2 "Subsequent License Renewal Service Air System North Anna Power Station Unit 2" of SLRA Drawing No. 12050-SLRM-082F displays at Coordinate D-6, a 2" NSR line inside containment connected to SR piping at Containment Penetration 42.

Issue

The staff notes that there are no "structural" identifiers on the drawing to ensure that the structural integrity of the NSR piping "anchors" inside Containment are managed for aging effects consistent with the SLRA Section 2.1.4.2 excerpt cited above during the period of extended operations. In particular, the subject SLRA drawing does not display seismically qualified equivalent supports for the two interfaces of these (a)(1)/(a)(2) system piping components.

NRC Request

Please provide a justification for not including a seismically qualified equivalent anchor for the interfaces of these (a)(1)/(a)(2) system piping components.

Dominion Response

The nonsafety-related piping components inside containment that are connected to the safety-related Containment Penetration 42 piping on SLRA drawings 11715-SLRM-082F, Sh. 1 and 12050-SLRM-082F, Sh. 2 for Unit 1 and Unit 2, respectively, consist of several branches of compressed air supply piping and associated valves that dead-end within Containment. All of the attached nonsafety-related piping and valves are highlighted orange [for leakage boundary or structural integrity (a)(2) function], are within the scope of subsequent license renewal, and are subject to aging management review.

Anchor notations do not identify specific component supports that must be included within scope, but identify the endpoint of piping that must be included within scope to ensure adequate support of attached safety-related piping. Anchor notations are provided for some safety/nonsafety transitions to indicate that beyond the notation point, it is not necessary to include piping within scope for the structural integrity (a)(2) function. As noted in NEI 95-10, Appendix F.4 (referenced in NEI 17-01), "An alternative to specifically identifying a seismic anchor or series of equivalent anchors that support the SR/NS piping interface is to include enough of the NS piping run to ensure these anchors are included and thereby ensure the piping and anchor intended functions are maintained."

Since there is no more attached nonsafety-related piping that could be added to scope to ensure that the required support piping was included, the specific location of the anchors is not depicted. The anchors/supports are addressed as structural commodities in SLRA Section 2.4.1.38.

5. SLRA Section 2.3.3.38, System Radiation Monitoring

Regulatory Basis:

Paragraph 54.4(a) of 10 CFR "Scope" reads in part:

(a) Plant systems, structures, and components within the scope of this part are--

(1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions--

(i) The integrity of the reactor coolant pressure boundary;

(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable. ...

In addition, 10 CFR 54.21(a) "Contents of application--technical information" reads in part:

Each application must contain the following information:

(a) An integrated plant assessment (IPA). The IPA must--

(1) For those systems, structures, and components within the scope of this part, as delineated in § 54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components--

(i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. ...

SLRA Section 2.1.4.2 "Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)" states in part:

For a nonsafety-related piping system that is directly connected to and provides structural support for a safety-related piping system; the nonsafety-related piping and supports shall be included within the scope of subsequent license renewal up to (1) the analytical boundary defined in the CLB seismic analysis for the safety-related piping or, (2) if the seismic boundary is not clearly defined in the CLB information, up to and including the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions. The location of the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions is identified using the guidance presented in NEI 95-10, Appendix F, Section 4 (as referenced in NEI 17-01).

RAI 2.3.3.38-1

Guidance

SRP-SLR: Section 2.1.3.1.2 "Nonsafety-Related"

Background

Unit 1 - Sheet 3 "Subsequent License Renewal Radiation Monitoring System North Anna Power Station Unit 1" of SLRA Drawing No. 11715-SLRM-082N displays:

(a) At Coordinate C-4, a 1" NSR line inside Containment "Open to Reactor Containment" connected to the SR piping at Containment Penetration 43; and

(b) At Coordinate D-4, a 1" NSR line inside Containment from "Vent Duct Piping" connected to SR piping at Containment Penetration 44.

Unit 2 - Sheet 2 "Subsequent License Renewal Instrument Air System North Anna Power Station Unit 2" of SLRA Drawing No. 12050-SLRM-082B displays:

(a) At Coordinate C-8, a 1" NSR line inside Containment "Open to Reactor Containment" connected to SR piping at Containment Penetration 43; and

(b) At Coordinate D-8, a 1" line inside Containment from "Vent Duct Piping" connected to SR piping at Containment Penetration 44.

Issue

The staff notes that there are no "structural" identifiers on the drawing to ensure that the structural integrity of the NSR piping "anchors" inside Containment are managed for aging effects consistent with the SLRA Section 2.1.4.2 excerpt cited above during the period of extended operations. In particular, the subject SLRA drawing does not display seismically qualified equivalent supports for the two interfaces of these (a)(1)/(a)(2) system piping components.

NRC Request

Please provide a justification for not including a seismically qualified equivalent anchor for the interfaces of these (a)(1)/(a)(2) system piping components.

Dominion Response

The nonsafety-related piping shown on SLRA drawings 11715-SLRM-082N, Sh. 3, grids C-4 and D-4, and 12050-SLRM-082B, Sh. 2, grids C-8 and D-8, is radiation monitor supply piping between the containment ventilation ring ducts and the safety-related containment penetration piping. All of this piping is shown highlighted orange [for leakage boundary or structural integrity (a)(2) function] on these drawings, and is connected to in-scope ductwork on the containment ventilation drawings (11715-SLRB-006A, Sh. 1 & 2).

Anchor notations do not identify specific component supports that must be included within scope, but identify the endpoint of piping that must be included within scope to ensure adequate support of attached safety-related piping. Anchor notations are provided for some safety/nonsafety transitions to indicate that beyond the notation point, it is not necessary to include piping within scope for the structural support function. As noted in NEI 95-10, Appendix F.4 (referenced in NEI 17-01), "An alternative to specifically identifying a seismic anchor or series of equivalent anchors that support the SR/NS piping interface is to include enough of the NS piping run to ensure these anchors are included and thereby ensure the piping and anchor intended functions are maintained."

Since all of the attached nonsafety-related piping is within scope, the specific location of the anchors is not depicted (there is no more attached piping that could be added to scope to encompass them). The anchors/supports themselves are addressed as structural commodities in SLRA section 2.4.1.38.

6. SLRA AMP B2.1.7, Pressurized Water Reactor (PWR) Reactor Vessel Internals

Background and Regulatory Basis

Paragraph 54.21(a)(3) of 10 CFR states "[f]or each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis (CLB) for the period of extended operation."

The applicant developed its AMR results for the PWR vessel internal (PWRVI) components based on the guidance in the NUREG-2191, Revision 0, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," and SRP-SLR reports, as supplemented by SLR-ISG-2021-01-PWRVI (ADAMS Accession No. ML20217L203). The NRC staff is reviewing the applicant's AMR results, as documented in SLRA Table 3.1.1 (Table 1), SLRA Table 3.1.2-2 (Table 2), and associated AMR further evaluations (FEs) in SLRA Sections 3.1.2.2.9 and 3.1.2.2.10, Subitem 2 (control rod drive penetration nozzle thermal sleeves), and revised per SLRA Supplement 2 dated March 17, 2021 (ADAMS Accession No. ML21076B025).

In order to have reasonable assurance that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff is reviewing the applicant's use of the SRP-SLR and GALL-SLR report recommendations (including deviations from these documents) for the plant-specific AMR results. The staff's review of the AMR results for PWRVI components addresses their consistency with the inspection and evaluation (I&E) guidelines in the PWRVI AMP described in SLRA Section B2.1.7; the SLRA AMP is based on the generic I&E guidelines in MRP-227, Revision 1-A (ADAMS Accession No. ML20175A112), as supplemented by the results of the applicant's MRP-227, Rev. 1-A Gap Analysis.

RAI B2.1.7-1 - Preventative Measures for Pitting and Crevice Corrosion (eRAI Letter #182, Question #277)

<u>Issue</u>

SLRA Table 1, Item 3.1.1-087 states in the "Discussion" column that that this item is "not applicable" since "loss of material for reactor vessel internal components exposed to reactor coolant and neutron flux is addressed by rows 3.1.1-028, 3.1.1-054, 3.1.1-059a, 3.1.1-059b, and 3.1.1-059c." This SLRA Table 1 item also states that the associated GALL-SLR Table IV.B2 items "are not used" in the SLRA Table 2 AMR results for the PWRVI components.

SRP-SLR Table 3.1-1, Item ID 087 credits the Water Chemistry AMP to mitigate loss of material due to pitting and crevice corrosion for PWRVI components. Use of the Water Chemistry AMP for mitigating loss of material due to pitting and crevice corrosion is also included in Element 2 of GALL-SLR AMP XI.M16A. SLRA Section B2.1.7 states that the PWRVI AMP is consistent with this GALL-SLR AMP element. SLRA Table 1, Items 3.1.1-028, 3.1.1-054, 3.1.1-059a, 3.1.1-059b, and 3.1.1-059c address the need for I&E to detect loss of material due to wear. The staff notes that loss of material due to pitting and crevice corrosion is a different aging effect and mechanism than loss of material due to wear since pitting and crevice corrosion are highly localized aging effects that may not be readily detected by VT-3 visual exam. As such, the SRP-SLR and GALL-SLR reports recommend the use of the Water Chemistry AMP for monitoring and control of PWR water chemistry in order mitigate pitting and crevice corrosion.

NRC Request

Address whether a revision to SLRA Table 1, Item 3.1.1-087 and an addition to SLRA Table 2 AMR results are needed to address the management of loss of material due to pitting and crevice corrosion in PWRVI components.

Dominion Response

Loss of material due to pitting and crevice corrosion of stainless steel is not an aging effect requiring management for reactor vessel internals (RVI) components.

As stated in NUREG-2192 (SRP-SLR), Section 3.1.2.2.9, as amended by SLR-ISG-2021-01-PWRVI, "In MRP-227 Revision 1-A, the EPRI MRP identified that the following aging mechanisms may be applicable to the design of the RVI components in [PWR] facilities: (a) stress corrosion cracking (SCC), (b) irradiation-assisted stress corrosion cracking (IASCC), (c) fatigue, (d) wear, (e) neutron irradiation embrittlement, (f) thermal aging embrittlement, (g) void swelling and irradiation growth or component distortion, and (h) thermal or irradiation-enhanced stress relaxation or irradiation enhanced creep."

Other EPRI technical reports evaluated aging-related degradation mechanisms for PWRVI components. Specifically, only the aging-related degradation mechanisms indicated above were evaluated in EPRI Technical Report 3002013220, MRP-191 Revision 2. Using the screening criteria in EPRI Technical Report 3002010268, MRP-175 Revision 1, other degradation mechanisms were considered, but it was determined that PWRVI components are not susceptible to other mechanisms, and no new degradation mechanisms were identified for SLR. Additionally, loss of material due to pitting and crevice corrosion is not expected in the nearly oxygen-free environment of the reactor coolant system.

Westinghouse letter LTR-AMLR-19-43, provides results of their expert panel review of MRP-191 Revision 2 in support of SLR for North Anna Power Station Units 1 and 2. As documented in LTR-AMLR-19-43, neither pitting nor crevice corrosion is identified as a screened-in aging-related degradation mechanism for any of the in-scope RVI components for NAPS. The only loss of material mechanism identified in the Westinghouse review for in-scope RVI components is wear. Other AMR line items from NUREG-2191 (GALL-SLR), Chapter IV.B2 that invoke AMP XI.M2, Water Chemistry, credit it as a program for managing SCC mechanisms only.

Additionally, the disposition of SRP Item 3.1.1-087 for North Anna Power Station is the same as for Surry Power Station, which was found acceptable by the Staff, as documented in the "Safety Evaluation Report Related to the Subsequent License Renewal of Surry Power Station, Units 1 and 2" (ML19360A020), Section 3.1.2.1.1.

Therefore, Item 3.1.1-087 is not applicable and no addition to the AMR results in SLRA Table 3.1.2-2 is required. However, for clarification, the discussion for SLRA Table 3.1.1 Item 3.1.1-087 is revised as follows:

> Not applicable. Loss of material <u>due to pitting and crevice corrosion is not an aging effect requiring management</u> for reactor vessel internal <u>(RVI)</u> components exposed to reactor coolant and neutron flux. <u>Westinghouse's expert panel review</u>

of MRP-191 Revision 2 for NAPS indicates wear is the only loss of material mechanism for in-scope RVI components. Loss of material due to wear is addressed by rows 3.1.1-054, 3.1.1-059a, 3.1.1-059b, ~~and~~ 3.1.1-059c, and 3.1.1-119. The associated NUREG-2191 aging items are not used.

Based on the above, SLRA Table 3.1.1 Item 3.1.1-087 is revised, as shown in Enclosure 3.

7. SLRA AMP B2.1.8, Flow-Accelerated Corrosion

Regulatory Basis

Title 10 of the Code of Federal Regulations (10 CFR) 54.21(a)(3) requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function or functions will be maintained consistent with the current licensing basis for the period of extended operation. In addition, 10 CFR 54.37(a) requires that information necessary to document compliance with the license renewal rule be retained in an auditable and retrievable form. 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. In order to complete its review and enable formulation of a finding for 10 CFR 54.29(a), the staff requires additional information regarding the matters described below.

RAI B2.1.8-1 (eRAI Letter #169, eRAI Number #263)

Background

Dominion Energy's SLRA Section B2.1.8, "Flow Accelerated Corrosion," notes that it is an existing aging management program (AMP) that relies on implementation of the Electric Power Research Institute (EPRI) Guidelines in Nuclear Safety Analysis Center (NSAC) 202L, "Recommendations for an Effective Flow Accelerated Corrosion Program." The SLRA also notes that, following an enhancement associated with infrequently used lines, it will be consistent with GALL-SLR Report," AMP XI.M17, "Flow Accelerated Corrosion."

The guidance in NSAC 202L specifies that the selection of an outage inspection sample includes multiple sources, including reviews of plant experience over the past operating cycle and reviews of industry operating experience. NSAC 202L includes consideration of additional inspection locations based on plant experience using information received from related plant organizations such as system engineering, maintenance, and operations. NSAC-202L also discusses program documentation that includes a report for *each outage, identifying (among other things) the basis for the sample selection, such as operating experience.*

In its evaluation of the Flow Accelerated Corrosion program, Dominion Energy lists Procedure ER-AA-FAC-102, "Flow-Accelerated Corrosion (FAC) Inspection and Evaluation Activities," as one of several implementing procedures. Procedure ER-AA-FAC-102, Section 3.10.2 includes a requirement for issuing a post-outage summary report and notes that it is a quality assurance record. Dominion Energy provided several post-outage summary reports on its ePortal as developmental references for the Flow Accelerated Corrosion program's operating experience.

The NRC staff reviewed the post-outage summary reports for 2016 through 2019 and noted that each report discussed the methodology for development of the outage inspection sample. Each report cited inputs from several items, including the Operational Experience Review required by procedure ER-AA-FAC-1003, "Flow-Accelerated Corrosion (FAC) Operational Experience Reviews." Procedure ER-AA-FAC-1003 notes that operational review personnel interviews and the operating experience reviews are to be incorporated into the outage summary report. In addition, this procedure states that the Dominion flow-accelerated corrosion operating experience database is to be maintained up-to-date to reflect reviews of pertinent industry events.

Issue

Based on the staff's reviews of the post-outage summary reports, it appears that the operational review personnel interviews and operating experience reviews, as prescribed by Dominion Energy procedure ER-AA-FAC-1003, are not being performed. This issue appears to have been acknowledged in the post-outage reports from 2016 and 2017 through reference to PA 3042187, which discusses procedure updates to address the issue. However, Procedure ER-AA-FAC-1003, Revision 6, which addressed items tracked by PA 3042187, did not include any changes associated with conducting operational interviews or operating experience reviews.

In addition, the operating experience review documentation included in the post-outage summary reports does not show that industry operating experience had been reviewed as part of the outage inspection sample selection. There is no mention of the event at Davis-Besse (LER 346/2015-002) as having been considered. The staff notes that PA 3004801 included consideration of the Davis-Besse event; however, the post-outage summary reports do not reflect that the operating experience had been considered as part of the outage inspection sample. The staff also notes that the 2015 Davis-Besse event report, which was caused by inaccurate FAC modeling parameters, included a discussion about a missed opportunity from a previous event that had also been caused by incorrect modeling parameters.

During the audit, Dominion Energy personnel indicated that the flow accelerated corrosion database, as prescribed in Procedure ER-AA-FAC-1003, had been replaced by quarterly fleet FAC conference calls with site program owners. Dominion Energy personnel further indicated that any applicable plant operating experience reports are reviewed during these quarterly conference calls and captured in meeting minutes through individual PAs.

Dominion Energy stated that these meeting minutes/PAs to provide the documentation of the operating experience reviews and take the place of the database discussed in Procedure ER-AA-FAC-1003. Meeting minutes and associated PAs from several recent conference calls were subsequently posted to the ePortal.

The NRC staff reviewed the meeting minutes and associated PAs to determine if effective operating experience were being performed and documented as delineated in NSAC-202L. Based on the available documentation, the staff is unable to determine if effective operating experience reviews were being performed for the development of the outage inspection sample. Also, based on the available documentation, both the current operating experience reviews and the maintenance of the flow-accelerated corrosion operating experience database appear to be inconsistent with Procedure ER-AA-FAC-1003. Finally, based on available documentation, it is not clear whether industry operating experience (such as Davis-Besse and IN 2019-08) has been effectively considered as part of the process for adjusting the Flow-Accelerated Corrosion program.

NRC Request

With respect to the flow-accelerated corrosion program, provide information for the following:

1. *As discussed during the audit breakout session, the post-outage summary reports do not appear to include documentation of the evaluation for the Davis-Besse event in LER 346/2015-002. Provide the bases to show that the existing documentation of these reviews are sufficient to demonstrate that effective industry operating experience reviews are being performed and, if applicable, describe changes operating experience review procedure to ensure such evaluation are completed and documented in the future.*
2. *As discussed during the audit breakout session, there was a recently identified FAC modeling error that was documented in PA 8264343, which was associated with a model discrepancy identified in 2018. Discuss the effectiveness of the operating experience reviews performed for NRC Information Notice 2019-02, associated with FAC modeling issues. Specifically address whether FAC model validation activities have been performed or will be performed prior to the subsequent period of extended operation. Alternatively, provide a discussion about that justifies the accuracy of the current FAC models.*
3. *Discuss whether operational review personnel interviews and maintenance of the FAC operating experience database are being performed as provided in procedure ER-AA-FAC-1003. And, if appropriate, discuss any modifications to the procedure to demonstrate that effective operating experience reviews are being performed.*

Dominion Response

1. The Davis-Besse event involved incorrect data being input, which caused the FAC software to underestimate the predicted wear rate. As a result, inspections were not performed to identify the piping wall thinning prior to the reported failure.

The Dominion Energy evaluation for the Davis-Besse event described in LER 346/2015-002 was provided in PA3004801, but was not included in a post-outage summary report as noted by the NRC Staff. NAPS evaluations of industry OE also have been performed and documented for Indian Point Unit 3 LER 286/2018-003 and for NRC Information Notice 2019-08.

The FAC database has been updated to include FAC-related plant-specific and industry OE (relevant industry OE is evaluated for applicability to the Dominion Energy plants and documented in a condition report for the affected plant(s) including the industry OE noted above). Plant-specific occurrences of erosion also will be included in this OE module of the FAC database (herein referred to as the FAC OE database) as the erosion program matures with additional inspection results based on recent procedural enhancements. An attachment created from the FAC OE database will be included in the post-outage summary reports for the affected plant(s) through an ongoing assignment in the Corrective Action Program. Parameters from the FAC OE database to be included in the summary report will be as follows:

- Condition report number, title, and date
- Affected Dominion Energy nuclear unit (internal OE) or Industry site (external OE)
- Summary of the condition for the affected component and notes of actions taken
- Applicability for other Dominion Energy nuclear units
- Actions and corrective actions for other affected Dominion Energy nuclear units

2. The Dominion Energy review of IN 2019-08 for NAPS resulted in actions being taken to address the OE listed for Davis-Besse and Indian Point 3 to avoid similar problems.

   The actions included:

   Davis-Besse – The complete list of restricting orifices in CHECWORKS for NAPS Units 1 and 2 was reviewed to determine which first pipe and first turbulence carbon steel or low-alloy components were not inspected or were not replaced with a FAC-resistant material. A list of additional Unit 1 and Unit 2 components requiring inspection was used to ensure the completeness of the FAC inspection scope.

   Indian Point 3 – Changes were made in an implementing procedure for the FAC program to provide instructions for inspections to be performed in locations downstream and upstream of a component that is found to be below minimum allowable wall thickness.

   A programmatic evaluation to determine the accuracy of the FAC modeling will be accomplished through the Corrective Action Program by selecting representative samples for comparison of measured inspection results and predicted wall thinning. Samples will include randomly selected components and those that require inspection based on industry or plant-specific OE. Applicable FAC model changes and/or program enhancements would be based upon the results of the representative samples and associated evaluation.

3. The FAC program includes guidance for identifying and evaluating FAC-related OE. INPO OE reports and NRC Information Notices that describe FAC-related industry issues are also reviewed for applicability to the other units in the Dominion Energy nuclear fleet. Plant-specific OE is identified by reviewing condition reports and station narrative logs, and by conducting interviews with station personnel. Evaluations of relevant OE determine whether additions to inspection scope or component replacements are needed for the unit being examined and for other units in the Dominion Energy nuclear fleet. Relevant OE is required to be summarized and entered in the FAC OE database.

   The interviews which are conducted with Station personnel prior to each refueling outage to provide input for establishing the scope of FAC inspections typically include the following topics:

   1. Are there any known leaking valves (manual valves, AOVs, MOVs) in a secondary system recirculation path?
   2. Are there any pumps in secondary systems (such as the condensate or secondary drains systems) that experience more operating time than others?
   3. Are there any valves that are not aligned as indicated on station drawings, such as valves that normally would be fully open but are used in a throttled position?
   4. Are there any steam traps with known operational problems, or are bypassed?
   5. Are there any check valves that leak by?

RAI B2.1.8-2 (eRAI Letter #193, Question #302)

<u>Background</u>

Dominion Energy's SLRA Section B2.1.8, "Flow-Accelerated Corrosion," notes that it is an existing condition monitoring aging management program (AMP) that also manages wall thinning due to erosion mechanisms. The SLRA also notes that the erosion activity implements the recommendations of the Electric Power Research Institute (EPRI) 3002005530, "Recommendations for an Effective Program Against Erosive Attack." The SLRA states that the basis for erosion monitoring is an Erosion Susceptibility Evaluation (ESE) that identifies components requiring inspection due to various erosion mechanisms, including liquid droplet impingement, and considers various inputs including operating experience. The NRC staff notes that EPRI 3002005530 includes guidance that low operating time should be the only basis for system exclusion if the operating service is severe.

Condition reports (CR) 117085, CR1033983, and CR1099475 discuss leakage downstream of component 2-BD-HCV-200B and note that the leak is not considered flow-accelerated corrosion, but rather a water impingement issue. (The NRC staff notes that this component is part of the low capacity blowdown subsystem designated as BD03.) Document ETE-CME- 2020-0005, "Erosion Susceptibility Evaluation – North Anna, Unit 2," notes that subsystem BD03 is not susceptible to erosion because it is kept in standby with an estimated usage of less than 2 percent of the operating time. Document ETE-

CME-2020-0013, "Engineering Evaluation for North Anna Systems Excluded from the Erosion Program Due to Low Operating Time," notes that its purpose is to evaluate subsystems excluded from the erosion portion of the program due to low operating time in order to confirm that components will qualify for the exclusion into the subsequent period of extended operation. The NRC staff notes that subsystem BD03 for the low capacity blowdown subsystem is not discussed in ETE-CME-2020-0013, even though it had been excluded due to infrequent operation.

Issue

Although the SLRA states that the erosion susceptibility evaluation considers operating experience, the reviews of plant-specific operating experience reports (e.g., CR 117085, CR 1033983, and CR 1099475) do not appear to have been appropriately considered in the erosion susceptibility evaluation, ETE-CME-2020-0005. In addition, the evaluation performed in ETE-CME-2020-0013, confirming that components will continue to qualify for exclusion from the erosion program based on infrequent operating time, did not appear to be comprehensive because it did not consider subsystem BD03 for the low capacity blowdown subsystem, which had been excluded based on infrequent operating time. In that regard, the erosion susceptibility evaluation did not discuss whether severe service had been considered as part of the evaluation to confirm that components can be excluded from the erosion portion of the program based on infrequent operating time.

NRC Request

In light of the apparent inconsistencies between plant-specific operating experience for the low capacity blowdown subsystem (BD03) documented in CR117085, CR1033983, and CR1099475 and the evaluations for erosion susceptibility and exclusion criteria confirmation in ETE-2020-0005 and ETE-2020-0013, provide information relative to the reviews of operating experience that will be performed to ensure that the erosion portion of the Flow-Accelerated Corrosion program effectively considers program adjustments based on operating experience.

Include information regarding severe service considerations for components that would otherwise be excluded from the erosion portion of the program based on infrequent operating time.

Dominion Response

The erosion monitoring activities associated with the *Flow-Accelerated Corrosion* program (B2.1.8) continues to be informed with erosion inspections performed in the spring 2021 Unit 1 refueling outage (RFO). Although there were no findings of erosion degradation, erosion inspections will continue to be planned for future RFOs.

As stated in the response to RAI B2.1.8-1, Request #1, erosion OE will be included in the FAC OE database. That database provides input for tasks listed in the erosion control program for integrating OE. Those tasks include:

1. Updating the Erosion Susceptibility Evaluation periodically based on relevant OE and any identified changes in system operating parameters
2. Updating the CHECWORKS database based on established OE review cycles
3. Using OE as an input for the erosion inspection plan during RFOs

The evaluation of erosion susceptibility is based on the following considerations:

1. Identification of the piping configuration during normal operation.
2. Evaluation of operating procedures which could change the configuration of piping during normal operation.
3. Conduct of interviews with Operations personnel to identify any unusual system alignments that are not normally used for plant operation.

As indicated in #2 above, changes in piping configuration that could affect erosion due to an alternate plant configuration are evaluated for possible erosion effects. Unexpected erosion due to severe service is not likely to occur since any alternate configuration that would have sufficient duration for the component to be affected would already have been evaluated for that possibility.

Plant procedures address normal system alignments and routine operations, as well as alternate plant configurations. An alternate plant configuration is an alignment consistent with system design, but not considered to be the normal configuration. Plant procedures include tasks to be completed, and documentation that is needed, when plant operation requires an alternate configuration. Configuration changes are accomplished using approved procedures, written work instructions, engineering design changes, and equipment clearances. For equipment clearances with a duration of more than 90 days, procedural guidance exists to evaluate the clearance as a potential alternate plant configuration. The evaluation considers possible erosion and cyclic stress and determines whether a need exists for engineering assistance and a 10 CFR 50.59 assessment.

The information stated above will provide reasonable assurance that reviews of operating experience will be performed to ensure that the erosion portion of the *Flow-Accelerated Corrosion* program (B2.1.8) effectively considers program adjustments based on operating experience.

8. SLRA AMP B2.1.16, Fire Water System

Regulatory Basis

Section 54.21(a)(3) of Title 10 of the Code of Federal Regulations (10 CFR) requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the U.S. Nuclear Regulatory Commission (NRC) 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 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. 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 B2.1.16-1 (Exception for Fire Pump Suction Screen Inspections) (eRAI Letter #190, eRAI Number #295)

Background

Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations," of NUREG-2191, Volume 2, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report" (Agencywide Documents Access and Management System (ADAMS) Accession No. ML17187A204), recommends that the inspection and testing of fire pump suction screens follow Section 8.3.3.7, "Suction Screens," of National Fire Protection Association (NFPA) 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems." Note 10 to Table XI.M27-1 of NUREG-2191, Volume 2, states, "...testing and inspections can be conducted on a refueling outage interval if plant-specific OE [operating experience] has shown no loss of intended function of the in-scope SSC [structures, systems, and components] due to aging effects being managed for the specific component (e.g., loss of material, flow blockage due to fouling)." Section 8.3.3.7 of NFPA 25 requires the suction screens be "inspected and cleared of any debris or obstructions" following the "waterflow portions of the annual test or fire protection system activations."

Table 3.3.2-42, "Auxiliary Systems – Fire Protection – Aging Management Evaluation," of the SLRA cites Item VII.G.AP-197, Standard Review Plan (SRP) Item 3.3.1-064 of NUREG-2191, Volume 1, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report" (ADAMS Accession No. ML17187A031), which addresses loss of material and flow blockage of steel and copper alloy exposed to raw water, treated water, and raw water (potable) as applicable aging effects to be managed using Aging Management Program (AMP) XI.M27, "Fire Water System."

SLRA Section B2.1.16, "Fire Water System," includes an exception to Element 4, "Detection of Aging Effects." Instead of the fire pump suction screens being inspected for applicable aging effects on a refueling outage interval based on operating experience, Section B2.1.16 of the SLRA states:

The circulating water [CW] and service water [SW] traveling screens will be monitored for a change in differential pressure (dp) since the water flow to the fire protection pumps travels through the respective circulating or service water traveling screens prior to the fire pump suction strainers. The dp across the circulating water and service water traveling screens are monitored once per shift by Operations personnel and the dp is recorded in the logs and trended for a change (10.0 inches and 3.5 inches maximum, respectively) as an indication of potential flow blockage. The circulating water and service *water screen wash operation are automatically initiated on increasing differential pressure. A main control room alarm indicates high differential pressure and requires operator corrective actions."*

SLRA Section B2.1.16 states that the CW and SW traveling screens have a 3/8-inch opening size, whereas the fire pump suction strainers have a larger ½-inch opening size. The justification for this exception concludes by stating, "Monitoring and trending of the circulating water and service water traveling screens dp will ensure clearing of any debris or obstructions from the fire protection suction is performed as a result of pump activations."

SLRA Sections 2.4.1.18, "Intake Structure," and 2.4.1.30, "Service Water Pump House," state, "The traveling screens are active components and do not require aging management." Therefore, the SLRA does not cite programs to manage applicable aging effects (i.e., loss of material and flow blockage) for the traveling screens.

During the audit of AMP XI.M27, the NRC staff reviewed documents, including condition reports and work orders, related to degradation of the SW traveling screens. Specifically one SW traveling screen was replaced and the screen trays and screen chains will be replaced for the remaining SW traveling screens. During the audit, the licensee stated that there has been no degradation history of the CW traveling screens.

<u>Issue</u>

Although SLRA Section B2.1.16 credits the CW and SW traveling screens for limiting the debris size that the fire pump suction screens might see, aging effects are not being managed for either set of traveling screens. Because age-related degradation (e.g., loss of material) of the traveling screens could allow larger size debris to pass through and potentially buildup on the fire pump suction screens, it is not clear how monitoring differential pressure across the traveling screens is sufficient to justify this exemption. High differential pressure across the traveling screens would tend to show that they are functioning properly (by filtering out the appropriate size debris), while a low differential pressure could be an indication that either the debris loading is low or that the traveling screens are degraded and allowing larger size debris to pass through.

In addition, although the inspections prescribed by Section 8.3.3.7 of NFPA 25 are for clearing the fire pump suction screens of any debris or obstructions, these periodic inspections could reasonably be expected to identify loss of material leading to a loss of intended function of the suction screens. The exception justification in SLRA Section B2.1.16, for not performing these outage-interval inspections, does not clearly say how loss of material of the fire pump suction screens will be managed and on what frequency.

<u>**NRC Request**</u>

1. *Given that low differential pressure across the traveling screens could either indicate a lack of debris is on the screens or that the screens are degraded and allowing larger debris to pass through them, provide additional information showing that differential pressure monitoring can reasonably "ensure clearing of any debris or obstructions from the fire protection suction is performed as a result of pump activations."*

Specifically provide information with appropriate acceptance criteria for how decreasing or increasing differential pressure across the traveling screens will prompt the inspections directed by NFPA 25 for inspecting and clearing any debris or obstructions from the fire pump suction screens. Alternatively, provide justification of appropriate changes to the SLRA for managing the applicable aging effects for the CW and SW traveling screens, such that there is reasonable assurance the debris allowed to pass through them will be limited to less than ½-inch size of the fire pump suction screen.

2. *Because the periodic inspections of the fire pump suction screens (as directed by NFPA 25) will not be performed, provide information regarding the activities (e.g., type, frequency) to manage loss of material for the fire pump suction screens.*

Dominion Response

1. Aging management of the CW and SW traveling screens consistent with NFPA 25 requires, "after the waterflow portions of the annual test or fire protection system activations, the suction screens shall be inspected and cleared of any debris or obstructions". The suction screen installation is consistent with NFPA 25, Figure A.8.2.2, for wet pit suction screen installation. The CW and SW traveling screens use spray wash to maintain the screens clean to prevent high differential pressure (dp). Cleaning is accomplished by spray operation using dp monitoring of CW and SW traveling screens that results in cleaning and removal debris or obstructions. In addition, periodic visual inspections of the CW and SW traveling screens to identify screen degradation or damage that result in a low dp provide adequate assurance that no large material will reach the fire pump suction strainer. The following activities have been credited as aging management activities for the CW and SW traveling screens as preventive measures in the *Fire Water System* program (B2.1.16).

   Circulating Water and Service Water Traveling Screen Aging Management Activities

   - Operator logs monitor, record and trend the dp (normal range 3.5-10.0 inches of water) across the circulating water traveling screens once per shift. The circulating water screen wash operations are automatically initiated on increasing differential level (pressure delta). SW screen wash is initiated on a 3.5 inch dp either locally or remotely.
   - Main Control Room alarm response procedures require operator response to a high differential level alarm and initiation of operator corrective actions.
   - Mechanical Maintenance PM's visually inspect the CW traveling screens every 6 months to provide adequate assurance no large material will reach the fire pump suction strainer. The screens are inspected for damaged or unsecured basket wire screen cloth. During the 6 month inspection, the screen wash spray nozzles are verified to wash the entire basket wire area; the gap between the nozzle tips and basket wire is confirmed; and the entire basket screen, including the corner of the screen and carrying lips is cleaned by the spray. If any unsatisfactory conditions or discrepancies are documented on the work order an Engineering review of the condition or discrepancy will be performed to determine if a Condition Report is

required to be submitted. If damaged or unsecured screen with degradation greater than 1/2-inch size is observed, Engineering would evaluate the screen for flow blockage impacts. The SW traveling screens are inspected annually to verify the screens aren't damaged or blocked. A Condition Report would be submitted for any unsatisfactory condition and Engineering would be required to perform an evaluation for impact on License Renewal.

- The differential level switch is calibrated every 4 years.
- Cold Weather PMs (CW traveling screens only): During the winter months, if the temperature of the North Anna Reservoir water decreases to approximately 42°F, small fish (Shad) may become immobilized and potentially drawn into the CW inlet, clogging the screens of the operating CW pumps. These PM's contain the same inspection scope as the PMs used to perform the 6 month inspection of the CW traveling screens. Although the annual Cold Weather PMs are scheduled in January and February, engineering evaluates the need to perform the PM based on in-service time and abnormal events such as the immobilized fish due to thermal shock from cold (freezing) weather changes.

<u>Circulating Water and Service Water Traveling Screen Operating Experience</u>

No documented aging-related degradation or screen damage that resulted in loss of screen filtration intended function was identified during a review of the CW and SW traveling screen PM inspections conducted from 2010 to 2020. The Unit 1 'A' SW traveling screen was replaced in March 2020 due to corrosion of the screen trays. There was no documented aging-related degradation or screen damage identified that resulted in a loss screen filtration intended function during replacement of the Unit 1 'A' SW traveling screen.

2. As noted in the *Fire Water System* program (B2.1.16) exception, the filtration intended function of the fire pump strainer element will be performed by the upstream service water or circulating water traveling screens which are active components and not subject to aging management review.

SLRA Table 3.3.2-42 is revised, as shown in Enclosure 3, to add Plant-Specific Note #13 to clarify aging management of the intended function associated with the fire pump suction strainer element.

RAI B2.1.16-2 (Internal Pipe Blockage and External Pipe Corrosion) (eRAI Letter #190, eRAI Number #296)

<u>Background</u>

SLRA Section B2.1.16 includes operational experience related to identification of debris on the internal surfaces of fire water system piping in 2012. In addition, thinning with excessive rust was observed on the external surface of the same portion of fire water system piping.

During the audit of this program, the NRC staff reviewed documents, including condition reports and work orders, related to this operational experience. Based on the audit, there *is a portion of piping that contains debris on the internal surfaces that still needs to be replaced. Based on the audit, this work has been scheduled; however, it has not yet been completed. Audit documents stated that the pressure maintenance devices are performing satisfactorily. The resolution of the external corrosion was that all of the piping was going to be replaced, so no additional corrective action was needed.*

SLRA Section B2.1.16 also discusses an effectiveness review of the existing program using the performance criteria identified in Nuclear Energy Institute (NEI) 14-12, "Aging Management Program Effectiveness." The "acceptance criteria" program element in NEI 14-12 includes anticipating rates of change and margin to loss of function, and the "corrective action" program element includes predicting the extent of degradation to effect timely preventive actions.

Issue

The SLRA does not address the portion of pipe with debris on the internal surface that still needs to be replaced or the degree of external corrosion. The NRC staff did not find information related to the determination that the pressure maintenance devices continue to meet their intended functions since discovery in 2012.

Documents reviewed as part of the audit of the Fire Water System program did not appear to address the guidance in NEI 14-12 regarding consideration of rates of change and margin to loss of function or prediction of the degradation extent to effect timely preventive actions.

NRC Request

1. *Given that the pipe with debris on the internal surfaces was discovered in 2012, please discuss what procedures are in place for periodic evaluation of determinations that intended functions continue to be met.*
2. *Discuss whether there are procedures in place for periodic evaluation relative to external corrosion that is performed if a corrective action is not completed in a "reasonable" timeframe (i.e., consideration of rates of change and margin to loss of function).*

Dominion Response

1. Documentation associated with Fire Water System program (B2.1.16) Operating Experience (OE) #1 identified that the section of piping with flow blockage occurred between the fire water jockey pump discharge piping and its connection to the electric motor-driven fire pump discharge piping to the main fire protection loop. A portion of the above ground piping (approximately 30 to 50 feet) was immediately replaced in 2012 due to external pipe thinning.

   The fire protection pressure maintenance sub-system continues to perform its intended function although sections of the fire water jockey pump discharge pipe are clogged or thinned. Control Room monitoring of fire water jockey pump activity and fire protection system pressure maintenance sub-system monitoring by station operators demonstrates that the intended functions continue to be maintained as noted below.

The fire protection system is normally maintained at required operating pressure by the fire protection pressure maintenance sub-system and is monitored such that loss of system pressure is detected and corrective actions initiated. A low-pressure condition is alarmed in the main control room by the auto start of the electric motor-driven fire pump, followed by the start of the diesel-driven fire pump if the low-pressure condition continues to degrade. Control room alarm response procedures require investigation of alarms and associated fire pump starts, in addition to the initiation of corrective actions, as appropriate.

In addition, once per shift, operator logs confirm the hydro-pneumatic tank normal operating level is between a minimum of 10% and maximum of 80% of sight glass level indication. The operator logs use the normal operating range of the sight glass of 10-80% which translates into a 54.6-gallon range. A significant leak in the fire protection piping would result in frequent cycling of the fire water jockey pump. This abnormal condition would be identified by operators during their shift inspection rounds. A four gpm leak would result in a noticeable 1-inch drop in tank level in one minute. The fire water jockey pump automatically starts when the hydro-pneumatic tank pressure is less than 105 psig and tank level is less than approximately 110 gallons (29 inches sight glass level) and stops at 140 gallons (36 inches). Fluctuating tank level and/or pressure due to a system leak greater than the capacity of the fire water jockey pump (30 gpm) to maintain level and pressure will automatically start the electric motor-driven fire pump if system pressure drops to less than 90 psig.

2. A portion of the above ground piping (approximately 30 to 50 feet) was immediately replaced in 2012 due to external pipe thinning. A work order has been developed, with the necessary materials allocated, to support replacement of the remaining fire protection piping due to debris on the internal surfaces. In the event that the affected piping is not replaced in a "reasonable" time-frame, Control Room monitoring of the fire water jockey pump activity and fire protection system pressure maintenance sub-system monitoring by station operators demonstrates that the intended functions will be maintained as noted above.

RAI B2.1.16-3 (Main Drain Testing) (eRAI Letter #190, eRAI Number #297)

<u>Background</u>

Table XI.M27-1 of NUREG-2191, Volume 2, recommends that main drain tests follow Section 13.2.5, "Main Drain Test," of NFPA 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems." Note 10 to Table XI.M27-1 of NUREG-2191, Volume 2, states, "...testing and inspections can be conducted on a refueling outage interval if plant-specific OE [operating experience] has shown no loss of intended function of the in-scope SSC [structures, systems, and components] due to aging effects being managed for the specific component (e.g., loss of material, flow blockage due to fouling)." Section 13.2.5 of NFPA 25 requires "main drain tests to be conducted annually at each water- based fire protection system riser to determine *whether there has been a change in the condition of the water supply piping and control valves." It also states, "When there is a 10 percent reduction in full flow pressure when compared to the original acceptance test or previously performed tests, the cause of the reduction shall be identified and corrected if necessary."*

SLRA Section B2.1.16 includes proposed enhancements related to main drain testing to be consistent with NFPA 25. Acceptance criteria will be based upon monitoring flowing pressures from test to test to determine if there is a 10 percent reduction in full flow pressure. During the audit of AMP XI.M27 the licensee stated that main drain testing had been discontinued.

Issue

It is unclear whether the 10 percent pressure reduction criteria for the test-to-test pressure monitoring will be compared to the original acceptance test (or comparable test results) as provided in NFPA 25. The NRC staff notes that if the test-to-test pressure monitoring only uses the immediately prior test result, significant degradation of the fire water system supply over several years would not be identified while still being less than a 10 percent reduction from the previous test. In addition, the staff did not identify any information related to the basis for the current discontinuation of main drain testing. It is unclear whether comparable bases will be used to determine impacts on the fire water system's ability to perform its function during the subsequent period of extended operation.

NRC Request

1. *Clarify whether the test-to-test pressure monitoring associated with the periodic main drain testing will be compared to the original acceptance test (or comparable test result) or will only use the immediately prior test results. If the original acceptance test (or comparable test result) will not be used, provide the bases to show that degradation of the fire water system supply will be adequately managed.*
2. *Discuss the basis for discontinuing main drain testing, including how the condition of the water supply piping and control valve are determined in absence of the main drain testing. Also discuss whether comparable bases will be used during the subsequent period of extended operation.*

Dominion Response

1. NFPA 25, Section 13.2.5.2, states when there is a 10% reduction in full flow pressure when compared to the original acceptance test or previously performed tests, the cause of the reduction shall be identified and corrected if necessary. Previous test results from 1996 will be used rather the original acceptance test data recorded in 1977.

   Copies of tests from 1996 (last test before testing was discontinued) and 1977 (original acceptance test) were compared using the test methodology described in NFPA 25, Section 13.2.5 and Annex 13.2.5.

The 1977 acceptance test did not record the initial supply pressure, isolate the alarm control valve on alarm valves, require stabilization of flow prior to obtaining the full flow pressure reading, record the time for the water supply pressure to return to the original static (non-flowing) pressure and then open the alarm control valve. The procedure then stopped the motor-driven fire pump. The motor-driven pump was not started at the beginning of the test and would have auto-started on low system pressure. This added a potential variable for inconsistent test results.

The 1996 test did not isolate the alarm control valve on alarm valves, record the time for the supply water pressure to return to the original static (non-flowing) pressure and open the alarm control valves. This test procedure did record the as-left static pressure, which is not required by NFPA 25. At the beginning of the test, either the motor-driven, or diesel-driven fire pump is started. NFPA 25 does not state this as a requirement, but it would be appropriate to prevent an automatic start of at least one of the main fire pumps.

NFPA 25 testing uses the initial system pressure, stabilized flowing pressure and the time to return to non-flowing pressure as the data points to be compared and trended to previous test results. The 1996 test data will provide similar data for future test comparison. The new test procedure will be developed using the methodology described in NFPA 25, Section 13.2.5 and Annex 13.2.5. The motor-driven fire pump will be started at the beginning of the test to prevent an automatic start of one or both main fire pumps and to minimize any data inconsistencies.

2. Main drain testing was discontinued in 1997 with endorsement from Nuclear Mutual Limited (NML) since adequate system/valve periodic testing was being performed to demonstrate satisfactory flow conditions and verify that no system blockages existed. NML guidance required the sprinkler system two-inch drain test to be performed once every 18 months. NML recognized other flow tests would show the water supply piping and valves are inspected and tested adequately to assure the reliable operation of the fire water supply system without performing the main drain test. Performance of the following tests met the criteria set by NML to delete the two-inch drain test:

   - Fire Water Valve Verification (valve position/lineup confirmation) (TRM, SR 7.1.1.4)
   - Fire Protection Valve Cycling (TRM, SRs 7.1.1.4, 7.1.1.9)
   - Annual Fire Protection Loop Flow Tests (TRM, SR 7.1.1.13)
   - Fire Suppression Water Systems Flow Test (3-year test to confirm delivery of 2500 gpm) (TRM, SR 7.1.1.1)
   - Fire Protection Water System Flush (TRM, SR 7.1.1.1)
   - Hydrant Flush (previously performed by PM's) (NFPA 25, Sect 7.3.2)
   - Post Indicator Valve Testing (TRM, SRs 7.1.1.4, 7.1.1.9)
   - Wet Pipe, Deluge, and Pre-action System Inspection (TRM, SRs 7.1.7.2, 7.1.7.3, 7.1.7.4)

In addition to the testing and inspections noted above, main drain testing will be implemented and performed prior to the subsequent period of continued operation consistent with SLRA Table A4.0-1, Item 16, Commitment 1b. The frequency of the testing will be performed consistent with the *Fire Water System* program (B2.1.16), Exception 2

RAI B2.1.16-4 (Cracking of Copper Alloy (>15% Zn)) (eRAI Letter #190, eRAI Number #300)

Background

Item VII.G.A-405a, SRP Item 3.3.1-132 in NUREG-2191, Volume 1 addresses cracking due to stress corrosion cracking (SCC) for copper alloy (>15% Zn or >8% Al) piping, piping components exposed to air, condensation to be managed by AMP XI.M36, "External Surfaces Monitoring of Mechanical Components." Also, Item VII.C1.A-473, SRP Item 3.3.1-160 in NUREG-2191, Volume 1 addresses cracking due to SCC for copper alloy (>15% Zn or >8% Al) piping components exposed to closed-cycle cooling water, raw water, waste water to be managed by several programs including AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components."

SLRA Table 3.3.2-42 states that cracking for copper alloy (>15% Zn) piping, piping components exposed internally to air – indoor uncontrolled and valve bodies exposed to raw water will be managed by the Fire Water System program. The corresponding AMR items (3.3.1-132 and 3.3.1-160) cite Standard Note E (consistent with GALL-SLR but different program credited) for the use of the Fire Water System program in lieu of the External Surfaces Monitoring of Mechanical Components program, and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, respectively.

AMP XI.M36 notes that periodic visual or surface examinations are conducted if this program is being used to manage cracking in stainless steel or aluminum components and notes that visual inspections may be conducted where it has been analytically demonstrated that surface cracks can be detected by leakage prior to a crack challenging the intended function of the component. Similarly, AMP XI.M38 notes that periodic surface examinations are conducted for managing cracking in stainless steel and aluminum components and states, "Visual inspections for leakage or surface cracks are an acceptable alternative to conducting surface examinations to detect cracking if it has been determined that cracks will be detected prior to challenging the structural integrity or intended function of the component."

Issue

AMP XI.M27 does not provide additional guidance for managing cracking, whereas XI.M36 and XI.M38 do provide additional guidance for managing cracking. SLRA Section B2.1.16 does not describe how the Fire Water System program inspections and testing performed in accordance with NFPA 25 will manage cracking of copper alloy (>15% Zn) for piping, piping components exposed internally to air – indoor uncontrolled and for valve bodies exposed internally to raw water.

NRC Request

Describe how the Fire Water System program will manage cracking of copper alloy (>15% Zn) piping, piping components exposed internally to air – indoor uncontrolled and valve bodies exposed internally to raw water. Specifically discuss whether surface examinations will be performed or whether analyses will be performed to demonstrate that surface cracks can be detected by leakage prior to a crack challenging the intended function of the component, such that visual inspections would suffice. Alternatively, propose the use of a different aging management program that already includes comparable guidance.

Dominion Response

SLRA Table 3.3.1, Item 160, Table 3.3.2-42, and Table 3.3.2-42 Plant-Specific Note 6 are revised to delete the *Fire Water System* program (B2.1.16) and replace it with the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25) to manage cracking of copper alloy (>15% Zn) components exposed to a raw water internal environment.

SLRA Table 3.3.1, Item 132, Table 3.3.2-42, and Table 3.3.2-42 Plant-Specific Note 8 are revised to delete the *Fire Water System* program (B2.1.16) as the program credited to manage cracking of copper alloy (>15% Zn) piping, piping components exposed to an air - indoor uncontrolled internal environment. Similar to the copper alloy (>15% Zn) rupture disc, sight glass (body), and valve body components exposed to an internal air - indoor uncontrolled internal environment, the copper alloy (>15% Zn) piping, piping components are associated with the piping and fittings downstream from hose rack isolation valves. However, since these components are normally connected to fire hoses and are not exposed internally to contamination from external leakage sources, cracking is not an aging effect requiring management. This is consistent with Table 3.3.2-42, Plant-Specific Note 4 which states the following:

> "Cracking of copper alloy (>15% Zn) in air and condensation environments requires the presence of ammonia-based compounds. In indoor air, such compounds could be conveyed to external surfaces of components via leakage through the insulation from bolted connections. However, internal surfaces of components are not exposed to contamination from external leakage sources. Therefore, internal cracking of these components is not expected."

Additionally, for consistency with other piping, piping components (copper alloy (>15% Zn), ductile iron, gray cast iron, and steel) with an internal air – indoor uncontrolled environment, the copper alloy piping, piping components and copper alloy (>15% Zn) valve body line items in SLRA Table 3.3.2-42 are revised to identify the *Fire Water System* program (B2.1.16) as the program credited to manage the aging effect of flow blockage.

Based on the above, SLRA Table 3.3.1, Items 132 and 160; Table 3.3.2-42; and Table 3.3.2-42 Plant-Specific Notes 6 and 8 are revised, as shown in Enclosure 3.

9. SLRA AMP B2.1.17, Atmospheric Metallic Tanks

RAI B2.1.17-1 (eRAI Letter #187, eRAI Number #291)

Regulatory Basis

Title 10 of the Code of Federal Regulations (10 CFR) 54.21(a)(3) 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. In addition, 10 CFR 54.37(a) requires that information necessary to document compliance with the license renewal rule be retained in an auditable and retrievable form. 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. In order to complete its review and enable formulation of a finding for 10 CFR 54.29(a), the staff requires additional information regarding the matters described below.

Background

Section 54.21(d) of 10 CFR requires each license renewal application to include a final safety analysis report (FSAR) supplement, containing a summary description of the programs and activities for managing the effects of aging. In its discussions about FSAR supplements, the Standard Review Plan for Subsequent License Renewal (NUREG-2192) notes that the description should be sufficiently comprehensive such that later changes to the program can be controlled by 10 CFR 50.59. NUREG-2192 also notes that Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (NUREG-2191), Table XI-01 provides examples of the type of information to be included. GALL-SLR Report Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs [AMP]," provides a description of the "Outdoor and Large Atmospheric Metallic Storage Tanks" program (AMP XI.M29), stating that loss of material is managed by conducting periodic internal and external visual examinations.

As amended by Dominion letter dated February 4, 2021 (ADAMS Accession No. ML21035A303), the corresponding AMP in SLRA, Section B2.1.17, notes that the emergency condensate storage tanks (ECSTs) are surrounded by 2-foot thick concrete missile shields. Consequently, SLRA Section B2.1.17 includes exceptions from the GALL-SLR Report AMP XI.M29 for the ECSTs, because the missile shields prevent any visual inspections of the external surfaces of the tanks, and because there is no caulking or sealant at the base of the tank between the concrete-tank interface. Although Section B2.1.17 states that the concrete missile shield and a 2-inch layer of expansion joint filler foam minimize water and moisture from penetrating to the inaccessible exterior tank *surfaces, the associated operating experience discussion notes that rain water leakage between the concrete missile shield and the outer surfaces of the ECSTs has been a chronic problem. Recent tank wall thickness measurements taken from the tank's inside surface have revealed loss of material on the external surface of the Unit 2 ECST, prompting periodic wall thickness measurements by the program.*

SLRA Section A1.17, "Outdoor and Large Atmospheric Metallic Storage Tanks," as amended by Dominion letter dated February 4, 2021, contains the FSAR supplement for the corresponding AMP. SLRA Section A1.17 does not describe the periodic inspections or preventive maintenance activities that will be performed on Unit 1 and Unit 2 ECSTs resulting from past chronic rain water leakage and the inability to visually inspect the external surfaces of the tanks.

Issue

In order to ensure that changes to the program, which could decrease the overall effectiveness of the program to manage the effects of aging, will receive appropriate review by a licensee, the FSAR supplement should be sufficiently comprehensive. The FSAR supplement for the Outdoor and Large Atmospheric Metallic Storage Tanks program appears to lack a sufficient description of the activities for managing the effects of aging for the ECSTs to provide appropriate administrative and regulatory controls for the program. The current program includes one-time and periodic wall thickness inspections of the ECSTs that are not described in the FSAR supplement. In addition, periodic inspections of the preventive measures to mitigate corrosion by minimizing water and moisture from penetrating to the inaccessible external surfaces of the ECSTs are not described in the FSAR supplement. The staff cannot complete its review of the FSAR supplement without additional information either a) explaining how the current description of the program and aging management activities will provide appropriate administrative and regulatory controls for the program, or b) providing a more detailed description of the program and aging management activities.

NRC Request

Regarding SLRA Section A1.17, provide additional information that either: a) explains how the current description of the program and aging management activities in the FSAR supplement will provide appropriate administrative and regulatory controls for changes to the program, or b) modifies the FSAR supplement to include a more detailed description of the program and aging management activities.

Dominion Response

SLRA Section A1.17 is revised to include the following:

> "One-time thickness measurements will be performed on the Unit 1 ECST interior wall and tank bottom prior to the subsequent period of extended operation to identify and assess potential degradation between the concrete missile shield and the metallic tank. Periodic wall thickness measurements

of the tank bottom and a minimum of five Unit 2 ECST interior vertical wall locations with the lowest wall thickness readings will be performed on a ten-year inspection frequency to evaluate degradation. The Unit 2 ECST vertical wall degradation projections to the end of the subsequent period of extended operation that exceed less than 0.1 inch wall thickness will be repaired prior to entering the subsequent period of extended operation and no longer require wall thickness measurements. The gasket on the ECST upper access concrete plug is replaced whenever it is removed to allow access for internal tank wall thickness measurements. The ECST vent and vacuum breaker caulking is periodically inspected during ECST concrete shield inspections."

In addition, SLRA Section B2.1.17, Exception 2 is revised to include the following:

> "The gasket on the ECST upper access concrete plug is replaced whenever it is removed to allow access for internal tank wall thickness measurements. The ECST vent and vacuum breaker caulking is periodically inspected during ECST missile shield inspections."

Based on the above, SLRA Sections A1.17 and B2.1.17 are revised as shown in Enclosure 3, to include the changes indicated above.

10. SLRA AMP B2.1.35, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

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.

RAI B2.1.35-1

Background

SLRA Section B2.1.35, in item 8 of the Operating Experience Summary, states that structures within the settlement monitoring program, including the Service Water Reservoir, the Service Water Pump House, and the Service Water Valve House, are monitored every 184 days, as specified in the Technical Requirements Manual (TRM), Section 3.7.7.

By letter dated March 10, 2021 (ADAMS Accession No. ML21XXX), the applicant noted that the inspection frequency for settlement was changed from 184 days to 12 months.

During the audit, the staff reviewed document ETE-CCE-2020-0001, Revision 0, "Station and Service Water Reservoir Technical Requirements Manual (TRM) Settlement Data

Trends," which notes that settlements do not typically challenge the current TRM action limits for settlement, with the exception of the Service Water Valve House which is close to the TRM action limit. The staff also reviewed document ETE-NA-2020-0015, Revision 0, "Reduction in Site Settlement Survey Frequency," which documents the history of settlement at NAPS and discusses extending the frequency of settlement monitoring from six months to twelve months.

Issue

No technical justification was provided for how the extended settlement inspection interval will continue to provide adequate aging management of settlement for structures within the scope of subsequent license renewal.

NRC Request

Explain how the longer interval will continue to provide adequate aging management of settlement for structures within the scope of subsequent license renewal, especially structures which may be close to the settlement action limits identified in the TRM (i.e., data trends indicate limits would be reached within one or two inspection intervals).

Dominion Response

Settlement monitoring of Class 1 Structures is governed by Technical Requirements Manual (TRM) 3.7.7. TRM 3.7.7 requires that a condition report is initiated if any of the monitored locations exceed 75% of the allowable settlement. The intent of initiating corrective actions at 75% of allowable settlement is to ensure that any affected SSCs will not become inoperable if 100% allowable settlement is reached.

As noted in the March 10, 2021 letter, the settlement surveillance frequency was changed from 184 days to 12 months. ETE-NA-2020-0015, Rev. 1, Reduction in Site Settlement Survey Frequency, was prepared to document the technical justification for extension of the settlement surveillance frequency to 12 months. The conclusions arrived at in ETE-NA-2020-0015 are based on review of Class 1 Structure settlement trends which are documented in ETE-CCE-2020-0001, Rev. 0, Station and Service Water Reservoir Technical Requirements Manual (TRM) Settlement Data Trends.

ETE-CCE-2020-0001 settlement data indicates the rate of settlement has shown a trend towards leveling off. To date, none of the identified settlement markers have reached the 75% settlement limit with the exception of settlement marker SM-28 (SW Valve House). Per TRM B3.7.7, the items that limit the settlement of the SW Valve House are service water piping expansion joints that are located in the SW Valve House expansion joint pit. The current allowable settlement for SM-28 provided in TRM 3.7.7 was established in 2009, which resulted from piping and expansion joint modifications performed at that time. As noted in the design change that implemented the 2009 modifications, if future settlement exceeds the 75% threshold, an increase in allowable settlement could be accommodated by adjusting the expansion joint tie-rods.

As documented in ETE-NA-2020-0015, based on a review of the settlement trends, the structures (including the SW Valve House) are not expected to experience the amount of settlement necessary to simultaneously cross the 75% threshold and challenge the 100% allowable settlement limit within the span of one settlement surveillance cycle of 12 months.

Enclosure 2

FLOW-ACCELETRATED CORROSION PROGRAM ENHANCEMENT COMPLETION

**Virginia Electric and Power Company
(Dominion Energy Virginia)
North Anna Power Station Units 1 and 2**

Flow-Accelerated Corrosion Program
Enhancement Completion

North Anna Power Station, Units 1 and 2
Subsequent License Renewal Application

Enhancement 1 associated with the *Flow-Accelerated Corrosion* program (B2.1.8), as noted below, has been incorporated into procedures and is deleted from SLRA Table B2-1, Section B2.1.8 and Table A4.0-1, Item 8.

1. An Engineering evaluation will be performed for systems that have been excluded from FAC monitoring activities due to no flow, or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time during the first period of extended operation. The purpose of the Engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The Engineering evaluation and subsequent modeling changes for tracking FAC monitoring activities will be completed prior to entering the subsequent period of extended operation.

Based on the above, SLRA Table B2-1, Section B2.1.8 and Table A4.0-1, Item 8 are supplemented, as shown in Enclosure 3, to delete Enhancement 1, identify the enhancement as completed, and specify the program as an existing condition monitoring program that is credited.

Enclosure 3

SLRA MARK-UPS
SET 2 RAIs

Virginia Electric and Power Company
(Dominion Energy Virginia)
North Anna Power Station Units 1 and 2

Table 2.3.3-7 Service Water

Component Type	Intended Function(s)
Pump casing (chemical addition)	Leakage Boundary (Spatial)
Pump casing (heating and ventilation)	Pressure Boundary
Pump casing (radiation monitoring)	Pressure Boundary
Pump casing (radiation monitoring) (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Pump casing (screen wash)	Pressure Boundary
Pump casing (service water sump)	Leakage Boundary (Spatial)
Pump casing (service water)	Pressure Boundary
Pump casing (sump pump)	Leakage Boundary (Spatial)
Pump casing (tie-in vault sump)	Leakage Boundary (Spatial)
Pump casing (transfer drain) (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Radiation monitor housing	Pressure Boundary
Radiation monitor housing (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Separator	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Spray nozzle	Spray Pattern
Strainer body	Pressure Boundary
Strainer body (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Strainer element	Filtration

See Table 2.1-1 for definitions of intended functions.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-083	Steel steam generator shell assembly exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. Loss of material of the steel steam generator shell assembly exposed to secondary feedwater or steam is addressed by item 3.1.1-012. The associated NUREG-2191 aging items are not used.
3.1.1-084	Steel top head enclosure (without cladding): top head, top head nozzles (vent, top head spray, RCIC, spare) exposed to reactor coolant	Loss of material due to general, pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.1.1-085	Stainless steel, nickel alloy, and steel with nickel alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.1.1-086	Stainless steel steam generator primary side divider plate exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, Water Chemistry	No	Not applicable. NAPS has no in-scope stainless steel steam generator primary side divider plate exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-087	Stainless steel, nickel alloy PWR reactor internal components exposed to reactor coolant, neutron flux	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry	No	Not applicable. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for reactor vessel internal (RVI) components exposed to reactor coolant and neutron flux. Westinghouse's expert panel review of MRP-191 Revision 2 for NAPS indicates wear is the only loss of material mechanism for in-scope RVI components. Loss of material due to wear is addressed by rows 3.1.1-054, 3.1.1-059a, 3.1.1-059b, ~~and~~ 3.1.1-059c, and 3.1.1-119. The associated NUREG-2191 aging items are not used.

3.3.2.1.7 Service Water

Materials

The materials of construction for the service water system component types are:

- Copper alloy
- ~~Copper alloy (>15% Zn)~~
- Ductile iron
- Elastomer
- Fiberglass
- Gray cast iron
- Nickel alloy
- Non-metallic thermal insulation
- Polymer
- Stainless steel
- Steel
- Steel with internal coating
- Zinc

Environment

The service water system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Condensation
- Petrolatum corrosion preventive casing filler
- Raw water
- Soil
- Treated water
- Underground
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the service water system, require management:

- Cracking
- Cracking or blistering
- <u>Cracking, blistering, loss of material</u>
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the service water system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-131	Steel, stainless steel, copper alloy, aluminum piping, piping components exposed to air, condensation	Flow blockage due to fouling	AMP XI.M27, Fire Water System	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation.
3.3.1-132	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, External Surfaces Monitoring of Mechanical Components or AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191~~ with a different program for some components~~. Cracking of copper alloy (>15% Zn) components exposed externally to air – indoor uncontrolled, air – outdoor, or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program.~~ Cracking of copper alloy (>15% Zn) hose rack piping components exposed internally to air – indoor uncontrolled in the fire protection system is managed by the Fire Water System (B2.1.16) program~~.
3.3.1-133	HDPE underground piping, piping components	Cracking, blistering	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. NAPS has no in-s.cope HDPE underground piping, piping components in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-134	Steel, stainless steel, copper alloy piping, piping components, and heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.
3.3.1-135	Steel, stainless steel pump casings exposed to waste water environment	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Engineered Safety Features (recirculation spray and safety injection) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-159	Fiberglass piping, piping components, ducting, ducting components exposed to air	Loss of material due to wear	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. NAPS has no in-scope fiberglass piping, piping components or ducting, ducting components exposed to air (internal) in the Auxiliary Systems. Loss of material of fiberglass components exposed to air - indoor uncontrolled (external) is addressed in row 3.3.1-082. The associated NUREG-2191 aging items are not used.
3.3.1-160	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, raw water, waste water	Cracking due to SCC	AMP XI.M20, Open-Cycle Cooling Water System, AMP XI.M21A, Closed Treated Water Systems, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191 with ~~exceptions and~~ a different program for some components. Cracking of copper alloy (>15% Zn) components exposed to waste water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Cracking of copper alloy (>15% Zn) components exposed to raw water in the domestic water system <u>and in the fire protection system</u> is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. ~~Cracking of copper alloy (>15% Zn) components exposed to raw water in the fire protection system is managed by the Fire Water System (B2.1.16) program. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program.~~ In addition to Auxiliary Systems, components in Steam and Power Conversion System (lubricating oil) are aligned to this item. Cracking of copper alloy (>15% Zn or >8% Al) components requires the presence of ammonia or ammonium compounds. These contaminants are not present in closed-cycle cooling water chemistries at NAPS.
3.3.1-161	Copper alloy heat exchanger tubes exposed to condensation	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.

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components (not covered by NRC GL 89-13)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Pump casing (auxiliary service water)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
Pump casing (chemical addition makeup)	LB	~~Stainless steel~~	~~(E) Air – indoor uncontrolled~~	~~Cracking~~	~~One-Time Inspection (B2.1.20)~~	~~VII.C1.AP-209a~~	~~3.3.1-004~~	~~A~~
				~~Loss of material~~	~~One-Time Inspection (B2.1.20)~~	~~VII.C1.AP-221a~~	~~3.3.1-006~~	~~A~~
			~~(I) Treated water~~	~~Loss of material~~	~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)~~	~~VII.G.A-55~~	~~3.3.1-066~~	~~E, 2~~
		Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A
Pump casing (chemical addition)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-33	3.3.1-064	E, 2
					Selective Leaching (B2.1.21)	VII.C2.AP-31	3.3.1-072	A

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (heating and ventilation)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
Pump casing (radiation monitoring)	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Pump casing (radiation monitoring) (not covered by NRC GL 89-13)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Pump casing (screen wash)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (service water sump)	LB	Gray cast iron	(E) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
Pump casing (service water)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
Pump casing (sump pump)	LB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (tie-in vault sump)	LB	Gray cast iron	(E) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (transfer drain) (not covered by NRC GL 89-13)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Radiation monitor housing	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	C
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	C
Radiation monitor housing (not covered by NRC GL 89-13)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	C
Separator	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
Sight glass	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A
Sight glass (body)	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Spray nozzle	SP	Stainless steel	(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
Strainer body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
Strainer body (not covered by NRC GL 89-13)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Strainer element	FLT	Nickel alloy	(E) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-206	3.3.1-034	B
		Stainless steel	(E) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
Tank (air receiver)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Tank (chemical mixing chamber)	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (descant dryer)	SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
Tank (polymer storage)	LB	~~Copper alloy (>15% Zn)~~	~~(E) Air – indoor uncontrolled~~	~~Cracking~~	~~External Surfaces Monitoring of Mechanical Components (B2.1.23)~~	~~VII.I.A-405a~~	~~3.3.1-132~~	~~A~~
			~~(I) Treated water~~	~~Loss of material~~	~~Selective Leaching (B2.1.21)~~	~~VII.C2.AP-32~~	~~3.3.1-072~~	~~A~~
					~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)~~	~~VIII.A.SP-101~~	~~3.4.1-016~~	~~E, 2~~
		Fiberglass	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
				Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
			(I) Treated water	Cracking, blistering, loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-644	3.3.1-175	A
Valve body	LB;PB;SI	Copper alloy	(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A, 1
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-33	3.3.1-064	E, 2
					Selective Leaching (B2.1.21)	VII.C2.AP-31	3.3.1-072	A
		Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-206	3.3.1-034	B

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Odorizer	PB	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-763a	3.3.1-234	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-763a	3.3.1-234	A
		Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
		Steel	(I) Air – indoor uncontrolled	Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	B
Piping, piping components	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.G.AP-132	3.3.1-069	A
			(I) Air – indoor uncontrolled	~~None~~Flow blockage	~~None~~Fire Water System (B2.1.16)	VII.G.A-404~~VII.J.AP-144~~	3.3.1-131~~3.3.1-114~~	B~~A~~
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-174	3.3.1-108	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A, 7
				Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A, 7
			(I) Air – indoor uncontrolled	~~Cracking~~	~~Fire Water System (B2.1.16)~~	~~VII.G.A-405a~~	~~3.3.1-132~~	~~E, 7, 8~~
				Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B, 4, 7

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
		Ductile iron with internal lining	(I) Raw water	Loss of coating or lining integrity; loss of material or cracking (for cementitious coatings/linings)	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.A-414	3.3.1-139	B
						VII.G.A-415	3.3.1-140	B
			(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B, 7
				Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 3
					Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D, 7
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A, 9
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A, 9
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B, 2, 9
		Gray cast iron with internal lining	(I) Raw water	Loss of coating or lining integrity; loss of material or cracking (for cementitious coatings/linings)	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.A-414	3.3.1-139	B
						VII.G.A-415	3.3.1-140	B
			(E) Soil	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	None	None	H, 11
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B, 7
				Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 3
					Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D, 7
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A, 9
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-400	3.3.1-127	B, 9
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B, 2, 9
Pump casing (diesel driven fire pump)	PB	Gray cast iron	(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (motor driven fire pump)	PB	Gray cast iron	(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Pump casing (pressure maintenance)	PB	Stainless steel	(E) Raw water	Loss of material	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	B
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	B
Rupture disc	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A, 4
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
Sight glass	PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Raw water	None	None	VII.J.AP-50	3.3.1-117	A

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass (body)	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A, 4
			(I) Raw water	Cracking	~~Fire Water System (B2.1.16)~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-473b	3.3.1-160	E, 6
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-47	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
Sprinkler head	SP	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(E) Air – outdoor	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	B
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	B
Strainer body	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Strainer element (deluge/alarm check valve)	FLT	Copper alloy	(E) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer element (pump suction)	FLT	Copper alloy	(E) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B, 13
Strainer element (turbine building supply header)	FLT	Copper alloy	(E) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
Tank (17-ton carbon dioxide storage)	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (6-ton carbon dioxide storage)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (carbon dioxide cylinder)	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (carbon dioxide delay)	PB	Steel	(I) Air – indoor uncontrolled	Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 3
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Tank (fire pump fuel oil)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234a	3.3.1-070	B
Tank (halon cylinder)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (hydropneumatic)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (nitrogen manual release)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (nitrogen)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (retarding chamber)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B, 10
			(E) Air – outdoor	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.G.AP-132	3.3.1-069	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B, 2
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Air – indoor uncontrolled	~~None~~Flow blockage	~~None~~Fire Water System (B2.1.16)	VII.G.A-404~~VII.J.AP-144~~	3.3.1-131~~3.3.1-114~~	~~A~~B, 4
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
			(I) Raw water	Cracking	~~Fire Water System (B2.1.16)~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-473b	3.3.1-160	E, 6
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-47	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB,PB	Ductile iron with internal lining	(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A, 12
				Loss of coating or lining integrity; loss of material or cracking (for cementitious coatings/linings)	Fire Water System (B2.1.16))	VII.G.A-416	3.3.1-138	E, 12
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A, 12
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B, 12
			(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
			(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
		Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Condensation	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-797b	3.3.1-263	A

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Stainless Steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B
				Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 3
					Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-400	3.3.1-127	B
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-42 Plant-Specific Notes:

1. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
2. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.
3. The Fire Protection (B2.1.15) program will manage loss of material for the steel Halon and carbon dioxide fire suppression piping, tanks, and valves exposed internally to air.
4. Cracking of copper alloy (>15% Zn) in air and condensation environments requires the presence of ammonia-based compounds. In indoor air, such compounds could be conveyed to external surfaces of components via leakage through the insulation from bolted connections. However, internal surfaces of components are not exposed to contamination from external leakage sources. Therefore, internal cracking of these components is not expected.
5. Cracking, hardening, loss of strength, and shrinkage are not aging effects requiring management for steel fire damper assemblies exposed to air.

6. The ~~Fire Water System (B2.1.16)~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will manage cracking of copper alloy (>15% Zn) components exposed to raw water.
7. This row includes piping and fittings downstream from hose rack isolation valves.
8. ~~The Fire Water System (B2.1.16) program will manage cracking of copper alloy (>15% Zn) piping, piping components exposed internally to air - indoor uncontrolled.~~Not used.
9. This row includes piping and fittings associated with standpipe risers.
10. Flow blockage is an aging effect requiring management only for copper alloy valve bodies in the water suppression portion of the fire protection system. It is not an aging effect requiring management in the carbon dioxide or Halon portions.
11. Cracking of buried gray cast iron piping due to cyclic loading is managed by the Buried and Underground Piping and Tanks (B2.1.27) program. CLB fatigue analysis does not exist.
12. Aging effects for lined ductile iron valves (01-FP-85 and 01-FP-90) are managed as follows: Loss of coating or lining integrity; loss of material due to general, pitting, crevice corrosion, and MIC; and flow blockage due to fouling are managed with the Fire Water System (B2.1.16) program. Full flow testing and flushing is performed annually, at design pressure and flow rate, on downstream hydrants to detect flow blockage due to fouling as result of corrosion products or coating debris. Valves are flushed fully open for greater than one minute until all foreign material has cleared. Loss of material due to selective leaching is managed by the Selective Leaching (B2.1.21) program, and long-term loss of material is managed by the One-Time Inspection (B2.1.20) program.
13. As noted in the Fire Water System (B2.1.16) program exception, the filtration intended function of the fire pump suction strainer element will be performed by the upstream service water or circulating water system traveling screens, which are active components and not subject to aging management review.

A1.16 FIRE WATER SYSTEM

The *Fire Water System* program is an existing condition monitoring program that manages cracking, flow blockage, and, loss of material for in-scope water-based fire protection systems. This program manages cracking, flow blockage, and, loss of material by conducting periodic visual inspections, flow testing, and flushes performed in accordance with the NFPA 25, 2011 Edition. Testing or replacement of sprinklers that have been in place for 50 years is performed in accordance with NFPA 25, 2011 Edition.

With exception of two locations that will be reconfigured to allow drainage, portions of the water-based fire protection system that have been wetted but are normally dry have been confirmed to drain and are not subjected to augmented testing and inspections.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated. Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed, and the source is detected and corrected. Inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

A1.17 OUTDOOR AND LARGE ATMOSPHERIC METALLIC STORAGE TANKS

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing condition monitoring program that manages the effects of cracking and loss of material on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil. This program is a condition monitoring program that manages aging effects associated with outdoor tanks with internal pressures approximating atmospheric pressure including the refueling water storage tanks (RWSTs), refueling water chemical addition tanks (CATs), casing cooling tanks (CCTs), and emergency condensate storage tanks (ECSTs). The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components consistent with standard industry practices. The RWSTs and CCTs are insulated and rest on a concrete foundation covered with an oil sand cushion. Caulking is used at the concrete-component interface of the RWSTs and CCTs. The CATs are skirt supported and insulated. The ECSTs are internally coated and protected by concrete missile barriers.

The program manages loss of material on tank internal bare metal surfaces by conducting visual inspections. Inspections of RWST and CCT caulking/sealants are supplemented with physical manipulation. Surface exams of external tank surfaces are conducted to detect cracking on the stainless-steel tanks. Thickness measurements of the tank's bottoms are conducted to ensure that significant degradation is not occurring. The external surfaces of insulated tanks are periodically sampling-based inspected. Inspections not conducted in accordance with ASME Code, Section XI requirements are conducted in accordance with plant-specific procedures that include inspection parameters such as lighting, distance, offset, and surface conditions.

One-time thickness measurements will be performed on the Unit 1 ECST interior wall and tank bottom prior to the subsequent period of extended operation to identify and assess potential degradation between the concrete missile shield and the metallic tank. Periodic wall thickness measurements of the tank bottom and a minimum of five Unit 2 ECST interior vertical wall locations with the lowest wall thickness readings will be performed on a ten-year inspection frequency to evaluate degradation. The Unit 2 ECST vertical wall degradation projections to the end of the subsequent period of extended operation that exceed less than 0.1 inch wall thickness will be repaired prior to entering the subsequent period of extended operation and no longer require wall thickness measurements. The gasket on the ECST upper access concrete plug is replaced whenever it is removed to allow access for internal tank wall thickness measurements. The ECST vent and vacuum breaker caulking is periodically inspected during ECST concrete missile shield inspections.

Consistent with the recommendations of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (A1.28), loss of coating integrity for the emergency condensate tanks is managed by this program. Internal surfaces of the RWSTs, CATs, and CCTs will be managed by the *One-Time Inspection* program (A1.20). Tank reinforced concrete foundations and the reinforced concrete missile barrier of the ECSTs will be managed by the *Structures Monitoring* program (A1.34).

A1.18 FUEL OIL CHEMISTRY

The *Fuel Oil Chemistry* program is an existing mitigative and condition monitoring and preventive program that manages cracking or blistering, flow blockage, hardening or loss of strength, loss of material, and reduction of heat transfer from tanks, piping, and components in a fuel oil environment. The program includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of subsequent license renewal.

This program relies on a combination of surveillance and maintenance procedures. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with Technical Specifications, the Technical Requirements Manual, and ASTM standards such as ASTM D 0975, D 1796, D 2276, D 2709, D 6217, and D 4057.

Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic cleaning/draining of tanks and by verifying the quality of new oil before its introduction into the storage tanks. Where internal cleaning and inspection are not physically possible, bottom thickness measurements of inaccessible tanks will be performed in lieu of cleaning and internal inspection.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	3. Procedures will be revised to provide acceptance criteria for inspection results for the following reactor vessel internal components in accordance with MRP-227, Revision 1-A: a. Thermal shield flexures b. Lower support forging c. Upper core plate 4. Procedures will be revised to provide guidance for one-time inspections of the core barrel MAW and LAW in accordance with MRP 2019-009, "Transmittal of NEI 03-08 'Good Practice' Interim Guidance Regarding MRP-227-A and MRP-227, Revision 1, PWR Core Barrel and Core Support Barrel Inspection Requirements".	B2.1.7	Program, accounting for the impacts of a gap analysis, will be implemented 6 months prior to the subsequent period of extended operation, or alternatively, a plant-specific program may be implemented 6 months prior to the subsequent period of extended operation.
8	*Flow-Accelerated Corrosion* program	The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that ~~will be enhanced as follows:~~is credited. 1. ~~An Engineering evaluation will be performed for systems that have been excluded from FAC monitoring activities due to no flow, or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time during the first period of extended operation. The purpose of the Engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The Engineering evaluation and subsequent modeling changes for tracking FAC monitoring activities will be completed prior to entering the subsequent period of extended operation.~~ (Updated - RAI Set 2)	B2.1.8	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

B2 Aging Management Programs

Table B2-1 lists the aging management programs described in this appendix and identifies the programs consistency with NUREG-2191. As discussed in Section B1.4, both plant specific and industry operating experience has been reviewed and considered as it relates to both new and existing aging management programs.

Table B2-1
NAPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B2.1.1	Existing	X	
Water Chemistry (Primary and Secondary)	B2.1.2	Existing		
Reactor Head Closure Stud Bolting (addressed by ISI program)	B2.1.3	Existing		X
Boric Acid Corrosion	B2.1.4	Existing		
Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components	B2.1.5	Existing		
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	B2.1.6	Existing		
PWR Vessel Internals	B2.1.7	Existing	X	
Flow-Accelerated Corrosion	B2.1.8	Existing	X	
Bolting Integrity	B2.1.9	Existing	X	
Steam Generators	B2.1.10	Existing		
Open-Cycle Cooling Water System	B2.1.11	Existing		X
Closed Treated Water Systems	B2.1.12	Existing	X	

B2.1.8 Flow-Accelerated Corrosion

Program Description

The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion, as well as wall thinning due to erosion mechanisms. Erosion monitoring is performed for the internal surfaces of metallic piping and components to manage the aging effect of wall thinning due to cavitation, flashing, liquid droplet impingement, and solid particle erosion.

The *Flow-Accelerated Corrosion* program is consistent with the Virginia Power response to NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," and relies on implementation of the EPRI guidelines in Nuclear Safety Analysis Center (NSAC)-202L, Revision 4, "Recommendations for an Effective Flow Accelerated Corrosion Program." The erosion activity implements the recommendations of EPRI 3002005530, "Recommendations for an Effective Program Against Erosive Attack".

The *Flow-Accelerated Corrosion* program includes (a) identifying flow accelerated corrosion (FAC)-susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analyses of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporating inspection data to refine FAC models.

The *Flow-Accelerated Corrosion* program tracks and predicts occurrences of wall thinning due to FAC using CHECWORKS-SFA™ software. Changes made in the CHECWORKS-SFA™ model are prepared and implemented by a qualified FAC engineer. Each change is then independently reviewed and validated by a qualified FAC engineer. Evaluations documenting the calculation of wear, wear rate, remaining life, next scheduled inspection, and sample expansion are independently reviewed by a qualified FAC engineer. The CHECWORKS-SFA™ model is evaluated and updated, as required, to reflect any significant changes in plant operating parameters such as power uprates. The CHECWORKS-SFA™ model is also refined by importing actual ultrasonic testing (UT) examination results as input for further wear rate analysis, thereby improving the predictive capability of the model for FAC-susceptible components included in the model. Wall thinning information available from the CHECWORKS-SFA™ software is one of the tools used to determine the scope and required schedule for inspections of FAC-susceptible components.

In addition to planned inspections performed for the *Flow-Accelerated Corrosion* program, opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation. The *Flow-Accelerated Corrosion* program goal is to ensure that piping remains above the minimum allowable wall thickness; inspections are scheduled to support a planned approach such that the component wall thickness will be managed until replacement can be scheduled.

Erosion Monitoring Description

The basis for erosion monitoring is an Erosion Susceptibility Evaluation (ESE) that identifies components that require inspection due to potential wall thinning caused by cavitation, flashing, liquid droplet impingement (LDI), or solid particle erosion (SPE). The ESE includes each system that could be degraded by any of these four mechanisms. The majority of the erosion monitoring inspection scope is based on the ESE, and is determined in a manner similar to the process for "Susceptible Non-modeled" (SNM) lines used for the FAC program. Lines are risk ranked based on the level of plant safety, erosion susceptibility, and consequence of failure. An additional input for identifying the scope of inspections is an engineering evaluation of components that are not susceptible to erosion because of infrequent operation. In addition, the evaluation did not identify any situations of non-routine system alignments that could increase erosion susceptibility.

Identification of components to be inspected for erosion monitoring is provided by an Engineering evaluation that considers operating experience reviews, components replaced at other units, re-inspections of previously-inspected component, input from other internal inspections, and previously-replaced components. Erosion monitoring includes calculations of wear rate based on nominal and measured wall thickness values, evaluations of remaining service life, and determination of whether a component requires immediate replacement, a future re-inspection, or no further inspection.

The CHECWORKS Erosion Module is not used to determine susceptibility, or select systems for inspection. All lines modeled in the Erosion Module are identified using the ESE. The outputs from the Erosion Module are used to predict locations on susceptible lines. Those outputs are not used to exclude lines from the inspection scope, but are used to help establish the priority of inspections. Determination of remaining service life or projected wall thickness is accomplished using Engineering evaluations performed outside of the Erosion Module.

While no preventive actions are required by this program, activities such as monitoring of water chemistry to control pH and dissolved oxygen content can be effective in reducing FAC. Similarly, selecting FAC-resistant materials, or changing piping geometry for susceptible locations can be effective in reducing FAC. The aging management strategy related to FAC emphasizes a preference for design improvement over simple management of wall thinning.

The *Flow-Accelerated Corrosion* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Flow-Accelerated Corrosion* program is an existing program that~~, following enhancement, will be~~ is consistent~~,~~ with NUREG-2191, Section XI.M17, Flow-Accelerated Corrosion.

Exception Summary

None

Enhancements

None ~~Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):~~

~~Scope of Program (Element 1) and Detection of Aging Effects (Element 4)~~

1. ~~An Engineering evaluation will be performed for systems that have been excluded from FAC monitoring activities due to no flow, or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time during the first period of extended operation. The purpose of the Engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The Engineering evaluation and subsequent modeling changes for tracking FAC monitoring activities will be completed prior to entering the subsequent period of extended operation.~~ (Updated - RAI Set 2)

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Flow-Accelerated Corrosion* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2012, during the Spring 2012 Unit 1 refueling outage, a degraded elbow was identified on a small-bore low pressure steam pipe. The degraded elbow was replaced using chrome-moly during the 2012 outage. Scope expansion was required, and eight additional components were inspected. No additional degradation was noted.
2. In September 2013, during the Fall 2013 Unit 1 refueling outage, three components on a high pressure steam line were found to have wall thickness above code minimum wall thickness. However, those components did not have remaining wall thickness that complied with FAC program requirement to be at least 75% of nominal for small-bore piping operating above 500 psi. The three components were replaced during the Fall 2013 refueling outage using chrome-moly.

3. In March 2016, during the Spring 2016 Unit 2 refueling outage, an elbow on a 2-inch low-pressure pipe on a feedwater heater drain pump was scheduled for inspection. Prior to the inspection, the pump was removed and shipped offsite for repair with the elbow attached. The elbow was one of two remaining carbon components on the 2-inch line. Based on inspections of similar carbon components on the opposite train heater drain pump, the elbow was identified as needing to be replaced within five years using chrome-moly. The replacement of the elbow was completed during the Spring 2016 refueling outage.
4. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Flow Accelerated Corrosion AMA (UFSAR Section 18.2.16).
5. In July 2016, a review by the Engineer responsible for the Flow Accelerated Corrosion AMA (UFSAR Section 18.2.16) found that components dispositioned as "No Further Inspections" (NFI) for the first 40-year operating period had not been formally re-evaluated to determine whether they required additional inspections during the extended license period. As such, there were likely components that were previously dispositioned as NFI that would now require further inspections to reach the licensed 60 years of operation. The importance of identifying these missed components is further escalated with the advent of the Subsequent License Renewal process for 80-year plant life. NFI components were included in the FAC Manager data migration updates for Units 1 and 2 through 80 years of operation. The data migrations included establishing a Next Scheduled Inspection (NSI) outage for each component.
6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal aging management programs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
7. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Flow Accelerated Corrosion AMA (UFSAR Section 18.2.16).

8. In April 2019, an effectiveness review was performed on the Flow Accelerated Corrosion AMA (UFSAR Section 18.2.16) that includes inspections for wall thinning in susceptible components. The AMA was evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness". No gaps were identified by the effectiveness review related to Flow Accelerated Corrosion AMA.

Erosion Operating Experience

9. In March 2010, during the Unit 2 refueling outage, a UT examination was performed on a 2-inch piping component on a 6-inch condenser header and found to have a wall thickness below the programmatic minimum value. Engineering evaluated two additional condenser headers scheduled for replacement in 2011 to determine whether the current inspection/replacement schedule would be appropriate. For Unit 1, condenser headers were previously inspected with an appropriate re-inspection interval. However, since some of the thinning in the condenser headers could have been due to liquid impingement and the replacement material was not resistant to liquid impingement, the three condenser headers previously replaced were assigned a re-inspection interval in CHECWORKS-SFA. Similarly for Unit 2, two condenser headers previously replaced were assigned a re-inspection interval in CHECWORKS-SFA.

10. In March 2018, during the Unit 1 refueling outage, while performing scheduled maintenance on a check valve in the secondary drains system, pitting was identified on the inside of the check valve body. The presence of pitting was an indication of possible erosion. The pitting resulted in a remaining wall thickness that was at the minimum allowable value. Corrective action was taken during the same refueling outage to perform weld repairs on the affected areas of the check valve body.

The above examples of operating experience provide objective evidence that the *Flow-Accelerated Corrosion* program includes activities to (a) identify susceptible piping systems and components; (b) develop FAC predictive models to reflect component geometries, materials, and operating parameters; (c) perform analyses of FAC models and, with consideration of operating experience, select a sample of components for inspection; (d) inspect components; (e) evaluate inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporate inspection data to refine FAC modeling. Additionally the *Flow-Accelerated Corrosion* program includes activities to manage wall thinning caused by flow-accelerated corrosion, as well as wall thinning due to erosion mechanisms. Occurrences identified under the *Flow-Accelerated Corrosion* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Flow-Accelerated Corrosion* program~~, following enhancement,~~ will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Flow-Accelerated Corrosion* program~~, following enhancement,~~ provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.17 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing condition monitoring program that manages the effects of loss of material and cracking on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil. This program manages aging effects associated with outdoor tanks with internal pressures approximating atmospheric pressure including the refueling water storage tanks (RWSTs), refueling water chemical addition tanks (CATs), casing cooling tanks (CCTs), and emergency condensate storage tanks (ECSTs).

The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components consistent with standard industry practices. The RWSTs and CCTs are insulated and rest on a concrete mat/foundation covered with an oil sand cushion. Caulking is used at the concrete-component interface of the RWSTs. Caulking is used at the concrete-component interface of the CCTs, where there are no grout pads.

The CATs are insulated, and skirt supported. The insulation jacketing on the RWSTs, CATs, and CCTs is corrugated aluminum (with a factory applied moisture barrier) with overlapped seams. The ECSTs are internally coated and protected by concrete missile barriers.

The program manages loss of material on tank internal bare metal surfaces by conducting visual inspections. Surface exams of external tank surfaces are conducted to detect cracking on the stainless steel tanks. Inspections of RWST and CCT caulking/sealants are supplemented by physical manipulation. UT examinations of the tanks' bottoms are conducted to ensure that design thickness and corrosion allowance criteria are met. A periodic sampling-based inspection is used on the external surfaces of insulated tanks. Inspections not conducted in accordance with ASME Code, Section XI requirements are conducted in accordance with plant-specific procedures that include inspection parameters such as lighting, distance, offset, and surface conditions. Additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending); however:

- For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected.
- For other sampling-based inspections there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at the other unit.

The additional inspections will be completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the first half of the next inspection interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval.

If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.

Consistent with the recommendations of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28), loss of coating integrity for the emergency condensate tanks is managed by this program. Internal surfaces of the RWSTs, CATs, and CCTs are managed by the *One-Time Inspection* program (B2.1.20). Tank reinforced concrete foundations and the reinforced concrete missile barrier of the ECSTs are managed by the *Structures Monitoring* program (B2.1.34).

NUREG-2191 Consistency

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks.

Exception Summary

The following program element(s) are affected:

Preventive Actions (Element 2); Parameters Monitored/Inspected (Element 3); Detection of Aging Effects (Element 4); Acceptance Criteria (Element 6); and Corrective Actions (Element 7)

1. NUREG-2191 specifies for outdoor tanks, that sealant or caulking is applied at the interface between the tank external surface and concrete or earthen surface to mitigate corrosion of the tank by minimizing the amount of water and moisture penetrating the interface. The ECSTs do not use caulking or sealant at the concrete-component interface and therefore, do not require inspection of the caulking or sealant. The RWSTs and CCTs have mastic sealant installed on the tank shell between the insulation and the tank concrete foundation to ensure water-tightness and to prevent water from getting to the tank.

Justification for Exception:

The ECSTs are insulated from the outside atmosphere by two inches of expansion joint filler foam and surrounded by a two-foot-thick layer of reinforced concrete that provides missile protection. The concrete missile shield and expansion joint filler foam configuration mitigates corrosion of the tank by minimizing water and moisture from penetrating inaccessible exterior tank surfaces.

The roofs and sides of the RWSTs, CATs, and CCTs are insulated and jacketed to mitigate corrosion of the tank by minimizing the amount of water and moisture on the exterior surfaces. As an additional preventive measure, the RWSTs and CCTs have mastic sealant installed on the tank shell between the insulation and the tank concrete foundation to ensure water-tightness and to prevent water from getting to the tank. The RWSTs, CATs, and CCTs have insulation jacketing installed with overlapping seams to provide a protective outer layer and to prevent water intrusion. The mastic sealant installed on the tank shell between the insulation and the tank concrete foundation provides a boundary to mitigate corrosion of the tank bottom surface and the concrete foundation. In addition, the RWSTs and CCTs bottom surface is protected by an oil sand cushion and caulk at the interface between the tank external surface and the concrete surface. Periodic inspections normally performed on the caulk at the tank and concrete foundation will be performed on the mastic sealant installed on the tank shell between the insulation and the tank concrete foundation. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWSTs and CCTs external insulation is removed and sampled for external surface visual examinations.

Detection of Aging Effects (Element 4)

2. NUREG-2191 recommends both visual and volumetric inspection techniques to identify degradation on carbon steel tank external surfaces, located outdoors on soil or concrete. The external surface of the ECSTs are encased in a two-foot-thick reinforced concrete missile shield with expansion joint filler foam between the external tank wall and the concrete missile shield. The concrete missile shield prevents visual and volumetric examinations of the external surface of the tank.

Justification for Exception:

The concrete missile shield and the expansion joint filler foam act as multiple barriers protecting the external tank surfaces. Initial License Renewal inspections of the Unit 1 and Unit 2 ECSTs external surfaces indicated differing inspection results and will be managed as follows during the subsequent period of extended operation.

Initial License Renewal inspections of the Unit 1 ECST external surfaces met the established acceptance criteria through-out the various inspection locations. One-time thickness measurements of a sample of the Unit 1 ECST interior wall will be performed prior to the subsequent period of extended operation. The samples will examine the Unit 1 ECST interior vertical steel shell region from the bottom of the tank along the pipe penetration area, extending six feet vertically up from the tank, as this is a region potentially most susceptible to degradation. The inspection results will be projected to the end of the subsequent period of extended operation to confirm the Unit 1 ECST intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate of degradation. Aging degradation not meeting acceptance criteria will require periodic 10-year thickness measurements and a sample expansion along the leakage path consistent with the observed degradation.

Initial License Renewal inspections of the Unit 2 ECST external surfaces indicated varying aging results. During September 2020, follow-up inspections of degraded areas identified pitting with wall thickness measurements of less than 0.1 inch in specific locations. Projected wall thickness measurements with less than 0.1 inch will be repaired prior to entering the subsequent period of extended operation. Periodic inspections of a minimum of five locations with the lowest wall thickness readings will be performed on a ten-year inspection frequency. Inspection results projected to the end of the subsequent period of extended operation that do not meet acceptance criteria will require an extent of condition and extent of cause to determine the further extent of inspection and corrective actions.

The program also inspects the external bottom surfaces of the Unit 1 and 2 ECSTs that are exposed to a soil or concrete environment by performing volumetric examination thickness measurements. The gasket on the ECST upper access concrete plug is replaced whenever it is removed to allow access for internal tank wall thickness measurements. The ECST vent and vacuum breaker caulking is periodically inspected during ECST missile shield inspections.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2); Parameters Monitored/Inspected (Element 3); Detection of Aging Effects (Element 4); Acceptance Criteria (Element 6); and Corrective Actions (Element 7)

1. Procedures will be revised to require periodic visual inspections of the RWSTs and CCTs be performed at each refueling outage to confirm that the mastic sealant at the RWSTs and CCTs insulation and concrete foundation interface is intact. The visual inspections of the sealant will be supplemented with physical manipulation to detect any degradation. If there are any identified flaws, the mastic sealant will be repaired or replaced, and follow-up examination of the tank's surfaces will be conducted if deemed appropriate. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWSTs and CCTs external insulation is removed and the caulk will be sampled for external surface visual examinations ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates.

Detection of Aging Effects (Element 4)

2. Procedures will be revised to require visual and surface examination of the exterior surfaces of the RWSTs, CATs, and CCTs be performed to identify any loss of material or cracking. A minimum of either 25 one-square foot sections or 20% of the surface area of insulation will be

required to be removed to permit inspection of the exterior surface of each tank. The procedure will specify that sample inspection points be distributed in such a way that inspections occur near the bottoms, at points where structural supports, pipe, or instrument nozzles penetrate the insulation, and where water could collect such as on top of stiffening rings. If no unacceptable loss of material or cracking is observed, subsequent external surface examinations of insulated tanks will inspect for indications of damage to the jacketing, evidence of water intrusion through the insulation, or evidence of damage to the moisture barrier of tightly adhering insulation.

3. Unit 1 ECST: Procedures will be revised to require one-time thickness measurements of a sample of the Unit 1 ECST interior wall and tank bottom prior to the subsequent period of extended operation to assess potential degradation due to leakage identified from the missile shield into the pipe penetration area in the Auxiliary Feedwater Pump House. The samples will examine the ECSTs interior vertical steel shell region from the bottom of the tank along the pipe penetration area, extending six feet vertically up from the tank, as this is a region potentially most susceptible to external surface degradation. Tank bottom thickness measurements will also be performed. The inspection results will be projected to the end of the subsequent period of extended operation to confirm the Unit 1 ECST intended function will be maintained throughout the subsequent period of extended operation based on the projected rate of degradation. Any degradation not meeting acceptance criteria will require periodic 10-year thickness measurements and a sample expansion along the leakage path consistent with the observed degradation.

   Unit 2 ECST: The Unit 2 ECST external vertical wall degradation projections to the end of the subsequent period of extended operation that exceed less than 0.1 inch wall thickness will be repaired prior to entering the subsequent period of extended operation. Periodic inspections of a minimum of five locations with the lowest wall thickness readings will be performed on a ten-year inspection frequency. Inspection results projected to the end of the subsequent period of extended operation that do not meet acceptance criteria will require an extent of condition and extent of cause to determine the further extent of inspection and corrective actions. Tank bottom thickness measurements will also be performed. (Revised - Supplement 1)

4. Procedures will be revised to require volumetric examination thickness measurements of the bottom of the RWSTs and CCTs be performed each 10-year period during the subsequent period of extended operation starting ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates.

Corrective Action (Element 7)

5. A new procedure will be developed to specify that additional inspections be performed consistent with NUREG-2191.

If any inspections do not meet the acceptance criteria, additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending).

a. For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected.

b. For other sampling based inspections there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at the other unit.

   The additional inspections will be completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the first half of the next inspection interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval.

   If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Outdoor and Large Atmospheric Metallic Storage Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2010, an internal inspection of the Unit 2 RWST was performed using Low Frequency Electromagnetic Technique (LFET) to scan the perimeter of the bottom plates of the RWST, including the weir, allowing adequate assessment of degradation due to pitting. In addition, a scan was performed along the welds in the inspection area. Ultrasonic testing (UT) examinations were performed on the tank bottom. Two indications were identified with the LFET. Both indications were visible topside dents, with UT readings being greater than the

nominal design thickness. The inspection concluded that there was no indication of age-related degradation on the Unit 2 RWST bottom.

2. In September 2010, UT examinations were performed on bottom of the Unit 1 CAT in the filled condition, in a two-inch wide ring around the drain pipe. The thickness measurements of the tank bottom exceeded the acceptance criteria. There was no indication of material loss.

3. In September 2013, during the Unit 1 Fall 2013 refueling outage an internal inspection of the Unit 1 RWST was performed in the filled condition. UT examinations of the tank bottom resulted in thicknesses above the nominal design thickness. Internal structures (e.g., piping) were in good condition and no visible pitting of the internal stainless-steel surfaces was observed. Floor plate, internal shell plate and nozzle welds were identified to be in good condition. Visual inspection of the tank did not indicate any adverse conditions or areas of concern. Based on the data collected from this inspection, no measurable corrosion was noted and the readings were at or above the design nominal thickness. As such, no meaningful corrosion rate can be established at this time. Based on no corrosion being found, API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," calculations show a 20-year inspection interval for this tank.

4. In May 2015, a work order was initiated to locate and resolve rain water leakage between the missile shield and outer tank wall at the Unit 1 ECST. Rain water leakage between the concrete missile shield and the outer surface of Unit 1 and Unit 2 ECSTs has been a chronic condition. The rain water collects between the two surfaces and leaks out of the piping penetrations and onto the floor of the Motor-driven Auxiliary Feedwater (MDAFW) Pump House. Fresh caulk was applied to three conduit penetrations, vent base plates, and the perimeter of vents with missile shields, but did not resolve the leakage issue. Another work order was initiated to identify the source of rain water leakage at the tank and repair the leakage. Piping penetration cover plates were removed to allow inspection of the area between the missile shield and outer tank wall. A small amount of water was found leaking from the penetration area. New sealant/gasket was applied, and the penetration cover plates were reinstalled. There have been no issues of water leakage at the Unit 1 ECST penetration area since the repair was performed.

5. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion reached was that performance deficiencies or learning opportunities were identified for the Tank Inspection Activities AMA (UFSAR Section 18.1.3). Engineering was tasked with an assignment to consider obtaining more wall/roof shell data on the Unit 1 ECST. An internal inspection was performed consisting of a visual inspection of the interior coating, UT examinations were performed on the tank bottom, wall and roof, and LFET on the bottom and wall. The inspection

identified 23 minor coating indications. Coating degradation and minor corrosion were also observed on the angle iron forming the roof/wall joint. Degraded areas identified were cleaned and recoated. UT examination was performed on the tank bottom and on a quarter section of the roof at the roof/wall joint. LFET was performed on the tank bottom and the tank walls. Data obtained on the bottom, wall, and roof was satisfactory showing no indications of significant corrosion or degradation.

6. In July 2016, a small puddle of dark colored water was observed on the bottom of the Unit 2 MDAFW Pump House directly under the MDAFW pump suction isolation valves. The leakage appeared to be coming from the caulked seal where the AFW suction pipes penetrate the missile shield, indicating water intrusion between the tank and the missile shield. The leakage was not active; but staining on the wall indicated the leakage was coming from the pipe penetrations under the MDAFW pump suction isolation valves. During the Spring 2016 Unit 2 refueling outage, the upper manway was inspected for water intrusion and found no damage or leaks. The manway was removed and replaced with a new gasket.

   Engineering developed and implemented an investigation plan to identify any water intrusion paths contributing to the leakage that included:

   a. Replacement of the roof over the Unit 2 MDAFW Pump House, and

   b. while the roof was removed, a walkdown was performed to inspect the 2-inch rattle space between the Unit 2 ECST and missile shield as well as any other potential areas corresponding to the leak, and

   c. after the new roof was installed, Security or Operations personnel checked (on normal rounds) to see if there was still a leak.

   Since the plan was implemented, there has been no evidence of leakage into the Unit 2 MDAFW Pump House.

7. In November 2016, external inspection and insulation replacement was performed on the Unit 1 RWST. Up until that time, in order to determine if any aging degradation was occurring on the exterior of insulated stainless steel tanks, insulation in selected areas was removed and the exterior was visually inspected for loss of material or cracking. Also, in March 2009, the insulation at the top of the Unit 1 RWST was observed to be degrading and falling off. A subsequent design change was developed to define the tank inspection activities, remove insulation from the Unit 1 RWST to perform external tank inspections, replace the insulation with like for like materials, and apply a new layer of weatherproofing protection. Grey aluminum corrugated flashing with a factory applied interior polyfilm moisture barrier covers the insulation. The grey aluminum corrugated flashing vertical seam overlaps are four inches and horizontal seam overlaps are three inches and are held in place with stainless steel

bands. Longitudinal overlaps are secured with stainless steel sheet metal screws. The inspections concluded that there were no adverse conditions identified.

8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

9. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion reached was that an area for improvement or enhancement was identified for the Tank Inspection Activities AMA (UFSAR Section 18.1.3). Results of the assessment indicated that inspections performed for some tanks under the Tank Inspection Activities AMA were not performed in accordance with the UFSAR description. The UFSAR states, "visual inspections of the internal and external surfaces will be performed. Volumetric examinations will be performed on tanks founded on soil or buried." However, in accordance with the Tank Inspection Activities AMA, volumetric examinations were performed on some tanks in lieu of internal inspections due to accessibility. In May 2017, Engineering was tasked to evaluate the deficiency and initiate any document changes or additional inspections that may be required. Subsequently, UFSAR Section 18.1.3, Tank Inspection Activities AMA, was updated to address the use of UT examinations in lieu of visual examinations for some tanks.

10. In April 2019, an effectiveness review was performed on the Tank Inspection Activities AMA (UFSAR Section 18.1.3) that includes the RWSTS, CATs, CCTs, and ECSTs among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." No gaps were identified by the effectiveness review.

The above examples of operating experience provides objective evidence that the *Outdoor and Large Atmospheric Metallic Storage Tanks* program includes activities to perform visual inspections of tank internal bare metal surfaces, surface examination of external tank surfaces, and UT examinations of tank bottoms to identify cracking or loss of material for aboveground metallic tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Outdoor and Large Atmospheric Metallic Storage Tanks* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Outdoor and Large Atmospheric Metallic Storage Tanks* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Outdoor and Large Atmospheric Metallic Storage Tanks* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.