VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

April 1, 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.:	21-074
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 1
AND CLARIFICATION TO AGING MANAGEMENT OF FIRE PROTECTION SYSTEM LINED DUCTILE IRON VALVES

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 and clarification of an aging management item are provided in the following Enclosures:

Enclosure 1:	Response to Requests for Additional Information - NAPS SLRA Safety Review – Set 1
Enclosure 2:	Proprietary Response to RAI 4.7.3-2 – (eRAI Letter #146, Question #239) – Set 1 Regarding NAPS SLRA
Enclosure 3:	Non-proprietary Response to RAI 4.7.3-2 – (eRAI Letter #146, Question #239) – Set 1 Regarding NAPS SLRA
Enclosure 4:	CAW-21-5164 Westinghouse Affidavit for Withholding Proprietary Information: LTR-SDA-II-21-14-P, dated March 10, 2021
Enclosure 5:	Clarification to Aging Management of Fire Protection System Lined Ductile Iron Valves
Enclosure 6:	SLRA Mark-ups – Set 1 RAIs

Enclosure 2, which includes the response to RAI 4.7.3-2, contains information proprietary to Westinghouse Electric Company LLC ("Westinghouse"). A redacted, non-proprietary

version of the information is provided in Enclosure 3. Enclosure 1 contains the response to the remaining RAIs.

Since Enclosure 2 contains information proprietary to Westinghouse, it is supported by an Affidavit signed by Westinghouse, the owner of the information, in Enclosure 4. The Affidavit sets forth the basis on which the information may be withheld from public disclosure by the Nuclear Regulatory Commission ("Commission") and addresses with specificity the considerations listed in paragraph (b)(4) of Section 2.390 of the Commission's regulations. Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations. Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse Affidavits should reference CAW-21-5164 and should be addressed to Camille T. Zozula, Manager, Regulatory Compliance & Corporate Licensing, Westinghouse Electric Company, 1000 Westinghouse Drive, Suite 165, Cranberry Township, Pennsylvania 16066.

Enclosure 5 clarifies the programs used for aging management of the fire protection system ductile iron valve bodies with internal linings exposed to raw water and indicates the associated SLRA changes that are included in Enclosure 6.

Enclosure 6 provides mark-ups of affected SLRA sections and/or tables associated with RAI Set 1 and Enclosure 5. It is noted that changes to two commitments (Items #34 and #49) are 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 1ST day of April, 2021.

My Commission Expires: 12/31/24

Notary Public

CRAIG D SLY
Notary Public
Commonwealth of Virginia
Reg. # 7518653
My Commission Expires December 31, 2024

Commitments made in this letter: None

Enclosures:

1. Response to Requests for Additional Information - NAPS SLRA Safety Review – Set 1
2. Proprietary Response to RAI 4.7.3-2 – (eRAI Letter #146, Question #239) – Set 1 Regarding NAPS SLRA
3. Non-proprietary Response to RAI 4.7.3-2 – (eRAI Letter #146, Question #239) – Set 1 Regarding NAPS SLRA
4. CAW-21-5164 Westinghouse Affidavit for Withholding Proprietary Information: LTR-SDA-II-21-14-P, dated March 10, 2021
5. Clarification to Aging Management of Fire Protection System Lined Ductile Iron Valves
6. SLRA Mark-ups – Set 1 RAIs

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Enclosure 1

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION
NAPS SLRA SAFETY REVIEW - SET 1

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 1

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

By letter 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 3.5.2.2.2.6, Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation

Paragraph 54.21(a)(1) of 10 CFR requires license renewal applicants to perform an integrated plant assessment and their application to identify and list systems, structures, and components (SSCs) that are within the scope of license renewal and subject to an AMR item.

Paragraph 54.21(a)(3) 10 CFR requires for the identified SSCs that the effects of aging will be adequately managed such that their intended functions are maintained consistent with the CLB for the subsequent period of extended operation. To complete its review and enable the staff making a reasonable assurance finding on functionality of reviewed SSCs consistent with 10 CFR 54.21, the staff requires under 10 CFR 54.29(a) additional information for the subsequent period of extended operation be provided regarding the matters described below.

RAI 3.5.2.2.2.6-1

Background

SLRA Section 3.5.2.2.2.6, as amended by Supplement 1 dated February 4, 2021, discusses for NAPS Units 1 and 2 the effects of aging manifested as loss of fracture toughness due to neutron irradiation embrittlement on each reactor vessel (RV) support steel materials in the neutron shield tank (NST). The applicant's loss of fracture toughness evaluation is based on a methodology detailed in Project Topical Report (PTR): Reactor Vessel Support for Unit No 1 Surry Power Station," Life Extension Evaluation of the

Reactor Vessel Support, including Appendix 3, Resistance to Brittle Fracture of the Neutron Shield Tank Materials," dated October 10, 1986 reviewed and evaluated in Surry SER (ADAMS Accession No. ML20052F523). Based on the PTR, Dominion authored the audited documents for SLR ETE-SLR-2019-2203 "Review of Loads on Neutron Shield Tank for NAPS Units 1 & 2 Reactor Vessel Supports," Revision 0 and ETE-SLR-2020-2204, "Assessment of Radiation Effects on Reactor Vessel Supports for NAPS Units 1 & 2," Revision 0. The staff reviewed Procedure ETE-SLR-2020-2204 and noted a discrepancy in the discussion regarding the structural integrity (i.e., embrittlement of welded steel plates) of the NST with that in SLRA Section 3.5.2.2.2.6.

Section 4.12 of NUREG-1555, Supplement 1, Revision 1, "Standard Review Plans for Environmental Reviews for Nuclear Power Plants: Operating License Renewal," directs the staff to "identify and calculate the likely cumulative environmental impacts for the area(s) or region(s) currently or likely to be affected by power plant operations and/or refurbishment activities associated with license renewal."

Issue

In the evaluation of the reactor vessel steel supports in SLRA Section 3.5.2.2.2.6 as amended by Supplement 1, Dominion evaluated the loss of fracture toughness of the steel plates of the NAPS Units 1 and 2 NSTs through fracture mechanics calculations as noted in the Background above. The staff however noted that, there was no discussion whether the fracture mechanics evaluations were applicable to the weldments and associated heat affected zones (HAZ) that join the individual steel plates of the NSTs. Since the weldments and HAZ of the NSTs have different material performance than those of the NST plates, the staff could not determine whether the fracture mechanics evaluations performed for the NST steel plates bound those of the weldments and HAZ, and if so how (by what margins).

NRC Request

1. *Clarify whether the fracture mechanics evaluations performed for the NST plates bound those of the weldments and HAZ*
2. *Explain how the fracture mechanics evaluations are bounding of the weldments and HAZ; or, provide an evaluation (or other method) that sufficiently addresses the aging effect of loss of fracture toughness due to irradiation for weldments and HAZ of the NST steel plates.*

Dominion Response

ASME Code, Section XI, Nonmandatory Appendix G, Figure G-2210-1 includes static fracture toughness data for both weldments and heat affected zones (HAZ). The fracture mechanics evaluation documented in ETE-SLR-2020-2204 uses a minimum toughness of 33.2 ksi$\sqrt{in}$ which accommodates an infinite amount of radiation embrittlement.

The qualification process in ASME Code, Section V, for welding procedures ensures that the plate material is stronger than the weld material.

The Unit 1 and 2 NSTs were stress-relief heat treated following welding, which ensures the toughness of weld material and HAZ, meeting the requirements of the purchase specification.

A comprehensive study of U.S. surveillance capsule testing of HAZ 30 ft-lb transition temperature values compared with 30 ft-lb values for the companion RPV plate or forging concluded that essentially all the 30 ft-lb values of HAZ were lower (tougher) than the 30 ft-lb values of the companion plate or forging[1] in the irradiated condition. Structural welds have many passes, which improves HAZ toughness properties relative to the base metal due to grain refinement, small regions of coarse grains, and tempering of martensite, all of which tend to increase toughness. Based on this study and the similarity of the low alloy steel plates, it is expected that the NST HAZs would behave in a similar manner. The embrittlement curves in NUREG-1509, Figure 3-1, and the Remec[2] study include weld metal data which is indistinguishable from the base metal.

Therefore, by use of ASME Code, Section XI, Nonmandatory Appendix G, Figure G-2210-1, the fracture mechanics evaluation for the NST plates in ETE-SLR-2020-2204 is applicable to plate, weldment, and HAZ and the plate material bounds the weldments and HAZ of the Unit 1 and 2 NSTs.

RAI 3.5.2.2.2.6-2

Background

SLRA Section 3.5.2.2.2.6 as amended by Supplement 1, dated February 4, 2021, discusses the effects of aging manifested as loss of fracture toughness due to neutron irradiation embrittlement on each of NAPS Units 1 and 2 reactor vessel (RV) support steel materials in the NST. In its review of audited ETE-SLR-2020-2204, "Assessment of Radiation Effects on Reactor Vessel Supports for NAPS Units 1 & 2," Revision 0, the staff noted that the applicant's evaluation does not provide an allowance for potential loss of material due to internal corrosion. The staff however noted in the audited NST fluid chemistry sampling history (Unit 1 and Unit 2 Sampling for 10 Years – Operating Experience Water Chemistry) that, although the level of Chromates in Unit 1 NST fluid are elevated to ensure corrosion protection, the tank has an elevated conductivity as well which could be indicative of potential corrosion.

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[1] Troyer, G. and Erickson, M., "Empirical Analyses of Effects of the Heat Affected Zone and Post Weld Heat Treatment on Irradiation Embrittlement of Reactor Pressure Vessel Steel," Effects of Radiation on Nuclear Materials: 26th Volume, STP 1572, Mark Kirk and Enrico Lucon, Eds., pp. 163–178, ASTM International, West Conshohocken, PA, 2014.ASME Section XI, Division 1, ASME Code Case N-838, "Flaw Tolerance Evaluation of Cast Austenitic Stainless Steel Piping," Approval Date: August 3, 2015.

2 Remec, I., Wang, J., and Kam, F., "HFIR Steels Embrittlement: The Possible Effect of Gamma Field Contribution," Effects of Radiation on Materials: 17th International Symposium, ASTM 1270, Eds D.S. Gelles, R.K. Nanstead, A.S. Kumar, and E.A. Little, ASTM 1996, 591.

Issue

EPRI Report, "Closed Cooling Water Guideline," Revision 2, identifies fluid conductivity as a diagnostic parameter for a corrosive environment. It recommends a conductivity value (≤2 µS/cm) far less than those being reported for the NAPS NST Unit 1 fluid. For systems maintaining corrosion inhibitors (including high concentration of chromates – 2500 ppm at 150° F), adequate pH levels and microbiological controls, the EPRI Report suggests that loss of material could occur in ferrous materials with values ranging from good (less than 0.3 mils per year year) to poor (greater than 0.5 mils per year). It is not clear whether the recorded high conductivity of the Unit 1 NST could be indicative of a potential loss of material in the tank that could affect its structural integrity, including its irradiated steel fracture mechanics evaluation.

However, it is also not clear if conductivity is a good diagnostic parameter for detection of such an aging effect, or simply an artifact of the NAPS Unit 1 NST fluid chemistry.

NRC Request

1. *Clarify why NAPS includes conductivity as a monitoring diagnostic parameter for the NST fluid.*
2. *Discuss the cause of increased conductivity in the Unit 1 NST.*
3. *Discuss whether the levels of high conductivity detected in the Unit 1 NAPS fluid are not of concern and whether conductivity should be used as a credible parameter for detection of loss of material aging effect that could adversely affect the Unit 1 NST structural steel integrity, including the NST irradiated steel fracture mechanics evaluation.*

Dominion Response

1. EPRI Report 3002000590, Revision 2, "Closed Cooling Water Chemistry Guideline," identifies conductivity as a diagnostic parameter to monitor program effectiveness, identify programmatic problems, and assist in problem diagnosis. Conductivity is an indirect measurement of the concentration of chemical treatment in the closed cycle cooling water system. High conductivity can also be an indication of a corrosive environment, system leaks or contaminant ingress. Accordingly, the Closed Treated Water Systems program (B2.1.12) includes conductivity as a diagnostic parameter for troubleshooting corrosion control treatment effectiveness. The chromate chemistry of the Neutron Shield Tanks (NSTs) is sampled and analyzed each refueling outage.
2. In 2004, the increase in conductivity in the Unit 1 NST was the result of the over-addition of chromates to the NST due to a human performance error. Prior to the chromate over-addition event, the Unit 1 NST conductivity was 844 µS/cm (micro-siemens per centimeter). The Unit 1 NST conductivity increased to 5290 µS/cm following the chromate over-addition event, as the result of an increase in chromate from 237 ppm to 2130 ppm.

3. The engineering evaluation of the elevated chromates concluded that the isolated chromate over-addition event would not adversely affect the Unit 1 NST and the associated cooling system since carbon seals are not installed in the recirculation pumps.

   Chromate is considered an anionic inhibitor that forms a protective layer of oxide film on the surface of metal that is resistant to corrosion. In addition to conductivity, the Unit 1 and 2 NSTs are analyzed for iron and copper as a diagnostic analysis to indicate if a loss of material is occurring on the protected metallic surfaces. A 10-year trending of the Unit 1 and Unit 2 NSTs indicated both iron and copper parameters remain below detectable limits. Thus, the structural integrity of the Units 1 and 2 NSTs are being maintained so that the pressure boundary and associated structural integrity is maintained consistent with the assumptions used in NST irradiated steel fracture mechanics evaluation.

RAI 3.5.2.2.2.6-3

Background

SLRA Section 3.5.2.2.2.6 as amended by Supplement 1, dated February 4, 2021, discusses the NAPS Units 1 and 2 RV structural steel supports that include their sliding foot assemblies and loading conditions used to calculate stresses for the fracture mechanics evaluation. It notes that the design load is based on dead weight combined with the square root of sum of the squares of design basis and LOCA loads. Section 18.3.5.3 of the UFSAR summarizes a Westinghouse detailed evaluation regarding large LOCAs and states that "double-ended breaks of reactor coolant pipes are not credible, and as a result, large LOCA loads on primary system components will not occur."

The audited calculation CE-1634, "The Effect of Reactor Pressure Vessel (RPV) Head Replacement on the RPV Support System Sliding Foot Assemblies and NST, NAPS Units 1 and 2," Revision 1, discusses the combined effects of seismic, pipe rupture, and deadweight loads on the RPV nozzle support pads and the NST for NAPS Unit 1 and 2. The calculations conclude that the RPV support system will maintain its structural integrity for all postulated loads with seismic loads re-evaluated based on response spectrum analysis (vs previous time history analyses). The document CE-1634-00A, addendum to CE-1634 titled "Analysis of Loss of Coolant Accident (LOCA) Loads for impact on the RPV System," discusses dynamic analyses of NAPS Units 1 and 2 RPV supports based on Westinghouse provided displacements. After comparison of its results to CE-1634, this document also concludes that the maximum loads calculated from dynamic analysis of four LOCA cases (accumulator and pressurizer surge line breaks) are acceptable at the RPV nozzle supports and at the base of the NSTs.

Issue

Despite the conservatism shown in Section 18.3.5.3 of the UFSAR for the reduction of pipe rupture loads and conclusions reached in CE-1634 and 1634-00A regarding the structural integrity of the RPV support system, the staff could not determine whether the effects of radiation on the RPV nozzle support pads/sliding foot assemblies were

addressed for the subsequent period of extended operation. It is not clear whether results of the audited LTR- REA-20-3, Revision 0, "North Anna Unit 1 and Unit 2 Neutron Shield Tank (NST) Neutron Fluence," have been considered in evaluating the structural adequacy of the RPV nozzle support pads/sliding foot assemblies for the subsequent period of extended operation.

NRC Request

For the RPV nozzle support pads/sliding foot assemblies:

1. *Clarify whether the aging effects of streaming radiation have been considered in evaluating their structural adequacy.*
2. *Demonstrate, consistent with 10 CFR 54.21(a)(3), how "the effects of aging [due to irradiation] will be adequately managed so that the[ir] intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation."*

Dominion Response

1. The effects of irradiation have been considered in evaluating the structural adequacy of the RPV nozzle support pads/sliding foot assemblies. Dominion has interpreted the verb "streaming" to mean the magnitude of neutron fluence (irradiation) as discussed in the audited LTR-REA-20-3, "North Anna Unit 1 and 2 Neutron Shield Tank (NST) Neutron Fluence," Revision 0.

   Dominion previously addressed the effects of irradiation on the RPV nozzle support pads/sliding foot assemblies in "Virginia Electric and Power Company North Anna Power Station (NAPS) Units 1 and 2 Update to Subsequent License Renewal Application (SLRA) Supplement 1," dated February 4, 2021 (ADAMS Accession No. ML 21035A303).

   EPRI Report 3002013084, "Long-Term Operations: Subsequent License Renewal Aging Effects for Structures and Structural Components (Structural Tools)," indicates that reactor vessel materials exposed to neutron fluence levels below 1E17 n/cm^2 (E>1.0 MeV) and structural steel components exposed to neutron fluence levels below 1E19 n/cm^2 (E>1.0 MeV) will not experience significant age-related degradation due to irradiation.

   Table 3-3 of LTR-REA-20-3, shown below, provides a projection of the neutron fluence levels at the top of the NST at 72 EFPY.

Table 3-3
Fast Neutron Fluence of the NST Vessel-Side Surface at the RPV Nozzle Azimuthal Angles and Top of the NST at 72 EFPY

	Fast Neutron (E > 1.0 MeV) Fluence (n/cm^2)		
	5°	25°	35°
Unit 1	3.87E+17	1.88E+17	1.44E+17
Unit 2	3.93E+17	1.87E+17	1.36E+17

Note(s):
1. The values reported in this table were determined at the elevation of the top of the NST. Note that the top of the NST is approximately 34.8 cm lower (i.e., closer to the elevation corresponding to the top of the active fuel) than the elevation of the lowest extent of the inlet nozzle welds.

The projected neutron fluence at the top of the NST, which is closer to the active fuel than the RPV nozzle support pads/sliding foot assemblies, is lower than the EPRI screening value of 1E19 n/cm^2 (E>1.0 MeV) for the structural steel components. Therefore, the sliding foot assemblies do not require aging management for aging affects due to irradiation.

2. While the RPV nozzle support pads/sliding foot assemblies do not require aging management for aging affects due to irradiation, SLRA Section 3.5.2.2.2.6 indicates that the ASME Section XI, Subsection IWF (B2.1.31) program manages aging of the sliding foot assemblies due to other considerations.

2. SLRA AMP B2.1.15, Fire Protection

Regulatory Basis:

Paragraph 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 CLB for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB. In order to complete its review and enable making a finding under 10 CFR 54.29(a), the staff requests additional information regarding the matters described below.

RAI B2.1.15-1 (eRAI Letter #131, Question #199)

Background:

SLRA Section 2.1.5.1 states:

"A complex assembly is a predominantly active assembly where the performance of its components is closely linked to that of the intended function of the entire assembly, such that testing and monitoring of the assembly is sufficient to identify degradation of these components. ...to the extent that complex assemblies include piping or components that interface with external equipment, or components that cannot be adequately tested or monitored as part of the complex assembly, those components are identified and subject to aging management review."

SLRA Section 2.3.3-42, "Fire Protection," states that diesel-driven fire pump engine components within the skid boundaries are part of the active assembly and are not subject to AMR. SLRA Drawing 11715-SLRB-41B does not show the heat exchanger for diesel-driven fire pump engine coolant as being within the scope of license renewal (i.e., not highlighted and not within the scoping flag for the fire protection system). The associated note says that the heat exchanger is part of a skid-mounted, active assembly (engine) and therefore not subject to AMR.

The independent industry operating experience database includes an August 20, 2017, event at North Anna where the diesel-driven fire pump engine coolant heat exchanger developed a leak. After the heat exchanger tube bundle was removed, several tubes were noted as visibly leaking. The event was classified as a maintenance preventable functional failure, because it could not be confirmed how long the engine would run with the heat exchanger leaking. The functional failure evaluation noted that the "zero run-to-failure" criteria for this component was too restrictive, because the pump only serves as an emergency backup for non-fire accident mitigation, which is not a risk significant function.

The staff notes that, for initial license renewal, SLRA Table 3.3.9-1, "Fire Protection," included AMR items for "Diesel Fire Pump Radiator" to manage loss of material and heat transfer degradation using the Fire Protection Program. This scoping/screening approach is consistent with NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal," (SRP-SLR) Table 2.1-2, "Specific Staff Guidance on Scoping," for complex assemblies and Table 2.1-6, "Typical Structures, Components, and Commodity Groups, and 10 CFR 54.21(a)(1)(i) Determinations for Integrated Plant Assessment," for all heat exchangers. However, comparable AMR items are not included in SLRA Table 3.3.2-42, "Fire Protection," for subsequent license renewal. The staff also notes that the industry's consideration of "complex assemblies," as provided in NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," (subsequently endorsed by the NRC for both initial and subsequent license renewal) has not changed since initially being issued in 1996.

The staff further notes that SRP-SLR Section 2.1.2.1, "Scoping," indicates that justifications for any scoping exceptions should provide a reasonable basis for an exception.

Issue:

The absence of highlighting and the system flag location for the diesel-driven fire protection pump engine coolant heat exchanger on the associated drawing indicates that the heat exchanger is not credited by the current licensing bases for performing an intended function within the scope of license renewal. However, the discussion in the associated drawing note, regarding the component not being subject to an AMR, implies that the heat exchanger is within the scope of license renewal, but was screened-out. The associated statement in SLRA Section 2.3.3-42 only refers to skid mounted "components" and does not specifically address the heat exchanger. During break-out session discussions, Virginia Electric and Power Company (Dominion Energy or the applicant) participants stated that the heat exchanger was within the scope of license renewal and clarified that the lack of highlighting on the drawing did not mean that the heat exchanger was not within the scope of license renewal.

SRP-SLR Table 2.3-2, "Examples of Mechanical Components Screening and Basis for Disposition," notes that diesel engine jacket water heat exchangers supplied by a vendor on a diesel generator skid are passive, long-lived components having intended functions that are subject to an AMR even though the diesel generator is considered "active." During break-out session discussions, applicant engineers said that the size difference between a diesel generator engine and a diesel-driven fire pump engine justifies the different approach for AMR. The staff notes that all heat exchangers have always been considered as passive, long-lived components that are subject to AMR, as reflected in SRP-SLR, Table 2.1-6.

SLRA Section 2.1.5.1 states that if components cannot be adequately tested or monitored as part of the complex assembly, then those components are identified and subject to AMR.

Based on North Anna operating experience, it is not clear that the heat exchanger for the diesel- driven fire pump engine can be adequately tested or monitored as part of the complex assembly and whether it should be identified and subject to aging management review.

Based on the NAPS initial license renewal application, the diesel-driven fire protection pump engine coolant heat exchanger was screened-in, consistent with the longstanding guidance for diesel engine jacket water heat exchangers. Although the screening of this component for the SLRA does not follow the current guidance in SRP-SLR, the staff notes that screening can be inconsistent with the guidance if justification is provided with a reasonable basis for the inconsistency.

NRC Request:

1. *Confirm that the fire protection diesel-driven pump engine coolant heat exchanger and associated components are within the scope of license renewal. If not, provide the bases to show that the diesel-driven fire pump can perform its current licensing basis intended function without the engine coolant heat exchanger or associated piping and components.*

2. *Given that the existing testing and monitoring of the "active assembly" (i.e., skid-mounted fire protection diesel-driven pump engine components) were unable to identify degradation of the engine coolant heat exchanger prior to a functional failure:*
   a. *discuss what changes were made to the testing and monitoring in order to demonstrate that the effects of aging will be adequately managed, comparable to that required by 10 CFR 54.21(a)(3).*
   b. *because the functional failure analysis notes that the "zero run-to-failure" criteria was too restrictive, discuss whether the criteria for the assembly has been changed.*
   c. *because the testing and monitoring activities of the assembly will not be part of an AMR, describe how these activities will be annotated to ensure that the applicable effects of aging for the diesel engine heat exchanger will continue to be managed during the subsequent period of extended operation.*

Dominion Response

In the SLRA, the diesel-driven fire pump engine and its skid-mounted subcomponents were addressed as a single active assembly not subject to aging management review, consistent with the guidance of NUREG-2192, Table 2.1-6, item 55. This position was previously approved by the NRC staff, most recently in the Peach Bottom Subsequent License Renewal Safety Evaluation Report, Section 2.3.3.14.2, RAI 2.3.3.14-3 Evaluation (ADAMS Accession No. ML20044D902). However, to address the concern with a single instance of a tube failure in the diesel-driven fire pump engine coolant heat exchanger, a new commitment is added to replace the heat exchanger tube bundle every 20 years.

1. The diesel-driven fire pump engine coolant heat exchanger is within the scope of subsequent license renewal.

2.a. and b. The diesel-driven fire pump (and heat exchanger) is monitored and tested in accordance with the Fire Protection and Maintenance Rule programs as part of the current licensing basis.

2.c. Inspection of the heat exchanger tube bundle for degradation is not practical due to the small diameter of the heat exchanger tubes. Therefore, the diesel-driven fire pump engine coolant heat exchanger tube bundle will be replaced on a 20-year frequency. With periodic replacements, the heat exchanger tube bundle is not subject to aging management review, per 10 CFR 54.21(a)(1)(ii).

Based on a review of site operating experience, a 20-year replacement frequency provides reasonable assurance that the heat exchanger tube bundle will be replaced before the loss of intended function of the diesel-driven fire pump.

SLRA Table A4.0-1 is revised, as shown in Enclosure 6, to add Commitment #49, for replacement of the diesel-driven fire pump engine coolant heat exchanger tube bundle on a 20-year frequency and replacement of the spare engine heat exchanger tube bundle prior to being placed in-service.

3. SLRA AMP B2.1.21, Selective Leaching

RAI B2.1.21-1 (eRAI Letter #155, Question #253)
(Selective Leaching - Basis for Extent of Inspections for Gray Cast Iron Exposed to Soil)

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. 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 making a finding under 10 CFR 54.29(a), the staff requires additional information in regard to the matters described below.

Background

As amended by letter dated February 4, 2021 (ADAMS Accession No. ML21035A303), SLRA Table 3.3.2-42, "Auxiliary Systems - Fire Protection - Aging Management Evaluation," states that loss of material due to selective leaching for gray cast iron piping and piping components exposed to soil will be managed by the Selective Leaching program.

SLRA Section B2.1.21, "Selective Leaching," states the following:

- *"[t]he Selective Leaching program is a new program that, when implemented, will be consistent, with [GALL-SLR Report AMP] XI.M33, Selective Leaching."*
- *"[a] sample of 3% of the population or a maximum of ten components per population at each unit will be visually and mechanically (gray cast iron and ductile iron components) inspected."*
- *"[o]pportunistic and periodic inspections will be conducted for raw water, wastewater, soil, and groundwater environments."*
- *"[p]periodic destructive examinations of components for physical properties (i.e., degree of dealloying, through-wall thickness, and chemical composition) will be conducted for components exposed to raw water, wastewater, soil, and groundwater environments."*

NUREG-2222, "Disposition of Public Comments on the Draft Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG–2192," provides the following bases for reducing the extent of inspections for selective leaching during the

subsequent period of extended operation (i.e., 3 percent with a maximum of 10 components per GALL-SLR Report guidance) from comparable extent of inspections during the initial period of extended operation (i.e., 20 percent with a maximum of 25 components per GALL Report, Revision 2 guidance):

1. *Opportunistic inspections will be conducted throughout the period of extended operation whenever components are opened, [or] buried or submerged surfaces are exposed, whereas opportunistic inspections were not recommended in the previous version of AMP XI.M33;*
2. *Destructive examinations provide a more effective means to detect and quantify loss of material due to selective leaching;*
3. *The slow growing nature of selective leaching generally coupled with the inspections conducted prior to the initial period of extended operation provides insights into the extent of loss of material due to selective leaching that can be used in the subsequent period of extended operation;*
4. *The staff's review of many license renewal applications (LRAs) has not revealed any instances where loss of intended function has occurred due to selective leaching;*
5. *The staff's review of industry operating experience (OE) has not detected any instances of loss of material due to selective leaching, which resulted in a loss of intended function for the component; and*
6. *Regional inspector input (provided based on IP 71003, "Post-Approval Site Inspection for License Renewal,") that selective leaching has been noted during visual and destructive inspections; however, no instances have been identified where there was the potential for loss of intended function.*

The NRC issued Information Notice (IN) 2020-04, "Operating Experience Regarding Failure of Buried Fire Protection Main Yard Piping," to inform the industry of OE involving the loss of function of buried gray cast iron fire water main yard piping due to multiple factors, including graphitic corrosion (i.e., selective leaching), overpressuration, low-cycle fatigue, and surface loads. As noted in the IN, a contributing cause to the failures of buried gray cast iron piping at Surry Power Station (SPS) was the external reduction in wall thickness at several locations due to graphitic corrosion.

During its audit, the staff reviewed a summary of buried piping inspections performed for initial license renewal and noted that a single fire protection valve was destructively examined for selective leaching, which identified some isolated interior and exterior locations of graphitic corrosion. The staff also noted that although North Anna Power Station (NAPS) inspected a number fire protection piping segments as part of its underground piping and tank integrity program, the results did not specify whether visual inspections had been augmented with mechanical examination techniques, such as chipping or scraping. The staff notes that, as discussed in GALL-SLR Report AMP XI.M33, graphitized cast iron cannot be reliably identified through visual examination.

Issue

The recommended extent of inspections in GALL-SLR AMP XI.M33 are based on the six conditions noted by the staff in NUREG-2222. The staff's comparison to these six conditions to the Selective Leaching program at NAPS follows:

- *Based on its review of SLRA Section B2.1.21, the staff notes that opportunistic inspections and destructive examinations for selective leaching will be performed, consistent with the first and second conditions in NUREG-2222.*
- *Although the staff previously accepted the reduced extent of inspections in GALL-SLR AMP XI.M33 for a site that had not performed multiple selective leaching inspections prior to the first period of extended operation (Ref: Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 (ADAMS Accession No. ML20044D902)), the staff subsequently became aware of operating experience at Peach Bottom after the issuance of the above safety evaluation report. The subsequent operating experience was a circumferential crack in buried gray cast iron piping attributed to external reduction in wall thickness (approximately 60 to 65 percent wall loss) due to graphitic corrosion. This information causes the staff to reconsider its previous position on the third condition, absent additional information.*
- *The fourth, fifth, and sixth conditions in NUREG-2222 focus on the staff's review of industry OE not identifying any instances of loss of material due to selective leaching which had resulted in a loss of intended function for the component. Based on recent industry OE at SPS (as documented in IN-2020-04), the last three conditions in NUREG-2222 are no longer applicable for gray cast iron piping exposed to soil. Since these conditions are no longer applicable (i.e., there is now industry OE involving loss of material due to selective leaching which resulted in a loss of intended function for gray cast iron piping exposed to soil), the staff requires additional information to determine if the reduced extent of inspections in GALL-SLR AMP XI.M33 are appropriate for this material and environment combination.*

NRC Request

Provide a technical justification for using the extent of inspections in GALL-SLR AMP XI.M33 for gray cast iron piping and piping components exposed to soil.

Dominion Response

Opportunistic and periodic inspections will be conducted consistent with the *Selective Leaching* program (B2.1.21) on a representative sample of buried gray cast iron fire protection piping that is lined with a cementitious coating using program sampling and inspection guidance. One ten-foot length piping sample at each Unit will be excavated for inspection during each 10-year inspection interval starting 10 years before the subsequent period of extended operation. Periodic inspections, including visual and destructive examinations of 100% of each 10-foot piping length, will be performed.

Consistent with NUREG-2191, Section XI.M33, Selective Leaching, each one-foot length or equivalent length counts as one sample.

The extent of inspections is based on the following additional considerations and operating experience that include lessons learned from IN 2020-04:

- Loss of material and cracking inspection samples focused on the bounding or lead components most susceptible to aging
- Use of enhanced fire water jockey pump monitoring to identify and mitigate elevated fire protection buried piping leakage as well as minimize aggressive wet soil environments and piping overpressure events
- Demonstration of the effectiveness of aging management for cementitious lined buried gray cast iron fire protection piping
- Corrective actions to minimize fire protection system overpressure events that could lead to piping rupture of cementitious lined gray cast iron piping with a casting defect (initial cracking)

Details regarding each of the above items is included below:

<u>Selection of Leading Sample Location</u>

Periodic inspections will be prioritized based on time-in-service and severity of external environmental conditions. The leading sample locations will consider external environments found to be continuously wetted due to leaking piping or valves, with high corrosivity ratings as determined by EPRI Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," and include insights obtained through a review of inspection results and findings and insights obtained from other excavations conducted at the station. See the response to RAI B2.1.27-2 for additional details.

<u>Enhanced Fire Water Jockey Pump Monitoring</u>

In addition to periodic inspections, enhanced fire water jockey pump monitoring will be implemented to monitor and trend fire water jockey pump starts or run time. The performance information will be used to project and prevent unexpected fire water jockey pump starts. If an unexpected fire water jockey pump start occurs, then further investigation will be conducted to isolate and identify the leak location. Inspections will be conducted following excavation at the affected location to determine the cause of failure and the findings included in the Corrective Action Program.

Performance monitoring and trending of the fire water jockey pump will provide early identification of system through-wall leakage that, with timely corrective actions, will reduce exposure of buried gray cast iron fire protection piping to an aggressive wet soil environment that promotes loss of material due to selective leakage. In addition to reducing exposure of cast iron piping to aggressive wet/corrosive environments, enhanced fire water jockey pump monitoring will minimize gray cast iron fire protection piping overpressure events by detecting crack growth that results in elevated fire protection piping leakage. Corrective actions to minimize elevated system leakage due to crack growth will prevent unexpected fire water jockey pump starts on low operating

pressure that create a potential for an overpressure event. Trending of enhanced fire water jockey pump monitoring will be performed on an interval not to exceed one month. SLRA Section B2.1.16 includes an enhancement to the "detection of aging effects" program element related to monitoring the activity of the fire water jockey pump consistent with the "detection of aging effects" program element of NUREG-2191 Report, AMP XI.M41, Buried and Underground Piping and Tanks. At Surry Power Station, the NRC staff previously accepted this enhancement against the corresponding program elements in NUREG-2191 Report, AMP XI.M27 and AMP XI.M41 and found it acceptable because, consistent with AMP XI.M41, monitoring the performance of the fire water jockey pump can provide insights into potential leaks in the fire water system (ADAMS Accession No. ML20052F523).

Aging Management Effectiveness

The *Buried and Underground Piping and Tanks* program (B2.1.27) is included as a part of the Underground Piping and Tanks Integrity (UPTI) program. Of the 30 buried pipe inspections performed by the UPTI program since its initial excavations in 2011, there were nine inspections of cementitious lined buried gray cast iron fire protection piping. In 2015, the piping inspection guidance of the UPTI program that included selective leaching inspection considerations was enhanced to consider susceptible materials and inspect for the presence of selective leaching by visual, mechanical, or other appropriate means. The UPTI inspections of cementitious lined buried gray cast iron fire protection piping did not identify through-wall leakage or minimum wall violations. In addition, based on corrective actions and associated maintenance documents noted in the operating experience summarized in SLRA Section B2.1.16, *Fire Water System* program, and SLRA Section B2.1.21, *Selective Leaching* program, there has been no cracking of cementitious lined buried gray cast iron fire protection piping documented since 2003 (second half of installed pipe service life).

Elimination of Fire Protection Over-Pressure Events - Corrective Action Effectiveness

Six pipe ruptures due to cracking of cementitious lined buried gray cast iron fire protection piping occurred between 1984 and 2003 during the first half of installed pipe service life. Evaluation of the 2003 event indicated that the cause was similar to past events and consisted of an original piping casting defect that eventually grew to critical flaw size due to pressure surges in the pipe from testing of the electric and diesel-driven fire water pumps. Crack growth of the casting defect resulted in leakage that promoted selective leaching due to an aggressive environment caused by wet soil conditions. In response, design changes were implemented that resulted in replacement of over 500 feet of cementitious lined buried gray cast iron fire protection piping with a higher pressure rated cementitious lined ductile iron piping. There have been no failures of the replaced fire water piping since installation.

Following these earlier events, further corrective actions as noted in SLRA Section B2.1.16, Operating Experience #2, were implemented to minimize or eliminate fire protection piping failures by performing fire water functional testing with the discharge valve shut, eliminating fire pump sequential start testing, and revising fire protection testing to avoid automatic fire pump starting.

As noted in SLRA Section B2.1.21, Operating Experience #2, opportunistic inspections of the cementitious internal coatings from 2001 through 2020 confirmed the internal coatings were intact and did not identify any degradation that resulted in a loss of coating integrity.

The above considerations and operating experience that include lessons learned from IN 2020-04 provide technical justification that the *Selective Leaching* program (B2.1.21) periodic inspections as supplemented with opportunistic inspections and enhanced fire water jockey pump monitoring will provide reasonable assurance that loss of material due to selective leakage and crack growth of preexisting casting flaws will be managed so that intended function is maintained during the subsequent period of extended operation.

Based on the above, the *Selective Leaching* program (B2.1.21) is supplemented as shown in Enclosure 6 to manage aging of cementitious lined gray cast iron piping in a soil environment for cracking due to cyclic loading.

RAI B2.1.21-2 (eRAI Letter #157, Question #259)

Regulatory Basis

Title 10 of 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. 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 under 10 CFR 54.29(a), the staff requires additional information regarding the matters described below.

Background

North Anna Power Station (NAPS) Subsequent License Renewal Application (SLRA)

Section B2.1.21, "Selective Leaching" states that it is a new program that will be consistent with the corresponding program in NUREG-2191, Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M33, "Selective Leaching." The SLRA also states that the program includes eight visual and mechanical inspections of components as prescribed in AMP XI.M33 for two-unit sites with sufficiently similar operating conditions and history.

In the program element comparison between the NAPS program and the GALL-SLR Report AMP XI.M33, ETE-SLR-2020-2324, Rev. 0, Section 3.4.2 (for the detection of aging effects) states that inspections are conducted on each material and environment combination as provided in Attachment 2, "One-Time and Periodic Inspection Sample Population." Note 5 of Attachment 2 states:

The buried selective leaching fire protection population is large bore gray cast iron piping and valves. One 8-foot piping segment at each unit can be excavated for the visual inspection (each one-foot segment is one sample). Excavating one 10-foot piping segment per unit will satisfy the visual inspections (8 samples) and the mandatory destructive examination (2 samples).

GALL-SLR Report AMP XI.M33, Detection of Aging Effects states that inspections are conducted of a representative sample of each population and that, where possible, focus on the bounding or lead components most susceptible to aging.

Issue:

Crediting eight 1-foot samples from a single location would appear to be eight samples of the same component instead of samples from eight different components. A similar issue applies to the two destructive samples from the same 10-foot segment. Unless the one 10-foot piping segment can be shown to be the most susceptible and bounding piping section, this sampling approach requires justification.

NRC Request:

Provide the criteria (and justification of the adequacy of the approach) that will be used to select the single 10-foot piping section in order to show that eight visual and mechanical inspections and two destructive examinations of a single location will provide a representative sample of the entire population.

Dominion Response

Opportunistic and periodic inspections will be conducted consistent with the *Selective Leaching* program (B2.1.21) on a representative sample of buried gray cast iron fire protection piping that is lined with a cementitious coating. Periodic inspections of 100% of each ten-foot length piping sample at each Unit will be performed on a ten-year inspection interval (i.e., eight visual inspections and two mandatory destructive examinations). Consistent with NUREG-2191, Section XI.M33, Selective Leaching, each one-foot length or equivalent length counts as one sample. The two mandatory destructive examinations will be selected based on the visual examination results for the two one-foot lengths with the most potential for degradation. The eight visual inspections may be reduced by two for each component that is destructively examined beyond the mandatory number of destructive examinations recommended in each 10-year interval.

Periodic Inspections: Sample Selection

Periodic inspection samples, where possible, focus on the bounding or lead components most susceptible to aging based on time-in-service and severity of operating conditions for each population. The selection of buried gray cast iron fire protection piping that is lined with a cementitious coating would be based on operating experience and consider the following:

- Older piping segments (i.e. not previously replaced)
- Piping found to be continuously wetted due to leaking piping/valves or in soil with high corrosivity ratings as determined by EPRI Report 3002005294, Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants
- Piping that is not cathodically protected
- Piping with significant coating degradation or unexpected backfill
- Consequence of failure (i.e. proximity to safety-related piping)
- Pipe locations with potentially high stress and/or cyclic loading conditions such as piping adjacent to locations that were replaced due to cracking/rupture, locations subject to settlement, or locations subject to heavy load traffic.

<u>Opportunistic Inspections: Enhanced Fire Water Jockey Pump Monitoring</u>

In addition to periodic inspections, enhanced fire water jockey pump monitoring will be implemented to monitor and trend fire water jockey pump starts or run time. The performance information will be used to project and prevent unexpected fire water jockey pump starts. If an unexpected fire water jockey pump start occurs, then further investigation will be conducted to isolate and identify the leak location. Inspections will be conducted following excavation at the affected location to determine the cause of failure and the findings included in the Corrective Action Program. See the response to RAI B2.1.27-1 for additional performance monitoring and trending details of the fire water jockey pump.

SLRA Section B2.1.16 includes an enhancement to the "detection of aging effects" program element related to monitoring the activity of the fire water jockey pump consistent with the "detection of aging effects" program element of NUREG-2191 Report, AMP XI.M41, Buried and Underground Piping and Tanks. At Surry Power Station, the NRC staff previously accepted this enhancement against the corresponding program elements in NUREG-2191 Report, AMP XI.M27 and AMP XI.M41 and found it acceptable because, consistent with AMP XI.M41, monitoring the performance of the fire water jockey pump can provide insights into potential leaks in the fire water system (ADAMS Accession No. ML20052F523).

4. SLRA AMP B2.1.27, Buried and Underground Piping and Tanks

<u>Regulatory Basis:</u>

Section 54.21(a)(3) of 10 CFR requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended

operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB. 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 B2.1.27-1 (eRAI Letter #102, Question #147)

Background:

As amended by letter dated February 4, 2021 (ADAMS Accession No. ML21035A303), SLRA Table 3.3.2-42, "Auxiliary Systems - Fire Protection - Aging Management Evaluation," states that cracking for internally-lined gray cast iron piping and piping components exposed to soil will be managed by the Buried and Underground Piping and Tanks program. The AMR item cites generic Note H, for which Dominion has identified cracking as an aging effect that is not in the GALL-SLR Report for this component, material, and environment combination. In addition, the AMR item cites plant-specific note 11, which states "[c]racking 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 [current licensing basis] fatigue analysis does not exist."

The SLRA includes several statements related to failures of buried gray cast iron piping in the fire protection system:

- *SLRA Section B2.1.16, "Fire Water System," states "[i]n May 2013, sections of cementitious lined cast iron piping were replaced with a higher pressure rated cementitious lined ductile iron piping. Additional isolation valves were also installed to improve system sectional isolation capability. These modifications were implemented due to six fire protection pipe failures that occurred from 1984 to 2003 because of either manufacturing flaws or a flaw that was initiated during the installation process. There were no reported instances due to age related degradation."*
- *SLRA Section B2.1.21, "Selective Leaching," states "[i]n October 2001 a rupture of fire protection main loop piping occurred. A metallurgical analysis determined that the failure most likely occurred as a result of a low cycle fatigue process that originated at a pre-existing manufacturing flaw in the pipe. The ruptured piping was replaced."*
- *SLRA Section B2.1.27, "Buried and Underground Piping and Tanks," states "[i]n May 2013, following replacement of cast iron with (and installation of new) ductile iron fire main piping, the scope of cast iron fire protection piping replacement with ductile iron was reduced to the portion identified as high priority due to the postulated pipe rupture in this area potentially challenging adjacent safety-related piping."*
- *SLRA Section 3.3.2.2.7, "Loss of Material Due to Recurring Internal Corrosion," states "[b]uried fire protection system piping is made of cast iron or ductile iron with a cementitious lining. In May 2013, a design change was completed to replace sections of cementitious lined cast iron piping with a higher pressure rated cementitious lined*

ductile iron due to internal pipe failures that were attributed to preexisting conditions in the cast iron pipe and not due to the failure of the lining."

The staff's acceptance letter for the NAPS SLRA (ADAMS Accession No. ML20258A284) states the following:

- *"[t]he application makes several references to buried gray cast iron piping in the "Fire Protection System." However, there are no aging management review items in Table 3.3.2-42, "Fire Protection," of the application for this component, material, and environment combination. The application states that sections of buried gray cast iron piping were replaced with ductile iron in 2013, but there is no mention of a full-scale replacement. Additionally, the Selective Leaching AMP discusses a failure due to cyclic fatigue, which is an aging effect not referenced in the GALL-SLR Report, for this component, material, and environment combination. The staff notes that the issue of cyclic fatigue of buried gray cast iron fire protection system piping will be subject to the NRC staff's detailed review and that it may require additional review time and requests for additional information (RAIs)."*

During its audit, the staff reviewed additional documents discussing buried cast iron fire main pipe ruptures that noted pre-existing flaws had grown as a result of low cycle fatigue from periodic system pump pressure testing. [Reference: Design Change No. 04-018, "Underground Fire Protection Piping Replacement/ North Anna/ Units 1&2," dated May18, 2006]. The staff also reviewed the failure analysis associated with the 2001 rupture and noted the conclusion that "from a condition assessment standpoint, any pipe still in service that may contain an [inside diameter] defect or flaw that is allowed to propagate to the size of four inches or greater will be susceptible to brittle fracture assuming it experiences similar loading conditions." [Reference: NESML-Q-473, "Material Analysis Report," dated October 15, 2001.]

GALL-SLR Table IX.F, "Use of Terms for Aging Mechanisms," lists cyclic loading as a standardized aging mechanism used in AMR line item tables in the GALL-SLR Report. In addition, the definition for cyclic loading states "[f]atigue cracking is a typical result of cyclic loadings on metal components."

Issue:

During its review, the staff notes that the February 4, 2021, supplement does not include changes to SLRA Section B2.1.27 with respect to how the Buried and Underground Piping and Tanks program will manage cracking due to cyclic fatigue for internally-lined gray cast iron piping and piping components exposed to soil. The staff also notes that GALL-SLR Report AMP XI.M41 does not generically address management of cracking due to cyclic fatigue for buried components.

NRC Request:

Provide additional information describing how the Buried and Underground Piping and Tanks program will manage cracking due to cyclic fatigue for internally-lined gray cast iron piping and piping components exposed to soil.

Dominion Response

Cracking due to cyclic loading in buried gray cast iron fire protection piping that is lined with a cementitious coating is managed by the *Buried and Underground Piping and Tanks* program (B2.1.27). NUREG-2191, AMP XI.M41, Buried and Underground Piping and Tanks program, allows monitoring the activity of the fire water jockey pump an alternative to performing visual inspections of the buried fire protection system components. Monitoring the activity of the fire water jockey pump will be performed by the *Fire Water System* program (B2.1.16). See the response to RAI B2.1.21-1 for additional details regarding fire water jockey pump monitoring.

SLRA Section B2.1.21, *Buried and Underground Piping and Tanks* program, is revised, as shown in Enclosure 6, to clarify the program manages cracking due to cyclic loading in buried gray cast iron fire protection piping that is lined with a cementitious coating.

RAI B2.1.27-2 (eRAI Letter #153, Question #249)

Regulatory Basis

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

Background

As amended by letter dated February 4, 2021, SLRA Section B2.1.27, "Buried and Underground Piping and Tanks," states the following:

- *"[t]he Buried and Underground Piping and Tanks program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks."*
- *"[t]he buried carbon steel piping of the service water system and the flood protection dike drain is protected by an active CP [cathodic protection] system."*
- *"[t]he buried carbon steel piping of the fuel oil system for the emergency electrical power system will be refurbished and reconnected to the service water CP system described above."*

- *[t]he buried carbon steel fill line piping for the security diesel fuel oil tank will be replaced with corrosion resistant material that does not require inspection (e.g., titanium alloy, super austenitic, or nickel alloy materials)."*

GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," Table XI.M41-1, "Preventive Actions for Buried and Underground Piping and Tanks," recommends that cathodic protection is provided for buried steel piping and tanks. In addition, the "preventive actions" program element of GALL-SLR Report AMP XI.M41 states the following:

Failure to provide cathodic protection in accordance with Table XI.M41-1 may be acceptable if justified in the SLRA. The justification addresses soil sample locations, soil sample results, the methodology and results of how the overall soil corrosivity was determined, pipe to soil potential measurements and other relevant parameters.

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

SLRA Table 3.3.2-40, "Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation," states carbon steel tanks exposed to soil will be managed for loss of material using the Buried and Underground Piping and Tanks program.

<u>Issue:</u>

A basis was not provided for why cathodic protection is not necessary for carbon steel tanks exposed to soil in the emergency diesel generator system.

<u>NRC Request:</u>

State the basis for why carbon steel tanks exposed to soil in the emergency diesel generator system are not provided with cathodic protection.

<u>Dominion Response</u>

The emergency diesel generator (EDG) fuel oil storage tanks (FOSTs) were not installed with a cathodic protection system. Existing preventative measures used for the two buried carbon steel EDG FOSTs include: 1) internal (epoxy) and external (Koppers Bitumastic 300-M) coatings; and 2) backfill using compacted sand, graded to provide uniform bearing and support.

NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks program, allows examinations either to be conducted from the external surface of the tank using visual techniques or from the internal surface of the tank using volumetric techniques, in lieu of cathodic protection. As such, the *Buried and Underground Piping and Tanks*

program (B2.1.27) conducts internal tank surface examinations of the buried EDG FOSTs consistent with the guidance in NUREG-2191, Section XI.M41, as an alternative to cathodic protection.

Additional plant-specific Operating Experience (OE) supporting operation of the EDG FOSTs without cathodic protection is provided below.

Internal Inspection Operating Experience

Previous internal inspection results associated with the EDG FOSTs wall thickness examinations and coating inspections were included in NAPS SLRA Supplement 1, dated February 4, 2021 (ADAMS Accession No. ML 21035A303), but are also provided below for your convenience:

Underground fuel oil storage tanks - The EDG FOSTs are cleaned and inspected on a 10-year frequency. During the 2013 EDG FOST inspections, a visual of the interior coating and an ultrasonic thickness examination from inside each tank were performed. Approximately 60 spot ultrasonic thickness readings were obtained from inside each tank, along the length of the tanks. Thickness readings on both tanks were acceptable and showed no degrading trend from the previous data recorded in 2002. Some minor coating degradation was identified within each tank and repairs were completed prior to returning the tanks to service.

Soil Survey Operating Experience

A baseline site soil survey was conducted in 2011 and included 24 sample locations within the scope of subsequent license renewal. Eleven of the 24 sample locations were associated with steel components. Soil samples were analyzed for the following parameters:

- soil resistivity
- water content
- pH
- sulfide content
- groundwater level (moisture)
- redox potential
- chloride concentration

During the 2011 baseline soil survey, a sample (D7) was collected near the Fuel Oil Pump House, which was the closest survey point to the EDG FOSTs. The following table provides the Sample D7 soil survey sample data results and corrosivity index as determined by the American Water Works Association (AWWA) C105, "Polyethylene Encasement for Ductile-Iron Pipe Systems" and EPRI Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants."

Soil Survey Sample D7 Results and Corrosivity Index

	Sample (Units)	Vendor Data	AWWA C105 Points	EPRI BPWORKS Points
		FO Pump House		Carbon Steel
Resistivity	Ohm-cm	17500	0	0
Water Content	%	<20	na	na
pH		8.25	0	0
Sulfides	L, M, H	L	2	0
Groundwater (Moisture)	Above/ Below Pipe	B	0	1
Redox Potential	mV	188	0	0
Chloride	ppm	0	na	0
Bacteria			na	not collected
Corrosivity Index			2	1
Corrosivity			**Non-corrosive**	**Mildly corrosive**

Soil survey Sample D7 had one of the lowest corrosivity indices and was assigned a "Mildly corrosive" rating using EPRI Report 3002005294, and a rating of "Non-corrosive" using AWWA C105, reflecting a low soil corrosivity environment. The next ten-year site soil survey will include pipe-to-soil potential measurements.

Future ultrasonic thickness examinations from inside each EDG FOST will provide a minimum of 25% examination coverage.

Based upon the above information, the EDG FOSTs are being managed consistent with the guidance in NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks program. The Future EDG FOST inspections combined with future soil corrosivity testing will provide reasonable assurance that the intended function of the EDG FOSTs will be maintained during the subsequent period of extended operation.

RAI B2.1.27-3 (eRAI Letter #153, Question #250)

<u>Regulatory Basis</u>

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

with the current licensing basis. In order to complete its review and enable making a finding under 10 CFR 54.29(a), the staff requires additional information in regard to the matters described below.

Background

GALL-SLR Report Table XI.M41-1 recommends that the following are externally coated in accordance with the "preventive actions" program element of GALL-SLR Report AMP XI.M41:

(a) buried steel and stainless steel components; and (b) underground steel and copper alloy components.

SLRA Section B2.1.27 states the following:

- *"[d]epending on the material, preventive and mitigative techniques include external coatings..."*
- *"[t]he required inspections of in-scope stainless steel piping were conducted [referring to Buried Piping and Valve Inspection program inspections performed prior to the initial period of extended operation]. In cases where stainless steel piping was found without coating or with significantly disbonded coating, no evidence of pitting or corrosion existed."*

During the audit, the staff noted the following: (a) buried stainless steel piping may be coated, wrapped, or tape-wrapped; (b) stainless steel piping is not required to be coated based on chloride index value of zero for each of the 24 soil sample locations throughout North Anna Power Station; (c) buried steel piping may be coated with coal tar epoxy, coal tar enamel, coal tar epoxy encased in concrete; or tape wrap; (d) acceptable applied coatings for underground steel and copper alloy piping are coal tar enamel, coal tar epoxy, unidentified material, and none; and (e) the investigation into the cause of a leak due to external corrosion on a buried carbon steel service water line identified that the piping was not coated and wrapped in accordance with the installation specification.

UFSAR Section 3.11.3, "Corrosion Prevention for Underground Piping," states the following:

The protective steps and measures taken are in accordance with National Association of Corrosion Engineers (NACE)[3] Recommended Practice RP-01-69. All underground steel pipelines and tanks are coated and wrapped in accordance with Section 5, Coatings, of the above standard. The standard does not address itself to stainless steel piping.

Analysis indicates that no protective coating is required. However, to provide additional protection for the buried stainless steel Fuel Oil piping an approved coating will be applied.

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[3] NACE RP-01-69, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." Houston, Texas: NACE International. 1983.

Issue

The staff seeks confirmation on whether the following are coated in accordance with the "preventive actions" program element of GALL-SLR Report AMP XI.M41: (a) buried steel and stainless steel piping and piping components; and (b) underground steel and copper alloy piping and piping components. In addition, the staff notes the following: (a) plant-specific operating experience indicates that portions of in-scope buried steel and stainless steel are not externally coated; (b) GALL-SLR Report AMP XI.M41 does not exclude buried stainless steel from being externally coated based on the non-presence of chlorides; and (c) UFSAR Section 3.11.3 indicates that only buried stainless steel fuel oil piping is externally coated.

NRC Request

Provide clarification regarding if the following are coated in accordance with the "preventive actions" program element of GALL-SLR Report Table XI.M41-1:

(a) buried steel and stainless steel piping and piping components; and
(b) underground steel and copper alloy piping and piping components. If all or portions of in-scope piping and piping components are not externally coated in accordance with the "preventive actions" program element of GALL SLR Report AMP XI.M41, provide justification for why external coatings are not provided.

Dominion Response

(a) Buried steel and stainless steel piping and piping components

Buried steel and stainless steel piping within the scope of subsequent license renewal is coated as shown in Table 1 below. Buried steel piping coating applications include coal tar epoxy, coal tar enamel, or tape wrap. Buried stainless steel piping coating applications include coal tar enamel or tape wrapped. No exclusion from the external coating of buried steel or stainless steel piping is being claimed by Table 1.

Table 1: Buried Piping and Tanks

Preventive Actions

Material Type	System	Acceptable Cathodic Protection	Acceptable Applied Coatings[a,b]	Acceptable Backfill[h]
Buried Pipe				
Stainless Steel	Quench Spray		Coal Tar Enamel	Sand, Engineered Fill
	Recirc Spray		Coal Tar Enamel	Sand
	Safety Injection		Coal Tar Enamel	Sand
	Chemical & Volume Control		Coal Tar Enamel	Sand, Engineered Fill
	Residual Heat Removal		Coal Tar Enamel	Sand
	Condensate		Coal Tar Enamel	Sand
	Fuel Oil		Coal Tar Enamel	CLSM[f]
Steel	Service Water	Impressed Current	Coal Tar Epoxy	Soil/Select Soil[e]
	Flood Prot Dike	Impressed Current	Tape Wrap[g]	Earthfill[g]
	Fuel Oil	Impressed Current	Coal Tar Enamel[i] Tape Wrap	CLSM[f]
	Security Diesel	N/A	Note **c**	Sand
	Fire Protection	N/A	Coal Tar Enamel[k] Note **l**	Sand
Copper	Fire Protection	N/A	Note **j**	Sand
Buried Tanks				
Steel	Fuel Oil	N/A	Note **m**	Sand
Fiberglass	Security Diesel	N/A	N/A	Pea Gravel[d]

a) ETE-NA-2012-0064, Rev. 5, Table 3.3.1, Appendix 1 & Appendix 2
b) NAS-3001, Installation Specification for Outside Containment Protective Coatings
c) Coated consistent with DNES-AA-MAT-CTG-1002 using coal tar epoxy, moisture cure urethane tar, multifunctional epoxy, or tape wrap. See Section 2.4, Enhancements, 3.b commitment to replace this carbon steel piping material with corrosion resistant material that does not require inspection.
d) Design Change NA-14-00003, Section 7.0 (p. 19 of 22)
e) NAS-3003, Specification for Excavation, Fill & Backfill SW Buried Piping
f) Design Change NA-17-00118, Section D (p. 15 of 19)
g) ETE-SLR-2020-2109, Rev. 0, Attachment A, Section 4.3.1 (p. 9 of 62)
h) Backfill is placed consistent with GMP-C-102, Excavation and Backfill.
i) NAS-277, Specification for Heating, Fuel Oil, and Chilled Water Systems (p. 10)
j) See Section 2.4, Enhancements, 3.a commitment to replace this copper fire protection piping material with carbon steel.
k) NAS-0074 specifies coating of cast iron fire protection piping material.
l) NAI-0034 specifies asphaltic coating for ductile iron fire protection piping material.
m) Drawing 11715-FV-46A specifies Koppers Bitumastic 300-M coating for the buried EDG fuel oil storage tanks.

(b) Underground steel and copper alloy piping and piping components

Underground steel and copper alloy piping within the scope of subsequent license renewal is coated as shown in Table 2 below. Underground steel and copper alloy piping coating applications include coal tar epoxy, moisture cure urethane tar, multifunctional epoxy, or tape wrap. No exclusion from the external coating of underground steel and copper alloy piping is being claimed by Table 2.

<table>
<tr><th colspan="5">Table 3.2.2-2 Underground Piping</th></tr>
<tr><th colspan="5">Preventive Actions</th></tr>
<tr><th>Material Type</th><th>System</th><th>Acceptable Cathodic Protection</th><th>Acceptable Applied Coatings[a,b]</th><th>Acceptable Backfill</th></tr>
<tr><td colspan="5">Underground Pipe</td></tr>
<tr><td rowspan="7">Stainless Steel</td><td>Quench Spray</td><td></td><td></td><td></td></tr>
<tr><td>Chemical & Volume Control</td><td></td><td></td><td></td></tr>
<tr><td>Condensate</td><td></td><td></td><td></td></tr>
<tr><td>Liquid Waste</td><td></td><td></td><td></td></tr>
<tr><td>Recirc Spray</td><td></td><td></td><td></td></tr>
<tr><td>Safety Injection</td><td></td><td></td><td></td></tr>
<tr><td>Gaseous Vents</td><td></td><td></td><td></td></tr>
<tr><td rowspan="8">Steel</td><td>Chilled Water</td><td></td><td rowspan="9">Note c</td><td></td></tr>
<tr><td>Service Water</td><td></td><td></td></tr>
<tr><td>Fuel Oil</td><td></td><td></td></tr>
<tr><td>Aerated Drains</td><td></td><td></td></tr>
<tr><td>Blowdown</td><td></td><td></td></tr>
<tr><td>Condensate</td><td></td><td></td></tr>
<tr><td>Main Steam</td><td></td><td></td></tr>
<tr><td>Feedwater</td><td></td><td></td></tr>
<tr><td>Copper</td><td>Drains Building Services</td><td></td><td></td></tr>
<tr><td>Polymer</td><td>Security Diesel</td><td></td><td></td><td></td></tr>
<tr><td colspan="5">a) ETE-NA-2012-0064, Table 3.3.1, Appendix 1 & Appendix 2
b) NAS-3001, Installation Specification for Outside Containment Protective Coatings
c) Coated consistent with DNES-AA-MAT-CTG-1002 using coal tar epoxy, moisture cure urethane tar, multifunctional epoxy, or tape wrap.</td></tr>
</table>

RAI B2.1.27-4 (eRAI Letter #153, Question #251)

Regulatory Basis

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

Background

SLRA Section A1.16, "Fire Water System," states "[t]his program manages cracking, flow blockage, and, loss of material by conducting periodic visual inspections, flow testing, and flushes performed in accordance with the NFPA [National Fire Protection Association] 25, 2011 Edition."

GALL-SLR AMP XI.M41 states for fire mains installed in accordance with NFPA 24, "Standard for the Installation of Private Fire Service Mains and Their Appurtenances,"[4] preventive actions beyond those in NFPA 24 need not be provided if the system undergoes a periodic flow test in accordance with NFPA 25[5]. The staff notes that NFPA 24 provides provisions for backfill quality in Section 10.9, "Backfilling."

During the audit, the staff noted plant-specific operating experience from 2012 where (a) unexpected backfill material was found against the surfaces of fire protection piping; (b) the backfill material contained gravel above the size of VDOT [Virginia Department of Transportation] Grade B granular fill material specified for the fire protection replacement project; and (c) the original fire protection installation specification does not identify a maximum backfill material size.

[4] NFPA 24, "Standard for the Installation of Private Fire Service Mains and Their Appurtenances." Quincy, Massachusetts: National Fire Protection Association. 2010.

[5] NFPA 25, "Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems, 2011 Edition." Quincy, Massachusetts: National Fire Protection Association. 2011.

Issue

Based on its review of plant-specific operating experience during the audit, the staff was not able to confirm that the backfill quality for buried fire protection piping meets the intent of NFPA 24, Section 10.9.

NRC Request

State the basis for how backfill quality for buried fire protection piping meets the intent of NFPA 24, Section 10.9.

Dominion Response

Dominion Specification NAI-0034, *Installation Specification for Underground Fire Protection Systems*, provided requirements used for backfill during installation of the existing fire protection system piping. The information provided in the table below demonstrates that the backfill requirements in NAI-0034 are consistent with NFPA-24, 2010 edition, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*, Section 10.9.

With exception of the unexpected backfill material identified during the 2012 piping excavation for the fire protection replacement project, there were no additional non-conforming backfill materials documented during Underground Piping and Tank Integrity (UPTI) program inspections (2011 to current). Examination of the piping surface identified during the 2012 excavation for the fire protection replacement project did not identify any coating damage, pitting, or corrosion that would affect the intended function of the piping.

NFPA 24 Section	Requirement	NAI-0034 Section	Specification
10.9	Backfilling	5.7	Backfilling and Tamping
10.9.1	Backfill shall be tamped in layers or puddled under and around pipes to prevent settlement or lateral movement and shall contain no ashes, cinders, refuse, organic matter, or other corrosive materials.	5.7.4	Fill Placement-...shall be placed in approximate 6 inch thick lifts and compacted evenly at the fill surface...Before pressure testing, lines shall be covered with tamped backfill...After the hydro test is complete the remaining final backfill layer shall be placed.
		5.7.1	Bedding material and the initial layer of backfill material shall be select granular material (see Section 5.7.2) free from cinders, ashes, frozen material, rocks or stones...
		5.7.2	Granular soil is the preferred backfill material for the fire line installation. Granular backfill shall be used within the protected area. Acceptable select backfill is VDOT #21A, VDOT #21 B, VDOT Grade B fine aggregate or a sand/gravel fill mixture...
10.9.2	Rocks shall not be placed in trenches.	5.7.1	Bedding material and the initial layer of backfill material shall be select granular material (see Section 5.7.2) free from cinders, ashes, frozen material, rocks or stones...
		5.7.2	Granular Backfill Material – Cumulative 100% passing 3/8 inch sieve size.
10.9.3	Frozen earth shall not be used for backfilling.	5.7.1	Bedding material and the initial layer of backfill material shall be select granular material (see Section 5.7.2) free from cinders, ashes, frozen material, rocks or stones...
10.9.4	In trenches cut through rock, tamped backfill shall be used for at least 6 in. (150 mm) under and around the pipe and for at least 2 ft (0.6 m) above the pipe.	5.2	Preparation of Trench Bottom-A minimum 6 inch bedding layer of select material shall be placed below the pipe and the pipe shall be set in the bedding such that it is embedded 1 inch into that bedding layer.
		5.1	Preparation of Trenches-Trenches shall be excavated to the depth required to provide at least five feet minimum cover over the fireline piping...

5. SLRA AMP B2.1.28, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

RAI B2.1.28-1 (eRAI Letter #154, Question #252)

Regulatory Basis

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

Background

As amended by letter dated February 4, 2021, SLRA Section B2.1.28 states the following:

- *"[t]he Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program is an existing program that, following enhancement, will be consistent, with exception [not related to this RAI], to NUREG-2191, Section XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks as modified by SLR-ISG-Mechanical-2020-XX, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance."*
- *"[f]rom 2014 to 2019 recurring internal corrosion (RIC) due to loss of coating integrity has occurred in the coated service water (SW) system piping and component cooling heat exchanger channel head."*
- *"[p]lant operating experience [OE] has demonstrated that component cooling heat exchanger channel heads inspections performed on a three-year frequency which allows early detection of degradation of coatings and the underlying metal before there is a loss of intended function."*

GALL-SLR Report Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers," recommends that internal coatings/linings for piping, piping components, heat exchangers, and tanks are inspected every 4 or 6 years based on the inspection category.

Issue

It appears that based on the plant-specific OE, the component cooling heat exchanger channel heads are inspected more frequently than the guidance provided in GALL-SLR Report Table XI.M42-1. Given that the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will be consistent with GALL-SLR Report AMP XI.M42, the frequency of inspections of the component cooling heat exchanger channel heads could exceed the triennial inspection interval because the frequency of inspections is not reflected in the current licensing basis for the SPEO.

NRC Request

State the basis for why the triennial inspections of the component cooling heat exchanger channel heads is not reflected in the current licensing basis for the SPEO. Alternatively, revise the SLRA as appropriate to reflect a triennial inspection frequency for the component cooling heat exchanger channel heads.

Dominion Response

The inspection frequency of the component cooling heat exchanger channel heads is consistent with the current licensing basis as documented in the updated response to Generic Letter 89-13 (GL 89-13) for North Anna Units 1 and 2, "Service Water System Problems Affecting Safety-Related Equipment," (ADAMS Accession No. ML20085H840) that states, "Maintenance schedules will be adjusted as required based on actual equipment performance and inspection results."

Consistent with the GL 89-13 commitments, the Unit 1 component cooling heat exchangers (CCHXs) are visually inspected on a triennial frequency based on Engineering evaluation. Note that the Unit 2 CCHXs are not in the scope of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) because the channel heads have titanium cladding.

Station procedures that implement the GL 89-13 program requirements reflect cleaning/inspection intervals as adjusted based on the results of previous maintenance activities and performance testing in accordance with the current licensing basis.

Since the GL 89-13 commitment for three-year (triennial) cleaning/inspection of the Unit 1 CCHXs is the more limiting frequency, a three-year coating inspection frequency is used instead of the 4-year (Category B) frequency specified in NUREG-2191, Table XI.M42-1, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks. If the GL 89-13 commitment for cleaning/inspection of the Unit 1 CCHXs were to be extended to a four-year frequency, current coating operating experience would support a four-year NUREG-2191, Table XI.M42-1 Category B inspection frequency.

6. SLRA AMP B2.1.34, Structures Monitoring Program

Regulatory Basis:

Paragraph 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 B2.1.34-1

Background

SLRA Section B2.1.34 states that the Structures Monitoring Program will be consistent with the ten [program] elements of GALL-SLR Report AMP XI.S6, "Structures Monitoring". As described in the SRP-SLR, and to ensure compliance with the 10 CFR 54.21(a)(3) requirements, for those programs that the applicant claims are consistent with the GALL-SLR Report, the NRC staff will verify that the applicant's programs are consistent with those described in the GALL-SLR Report and/or with plant conditions and operating experience during the performance of an AMP audit and review.

In SLRA Section B2.1.34, Dominion included enhancement No. 3 to the Structures Monitoring Program to demonstrate consistency with the "parameters monitored or inspected" program element of the GALL-SLR Report AMP XI.S6. This enhancement states, in part, that procedures will be revised to specify that aluminum and stainless steel (SS) structural components such as louvers, cable trays, conduits, and structural supports will be monitored for cracking due to Stress Corrosion Cracking.

Issue

The enhancement provided in SLRA Section B2.1.34 suggests that only the aging effects of cracking will be monitored for the aluminum and SS structural components.

SRP-SLR Section 3.5.2.2.2.4 recommends enhancing the applicable AMP (i.e. Structures Monitoring Program) to ensure that aging effects of loss of material and cracking are adequately managed for SS and aluminum components during the period of extended operations.

NRC Request

Clarify if the aging effect of loss of material will be monitored for aluminum and stainless steel structural components within the scope of the Structures Monitoring Program, or provide a technical justification for not monitoring this aging effect for these components. Revise the SLRA and enhancement No. 3 accordingly.

Dominion Response

The *Structures Monitoring* program (B2.1.34) is revised to include the aging effect of loss of material, in addition to the aging effect of cracking, for aluminum and stainless steel structural components within the scope of the program.

Consistent with the RAI response, SLRA Section B2.1.34, Enhancement 3, and Table A4.0-1, Item 34 are revised, as shown in Enclosure 6, to include loss of material as an aging effect.

RAI 3.5.2.3-1

Background

SLRA Table 3.5.2 26 states that hardening or loss of strength, loss of material, and cracking or blistering of carbon fiber reinforced polymer wrap exposed to air will be managed by the Structures Monitoring Program. The AMR item cites generic note H, since these aging effects are not generally addressed in the GALL-SLR Report for this component, material and environment combination by the Structures Monitoring Program.

As described in the SRP-SLR, AMR results not consistent with or not addressed in the GALL- SLR Report need to follow the acceptance criteria described in Appendix A.1 of the SRP-SLR. Specifically, the credited program should, in part, identify the specific structures and/or components within scope of the program, identify the aging effects that the program manages, and describe the acceptance criteria that will be used to ensure that the intended function(s) are maintained consistent with the CLB during the subsequent period of extended operation.

Issue

During the audit, the staff reviewed procedure ER-NA-INS-104, Revision 10, "Monitoring of Structures North Anna Power Station," and noted that the scope of the existing program does not include the carbon fiber reinforced polymer wrap material/component, its associated aging effects (i.e. aging effects of hardening, loss of strength, loss of material, cracking or blistering), and associated acceptance criteria. The staff also noted that SLRA Section B2.1.34 does not include an enhancement to the Structures Monitoring Program to ensure that this component, aging effects, and acceptance criteria are added to the scope of the program to ensure compliance with the 10 CFR 54.21(a)(3) requirements.

NRC Request

Provide the necessary information and/or enhancement to demonstrate that carbon fiber reinforced polymer wrap will be in the scope of the Structures Monitoring Program (or other appropriate AMP) and that the effects of aging for this component will be adequately managed for the period of extended operation.

Dominion Response

The *Structures Monitoring* program (B2.1.34) is revised to add a new Enhancement that will ensure the carbon fiber reinforced polymer (CFRP) wrap of the concrete poles for the reserve station service transformer (RSST) tube bus and associated aging effects of hardening or loss of strength, loss of material, cracking or blistering that could lead to the reduction or loss of intended function are included within the scope of the program.

Consistent with the RAI response, SLRA Section A1.34, Section B2.1.34 and Table A4.0-1, Item 34 are revised, as shown in Enclosure 6, to indicate the carbon fiber reinforced polymer wrap in the scope of the *Structures Monitoring* program will be adequately managed for the subsequent period of extended operation.

7. SLRA TLAA 4.3, Metal Fatigue

Regulatory Basis:

Pursuant to 10 CFR 54.21(c), the SLRA shall include an evaluation of time-limited aging analyses (TLAAs). The applicant shall demonstrate that (i) the analyses remain valid for the period of extended operation; (ii) the analyses have been projected to the end of the period of extended operation; or (iii) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

RAI 4.3-1 (eRAI Letter #149, Question #245)

Background:

As described in SLRA Section 4.3.2.6, the applicant proposed to disposition the TLAA for the Pressurizer (including Nozzle Weld Overlays) in accordance with 10 CFR 54.21(c)(1)(iii), by demonstrating that the effects of fatigue on the intended functions of these components will be adequately managed for the subsequent period of extended operation. Specifically, the applicant stated that the effects of fatigue on the intended function(s) of the pressurizer surge line will be adequately managed by the Fatigue Monitoring program (SLRA Section B3.1) for the subsequent period of extended operation. The application also states that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (SLRA Section B2.1.1) will manage the pressurizer surge line thermal stratification through inspection every ten years based upon the ASME Code, Section XI, Appendix L methodology approved by the NRC.

As described in SLRA Section 4.3.2.7, the applicant proposed to disposition the TLAA for the Class 1, United States of America Standards (USAS) (American National Standards Institute (ANSI)) B31.7 Piping in accordance with 10 CFR 54.21(c)(1)(i), by demonstrating that the analyses for these components remain valid for the subsequent period of extended operation.

As described in SLRA Section 4.3.6, the applicant proposed to disposition the TLAA for the High Energy Line Break Analyses in accordance with 10 CFR 54.21(c)(1)(i), by

demonstrating that the analyses for these components remain valid for the subsequent period of extended operation.

With respect to the TLAAs described above in SLRA Sections 4.3.2.6 and 4.3.2.7, SLRA Section A3.3.2 states that the effects of fatigue on the intended function(s) of ASME Code, Section III components will be adequately managed by the Fatigue Monitoring program (Section A2.1) for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

With respect to the TLAA described above in SLRA Section 4.3.6, SLRA Section A3.3.6 states that the effects of fatigue on the intended function(s) of ASME Code, Section III components will be adequately managed by the Fatigue Monitoring program (Section A2.1) for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

Issue:

The applicant's proposed disposition of the TLAAs described in SLRA Sections 4.3.2.6, 4.3.2.7 and 4.3.6 are inconsistent with the Updated Final Safety Analysis Report (UFSAR) Supplement for these TLAAs in Appendix A.

Specifically, the staff noted the following inconsistencies:

- *SLRA Section A3.3.2 does not indicate that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) will manage the pressurizer surge line thermal stratification through inspection every ten years based upon the ASME Code, Section XI, Appendix L methodology approved by the NRC.*
- *SLRA Section A3.3.2 indicates the disposition for the Class 1, USAS (ANSI) B31.7 Piping TLAA is in accordance with 10 CFR 54.21(c)(1)(iii), whereas SLRA Section 4.3.2.7 indicates that this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).*
- *SLRA Section A3.3.6 indicates the disposition for the High-Energy Line Break TLAA is in accordance with 10 CFR 54.21(c)(1)(iii), whereas SLRA Section 4.3.6 indicates that this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).*

NRC Request:

Clarify the discrepancy identified between SLRA Section 4.3 and Appendix A of the SLRA. Provide a revision to the SLRA, if necessary.

Dominion Response

SLRA Sections A3.3.2 and A3.3.6 are revised, as shown in Enclosure 6, to correct the inadvertent discrepancies in dispositions between SLRA Section 4.3 and Appendix A.

RAI 4.3-2 (eRAI Letter #149, Question #246)

Regulatory Basis

Pursuant to 10 CFR 54.21(c), the SLRA shall include an evaluation of TLAAs. The applicant shall demonstrate that (i) the analyses remain valid for the period of extended operation; (ii) the analyses have been projected to the end of the period of extended operation; or (iii) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

Background

As described in SLRA Section 4.3.4, the applicant proposed to disposition the TLAA for Environmentally Assisted Fatigue in accordance with 10 CFR 54.21(c)(1)(iii), by demonstrating that the effects of fatigue on the intended functions of these components will be adequately managed for the subsequent period of extended operation.

SLRA Section 4.3.4 states that calculations were prepared to document the evaluations of environmentally-assisted fatigue (EAF) for ASME Code, Section III pressure boundary components and USAS (ANSI) B31.7, Class I piping that contact the reactor coolant, and determine fatigue-sensitive locations for comparison and ranking.

Issue

During its audit, the staff noted that SIA Report 1701098.403P, Revision 0, "Determination of Final Set of Environmentally-Assisted Fatigue (EAF) Sentinel Locations for North Anna Power Station (NAPS) Units 1 and 2," determined the pressurizer surge nozzle weld overlay (nickel- based alloy) is bounded by the (a) replacement reactor vessel closure head J-groove weld (nickel-based alloy) and (b) 14" hot leg surge nozzle (stainless steel). The basis provided in SIA Report 1701098.403P (i.e., environmentally-adjusted cumulative usage factor (CUF_{en}) of the bounding locations are greater than pressurizer surge nozzle weld overlay (nickel-based alloy) is not sufficient. Specifically, the applicant did not adequately justify that (1) a component of the same material from a different transient section is bounding, and (2) a component of different material from the same transient section is bounding. The staff noted that aspects such as, but not limited to, the amount of rigor in calculating CUF, the use of the same fatigue curves (if applicable), and the assessment of differences in material properties for nickel based alloy and stainless steel and in severity of transients in these transient sections, can impact CUF_{en} values; thus, only a comparison of CUF_{en} values for these components is not sufficient.

In addition, SLRA Section 4.3.4 states the following: "[f]or two pressurizer FSWOL nozzle locations with U_{en} values greater than unity, Surge Nozzle (Ni-Cr-Fe), and Spray Nozzle (stainless steel pipe to safe weld) these locations will be managed through the Fatigue Monitoring program (SLRA Section B3.1) during the subsequent period of extended operation. While not required for EAF since these full structural weld overlays are managed by the Fatigue Monitoring program (SLRA Section B3.1), they are inspected in accordance with ASME Code Case N-770-2."

However, the supporting technical basis (SIA Report 1701098.403P, Revision 0) is inconsistent with the SLRA and indicates that only the nickel-based alloy portion of the pressurizer spray nozzle weld overlay weld will be inspected per ASME Code Case N-770-2.

Thus, the following requires clarification:

- *The supporting technical basis that the pressurizer surge nozzle weld overlay (nickel-based alloy) is bounded by the (a) replacement reactor vessel closure head J-groove weld (nickel- based alloy) and (b) 14" hot leg surge nozzle (stainless steel) for environmentally assisted fatigue during the subsequent period of extended operation.*
- *Whether the pressurizer surge nozzle weld overlay (nickel-based alloy) is inspected in accordance with ASME Code Case N-770-2.*

NRC Request

1. *With respect to environmentally assisted fatigue during the subsequent period of extended operation, provide the supporting technical basis that the pressurizer surge nozzle weld overlay (nickel-based alloy) is bounded by the replacement reactor vessel closure head J- groove weld (nickel-based alloy) and 14" hot leg surge nozzle (stainless steel).*
2. *Clarify whether the pressurizer surge nozzle weld overlay (nickel-based alloy) will be inspected in accordance with ASME Code Case N-770-2 and is credited for aging management during the subsequent period of extended operation.*

Dominion Response

1. A similar degree of rigor is used in development of the CUF and F_{en} values for the pressurizer surge nozzle weld overlay and reactor vessel closure head J-groove weld. Framatome designed and fabricated the replacement reactor vessel head and full structural weld overlay for the pressurizer surge nozzle. Framatome performed an NB-3200 analysis for both the J-groove weld and pressurizer surge nozzle weld overlay. An NB-3200 evaluation was also performed for the pressurizer surge line hot leg nozzle.

   For final EAF screening, EPRI Report 1024995, "Environmentally-Assisted Fatigue Screening Process and Technical Basis for Identifying EAF Limiting Locations" was used to develop the sentinel locations arranged by transient sections as reflected in SLRA Table 4.3.4-2:

   - Section 1 Reactor Coolant Transients (Cold Leg),
   - Section 2a RHR (RHR plus High Head Injection Path),
   - Section 2b Reactor Coolant Transients (Hot Leg),
   - Section 2c Reactor Coolant Transients (Steam Generators),
   - Section 3 Charging (Normal and Alternate),

- Section 5 Pressurizer Lower Head and Surge Line, and
- Section 6 Pressurizer Upper Head.

There are no sentinel locations associated with transient sections 4 and 7.

RAI 4.3-2 discusses locations in Transient Section 2 and Transient Section 5. The replacement reactor vessel closure head J-groove weld is associated with Transient Section 2 while the 14-inch branch pressurizer surge line hot leg nozzle and pressurizer surge nozzle weld overlay is associated with Transient Section 5.

For final EAF screening, the J-groove weld (associated with Transient Section 2) was confirmed to bound the pressurizer surge nozzle weld overlay (associated with Transient Section 5). Boundedness Rule 1 was used to validate that the J-groove weld bounds the pressurizer surge nozzle weld overlay, as indicated below:

Boundedness Rule 1 - One Thermal Zone can bound another Thermal Zone in a System

This circumstance could be achieved if within the same system, both the CUF and F_{en} values for one Sentinel Location in one Thermal Zone are each higher than the CUF and F_{en} values for the Sentinel Locations in other Thermal Zones.

The CUF and F_{en} values for the J-groove weld are 0.238 and 3.93 respectively while the CUF and F_{en} values for the pressurizer surge nozzle weld overlay are 0.174 and 3.746 (when the factor of 10 is removed for adjustment of the fatigue curve).

For final EAF screening, the 14-inch branch nozzle pressurizer surge hot leg nozzle (stainless steel) was confirmed to bound the pressurizer surge nozzle weld overlay (nickel base alloy). Both the 14-inch branch nozzle pressurizer surge hot leg nozzle and pressurizer surge nozzle weld overlay are associated with Transient Section 5. Boundedness Rule 2 was used to validate that the 14-inch branch nozzle pressurizer surge hot leg nozzle bounds the pressurizer surge nozzle weld overlay.

Boundedness Rule 2 - One material in a Thermal Zone can bound other materials in the same Thermal Zone

This circumstance could be achieved if within the same Thermal Zone, both the CUF and F_{en} values for one Sentinel Location composed of one material are each higher than the CUF and F_{en} values for the Sentinel Locations composed for all other materials.

The CUF and F_{en} value for the pressurizer 14-inch hot leg surge nozzle (stainless steel) nozzle is 8.856 and 8.555, respectively while the CUF and F_{en} value for the pressurizer surge nozzle weld overlay are 0.174 and 3.746 (when the factor of 10 is removed for adjustment of the fatigue curve).

Through use of Boundedness Rules 1 and 2, the J-groove weld and 14-inch hot leg surge nozzle are verified to bound the pressurizer surge nozzle weld overlay.

For the nickel-base alloy material, the reactor vessel (RV) control rod drive mechanism (CRDM) sleeve (head adapters - J-groove weld) in Transient Section 2 bounds the nickel-based alloy pressurizer surge nozzle weld overlay weld in Transient Section 5

because the original CUF and F_{en} are both higher for the J-groove weld than the pressurizer surge nozzle weld overlay weld. Using the original CUF values, the RV CRDM sleeve head adapters - J-groove weld location is not retained as a sentinel location because the $U_{en} < 1.0$. While the J-groove weld was not selected as a sentinel location because the U_{en} value is less than unity, it is inspected per ASME Code Case N-729.

The 14-inch hot leg surge nozzle bounds all other locations in the Transient Section 5, including the pressurizer surge nozzle weld overlay weld.

The pressurizer surge nozzle weld overlay location is in a high radiation environment and the pressurizer heater cables can be damaged during an inspection requiring removal of the insulation. Accordingly, the NRC has granted a Relief Request[6,7]] for the inspection of the pressurizer surge nozzle inner radius and weld that attaches the nozzle to the pressurizer as part of the Class 1 system leakage test due to ALARA concerns and the possibility of damaging cables. Therefore, Dominion is proposing to use two surrogate locations to each bound the pressurizer surge nozzle weld overlay weld. The two surrogate locations are the hot leg surge nozzle and the RV CRDM sleeve (head adapters - J-groove weld). The hot leg surge nozzle bounds the pressurizer surge nozzle weld overlay weld on the basis of Boundedness Rule 2 and is inspected on a ten-year frequency. The RV CRDM sleeve (head adapters - J-groove weld) bounds the pressurizer surge nozzle weld overlay on the basis of Boundedness Rule 1 and is inspected per ASME Code Case N-729.

For initial license renewal in NUREG-1776, the NRC staff considered the surge line hot leg nozzle to be the most limiting component to represent the effects of the reactor water environment on the fatigue life of pressurizer components during the period of extended operation.

2. There are six full structural weld overlays installed on the pressurizer nozzles: spray (1), surge (1), relief (2), and safety (2). The pressurizer surge line weld overlay is a population of six nozzle weld overlays for inspection per ASME Code Case N-770-5 (Category F-1). ASME Code Case N-770, Category F-1 requires that 25% of the population be inspected every 10 years. As discussed in Item 1, due to radiation dose considerations and the possibility of damaging the cables under the pressurizer, the surge nozzle weld overlay was not selected for inspection during this ISI Interval. It is pre-decisional to determine which weld overlay nozzles will be selected for inspection during future ISI Intervals because these ISI plans have not yet been developed.

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[6] NRC Relief Request, Serial Number 19-207, Inservice Inspection Alternative Requests N1-I5-NDE-001 and N2-I5-NDE-001 – North Anna Power Station Units 1 and 2 (EPID L-2018-LLR-0114, ADAMS Accession Number ML18235A316.

[7] North Anna Power Station, Unit Nos. 1 and 2 – Inservice Inspection Alternative Requests N1-15-NDE-001 and N2-15-NDE-001 (EPID L-2018-LLR-0114), Serial # 19-207, April 15, 2019, ADAMS Accession Number ML 19092A417.

However, aging management due to environmental fatigue of the pressurizer surge weld overlay is accomplished through inspection of three other bounding locations:

1. Reactor Vessel Head J-groove weld overlay (ASME Code Case N-729),
2. Steam Generator Tubing (Steam Generator Eddy Current Program), and
3. Pressurizer surge line hot leg nozzle (ISI Program).

Nonetheless, the nickel-based pressurizer surge nozzle weld overlay must be and will be re-inspected every 19.2 years per the mitigation evaluation period discussed under footnote 10 of ASME Code Case N-770. Inspections performed under ASME Code Case N-770 are for management of stress corrosion cracking and not EAF.

8. SLRA TLAA 4.7.3, Leak-Before-Break

Regulatory Basis:

In accordance with 10 CFR 54.21(c)(1), the applicant is required to provide a list of TLAAs as defined in 10 CFR 54.3. The applicant is also required to demonstrate that: (i) the analyses remain valid for the period of extended operation; (ii) the analyses have been projected to the end of the subsequent period of extended operation; or (iii) the effects of aging on the intended function(s) will be adequately managed for the subsequent period of extended operation.

Background:

Section 4.7.3 of NAPS SLRA addresses the leak-before-break (LBB) time-limited aging analysis (TLAA) for NAPS Units 1 and 2. As part of the SLRA, the applicant (Dominion Energy) also submitted WCAP-11163, Revision 2 that describes the technical basis of the LBB TLAA.

WCAP-11163, Revision 2 indicates that NAPS has unmitigated Alloy 82/182 welds at Unit 1 steam generator outlet nozzles, which is susceptible to primary water stress corrosion cracking (PWSCC). Specifically, Section 7.3 of the WCAP report states that a conservative factor of 1.69 to account for PWSCC is applied to the leakage flaw size calculation. During the audit on January 4. 2021, the applicant explained that the conservative factor accounts for the effect of PWSCC crack morphology on leakage rates in the LBB analysis and that the approach is consistent with that used in WCAP-17187 and WCAP-17262, Revision 1, which describe previous LBB analyses for other plants.

RAI 4.7.3-1 (eRAI Letter #146, Question #238)

NRC Request:

The staff noted that the conservative factor for Alloy 82/182 welds previously used in WCAP-17262, Revision 1, Table 6 1 and the related analysis suggest that a conservative factor greater than 1.69 is applied to account for the effect of PWSCC crack morphology.

In addition, WCAP-11163, Revision 2 for NAPS does not clearly address an analysis of crack growth from the leakage crack to the critical crack in order to confirm that the crack growth will take a sufficient time to detect leakage and shut down the reactor safely. Based on the discussion above, provide the following information.

1. *If the LBB TLAA uses a conservative factor for Alloy 82/182 welds less than that used previously (e.g., WCAP-17262, Revision 1), explain the basis for the change.*
2. *Discuss a relevant crack growth analysis to confirm that the crack growth from the leakage crack to the critical crack in the Alloy 82/182 welds will take a sufficient time to detect leakage and shut down the reactor safely.*

Dominion Response

1. Table 6-1 of WCAP-17262, Revision 1, "Technical Bases for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Fort Calhoun Unit 1," documents the calculated leakage flaw sizes for the critical evaluations of the Fort Calhoun Unit 1 reactor coolant loop (RCL) piping. Those results are based on the stainless-steel material properties, not the nickel-based alloy. The respective leakage flaw size results for the Alloy 82/182 of Fort Calhoun are reported separately from Table 6-1 of WCAP-17262. The reported Alloy 82/182 leakage flaw size in WCAP-17262 includes a primary water stress corrosion cracking (PWSCC) crack morphology factor of 1.69 (69% increase). The evaluation for the NAPS RCL piping uses the same PWSCC crack morphology factor of 1.69 in calculating the leakage flaw size reported in Table 7-5 of WCAP 11163 P, Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for North Anna Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation."
2. Table 8-2 of WCAP 11163-P, Revision 2 specifically addresses the fatigue crack growth (FCG) in the Alloy 82/182 (Inconel) material. These results show that the flaw growth is very slow and that a surface flaw cannot result in a through-wall flaw over the design life of the plant. While FCG is not explicitly performed for a through-wall flaw, correlation can be drawn against the very small growth of a surface flaw over the operating life of the plant. Crack growth can occur by either FCG or PWSCC. A literature search reveals that the possibility of PWSCC growth has been generically investigated by EPRI. Table 7-1 of EPRI Technical Report 1011808, "Materials Reliability Program: Leak-Before-Break Evaluation for PWR Alloy 82/182 Welds (MRP-140)," shows long periods of time for PWSCC growth for nickel-based alloy material. For FCG and PWSCC, it can be justified that the growth of a through-wall leakage flaw would generally take several months, years, or even decades of plant operation before growing to a critical size.

   Technical Specification 3.4.13 specifies actions that require a reactor shutdown in the event of reactor coolant pressure boundary through-wall leakage. Considering slow crack growth and the Technical Specification required actions, sufficient time is available for the flaw to be identified and for the reactor to be shut down.

RAI 4.7.3-2 (eRAI Letter #146, Question #239)

See Enclosures 2 and 3 for Proprietary and Non-proprietary responses, respectively.

RAI 4.7.3-3 (eRAI Letter #146, Question #240)

NRC Request:

SRLA Section 4.7.3 addresses the LBB TLAA, including the Alloy 82/182 welds that are susceptible to PWSCC. As discussed in SLRA Section B2.1.5, cracking due to PWSCC in nickel alloy welds is managed by performing the inspections in accordance with ASME Code Case N-770 as incorporated by reference in 10 CFR 50.55a, "Codes and standards."

In contrast, the applicant (Dominion Energy) dispositioned the LBB TLAA in accordance with 10 CFR 54.21(c)(1)(ii) but not in accordance with 10 CFR 54.21(c)(1)(iii) that includes the performance of aging management activities in connection with the TLAA. Explain the basis for the dispositioning of the TLAA (not including aging management activities) even though cracking due to PWSCC in the Alloy 82/182 welds within the scope of LBB TLAA is managed by the inspections in accordance with ASME Code Case N-770 as required by 10 CFR 50.55a.

Dominion Response

The LBB TLAA was dispositioned in accordance with 10 CFR 54.21(c)(1)(ii) because the evaluation was revised for operation through the subsequent period of extended operation.

In SLRA Section B2.1.5, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components," cracking due to primary water stress corrosion cracking in nickel alloy welds is managed by performing inspections in accordance with ASME Code Case N-770 as incorporated by reference in 10 CFR 50.55a, "Codes and Standards". Table 1 of ASME Code Case N-770 outlines the examination requirements, method of examination, and frequency for the various nickel alloy welds.

Dominion cited ASME Code Case N-770 for management of cracking in nickel-based alloy welds in SLRA Section B2.1.5 because inspections are currently required and performed in accordance with ASME Code Case N-770 as required by 10 CFR 50.55a.

Enclosure 3

NON-PROPRIETARY RESPONSE TO RAI 4.7.3-2
(eRAI Letter #146, Question #239)
SET 1 REGARDING NAPS SLRA

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

NON-PROPRIETARY RESPONSE TO RAI 4.7.3-2
(eRAI Letter #146, Question #239)
SET 1 REGARDING NAPS SLRA

NRC Request:

Section 7.0 of WCAP-11163, Revision 2 indicates that an elastic-plastic facture mechanics analysis is performed for cast austenitic stainless steel locations considering applied J-integral values as a driving force for fracture in the LBB TLAA.

The Ramberg-Osgood parameters are used in the applied J-integral estimations (i.e., α, ν, ε_o and σ_o ιν $\varepsilon/\varepsilon_o = (\sigma/\sigma_o) + \alpha(\sigma/\sigma_o)^n$ as addressed in NUREG-1061, Volume 3, Section A2.3.1). These parameters may be time-dependent in the LBB TLAA. If so, discuss how these time- dependent parameters are calculated as part of the LBB analysis. In addition, provide the parameter values used in the analysis.

Dominion Response

Determination of the Ramberg-Osgood parameters considers the (unaged) tensile test properties (yield and ultimate strength) from Certified Material Test Reports (CMTRs) reviewed by the NRC staff during the Aging Management Audit, as well as the n_1 and α_1 calculations provided in NUREG/CR-4513, "Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR Systems," (Equations 3.4.13a through 3.4.19 of Revision 1, Equations 59 through 66 of Revision 2).

The n_1 and α_1 parameters are used to establish the engineering stress versus strain behavior of aged CASS materials. The time-dependency is captured in the n_1 and α_1 equations from NUREG/CR-4513. The Ramberg-Osgood parameters, n and α used in the J-integral analysis are developed from a [

]^{a,c,e}

The time-dependent effect of thermal aging results in an increase of the tensile properties. However, the use of unaged (lower) tensile properties results in a more conservative fracture evaluation.

The Ramberg-Osgood parameters for the critical analysis locations in WCAP 11163-P, Revision 2 are shown in the following table.

a,c,e

Note: Excluding Location 5, material heats listed are bounding of all material heats at the given location for both Units

Enclosure 4

CAW-21-5164
WESTINGHOUSE AFFIDAVIT FOR WITHHOLDING PROPRIETARY INFORMATION:
LTR-SDA-II-21-14-P, DATED MARCH 10, 2021

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

COMMONWEALTH OF PENNSYLVANIA:
COUNTY OF BUTLER:

(1) I, Camille T. Zozula, have been specifically delegated and authorized to apply for withholding and execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse).

(2) I am requesting the proprietary portions of LTR-SDA-II-21-14-P be withheld from public disclosure under 10 CFR 2.390.

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

(4) Pursuant to 10 CFR 2.390, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse and is not customarily disclosed to the public.

(ii) The information sought to be withheld is being transmitted to the Commission in confidence and, to Westinghouse's knowledge, is not available in public sources.

(iii) Westinghouse notes that a showing of substantial harm is no longer an applicable criterion for analyzing whether a document should be withheld from public disclosure. Nevertheless, public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar technical evaluation justifications and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable

others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

(5) Westinghouse has policies in place to identify proprietary information. Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

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

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

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

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

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

(6) The attached documents are bracketed and marked to indicate the bases for withholding. The justification for withholding is indicated in both versions by means of lower-case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower-case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (5)(a) through (f) of this Affidavit.

I declare that the averments of fact set forth in this Affidavit are true and correct to the best of my knowledge, information, and belief.

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

Executed on: 12 Mar 2021

Camille Zozula

Camille T. Zozula, Manager
Regulatory Compliance & Corporate Licensing

Enclosure 5

CLARIFICATION TO MANAGEMENT OF AGING EFFECTS FOR FIRE PROTECTION SYSTEM LINED DUCTILE IRON VALVES

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

Aging Management Clarification
Fire Protection System Lined Ductile Iron Valves

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

SLRA Table 3.3.1, Item 138 and Table 3.3.2-42 are revised to clarify the Fire Water System (B2.1.16) program manages loss of coating or lining integrity of ductile iron valve bodies with internal lining exposed to raw water.

A plant-specific note is added to SLRA Table 3.3.2-42 to clarify the 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 by 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 a 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.
- Long-term loss of material is managed by the One-Time Inspection (B2.1.20) program.

Based on the above, the SLRA is supplemented as shown in Enclosure 6, to clarify the aging management programs that manage aging of fire protection system lined ductile iron valves in the following:

SLRA Table
3.3.1, Item 138
3.3.2-42

Enclosure 6

SLRA MARK-UPS
SET 1 RAIs

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

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
3.3.1-138	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191 with exceptions and a different aging management program for some components. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program implementation. In addition to Auxiliary Systems, components in Structures and Component Supports (Flood Protection Dike) are aligned to this item. The Fuel Oil Chemistry (B2.1.18) program manages loss of coating or lining integrity of steel with internal coating components exposed to fuel oil in Auxiliary Systems (emergency diesel generator). The Fire Water System (B2.1.16) program will manage loss of coating or lining integrity of ductile iron valve bodies with internal lining exposed to raw water in Auxiliary Systems (fire protection).
3.3.1-139	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191 with exceptions and a different aging management program for some components. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program implementation. The Fuel Oil Chemistry (B2.1.18) program manages loss of material of steel with internal coating components exposed to fuel oil in Auxiliary Systems (emergency diesel generator).
3.3.1-140	Gray cast iron, ductile iron piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program implementation.

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)~~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~~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)~~Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)~~	VII.G.A-33~~VII.G.A-414~~	3.3.1-064~~3.3.1-139~~	B, 12
						~~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
		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) 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.
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.

A1.33 MASONRY WALLS

The *Masonry Walls* program is an existing condition monitoring program that is implemented as part of the *Structures Monitoring* program (A1.34) and manages cracking, loss of material, and loss of material (spalling and scaling) that could impact the intended function of the masonry walls. The *Masonry Walls* program consists of inspections, consistent with Inspection and Enforcement Bulletin 80-11, and plant-specific monitoring, proposed by Information Notice 87-67, for managing shrinkage, separation, gaps, loss of material and cracking of masonry walls such that the evaluation basis is not invalidated and intended functions are maintained.

A1.34 STRUCTURES MONITORING

The *Structures Monitoring* program is an existing condition monitoring program that monitors the condition of structures and structural supports that are within the scope of subsequent license renewal to manage the following aging effects:

- Cracking
- Cracking and distortion
- Cracking, loss of bond, and loss of material (spalling, scaling)
- Cracking, loss of material
- Hardening or loss of strength, loss of material, cracking or blistering
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- Increase in porosity and permeability, cracking, loss of strength
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking
- Reduction or loss of isolation function

This program consists of periodic visual inspection and monitoring the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as those described in ACI 349.3R, ACI 201.1R, and other documents) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Inspections also include seismic joint fillers, elastomeric

materials; and steel edge supports and steel bracings associated with masonry walls, and periodic evaluation of groundwater chemistry and opportunistic inspections for the condition of below grade concrete. Quantitative results (measurements) and qualitative information from periodic inspections are trended with photographs and surveys for the type, severity, extent, and progression of degradation. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and quantitative acceptance criteria of ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures."

Qualified inspectors identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *Structures Monitoring* program (A1.34), the *ASME Section XI, Subsection IWL* program (A1.30), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (A1.35).

A1.35 INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program is an existing condition monitoring program, which is implemented as part of the *Structures Monitoring* program (A1.34), and manages the following aging effects:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of material; loss of form

This program consists of inspection and surveillance of raw-water control structures associated with emergency cooling systems or flood protection. The program also includes structural steel and structural bolting associated with water-control structures. In general, parameters monitored are consistent with Section C.2 of Regulatory Guide 1.127, Revision 1 (March 1978), "Inspection of Water-Control Structures Associated with Nuclear Power Plants," and quantitative measurements are recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. The inspections of the water-control structures within the scope of subsequent licensing renewal are conducted at a frequency not to exceed five years.

than the 40-year design cycles (CLB cycles) used in the fatigue analyses. Therefore, the fatigue analyses for ASME Code, Section III components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the ASME Code, Section III fatigue analyses, the Fatigue Monitoring program (B3.1) will track cycles for significant fatigue transients and ensure corrective action is taken prior to potentially exceeding fatigue design limits. A Condition Report will be initiated based upon an administrative limit of 90% of the fatigue cycles.

A3.3.2 ASME Code, Section III, Class I Fatigue Analyses

Fatigue analyses are performed per ASME Code, Section III. Each analysis is required to demonstrate that the Cumulative Usage Factor (CUF) for the component will not exceed the Code design limit 1.0 when the component is exposed to all postulated transients.

The following ASME Code, Section III components were assessed for impact on fatigue:

- Control Rod Drive Mechanism (CRDM)
- Pressurizer (including Nozzle Weld Overlays)
- Reactor Coolant Pump
- Reactor Vessel
- Steam Generator (including Unit 1 Inlet Nozzle Weld Overlays)
- Pressurizer Surge Line
- Class I B31.7 Piping
- ASME Code, Section III, Component Fatigue Waivers
- Loop Stop Isolation Valves

In addition, a detailed fatigue evaluation is not required if components conform to the waiver of fatigue requirements per ASME Code, Section III. These fatigue waivers depend on the numbers of anticipated transients over the life of the plant and therefore constitute TLAAs.

The 40-year design cycles (CLB cycles) were postulated to bound 80 years of plant operations. Therefore, the fatigue analyses and fatigue waivers remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the fatigue analyses and fatigue waivers, the *Fatigue Monitoring* program (Section A2.1) will track cycles for significant fatigue transients listed in the UFSAR, Table 5.2-4 and Section 18.4.2, and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

~~The effects of fatigue on the intended function(s) of ASME Code, Section III components will be adequately managed by the *Fatigue Monitoring* program (Section A2.1) for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).~~

For the all of the above-listed ASME Code, Section III components except Class I B31.7 Piping the effects of fatigue on the intended function(s) will be adequately managed for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii) by the Fatigue Monitoring program (Section A2.1), and, for pressurizer surge line thermal stratification EAF considerations, also managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) through inspection every ten years based upon the ASME Code, Section XI, Appendix L methodology approved by the NRC.

The transient cycles considered for the Class I B31.7 Piping bound the corresponding 80-year transient cycles for all transients. Therefore, the CUF values will remain less than unity for the fatigue analyses of record during the subsequent period of extended operation and thus this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.3.3 ANSI B31.1 Allowable Stress Analyses

The reactor coolant system's primary loop piping is constructed in accordance with USAS (ANSI) B31.7, "Nuclear Power Piping," 1969 Edition with 1970 and 1971 Addenda and Class II, Class III, and, the balance-of-plant piping in scope for subsequent license renewal are analyzed to the requirements of ANSI B31.1, "Power Piping." As identified in USAS (ANSI) B31.7, Class I piping is designed for the cumulative effect of two or more types of stress cycles by use of a cumulative usage factor (CUF). Fatigue for Class I piping is addressed as a TLAA in Section A.3.3.2.

For piping systems designed in accordance with USAS (ANSI) B31.1, explicit analyses of cumulative fatigue usage are not required. Instead, cyclic loading is considered in a simplified manner in the design process. Allowable thermal stresses are reduced using a stress range reduction factor based on the number of anticipated thermal cycles expected during the component operating lifetime. Stress range reduction factors are specified in USAS (ANSI) B31.1, Table 102.3.2(c). No reduction of allowable stresses is required for piping that is subjected to less than 7,000 equivalent full temperature cycles during plant service. The evaluations for required stress reduction factors are implicit fatigue analyses because they are based on the number of fatigue cycles anticipated for the life of the component, therefore, they are TLAAs requiring evaluation for the subsequent period of extended operation.

USAS (ANSI) B31.1 systems are generally subject to continuous steady state operation and operating temperatures vary only during plant heatup and cooldown, during plant transients, or during periodic testing. Portions of piping systems designed in accordance with ANSI B31.1 requirements that are attached to the reactor coolant system or other power cycle related systems are subject to a similar number or fewer cycles as the reactor coolant system. These include condensate, containment vacuum, extraction steam, feedwater, primary and secondary gas supply, main steam, reactor coolant, steam drains, and vacuum priming systems. Portions of some of these

uprate conditions, updated structural evaluations were performed for the upper and lower core plates to demonstrate that they would maintain their structural integrity at proposed power uprate conditions. The lower and upper core plates are not part of the reactor coolant system pressure boundary. As part of the structural evaluations, fatigue analyses of the upper and lower core plates were performed to the 1989 edition of ASME Code, Section III, Division 1, Subsection NG. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. The analysis of record fatigue CUF results are less than 1.0.

The 40-year design cycles (CLB cycles) were postulated to bound an 80-year operating period. Therefore, the reactor vessel internals fatigue analyses remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A3.3.6 High Energy Line Break Fatigue

The selection of Class 1 piping HELB locations depends on usage factors, which will remain valid as long as the assumed numbers of cycles are not exceeded. The HELB evaluation uses CUF values greater than 0.1 for screening potential pipe break locations. The projected 80-year transient cycles are bounded by the 40-year design transients. The original locations with CUF values equal to or less than 0.1 will remain the same for the fatigue analysis of record during the subsequent period of extended operation. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).~~The *Fatigue Monitoring* program (Section A2.1) ensures that the analytical bases of the HELB locations are maintained or that a HELB analysis for the new locations with a CUF greater than 0.1 is performed.~~

~~The effects of fatigue on the intended function(s) of Class 1 piping HELB locations will be adequately managed by the *Fatigue Monitoring* program (Section A2.1) for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).~~

A3.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

Thermal, radiation, and cyclical aging analyses of plant electrical and I&C components, developed to meet 10 CFR 50.49 requirements, have been identified as time-limited aging analyses (TLAAs). The NRC nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49 require that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments is qualified to perform applicable safety functions in those harsh environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a loss-of-coolant accident (LOCA), high energy line break (HELB) or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

The *Environmental Qualification of Electric Equipment* program (A2.3) will manage the effects of aging for EQ equipment through the subsequent period of extended operation in accordance with

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
31	*ASME Section XI, Subsection IWF* program	The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 2. Procedures will be revised to specify that, for high-strength bolting greater than one inch nominal diameter within the scope of the *ASME Section XI, Subsection IWF* program, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population or a maximum of 19 high-strength bolts per unit will be inspected for IWF supports located in an "air" environment. 3. Procedures will be revised to specify a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation. 4. ~~Procedures will be revised to require that if a component support does not exceed the acceptance standards of IWF-3400 but is repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.~~(Completed - Supplement 1)	B2.1.31	Program will be implemented and a one-time inspection of an additional 5% of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports is conducted within 5 years prior to the subsequent period of extended operation, and are to be completed prior to the subsequent period of extended operation, are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
32	*10 CFR 50, Appendix J* program	The *10 CFR 50, Appendix J* program is an existing condition monitoring program that is credited.	B2.1.32	Ongoing
33	*Masonry Walls* program	The *Masonry Walls* program is an existing condition monitoring program that is credited.	B2.1.33	Ongoing
34	*Structures Monitoring* program	The *Structures Monitoring* program Is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: Administration Building (aka Office Building), Decontamination Building, Domestic Water Treatment Building, Heater Boiler Room, Maintenance Building, New Fuel Receiving Building, Waste Disposal (Clarifier) Building, Waste Solids Building, 17-ton Carbon Dioxide tank foundation, and Backup 34.5 kV Circuit Power Poles (Switchyard to the Reserve Station Service Transformers). Baseline inspections for the added structures will be performed under the enhanced program in order to establish quantitative inspection data prior to conduct of periodic inspections in the subsequent period of extended operation. The baseline inspections will include baseline inspections of the masonry walls in the Administration Building, Decontamination Building, Domestic Water Treatment Building, and the Maintenance Building.	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
34	*Structures Monitoring* program	2. Procedures will be revised to specify that structural components inspected include structural bolting, anchor bolts and embedments, component support members, pipe whip restraints and jet impingement shields, transmission towers, panels and other enclosures, racks, sliding surfaces, sump and pool liners, electrical cable trays and conduits, tube tracks, trash racks associated with water-control structures, electrical duct banks, manholes, doors, penetration seals, seismic joint filler and other elastomeric materials. 3. Procedures will be revised to specify that aluminum and stainless steel structural components such as louvers, cable trays, conduits, and structural supports will be monitored for loss of material and cracking due to SCC that could lead to the reduction or loss of their intended function. (Revised - RAI Set 1) 4. Procedures will be revised to specify that elastomeric vibration isolators, structural sealants, and seismic joint fillers will be monitored for cracking, loss of material, and hardening that could lead to the reduction or loss of their intended function. Visual inspection of elastomeric elements is supplemented by tactile inspection to detect hardening if the intended function is suspect. 5. Procedures will be revised to specify that the carbon fiber reinforced polymer (CFRP) wrap of the concrete poles for the reserve station service transformer (RSST) tube bus will be monitored for hardening or loss of strength, loss of material, cracking or blistering that could lead to the reduction or loss of intended function. (Added - RAI Set 1) 6. Procedures will be revised to specify that accessible sliding surfaces will be monitored for indications of excessive loss of material due to corrosion or wear and debris or dirt that could restrict or prevent sliding of the surfaces. (Renumbered - RAI Set 1) 7. Procedures will be enhanced to specify that evaluations of neutron shield tank findings consider its structural support function for the reactor pressure vessel. (Renumbered - RAI Set 1)	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
35	*Inspection of Water-Control Structures Associated with Nuclear Power Plants* program	The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to include the Circulating Water Intake Tunnel Header and the Discharge Tunnel Seal Pit within the scope of the program. 2. Procedures will be revised to specify underwater inspections or dewatering to permit visual inspections for submerged structures, on a frequency not to exceed five years.	B2.1.35	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
36	*Protective Coating Monitoring and Maintenance* program	The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that is credited.	B2.1.36	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
49	N/A	Procedures will be developed to replace the diesel-driven fire pump engine heat exchanger tube bundle on a 20-year frequency and require the heat exchanger tube bundle for the spare engine to be replaced prior to being placed in-service with the diesel-driven fire pump. (Added – RAI Set 1)	N/A	Procedures to replace the diesel-driven fire pump heat exchanger tube bundle will be in place 5 years prior to the heat exchanger tube bundle achieving 20 years of active service.

B2.1.21 Selective Leaching

Program Description

The *Selective Leaching* program is a new condition monitoring program that will manage loss of material of the susceptible materials located in a potentially aggressive environment. The materials of construction for these components may include gray cast iron, ductile iron, and copper alloys (greater than 15% zinc).

The *Selective Leaching* program will also manage cracking due to cyclic loading of cementitious lined gray cast iron piping in a soil environment.. Periodic inspections of cementitious lined gray cast iron piping in a soil environment will be performed as a separate sample population and include inspections to detect selective leaching of cementitious lined gray cast iron piping.

A one-time inspection of components exposed to closed-cycle cooling water or treated water environments will be conducted when plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for raw water, waste water, soil, and groundwater environments, and for closed-cycle cooling water or treated water environments when plant specific operating experience has revealed selective leaching in these environments. A sample of 3% of the population or a maximum of ten components per population at each unit will be visually and mechanically (gray cast iron and ductile iron components) inspected. If the inspection conducted for ductile iron in the 10-year period prior to a subsequent period of extended operation (i.e., the initial inspection) meets acceptance criteria, periodic inspections do not need to be conducted during the subsequent period of extended operation for ductile iron.

Periodic destructive examinations of components for physical properties (i.e., degree of dealloying, through-wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste water, soil, and groundwater environments or for closed-cycle cooling water or treated water environments when plant specific operating experience has revealed selective leaching in these environments. For sample populations with greater than 35 susceptible components at each unit, two destructive examinations will be performed for that population. In addition, for sample populations with less than 35 susceptible components at each unit, one destructive examination will be performed for that population. For opportunistic and periodic inspections, the number of visual and mechanical inspections may be reduced by two for each component that is destructively examined beyond the minimum number of destructive examinations recommended for each sample population. For one-time inspections, the number of visual and mechanical inspections may be reduced by two for each component that is destructively examined for each sample population.

For two-unit sites the periodic visual and mechanical inspections can be reduced from ten to eight because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate,

chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Past power up-rates were implemented for both units at approximately the same time. Historically, water chemistry conditions between the two units have been very similar. The raw water source for both units is Lake Anna. Emergency diesel generator runs are managed to equalize total run times among the diesels, so as to equalize wear and aging. The soil corrosivity analysis performed on soil samples was consistent between the two units. The soil analysis demonstrated that the soil environment was not evaluated as severely corrosive or corrosive. Operating experience for each unit demonstrates no significant difference in aging effects of systems in the scope of this program between the two units.

Inspections will be performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspection procedures will include requirements for items such as lighting, distance, offset, and surface conditions.

Inspection results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. The acceptance criteria are:

(a) for copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide;

(b) for gray cast iron and ductile iron, the absence of a surface layer that can be easily removed by chipping or scraping or identified in the destructive examinations,

(c) the presence of no more than a superficial layer of dealloying, as determined by removal of the dealloyed material by mechanical removal, and

(d) the components meet system design requirements such as minimum wall thickness, when extended to the end of the subsequent period of extended operation.

When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the subsequent period of extended operation, additional inspections will be performed. If 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. Extent of condition and extent of cause analysis will include evaluation of difficult-to-access surfaces if unacceptable inspection findings occur within the same material and environment population. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function.

NUREG-2191 Consistency

The *Selective Leaching* program is a new program that, when implemented, will be consistent, with NUREG-2191, Section XI.M33, Selective Leaching.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Selective Leaching* program 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 December 2015, a buried fire protection supply isolation valve was leaking by its closed seat. The valve had a metallurgical analysis performed which identified some isolated locations of graphitic corrosion on the interior and exterior of the valve body. The corrosion had minimal impact on the valve body thickness. In March of 2016, the six-inch cast-iron valve was replaced with a new valve fabricated from ductile iron body, which has improved corrosion resistance.
2. In June 2020, a review of 2001 through 2020 operational experience for buried and underground piping susceptible to selective leaching within the scope of subsequent license renewal was performed and did not identify any loss of intended function due to selective leaching. Inspection reports did not identify internal coating failures. In addition, isolated areas of external surface degradation with no pitting or gross corrosion were observed. Metallurgical analysis performed on removed piping indicated the internal cementitious coating was intact, showing only a fine, craze surface cracking in some areas. Opportunistic or scheduled inspections noted below indicated the piping was in good condition.
    - In October 2001 a rupture of fire protection main loop piping occurred. A metallurgical analysis determined that the failure most likely occurred as a result of a low cycle fatigue process that originated at a pre-existing manufacturing flaw in the pipe. The ruptured piping was replaced.
    - In August 2011 opportunistic inspections were performed on the southside section of the fire protection main yard loop piping during system modifications. There were no signs of degradation.
    - In September 2011 opportunistic inspection of NANIC fire protection piping during modifications for North Anna 3 site separation activities was performed. The cast iron piping was in satisfactory condition, no repairs required.

- In December 2011 opportunistic inspection of fire protection piping outside the southeast corner of the protected area during modifications for North Anna 3 site separation activities was performed. The cast iron piping was in satisfactory condition, no repairs required.
- In September 2012 opportunistic inspection of fire protection piping during modification for the Unit 3 tie-in to main fire loop was performed. The external coating was found to be covering the pipe and not degraded by the condition. There was no bare metal observed and no signs of corrosion or pitting. The internal lining was found to be fully intact.
- In November 2012 opportunistic inspection of the fire protection pipe replacement design change, opportunistic inspection of the cast iron fire protection main loop to the auxiliary building room was performed. There were small areas of external coating degradation, no pitting was observed, and the internal mortar lining was found to be fully intact. Opportunistic inspection was also performed on a southside section of the cast iron fire protection main yard loop piping. The external coating was in good condition with no damage. The cast iron piping external surfaces did not show evidence of pitting or corrosion. The internal mortar lining was found to be fully intact and protecting the pipe.
- In May 2013, following replacement of cast iron fire main piping segments with ductile iron fire main piping, the scope of the replacement project was reduced to areas potentially challenging adjacent safety-related piping. The buried fire protection piping on the west side of the station that serves as the backup water supply to the Unit 2 auxiliary feedwater system was replaced. Also, the buried cast iron fire protection piping at the northwest and southwest tie-in connection points was replaced with ductile iron pipe. New ductile iron pipe was installed at the Southeast Security Building. The external coating was in good condition. There was no corrosion identified on the external surface. The internal cementitious lining was determined to be in good condition, fully intact, and protecting the pipe in these cases.
- In August 2015, cast iron North Yard fire protection piping from the main fire loop to the Unit 2 Turbine Building was excavated for a buried pipe inspection. The cast iron fire protection piping is internally lined with a cementitious coating and externally coated with a coal tar epoxy. Inspection required removal of a portion of the exterior coating on each pipe for visual and wall thickness examinations. Coatings were in good condition. Visual and wall thickness examinations indicated minor corrosion and pitting in a few places. There was no significant loss of material or minimum wall thickness identified. The piping was recoated prior to backfill.

The above examples of operating experience provide objective evidence that the *Selective Leaching* program will include activities to perform visual and mechanical inspections or destructive examinations to identify loss of material for piping, valve bodies and bonnets, pump casings, and heat exchanger components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Selective Leaching* program will be 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 will be provided for locations where aging effects are found. The program will be 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 implementation of the *Selective Leaching* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Selective Leaching* program will provide 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.

B2.1.27 Buried and Underground Piping and Tanks

Program Description

The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that manages blistering, cracking, hardening or loss of strength, and loss of material on external surfaces of piping and tanks in soil, concrete, or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses stainless steel, carbon steel, cast iron, ductile iron, copper alloy, and fiberglass piping and tanks.

The program will also manage cracking due to cyclic loading in buried gray cast iron fire protection piping that is lined with a cementitious coating.

Depending on the material, preventive and mitigative techniques include external coatings, cathodic protection (CP), and the quality of backfill. Direct visual inspection quantities for buried components are planned using procedural categorization criteria. Transitioning to a higher number of inspections than originally planned is based on the effectiveness of the preventive and mitigative actions. Also, depending on the material, inspection activities include annual surveys of CP, non-destructive evaluation of pipe or tank wall thicknesses, and visual inspections of the pipe from the exterior.

The buried carbon steel piping of the service water system and the flood protection dike drain is protected by an active CP system. Periodic inspections confirm CP system availability and reliability. Annual CP surveys are conducted to assess the effectiveness of the CP system. The program uses the -850 mV relative to CSE (copper/copper sulfate reference electrode), instant off criterion specified in NACE SP0169 for acceptance criteria for steel piping and tanks and determination of cathodic protection system effectiveness in performing cathodic protection surveys. The program includes an upper limit of -1200 mV on cathodic protection pipe-to-soil potential measurements of coated pipes to preclude potential damage to coatings. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured. The buried carbon steel piping of the fuel oil system for the emergency electrical power system will be refurbished and reconnected to the service water CP system described above.

Soil sampling and testing is performed during each excavation and a station-wide soil survey based on initial baseline data is also performed once in each 10-year period to confirm the soil corrosivity level near components within the scope of license renewal for the installed material types. Soil sampling and testing is consistent with EPRI Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants." Soil survey baselines were performed in 2011.

External inspections of buried components within the scope of subsequent license renewal will occur opportunistically when they are excavated for any reason.

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the subsequent period of extended operation an increase in the sample size is conducted.

As an alternative to performing visual inspections of the buried fire protection system components, monitoring the activity of the jockey pump is performed by the *Fire Water System* program (B2.1.16). The water-based fire protection system is normally maintained at required operating pressure and is monitored such that a loss of system pressure is detected and corrective action initiated.

The *Selective Leaching* program (B2.1.21) is applied in addition to this program to manage selective leaching for applicable materials in soil environments.

The *Buried and Underground Piping and Tanks* 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 *Buried and Underground Piping and Tanks* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks.

Exception Summary

None

Enhancements

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

Preventive Actions (Element 2)

1. Procedures will be revised to obtain pipe-to-soil potential measurements for piping in the scope of SLR during the next soil survey within 10 years prior to entering the subsequent period of operation.

Detection of Aging Effects (Element 4) and Corrective Actions (Element 7)

2. The following service water CP subsystems will be refurbished and reconnected before the last five years of the inspection period prior to entering the subsequent period of extended operation.

   a. The service water 'D' CP subsystem

   b. The service water 'C' CP subsystem associated with the buried carbon steel piping of the fuel oil system for the emergency electrical power system

Scope of Program (Element 1), Preventive Actions (Element 2) and Detection of Aging Effects (Element 4)

3. The following buried piping materials will be replaced before the last five years of the inspection period prior to entering the subsequent period of extended operation. (Added - Supplement 1)

   a. The buried copper piping between the fire protection jockey pump and the hydropneumatic tank will be replaced with carbon steel.

   b. The buried carbon steel fill line piping for the security diesel fuel oil tank will be replaced with corrosion resistant material that does not require inspection (e.g., titanium alloy, super austenitic, or nickel alloy materials).

Acceptance Criteria (Element 6)

4. Procedures will be revised to specify that cathodic protection surveys use the -850 mV polarized potential, instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives will include the -100 mV polarization criteria, -750 mV criterion (soil resistivity is greater than 10,000 ohm-cm to less than 100,000 ohm-cm), -650 mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate.

   a. The external loss of material rate is verified:

      - Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate.
      - Every 2 years when using the 100 mV minimum polarization.
      - Every 5 years when using the -750 or -650 mV criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.

   b. As an alternative to verifying the effectiveness of the cathodic protection system every five years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of ten annual consecutive soil samples, soil resistivity testing can be extended to every five years if the results of the soil sample tests consistently

have verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, measured soil resistivity values were greater than 10,000 ohm-cm).

c. When using the electrical resistance corrosion rate probes:

- The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar
- The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Buried and Underground Piping and 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 November 2005, a through-wall leak was discovered in a weld in Unit 1 underground stainless steel safety injection system piping. A portion of the piping was replaced and weld repair was also performed. The Root Cause Evaluation determined the cause to be stress corrosion cracking due to inadequate original construction welding procedures that did not specify the maximum heat input. The high heat input applied during welding to this type of material resulted in sensitizing the weld. The adverse environmental condition attributed to the inside diameter cracking was possible high chloride content in the fluid. Groundwater dripping on the piping was the source for the adverse environmental condition for the outside diameter cracking.

2. In May 2010, stainless steel chemical and volume control, quench spray, residual heat removal, and safety injection buried piping associated with the Unit 1 refueling water storage tank was excavated and inspected. A portion of the external coating was degraded and brittle. No adverse condition or corrosion was found and the coating was restored and the pipes were reburied.

3. In June 2010, stainless steel and carbon steel piping associated with the Unit 1 chemical addition tank was excavated and inspected. The stainless steel piping had no indications of pitting or corrosion. The carbon steel piping had degraded coating with general surface corrosion.

4. In January 2012, stainless steel quench spray piping associated with the Unit 1 refueling water storage tank was excavated and inspected. Both pipes had disbonded coating, but there were no signs of corrosion or degradation. Ultrasonic test results were reviewed by Engineering and found to be acceptable minimum wall thickness. The disbonded coating was repaired.

5. In September 2012, opportunistic inspection of stainless steel Unit 2 Casing Cooling Pump House floor drain piping was excavated and inspected. Coating was found to be disbonded and removed after excavation. There were no indications of pitting or corrosion. Ultrasonic testing indicated greater than minimum wall thickness.The disbonded coating was repaired.
6. In May 2013, following replacement of cast iron with (and installation of new) ductile iron fire main piping, the scope of cast iron fire protection piping replacement with ductile iron was reduced to the portion identified as high priority due to the postulated pipe rupture in this area potentially challenging adjacent safety-related piping. The buried fire protection piping on the west side of the station that serves as the backup water supply to the Unit 2 auxiliary feedwater system was replaced. Also, the buried cast iron fire protection piping at the northwest and southwest tie-in connection points was replaced with ductile iron pipe. New ductile iron pipe was installed at the Southeast Security Building. The basis for scope reduction also included the good condition of existing fire piping found in at least five buried fire main locations. The internal cementitious lining was determined to be in good condition, fully intact, and protecting the pipe in these cases.
7. In November 2014, evaluation was completed of a baseline soil survey conducted during 2011 that involved 25 samples (24 sample locations are within the scope of subsequent license renewal). Soil samples were extracted from various plant locations where safety related piping or piping that contained nuclear/environmentally hazardous material was buried. Ratings for soil resistivity, water content, pH, sulfide content, groundwater level, redox potential, and chloride concentration parameters were compiled to determine a corrosivity index. Using a corrosivity index consistent with American Water Works Association C105, "Polyethylene Encasement for Ductile-Iron Pipe Systems," the 24 samples within the scope of subsequent license renewal were determined to be non-corrosive.
8. In July 2015, service water CP system test results indicate that the majority of the piping associated with CP subsystems 'A,' 'B,' and 'C' are receiving adequate cathodic protection as defined in NACE SP 0169-2013 for both the -0.850 volt and 100-millivolt criteria. Test results indicate a lack of protection on the extreme ends of the system where the pipes enter the concrete vaults or buildings. The 'D' subsystem was shut off because test results indicated that the service water piping was not receiving a level of protection consistent with the 'D' subsystem's rectifier output. The service water piping protected by the 'D' subsystem was volumetrically inspected. There are no issues with the service water piping and no issues will be induced from shutting off the 'D' subsystem; the service water piping remains fully capable of performing its intended functions. CP 'D' subsystem will be refurbished and reconnected before the last five years of the inspection period prior to entering the subsequent period of extended operation.

9. In August 2015, during an Underground Piping and Tanks program inspection of cast iron fire protection and carbon steel bearing cooling piping associated with the bearing cooling tower found the pipe to be in good condition. In particular, the bearing cooling piping excavated did not show evidence of material degradation, pitting, gross corrosion, or other abnormalities. New coatings were applied to the bearing cooling piping prior to backfill.
10. 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 Buried Piping and Valve Inspection AMA (UFSAR Section 18.1.1). From a review of inspection documentation, no discussion of tape wrap removal to inspect epoxy coating was discovered. A follow-on action was initiated ensure evaluation of this omission as part of summarizing buried piping activities for license renewal. The required inspections of in-scope stainless steel piping were conducted. In cases where stainless steel piping was found without coating or with significantly disbonded coating, no evidence of pitting or corrosion existed. It was concluded that there is no benefit to the removal of any tape wrap to inspect the coating underneath.
11. In September 2016, unsatisfactory output voltage and current were measured while performing bimonthly inspection of service water CP subsystem 'C.' Although the output voltage and the output current have not been within the procedural band (−850 mV relative to a CSE, instant off, and 100 mV minimum polarization), the "On" potentials and the "Instant Off" potentials have been consistent and within the acceptable band since May 2013. Engineering will continue to monitor this CP Subsystem on the bimonthly schedule.
12. In October 2016, leakage was observed outside the Unit 1 Auxiliary Feedwater Pump House. A leak of 1-2 gallons per minute was observed from the joint between the concrete walkway and the foundation. After excavation, the leak location was identified in an elbow of a direct buried service water pipe. The failure mechanism was determined to be external corrosion caused by the lack of an external protective coating. The service water elbow was replaced and protective coating was applied to the external surfaces. The accessible adjacent service water piping was also tape-wrapped. The service water line was returned to service.
13. In December 2016, suspected leakage in buried carbon steel piping from the Fuel Oil Pump House to the '2H' diesel room was identified. The leakage was due to localized corrosion on the outside diameter of the pipe due to coating / tape wrap degradation (direct cause). The failure of the coating permitted localized corrosion on the pipe due to chemical attack from the buildup of contaminants on the surface of the pipe.

    The extent of condition included pressurized fuel oil supply lines buried between the Fuel Oil Pump House and each EDG room, along with the SBO EDG room. The buried fuel oil lines in that scope have been replaced with stainless steel and placed in service.

14. 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.
15. 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 was reached that no areas for improvement or enhancements were identified for the Buried Piping and Valve Inspection Activities AMA (UFSAR Section 18.1.1).
16. In April 2019, an effectiveness review was performed on the Buried Piping and Valve Inspection Activities AMA (UFSAR Section 18.1.1) 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 provide objective evidence that the *Buried and Underground Piping and Tanks* program includes activities to perform volumetric and visual inspections to identify blistering, cracking, hardening or loss of strength, and loss of material for buried and underground piping and tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Buried and Underground Piping and 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 *Buried and Underground Piping and Tanks* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Buried and Underground Piping and 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.

B2.1.34 Structures Monitoring

Program Description

The *Structures Monitoring* program is an existing condition monitoring program that manages aging of the structures and components that are within the scope of subsequent license renewal by managing the following aging effects:

- Cracking
- Cracking and distortion
- Cracking, loss of bond, and loss of material (spalling, scaling)
- Cracking, loss of material
- Hardening or loss of strength, loss of material, cracking or blistering
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- Increase in porosity and permeability, cracking, loss of strength
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking
- Reduction or loss of isolation function

The *Structures Monitoring* program implements the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," consistent with guidance of U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.160 (RG-1.160), "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and Nuclear Management and Resources Council 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

The *Structures Monitoring* program relies on periodic visual inspections to monitor and maintain the condition of structures and structural components. Inspections are conducted by qualified personnel at a frequency not to exceed five years. The interval between successive recurring inspections may be decreased based on conditions discovered in previous inspections. Evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to

such inaccessible areas. Inaccessible areas are assessed for aging and opportunistically inspected when made accessible by other plant activities.

For concrete and associated components, ACI-349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," and other applicable industry documents are used as guidance for the inspections, inspector qualifications, and evaluation of inspection results. The inspection program for structural steel is similar to the concrete program and is based on the guidance provided by the American Institute of Steel Construction (AISC) Specification for Structural Steel Buildings and Code of Standard Practice. For earthen structures, evaluation of inspection results is performed by a qualified civil/structural engineer.

Procedures include preventive actions to ensure structural bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325 and ASTM A490 bolts, preventive actions for storage, lubricant selection, and bolting and coating material selection are consistent with Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using High-Strength Bolts." Twist-off type ASTM F1852 and ASTM F2280 bolts are not specified or stocked for use.

In order to evaluate the potential of water to cause degradation of concrete, samples of groundwater are taken at intervals not to exceed five years. The water chemistry is evaluated, and should the results of water testing indicate potentially harmful levels of substances such as chlorides > 500 ppm, sulfates > 1,500 ppm, or a pH < 5.5, excavation and examination of buried concrete surfaces may be necessary. Groundwater monitoring has shown the groundwater to be non-aggressive. There have been no indications of concrete degradation due to aggressive groundwater anywhere in the plant.

For surfaces provided with protective coatings, observation of the condition of the coating is an effective method for identifying the absence of degradation of the underlying material. Therefore, coatings on structures within the scope of the *Structures Monitoring* program are inspected only as an indication of the condition of the underlying material.

Plant-specific OE has identified loss of material due to pitting or crevice corrosion or cracking of stainless steel piping components exposed to air or condensation in an underground environment. There has been no documented loss of material due to pitting or crevice corrosion or cracking of stainless steel or aluminum structural components within the scope of the Structures Monitoring Program. The potential for loss of material or cracking of stainless steel and aluminum structural components exposed to air or condensation environments will be managed by the Structures Monitoring program.

Aluminum and stainless steel structural components such as louvers, cable trays, conduits, and structural supports will be monitored for loss of material and cracking due to SCC that could lead to the reduction or loss of their intended function.

Carbon fiber reinforced polymer (CFRP) wrap of the concrete poles for the reserve station service transformer (RSST) tube bus will be monitored for hardening or loss of strength, loss of material, cracking or blistering that could lead to the reduction or loss of intended function.

Concrete inspection results will be evaluated to identify changes that could be indicative of Alkali-Silica Reaction (ASR) development. If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program (B2.1.30), the *Structures Monitoring* program (B2.1.34), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35).

Structural sealants, seismic gap joint filler, vibration isolation elements, and other elastomeric materials will be monitored for cracking, loss of material, and hardening. These elastomeric elements are acceptable if the observed loss of material, cracking, and hardening will not result in a loss of intended function.

Visual inspection of elastomeric elements will be supplemented by tactile inspection to detect hardening if the intended function is suspect.

The Spent Fuel Pool level is monitored by a level switch that will actuate if the water level decreases to six inches below normal water level. Instrumentation provided gives local indication in the Fuel Building and the Auxiliary Building and remote indications and alarms in the main control room (UFSAR, Section 9.1.3.5). Leakage from the Spent Fuel Pool telltale drains is evaluated by a separate plant procedure. A review of recent telltale drain monitoring reports by the Responsible Engineer shows acceptable leakage rates. However, leakage from three of the telltale drains have shown a decreasing trend that could potentially indicate blockages in the drains. Performance of a borescope inspection on the Spent Fuel Pool telltale drains has been initiated.

The *Masonry Walls* program (B2.1.33) and the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35) are implemented as part of this program.

NUREG-2191 Consistency

The *Structures Monitoring* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.S6, Structures Monitoring.

Exception Summary

None

Enhancements

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)

1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: Administration Building (aka Office Building), Decontamination Building, Domestic Water Treatment Building, Heater Boiler Room, Maintenance Building, New Fuel Receiving Building, Waste Disposal (Clarifier) Building, Waste Solids Building, 17-ton Carbon Dioxide tank foundation, and Backup 34.5 kV Circuit Power Poles (Switchyard to the Reserve Station Service Transformers). Baseline inspections for the added structures will be performed under the enhanced program in order to establish quantitative inspection data prior to conduct of periodic inspections in the subsequent period of extended operation. The baseline inspections will include baseline inspections of the masonry walls in the Administration Building, Decontamination Building, Domestic Water Treatment Building, and the Maintenance Building.

Scope of Program (Element 1) and Parameters Monitored/Inspected (Element 3)

2. Procedures will be revised to specify that structural components inspected include structural bolting, anchor bolts and embedments, component support members, pipe whip restraints and jet impingement shields, transmission towers, panels and other enclosures, racks, sliding surfaces, sump and pool liners, electrical cable trays and conduits, tube tracks, trash racks associated with water-control structures, electrical duct banks, manholes, doors, penetration seals, seismic joint filler and other elastomeric materials.

Parameters Monitored/Inspected (Element 3); Detection of Aging Effects (Element 4); and Acceptance Criteria (Element 6)

3. Procedures will be revised to specify that aluminum and stainless steel structural components such as louvers, cable trays, conduits, and structural supports will be monitored for loss of material and cracking due to SCC that could lead to the reduction or loss of their intended function. (Revised - RAI Set 1)

4. Procedures will be revised to specify that elastomeric vibration isolators, structural sealants, and seismic joint fillers will be monitored for cracking, loss of material, and hardening that could lead to the reduction or loss of their intended function. Visual inspection of elastomeric elements is supplemented by tactile inspection to detect hardening if the intended function is suspect.

5. Procedures will be revised to specify that the carbon fiber reinforced polymer (CFRP) wrap of the concrete poles for the reserve station service transformer (RSST) tube bus will be

monitored for hardening or loss of strength, loss of material, cracking or blistering that could lead to the reduction or loss of intended function. (Added - RAI Set 1)

Parameters Monitored/Inspected (Element 3) and Acceptance Criteria (Element 6)

6. Procedures will be revised to specify that accessible sliding surfaces will be monitored for indications of excessive loss of material due to corrosion or wear and debris or dirt that could restrict or prevent sliding of the surfaces. (Renumbered - RAI Set 1)

Corrective Actions (Element 7)

7. Procedures will be enhanced to specify that evaluations of neutron shield tank findings consider its structural support function for the reactor pressure vessel. (Renumbered - RAI Set 1)

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Structures Monitoring* 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 July 2009, a broken pipe support U-bolt was discovered on the emergency diesel generator lube oil pump discharge line. A design change was installed to modify the piping and support configuration to isolate the emergency diesel generator lube oil piping and its supports from the radiator enclosure structure, which subjects the piping and supports to high cyclical loads.
2. In December 2010, during the inspection of the Safeguards Valve Pit Valves, active groundwater leakage was observed in the Safeguards Valve Pits for both units. Groundwater had accumulated on the floor of the valve pit with calcium buildup occurring under the pipe.

   A 2006 Engineering evaluation indicated the preferred corrective action to eliminate the leakage was grout injection. The grout injections did not prevent groundwater leakage from reoccurring. Some leakage, calcium buildup, residue, and discoloration were identified on various piping, but an Engineering evaluation did not note any concerns with the pipe welds following the grout injections. The conditions noted on the pipes and the calcium deposits were determined to be a housekeeping issue. New groundwater diversion devices (drip trays) and temporary catch containers were installed to collect groundwater in-leakage.
3. In December 2015, a design change was approved to address degradation of the precast concrete poles supporting the 3-phase buses that run overhead from the Turbine Building to the Reserve Service Station Transformers. This degradation included large open cracks and evidence of alkali-silica reaction (ASR). The design change is replacing 14 of the 17 concrete poles with new steel poles and installing a carbon fiber reinforced polymer wrap for the full length of the remaining three poles. These poles were manufactured off-site utilizing materials

and mix designs that are different from other concrete structures. The existence of ASR in these components is not indicative of this aging mechanism occurring in any other structure.

4. 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 Infrequently Accessed Area Inspection Activities AMA (UFSAR Section 18.1.2). Three areas listed in the Infrequently Accessed Area Inspection AMA were not listed as Infrequently Accessed Areas in UFSAR Section 18.1.2. The areas consisted of the following:

   - Manholes containing equipment or power and control cables for safety-related components and components associated with the five regulated events
   - Service Water Pump House Underwater skirt
   - Tunnel/passageway between Auxiliary Building and Decontamination Building

   It was determined that these areas are being inspected, and no changes to UFSAR Section 18.1.2 were recommended.

   Also in the May 2016 assessment, the conclusion was reached that performance deficiencies or learning opportunities were identified for the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6). Plant procedures did not include dewatering and installation of shielding as activities to consider that could potentially result in a normally inaccessible structural component becoming accessible for inspection. Plant procedures were revised to include dewatering and installation of shielding as activities to consider that could potentially result in a normally inaccessible structural component becoming accessible for inspection.

   Also in the May 2016 assessment, the conclusion was reached that performance deficiencies or learning opportunities were identified for the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9). The General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) did not consider or include missile doors and Containment pressure relief doors. Plant procedures were revised to include inspection of the doors, and the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) was revised to enhance the discussion of door inspections.

5. 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.

6. 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 Infrequently Accessed Area Inspection Activities AMA (UFSAR Section 18.1.2). The evaluation to close the commitment for infrequently accessed areas did not provide details of inspector qualifications. In addition, there appeared to be a conflict between two license renewal commitments in UFSAR Table 18-1 (Commitments 9 and 17) concerning the inspection scope (use of representative samples). The license renewal commitments have been revised to discuss inspector qualifications and clarify the use of representative samples.

   Also in the May 2017 assessment, the conclusion was reached that no areas for improvement or enhancements were identified for the Battery Rack Inspections AMA (UFSAR Section 18.2.2), the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6), and the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) related to the *Structures Monitoring* program.

7. In April 2019, an effectiveness review was performed on the Infrequently Accessed Area Inspection Activities AMA (UFSAR Section 18.1.2), the Battery Rack Inspections AMA (UFSAR Section 18.2.2), the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6), and the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) that include periodic inspections for aging management to ensure the continuing capability of civil engineering structures to meet their intended functions consistent with the current licensing basis. The AMAs were evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." No gaps were identified by the effectiveness review related to the *Structures Monitoring* program.

8. From December 2006 to May 2019, samples of groundwater were analyzed quarterly. This monitoring showed the site groundwater to be non-aggressive (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm).

9. From February 2010 to June 2019, leakage from the Spent Fuel Pool telltale drains was evaluated every six months. A review of telltale drain monitoring reports shows acceptable leakage rates. Leakage from three of the telltale drains have shown a decreasing trend that could potentially indicate blockages in the drains. Performance of a borescope inspection of the Spent Fuel Pool telltale drains has been initiated. The Spent Fuel Pool level is monitored by a level switch that will actuate if the water level decreases to six inches below normal water

level. Instrumentation gives local indication in the Fuel Building and the Auxiliary Building and remote indications and alarms in the main control room.

10. From April 2001 to September 2019, settlement of structures has been monitored every 184 days, as specified in the Technical Requirements Manual (TRM), Section 3.7.7. UFSAR Section 3.8.4.5.3 describes the Settlement Monitoring Program. The elevations of points located on structures and components at the Service Water Reservoir and at the main plant were monitored for settlement, beginning in 1975. Structures with minimal movement are no longer monitored. The structures and components that are currently being monitored are the Service Water Reservoir, Service Water Pump House, service water lines, Service Water Valve House, Service Water Tie-in Vault, Service Building, and Main Steam Valve House. The initial baseline elevations for these structures and components are listed in UFSAR Table 3.8-15. If differences between observed values and baseline elevations exceed prescribed limits given in TRM Section B 3.7.7, appropriate action is taken in accordance with the Corrective Action Program. No settlements have been found to exceed the TRM limits.

The above examples of operating experience provide objective evidence that the *Structures Monitoring* program includes activities to perform visual inspections to identify aging effects for structures, structural supports, and structural commodities within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Structures Monitoring* 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 *Structures Monitoring* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Structures Monitoring* 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.