CONFIDENTIAL INFORMATION – WITHHOLD UNDER 10 CFR 2.390

VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

September 3, 2019

10 CFR 50
10 CFR 51
10 CFR 54

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

Serial Nos.: 19-344
19-344A
19-344B
NRA/DEA: R2
Docket Nos.: 50-280/281
License Nos.: DPR-32/37

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION (SPS) UNITS 1 AND 2
SUBSEQUENT LICENSE RENEWAL APPLICATION
RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION – SETS 3 AND 4

By letter dated October 15, 2018 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML18291A842), Virginia Electric and Power Company (Dominion Energy Virginia or Dominion) submitted an application for the subsequent license renewal of Renewed Facility Operating License Nos. DPR-32 and DPR-37 for Surry Power Station (SPS) Units 1 and 2, respectively.

In an August 2, 2019 email from Emmanuel Sayoc (NRC) to Daniel Stoddard (Dominion) (Serial No. 19-344), "Final Requests for Additional Information for the Safety Review of the Surry Power Station, Units 1 and 2 Subsequent License Renewal Application – Set 3," the NRC staff provided specific requests for additional information (RAIs), to support their review of the SLRA.

In a subsequent email from Emmanuel Sayoc (NRC) to Daniel Stoddard (Dominion) dated August 5, 2019 (Serial No. 19-344A), "Revised Requests for Additional Information B3.2-1-a for Safety Review of the Surry Power Station, Units 1 and 2 Subsequent License Renewal Application – Set 3," the NRC staff modified one of the RAI (B3.2-1-a) to more clearly document the staff's request. All other RAIs remained as originally transmitted. Additionally, the August 5, 2019 email reset the response due date for RAI Set 3 to within 30 days from the date of the email.

On August 14, 2019, in an email from Emmanuel Sayoc (NRC) to Daniel Stoddard (Dominion) (Serial No. 19-344B), "Final Requests for Additional Information for the Safety Review of the Surry Power Station, Units 1 and 2 Subsequent License Renewal

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NRR

Enclosure 4 contains information that is being withheld from public disclosure under 10 CFR 2.390.
Upon separation from Enclosure 4, this letter is decontrolled.

Application – Set 4," the NRC staff provided further requests for additional information, to assist with completion of their review of the SLRA.

Dominion's response to the NRC RAIs is provided in the following Enclosures:

Enclosure 1:	Response to Requests for Additional Information - Set 3 - Regarding SPS SLRA
Enclosure 2:	Response to Requests for Additional Information - Set 4 - Regarding SPS SLRA
Enclosure 3:	SLRA Mark-ups – Set 3 and Set 4 RAIs
Enclosure 4:	WCAP-18205-NP, Revision. 0, December 2016, "Reactor Internals Fluence Evaluation for a Westinghouse 3-Loop Plant with Twin Units – Subsequent License Renewal," Non-proprietary
Enclosure 5:	Dominion Affidavit for Withholding Confidential Information, dated September 4, 2019

Enclosures 1 and 2 contain the response to the RAIs and Enclosure 3 provides associated SLRA mark-ups. Additionally, the last five pages of Enclosure 3 contain SLRA mark-ups that are a result of administrative corrections.

Since Enclosure 4 contains information confidential to Dominion, it is supported by an Affidavit signed by Dominion, the owner of the information, in Enclosure 5. 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 confidential to Dominion 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 confidential aspects of the items listed above or the supporting Dominion Affidavit should be addressed to Craig D. Sly, Manager, Nuclear Regulatory Affairs, Dominion Energy, 5000 Dominion Blvd., Glen Allen, Virginia 23060.

If you have any questions or require additional information regarding this submittal, please contact Mr. Paul Aitken at (804) 273-2818.

Sincerely,

Mark D. Sartain
Vice President – Nuclear Engineering & 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 & 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 3rd day of September, 2019.

My Commission Expires: 12/31/20

CRAIG D SLY
Notary Public
Commonwealth of Virginia
Reg. # 7518653
My Commission Expires December 31, 2020

Notary Public

Commitments made in this letter: None

Enclosures:

1. Response to Requests for Additional Information - Set 3 - Regarding SPS SLRA
2. Response to Requests for Additional Information - Set 4 - Regarding SPS SLRA
3. SLRA Mark-ups – Set 3 and Set 4 RAIs
4. WCAP-18205-NP, Revision. 0, December 2016, "Reactor Internals Fluence Evaluation for a Westinghouse 3-Loop Plant with Twin Units – Subsequent License Renewal," Non-proprietary
5. Dominion Affidavit for Withholding Confidential Information, dated September 4, 2019

cc: (w/o Enclosures except *)

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Enclosure 1

RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION
SET 3
REGARDING SPS SLRA

Virginia Electric and Power Company
(Dominion Energy Virginia or Dominion)
Surry Power Station Units 1 and 2

RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION SET 3 - REGARDING SPS SLRA

By letter dated October 15, 2018 (Agencywide Documents Access and Management System (ADAMS Accession No. ML18291A842), as supplemented by letters dated January 29, 2019 (ADAMS) Accession No. ML19042A137), and April 2, 2019 (ADAMS Accession No. ML19095A666), Virginia Electric and Power Company (Dominion Energy Virginia or Dominion) submitted to the U.S. Nuclear Regulatory Commission (NRC or staff) an application to renew the Renewed Facility Operating License Nos. DPR-32 and DPR-37 for the Surry Power Station, Unit Nos. 1 and 2. Dominion submitted the application pursuant to Title 10 of the *Code of Federal Regulations* Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," for subsequent license renewal.

From July 15, 2019 through July 30, 2019, the U.S Nuclear Regulatory Commission (NRC) staff sent Dominion draft Requests for Additional Information (RAIs) for various technical review packages (TRP). Dominion subsequently informed the NRC staff that clarification calls were needed to discuss the information requested. Between July 15, 2019 through August 1, 2019, clarification calls were completed for the draft RAIs unless Dominion declined having a call. Final RAIs (Set 3) resulting from these calls were received in an email from the NRC to Dominion dated August 2, 2019. Subsequently, the NRC staff made some modifications to one of the RAIs to more clearly document the staff's request. The revised RAI was sent to Dominion, superseding the previous RAI. The other RAIs remained unchanged; however, the response due date for all the RAIs was reset to September 9, 2019.

The response to the Set 3 RAIs are provided in this Enclosure.

RAI B2.1.21-1

Background:

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

- *The Selective Leaching program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.M33, Selective Leaching.*
- *External surfaces of buried components that are coated consistent with the Buried and Underground Piping and Tanks program (B2.1.27) are excluded from the sample population.*

GALL-SLR Report AMP XI.M33, "Selective Leaching," states the external surfaces of buried components may be excluded for the scope of the program if they are externally-coated in accordance with Table XI.M41-1, "Preventive Actions for Buried and Underground Piping and Tanks," of GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," and where direct visual examinations of buried piping in the scope of license renewal have not revealed any coating damage.

The response to RAI B2.1.27-1 dated June 27, 2019 (ADAMS Accession No. ML19183A440), states "[i]n 2004, a two-inch auxiliary feedwater (AFW) line piping leak was identified due to poorly installed coating."

SLRA Section B2.1.27 documents that in May 2017, during the as-found coating inspection on Unit 2 buried carbon steel condensate makeup piping, coating was missing on approximately 270 degrees of the pipe circumference from the center of the excavated area into the soil on the east side.

Issue:

An adequate basis was not provided for why the external surfaces of buried components are excluded from the Selective Leaching program. Plant-specific operating experience (OE) has identified instances of failed or missing coatings of buried components.

Request:

State the basis for why the external surfaces of buried components susceptible to selective leaching are excluded from the scope of the Selective Leaching program.

Dominion Response:

There are no copper alloy >15% zinc, copper alloy >8% aluminum, or ductile iron buried components within the scope of license renewal that are susceptible to selective leaching. The gray cast iron fire main piping and valves are the only buried components that are within the scope of license renewal that are susceptible to selective leaching. The fire main piping is internally lined with a cementitious mortar and externally coated with a bituminous coating. The external surface coating is consistent with NUREG-2191 Table XI.M41-1, "Preventive Actions for Buried and Underground Piping and Tanks." During initial construction of SPS, yard water and fire protection systems were some of the first systems installed. Design, procurement and installation of the yard water and fire protection systems were performed consistent with a 1968 specification that was distinct and separate from a later specification that procured and installed auxiliary feedwater system buried piping. Subtle differences for coatings and backfill requirements exist between the yard water and fire protection systems specification and the other system specifications for buried components.

Direct visual examinations of buried fire water system piping within the scope of subsequent license renewal and fire water system components not within the scope of subsequent license renewal have resulted in no documented cases of coating damage that caused significant external surface degradation or a loss of intended function.

- July 2003 - Leakage occurred at a 6-inch tee of fire protection piping adjacent to the administration building. A hair-line crack was identified as the cause of the leakage. An engineering evaluation of the external piping coating condition stated that the coating was intact and tightly, adhered, with no indications of holidays (discontinuities).

- October 2008 – Approximately six feet of ten inch fire protection piping was excavated as part of the Unit 1 Flow Assisted Corrosion excavation. The entire length of the piping was completely encased in a hardened crust of course sand and small rocks, which was tightly adhered to the pipe surface. A 27 inch length of the piping was cleaned using hand tools and found to be in satisfactory condition with no evidence of significant corrosion. A significant amount of the coating appeared to come off with the removal of the crusted sand and rock leaving the surface speckled with bare area, some of which displayed light surface corrosion indicating that moisture had penetrated to the pipe surface. The cleaned area had indications of shallow pitting consistent with cast iron piping. The coating that remained on the pipe was tightly adhered.

- August 2013 – The fire protection suction line and associated coating to fire protection/domestic water storage tank 1B was visually inspected and found to be in good condition. The inspection was performed where the piping enters the soil to address industry experience indicating the potential for corrosion at this location.

- September 2014 – An inspection of the eight inch fire protection supply piping to the Surry Radwaste Facility was performed as a follow-up to a leak that was identified and repaired in 2011. The apparent cause of the 2011 leak was general corrosion and pitting resulting from a through-wall crack in the pipe wall. The material evaluation indicated the pipe crack was a casting defect, such as a shrinkage crack, that was present in the pipe since fabrication. The leakage saturated the surrounding natural earth backfill causing a more active pitting/corrosion along the lower exterior of the pipe, which resulted in the three through-wall leaks identified during the excavation. As a follow-up to the 2011 inspection, the pipe surfaces were visually inspected in 2014 and found to be in satisfactory condition with no significant corrosion/pitting observed. Minor deterioration of the original shop coating was observed in some areas. No coating repair was performed.

- July 2019 – A buried Fire Protection piping failure occurred to the west of the Old Administration Building. Investigation of the failure is ongoing and will be discussed in the SLR Annual Update letter.

Review of operating experience associated with fire water system surface water leakage documented in NRC Request for Confirmation of Information (RCI) #13 also did not identify any examples of coating system damage on gray iron fire water system components. The NRC RCI #13 review of the *Buried and Underground Piping and Tanks* program operating experience included the buried fire water system supply loops that encircle each Unit <u>and</u> fire water system components not within the scope of license renewal.

The external surfaces of buried gray iron fire water system components may be excluded from the scope of the program because they are externally-coated consistent with NUREG-2191, Table XI.M41-1, "Preventive Actions for Buried and Underground Piping and Tanks," and direct visual examinations of the buried gray iron fire water system components (within the scope of subsequent license renewal <u>and</u> fire water system components not within the scope of subsequent license renewal) have not revealed any coating damage that resulted in significant external surface degradation or detected a loss of intended function.

<u>RAI B2.1.27-1a</u>

<u>*Background:*</u>

1. *SLRA Section B2.1.27, "Buried and Underground Piping and Tanks," states that 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."*

The responses to RAIs B2.1.27-1 and B2.1.27-2 dated June 27, 2019 (ADAMS Package Accession No. ML19183A440), state the following:

- *Buried cementitious piping within the scope of subsequent license renewal (SLR) is precast reinforced concrete pipe installed with specifications that* *are consistent with American Water Works Association (AWWA) C302, "Reinforced Concrete Pressure Pipe, Noncylinder Type."*

- *Buried cementitious piping does not have an external coating and will not be cathodically protected.*

GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," recommends external coatings and cathodic protection for buried cementitious piping.

During its review of Concrete Pressure Pipe - Manual of Water Supply Practices, the staff noted that external corrosion protection is recommended for buried reinforced concrete piping when the following conditions are present.

- *Where pipe is to be buried in soils with resistivity readings below 1,500 ohm-cm and the water soluble chloride contents exceeds 400 ppm at those same locations, one of the following protective measures should be used: (a) moisture barrier should be used to protect the exterior surfaces; (b) silica fume in an amount equal to 8 to 10 percent of the cement weight or a corrosion inhibitor should be included in the exterior mortar or concrete; or (c) cathodic protection should be installed if monitoring of the pipeline detects the onset of corrosion.*
- *For installations of mortar-coated pipe in soils with more than 5,000 ppm water-soluble sulfates, a barrier material should be considered.*
- *In clay soils, supplemental precautions against acid attack generally are not needed.*
- *In granular soils, when the soil pH immediately after sample excavation is greater than 5, supplemental precautions against acid attack of the mortar coating generally are not needed.*

SLRA Section B2.1.34, "Structures Monitoring," states that groundwater samples are obtained at intervals not to exceed 5 years. The water chemistry is evaluated and limits are established for chlorides, sulfates, and pH.

2. *The response to RAI B2.1.27-1 dated June 27, 2019 (ADAMS Package Accession No. ML19183A440), states the following:*
    - *Forty-four of 48 soil samples tested in 2012 were found to be mildly corrosive or noncorrosive (the corrosive samples were not applicable to buried components within the scope of license renewal).*

- *The soil type and soil conditions from the analyzed soil samples at Surry in 2018 are mildly corrosive (lowest corrosive ranking) using the Electric Power Research Institute (EPRI) index and non-corrosive using the AWWA index.*
- *In 2004, a two-inch auxiliary feedwater (AFW) line piping leak was identified due to poorly installed coating. As a corrective action, the Unit 1 and Unit 2 AFW recirculation system piping is no longer buried and was rerouted through the safeguards building basement.*
- *Pipe-to-soil potential measurements were not addressed during the 2018 soil survey.*

SLRA Section B2.1.27 states the following:

> *Soil sampling and testing is performed during each excavation and a station-wide soil survey is also performed once in each 10-year period to confirm that the soil environment of components within the scope of license renewal is not corrosive 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."*

SLRA Section B2.1.27 documents that in May 2017, during the as-found coating inspection on Unit 2 buried carbon steel condensate makeup piping, coating was missing on approximately 270 degrees of the pipe circumference from the center of the excavated area into the soil on the east side.

GALL-SLR Report AMP XI.M41 recommends cathodic protection for buried steel piping. 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.*

During the audit, the staff noted plant-specific OE indicating instances of leaks, coating degradation, and minor external degradation of buried steel piping.

Licensee Event Report (LER) 281-2004-01, "Surry Power Station Regarding Switchyard Device Failure Results in a Reactor Trip," (ADAMS Accession No. ML043280416) states the following:

> *On May 22, 2004, following refill of the Emergency Condensate Storage Tank, an unisolable leak in a buried Unit 2 AFW recirculation line was discovered. The AFW system was declared inoperable. Further evaluations determined that the AFW system was capable of performing its intended function. The cause of the AFW piping leak was external galvanic corrosion of the buried carbon steel piping due to the failed corrosion protection.*

Issue:

1. *An adequate basis was not provided for why external corrosion protection (i.e., cathodic protection or external coatings) are not necessary for buried cementitious piping. Based on its review of Concrete Pressure Pipe - Manual of Water Supply Practices, the staff noted that various soil parameters determine if external corrosion protection is recommended for buried cementitious piping (i.e., soil resistivity, pH, chlorides, and sulfates).*

   Although samples of groundwater are obtained for the Structures Monitoring program: (a) they are not necessarily obtained in the vicinity of the in-scope buried cementitious piping; (b) groundwater samples might not be representative of soil parameters in close proximity to the in-scope buried cementitious piping; (c) groundwater parameter acceptance criteria is different than that recommended in the Concrete Pressure Pipe - Manual of Water Supply Practices; and (d) soil resistivity readings are not obtained.

   Absent a technical justification for why external corrosion protection is not necessary, the staff seeks clarification for why additional inspections, beyond those recommended in GALL-SLR Report Table XI.M41-2, "Inspection of Buried and Underground Piping and Tanks," are not appropriate if exceptions are taken to the "preventive actions" program element of GALL-SLR Report AMP XI.M41.

2. *An adequate basis was not provided for why cathodic protection is not necessary for the balance of buried steel piping. Specifically, the staff notes the following:*

   - *The staff seeks clarification for why the four corrosive samples tested in 2012 are not applicable to buried components within the scope of SLR. For example, are local conditions at the sample point unique enough that they* *would never be representative of conditions in the vicinity of in-scope buried piping?*

- *The staff notes the following regarding the use of EPRI Report 3002005294 in each 10-year period to confirm that the soil environment of components within the scope of license renewal is not corrosive for the installed material types.*

  i. *EPRI Report 3002005294 provides two tables that provide guidance related to determining soil corrosivity. The response to RAI B2.1.27-4 did not state which one of these tables is used to determine soil corrosivity. If EPRI Report 3002005294, Table 9-4 will be utilized (i.e., using column three for gray cast iron, column four for steel, and column seven for stainless steel), the SLRA did not state how "non-corrosive soil" determination was concluded because based on EPRI Report 3002005294, soil can only be classified as mildly corrosive, moderately corrosive, appreciably corrosive, or severely corrosive (i.e., there is no classification designated as "non-corrosive").*

  ii. *Neither SLRA Section B2.1.27 nor the RAI responses state the number of soil corrosivity samples, location of samples, and timing of samples (e.g., during maximum rainfall periods) in each 10-year period to confirm that the soil environment of components within the scope of license renewal is not corrosive for the installed material types.*

  iii. *There are no corrective actions for adverse soil sampling results. Soil being classified as corrosive vs. non-corrosive (if using AWWA C105, "Polyethylene Encasement for Ductile-Iron Pipe Systems," Table A.1, "Soil-Test Evaluation," as recommended in GALL-SLR Report AMP XI.M41); or mildly corrosive, moderately corrosive, appreciably corrosive, or severely corrosive (if using EPRI Report 3002005294) does not appear to impact the Buried and Underground Piping and Tanks program (e.g., increased inspections, installation of cathodic protection).*

  The staff has concluded that even mildly corrosive soil could result in a loss of pressure boundary function in the absence of cathodic protection if there are localized areas where coatings were not installed properly or were missing.

- *The technical basis for not providing cathodic protection does not address pipe-to-soil potential measurements and other relevant parameters (e.g., external corrosion rate measurements). The response to RAI B2.1.27-1 only addresses soil corrosivity testing, which provides a general classification of corrosion susceptibility but cannot be used to accurately predict corrosion rates. GALL-SLR Report AMP XI.M41 recommends that soil corrosivity testing can be used to guide inspection quantities (i.e., moving between Preventive Action Categories E to F), but not as a sole technical basis for why cathodic protection is not necessary. Although a new enhancement has been added to the program to measure pipe-to-soil potentials prior to the subsequent period of extended operation there are no proposed: (a) acceptance criteria for the testing, and (b) no proposed actions (e.g., increased inspections, installation of cathodic protection) if the results are not acceptable.*

- *Based on its review of plant-specific OE, including the buried steel piping leak associated with LER 281-2004-01, the staff seeks clarification regarding how the intended function(s) of buried steel piping will be maintained through 80 years of operation without cathodic protection.*

    i. *The staff notes that the corrective action to address LER 281-2004-01 does not address all buried steel piping within the scope of SLR.*

    ii. *The staff notes that an explanation was not provided regarding why failed or missing coatings would also not be occurring in other locations that have not yet been self-revealing.*

    iii. *The staff notes that the design life of typical buried piping coatings is less than 80 years. An explanation was not provided regarding why coatings can be relied upon through 80 years of operation without cathodic protection.*

<u>*Request:*</u>

1. *State the basis for why buried cementitious piping within the scope of SLR is not provided with external coatings or cathodic protection.*

2. *State the basis for why the balance of buried steel piping and tanks within the scope of SLR are not provided with cathodic protection, including at a minimum the basis of: (a) acceptance criteria for subsequent soil testing; and (b) corrective actions including increased excavated buried pipe inspections as a result of not installing cathodic protection in light of plant-specific operating experience associated with coatings.*

Dominion Response:

Response to RAI B2.1.27-1a, Request 1

See the response to RAI B2.1.27-2a. Request 2 below. As noted in Table 3.3.2-5 provided in the response to the SLRA Set 1 RAIs, dated June 27, 2019 (ADAMS Package Accession No. ML19183A440), aging of the 96-inch circulating water system buried water piping is managed with the *Open-Cycle Cooling Water* program (B2.1.11) instead of the *Buried and Underground Piping and Tanks* program (B2.1.27).

Response to RAI B2.1.27-1a, Request 2

As indicated in EPRI Report 3002005294, soil properties, in relation to coatings and corrosion, can determine whether a cathodic protection and coating system is required on buried components. Coatings are the first line of defense in separating the metal surface from the environment. Cathodic protection provides a second line of defense in instances where there is damage to the coating and the metal surface becomes exposed to the environment. The soil properties affect the performance of coating systems in a given environment.

The emergency diesel generator (EDG) fuel oil system is the only buried carbon steel piping that is cathodically protected. Other buried carbon steel components do not include cathodic protection as part of the system design. With exception of buried fire protection system piping, 24-inch service water piping at the Low Level Intake Structure, and EDG fuel oil piping, the remaining buried carbon steel piping within the scope of subsequent license renewal is concentrated in a small area next to each unit's Containment and north of the Service Building in the vicinity of the refueling water storage tank, the emergency condensate storage tank, and the emergency condensate makeup tank. Installation of a cathodic protection system has been determined to not be justified based on the following considerations:

1. Buried Fire Protection System Piping Does Not Require Cathodic Protection
   As noted in the response to RAI B2.1.27-3, Request 2, dated June 27, 2019, buried carbon steel fire protection mains are installed consistent with the additional preventative measures identified in NFPA 24, Section 10.9. In addition, the activity of the jockey pump will be monitored consistent with the "detection of aging effects" program element of NUREG-2191, Section XI.M41. Buried fire protection piping meeting the intent of NFPA 24, Section 10.9 and monitoring the activity of the fire protection jockey pump, will be acceptable alternatives to the preventive actions in NUREG-2191, Table XI.M41-1 (i.e. installation of cathodic protection).

2. Aging Management of 24-Inch Service Water piping at the Low Level Intake Structure

   A cathodic protection system will be installed for protection of the 24-inch service water piping at the Low Level Intake Structure five years before entering the subsequent period of operation.

3. Soil Surveys Used to Identify Aggressive (Corrosive) Environments

   Soils at the site are not extremely conducive to pipe corrosion, as evidenced by direct inspection results of piping to date and 2012 and 2018 soil analysis results which indicate soil in the vicinity of buried components within the scope of subsequent license renewal to not be aggressive corrosive environments (i.e., not appreciably or severely corrosive).

   2012 Soil Survey Results

   Forty-four of the forty-eight soil samples tested in 2012 were found to be mildly corrosive or noncorrosive. The following four samples were determined to be corrosive or severely corrosive,

   a) The sample from Hole 2 (corrosive) is not applicable because concrete missile shielding exists between the elevation of the samples and the piping, making the backfill near the pipe inaccessible.
   b) The sample from Hole 5-B1 (corrosive) was taken from the bottom of an open trench just below the lowest pipelines in the trench. Other samples taken from the trench walls at slightly higher elevations were found to be non-corrosive. The trench was exposed for several days after significant rainstorms kept the bottom of the trench filled with groundwater. The sample was used conservatively for program purposes, but the data is considered to be inaccurate.
   c) The samples from Holes 7-1 and 7-2 (severely corrosive) resulted from a high indication of sulfides and a lower redox potential. The locations contain the fuel oil fill line for the site EDG fuel oil storage tank. Since these locations are near the used oil storage and handling area, the high sulfides were attributed to historical spillage/leakage at this area. This area was re-sampled in 2018 and determined to be mildly corrosive due to 6.1% moisture, 7.36 pH, and positive soil consortia.

   2018 Soil Survey Results

   The 2018 soil survey indicated the soil samples were mildly corrosive using the EPRI index and noncorrosive using the AWWA index. A comparison of the soil testing acceptance criteria for the EPRI Index and the AWWA Index is discussed below.

Comparison of EPRI and AWWA Soil Survey Indices

EPRI Report 3002005294, Table 9-3 provides the AWWA C105 cast iron soil corrosivity index for soil characteristics of: resistivity, pH, redox potential, sulfides, and moisture. Based on scoring of samples results, the following table provides the corrosivity index based upon AWWA C105.

AWWA Corrosivity Index	Corrosivity
0-9	Non-Corrosive
Greater than or equal to 10	Corrosive to ductile iron

EPRI Report 3002005294, Table 9-4 provides the grey cast iron, steel and stainless steel corrosivity index values for soil characteristics of: resistivity, pH, redox potential, sulfides, chlorides, and soil consortia (bacteria). Based on scoring of samples results, the following table provides the corrosivity index based upon EPRI Report 3002005294.

EPRI Soil Corrosivity Index	Corrosivity
0-5	Mildly Corrosive
5-10	Moderately Corrosive
10-15	Appreciably Corrosive
15+	Severely Corrosive

In general, the indices provide equivalent results. The EPRI soil corrosivity includes the AWWA soil characteristics plus considerations for chlorides and soil consortia. Both indices rank values above 10 to be corrosive (AWWA) or appreciably/severely corrosive (EPRI) and would be subject to evaluation and corrective actions. Both indices rank values below 10 to be non-corrosive (AWWA) or mildly/moderately corrosive (EPRI). Using the four levels of the EPRI soil corrosivity index allows a graded approach to subsequent evaluations and corrective actions.

Future Soil Surveys
Program procedures for soil surveys are consistent with NUREG-2191 and require soil testing every 10 years. Data collected at each location includes: soil resistivity, soil consortia (bacteria), pH, moisture, chlorides, sulfates, and redox potential. In addition to evaluating each individual parameter, overall soil corrosivity is determined consistent with EPRI Report 3002005294 indices.

Eleven sample locations, of which a minimum of nine are in the vicinity of components within the scope of subsequent license renewal, are proposed to confirm that the soil environment is not corrosive for installed material types. The eleven sample locations would be consistent with the 2018 sample locations unless aggressive soil environments that require monitoring are discovered during future excavations. The sampling program currently requires additional soil samples be taken during each program inspection excavation. Each ten-year period soil sample would be performed within two years of entering the ten-year inspection period for the underground piping to allow for excavation and outage planning. Samples would be obtained during maximum rainfall periods. Prior sample locations will be evaluated by engineering and updated as necessary to include locations where external corrosion had previously been observed along with other considerations that are noted in chapter 6.1 of EPRI Report 3002005294.

4. Buried Pipe Exterior Surfaces are Coated and Wrapped
Buried piping exterior surfaces are coated and wrapped, as noted, and surrounded with engineered fill to protect the piping from various forms of environmental attack. Coatings are consistent with NUREG-2191, Table XI.M42-1, Preventive Actions for Buried and Underground Piping and Tanks. The results of completed inspections indicate that coating systems for buried piping were in generally good condition. However, some coating anomalies have been identified in plant operating experience. These anomalies include cases of poor or failed bonding of the coating system to carbon steel piping. In most of these cases, poor coating system application was apparent. However, the piping at these locations was determined to be in good to satisfactory condition.

Some surface corrosion/shallow pitting was found on certain carbon steel piping, which was examined using NDE to determine wall thickness and then evaluated for fitness-for-service (calculation of remaining life) in accordance with program procedures. To date, the program has required performance of fitness-for-service calculations on thirteen lines of which five lines were within the scope of license renewal. In each case the overall condition of carbon steel pipe surfaces was determined to be satisfactory.

5. Piping Failures Replaced, Rerouted (not buried) or Repaired
Of the buried piping within the scope of subsequent license renewal, only a few self-revealing issues have been discovered, including EDG fuel piping leaks in 1987 and 1994, a two-inch auxiliary feedwater piping leak in 2004, and a ten-inch condensate piping leak in 2011. These piping segments have been replaced, rerouted (not buried) or repaired. Since full implementation of NEI 09-14, no additional loss of intended function due to external degradation has been identified for buried piping within the scope of subsequent license renewal.

6. Challenges associated with Adding Cathodic Protection
With the exceptions of buried fire protection system piping, 24-inch service water piping at the Low Level Intake Structure, and EDG fuel oil piping, the remaining buried carbon steel piping within the scope of license renewal is concentrated in a small area next to each Unit's Containment and north of the Service Building in the vicinity of the refueling water storage tank, the emergency condensate storage tank, and the emergency condensate makeup tank. This area is highly congested with various buried stainless steel and carbon steel piping systems within the scope of subsequent license renewal and systems not within the scope of subsequent license renewal.

   Piping systems and tanks are connected to the plant grounding system and underground piping is laid out in various directions and depths throughout the plant (e.g., piping runs in various directions at various depths on top of each other and beside each other). There are also nearby buildings and structures that can affect stray current. The current density required to polarize a mixed metal system consisting of copper and iron to an adequate potential necessary to protect the ferrous portion of the system may be 10 to 20 times as high as that required to protect an isolated ferrous piping system. Models have shown that up to 99.2% of the current flowing from the cathodic protection system will flow into the copper grounding grid with the remaining 0.8% protecting the exposed surfaces of the buried piping. In order to protect various pipes, they would need to be isolated from the grounding grid or the entire underground pipe system would need to be energized. Isolating the pipe from the grounding grid would improve its corrosion resistance. Since there are different materials/alloys in the underground pipe systems, some pipes would corrode in preference to pipes of more noble materials/alloys. Locations where pipe enters or exits a structure affect cathodic protection since structures can disperse cathodic protection currents. As a result, installing a cathodic protection system in the small congested area between a variety of plant structures could result in unintended consequences, such as stray current corrosion and coating disbondment.

The six considerations presented above provide adequate technical justification for not installing cathodic protection on carbon steel components other that the existing cathodic protection system installed on the EDG fuel oil system piping and the cathodic protection system that will be installed on the 24-inch service water piping at the Low Level Intake Structure five years before entering the subsequent period of operation.

The existing program procedures require corrective actions for coatings, backfill, or degradation extrapolation that do not meet acceptance criteria. Required corrective actions are consistent with the following NUREG-2191, Section XI.M41, Element 7 guidance for corrective actions:

- Element 7a – coating damage caused by nonconforming backfill
- Element 7b – piping wall thickness degradation extrapolated to end of subsequent period of operation
- Element 7c – sample size increase and timing of inspections when acceptance criteria are not meet.

The existing procedures also require transitioning to a higher number of inspections than originally planned at the beginning of a 10-year interval when coating, backfill, or the condition of exposed piping does not meet acceptance criteria. Program transitioning requirements guidance is consistent with NUREG-2191, Section XI.M41, Element 4.a guidance.

<u>SLRA Changes</u>

SLRA Section B2.1.27 and Table A4.0-1, Item 27 are supplemented, as shown in Enclosure 3, to add an enhancement to install a cathodic protection system for protection of the 24-inch service water piping at the Low Level Intake Structure five years before entering the subsequent period of operation.

SLRA Section B2.1.16 and Table A4.0-1, Item 16 are supplemented, as shown in Enclosure 3, to add an enhancement to monitor the activity of the jockey pump consistent with the "detection of aging effects" program element of NUREG-2191, Section XI.M41.

Two editorial clarifications have also been made to SLRA Section B2.1.27 to indicate that Enhancement 3 applies to Element 2 and Enhancement 4 applies to Element 2 and Element 4, as shown in Enclosure 3.

<u>RAI B2.1.27-2a</u>

<u>Background:</u>

1. *The response to RAI B2.1.27-2 dated June 27, 2019 (ADAMS Package Accession No. ML19183A440), states that each uncoated stainless steel segment will be coated consistent with Table 1 of NACE SP0169-2007, "Standard Recommended Practice, Cathodic Protection of Prestressed Concrete Cylinder Pipelines." GALL-SLR Report AMP XI.M41 recommends that buried stainless steel piping is coated in accordance with Table 1 of NACE SP0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems."*

2. *The response to RAI B2.1.27-2 dated June 27, 2019 ADAMS Package Accession No. ML19183A440), states the following:*

    - *The eight concrete circulating water lines without external coating comprise the total of approximately 1000 feet of buried cementitious piping within the scope of SLR. The Open Cycle Cooling Water Systems program will periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The Open Cycle Cooling Water Systems program will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. One hundred percent of the accessible circulating water line internal surfaces will be inspected in a ten year period. The Buried and Underground Piping and Tanks program will opportunistically inspect buried concrete circulating water lines when scheduled maintenance work permits access.*
    - *Ground water monitoring has shown historically the external environment of these circulating water lines to be non-aggressive. The internal environment is considered to be slightly more aggressive since the brackish water is drawn from the James River. GALL-SLR Report AMP XI.M41 recommends periodic inspections for buried cementitious piping.*

<u>Issue:</u>

1. *The staff seeks confirmation on whether uncoated stainless steel segments will be coated consistent with Table 1 of NACE SP0169-2007. The title referenced in the response to RAI B2.1.27-2 references a standard related to concrete cylinder pipelines.*

2. *The staff notes that various GALL-SLR Report AMPs (e.g., AMP XI.M36, "External Surfaces Monitoring of Mechanical Components") state that for situations where the similarity of the internal and external environments are such that the external surface condition is representative of the internal surface condition, inspections of either the internal or external surfaces of the component may be credited for managing the effects of aging for the other surface. The staff seeks clarification regarding why the internal environment of brackish water and the external soil environment are representative of one another. As documented in RAI B2.1.27-1a, it is not clear that the plant-specific groundwater sampling requirements will yield results representative of the aggressiveness of the soil conditions in the vicinity of the buried cementitious piping.*

Request:

1. *Provide clarification on whether uncoated stainless steel segment will be coated consistent with Table 1 of NACE SP0169-2007.*
2. *State the basis for why the environments of brackish water and soil are representative of one another, specifically as it relates to degradation of external surfaces of the cementitious piping. Alternatively, state the basis for why opportunistic inspections, in lieu of periodic inspections, are appropriate for buried cementitious piping.*

Dominion Response:

Response to RAI B2.1.27-2a, Request 1

The response to RAI B2.1.27-2, provided in Dominion letter dated June 27, 2019 (ADAMS Package Accession No. ML19183A440), is revised to reference the correct title of NACE SP0169-2007 herein as, "NACE SP0169-2007, Control of External Corrosion on Underground or Submerged Metallic Piping Systems."

Response to RAI B2.1.27-2a, Request 2

Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement, and loss of material due to delamination, exfoliation, spalling, popout, or scaling aging effects of the concrete 96-inch inlet circulating water piping exposed to groundwater and raw water environments are managed using applicable portions of the *Structures Monitoring* program (B2.1.34). The *Structures Monitoring* program also manages the same aging effects of the groundwater and the raw water environments for the High Level Intake Structure, Discharge Tunnel and Seal Pit structures. This is consistent with Initial License Renewal commitments that managed the concrete circulating water pipe as part of the Intake Structures group that also included the High Level Intake Structure, Discharge Tunnel and Seal Pit structures.

Consistent with NUREG-2191, Section VII.C1, cracking and loss of material aging effects of the concrete 96-inch inlet circulating water piping exposed to a raw water environment are managed by the *Open Cycle Cooling Water System* program. Implementing procedures for the *Open Cycle Cooling Water System* program manage the aging of the concrete 96-inch inlet circulating water piping exposed to a groundwater environment by referencing and using applicable portions of the *Structures Monitoring* program.

In addition to the aging effects managed, both programs share the following common aging management characteristics:

- ACI 349.3R provides an acceptable basis for selection of parameters to be inspected.
- 100% of accessible surfaces are inspected on a periodic frequency
- Inspectors and responsible engineers are qualified consistent with ACI 349.3R
- Concrete acceptance criteria are consistent with ACI 349.3R

Parameters Monitored or Detected

Parameters monitored or detected include the following considerations:

- Water flowing through concrete may result in corrosion of reinforcing steel, which causes expansion of the steel, resulting in spalling of concrete at the surface and brown staining on the concrete.
- CW pipe wall thickness is much thinner than any concrete building wall, so spalling can occur on both faces (interior and exterior) regardless of the source of the water.
- Because of the relatively thin pipe wall, cracking will likely propagate completely through the wall regardless of which face it originates on, resulting in brown staining (rust) appearing on both faces if the reinforcing steel is corroding.

Monitoring of the Groundwater Environment

Groundwater monitoring for the concrete 96-inch inlet circulating water piping locations are located between the Turbine Buildings and the High Level Intake Structures. Groundwater monitoring procedures require periodic sampling at the three specific locations indicated below in the vicinity of the concrete 96-inch inlet circulating water piping. Groundwater monitoring sampling intervals do not exceed five years and evaluations account for seasonal variations.

- P22 - between the condensate storage tanks and the Unit 1 circulating water inlet piping from the High Level Intake Structure
- P28 - between the Unit 1 circulating water inlet piping from the High Level Intake Structure and the Unit 2 circulating water inlet piping from the High Level Intake Structure
- P20 - between the distillate storage tank and the Unit 2 circulating water inlet piping from the High Level Intake Structure

The three groundwater sampling locations identified above will provide representative groundwater samples of the backfill soil used in the vicinity of the concrete 96-inch inlet circulating water piping. Groundwater samples are monitored to confirm a nonaggressive groundwater environment of pH > 5.5, chlorides < 500 ppm, and sulfates <1,500 ppm. The March 2019 *Structures Monitoring* program groundwater sample results at the three locations noted above confirm a nonaggressive groundwater environment.

In addition, the Open Cycle Cooling Water System Program (B2.1.11) will be enhanced to perform two soil corrosivity samples: one adjacent to the Unit 1 circulating water inlet piping and another adjacent to the Unit 2 circulating water inlet piping. Sampling will be performed on a 10 year interval. Data collected at each location will include: soil resistivity, soil consortia (bacteria), pH, moisture, chlorides, sulfates, and redox potential. In addition to evaluating each individual parameter, corrosivity of carbon steel reinforcement and concrete degradation in high sulfate and acidic environments will be evaluated.

<u>Aging Management (Non-Aggressive Groundwater/Soil Environment)</u>

For non-aggressive environments, the *Structures Monitoring* program (B2.1.34):

- Evaluates the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation in accessible areas, and
- Examines samples of the exposed portions of the below grade concrete, when excavated for any reason.

<u>Aging Management (Aggressive Groundwater/Soil Environment)</u>

For aggressive groundwater/soil environments and/or when concrete 96-inch inlet circulating water piping and structures have experienced degradation, corrective actions will be implemented to manage the concrete aging, accounting for the extent of the degradation experienced.. Corrective actions may include evaluations, destructive testing, and/or focused inspections of accessible (leading indicator) or below-grade inaccessible concrete structural elements exposed to aggressive groundwater/soil.

SLRA Changes

SLRA Section B2.1.11 and Table A4.0-1, Item 11 are supplemented, as shown in Enclosure 3 to add an enhancement for the performance of two soil corrosivity samples; one adjacent to the Unit 1 circulating water inlet piping and another adjacent to the Unit 2 circulating water inlet piping.

SLRA Section B2.1.27 and Table A4.0-1, Item 27 are supplemented, as shown in Enclosure 3 to correct the title of NACE SP0169-2007 as described above.

RAI B2.1.28-6a

Background:

SLRA Section B2.1.28, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," states 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 with exception (not related to this RAI).

As amended by letter dated April 2, 2019, SLRA Section B2.1.28, Enhancement No. 7 states "[p]rocedures will be revised to require a pre-inspection review of the previous "two" condition assessment reports, when available, be performed, to review the results of inspections and any subsequent repair activities."

In addition to the statement above, GALL-SLR Report AMP XI.M42 states the following:

> *A coatings specialist prepares the post-inspection report to include: a list and location of all areas evidencing deterioration, a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage, and where possible, photographic documentation indexed to inspection locations.*

The response to RAI B2.1.28-6 dated June 27, 2019 ADAMS Package Accession No. ML19183A440), states that Enhancement No. 7 does not include recommendations for a post inspection report because the program procedures require preparation of a Coating Report Summary that includes the following information: (a) list and location of all areas evidencing deterioration; (b) prioritization of the repair areas that must be repaired before returning the system to service; (c) areas where repair can be postponed to the next refueling outage; and (d) where possible, photographic documentation indexed to inspection locations.

Issue:

The response to RAI B2.1.28-6 does not address the qualifications of the individual preparing the post-inspection report. The staff seeks clarification for why Enhancement No. 7 does not include the GALL-SLR Report AMP XI.M42 recommendation regarding preparation of a post-inspection report by a coatings specialist.

Request:

State the basis for why Enhancement No. 7 does not include the GALL-SLR Report AMP XI.M42 recommendation regarding preparation of a post-inspection report by a coatings specialist.

Dominion Response:

Enhancement #7 in SLRA Section B2.1.28 is being revised as follows to indicate a coatings specialist will prepare the coatings post-inspection condition assessment report:

> "Procedures will be revised to require a coatings specialist to prepare the coatings post-inspection condition assessment report. A pre-inspection review will be performed of the coating inspections and any subsequent repair activities from the previous two coatings post-inspection condition assessment reports, when available."

SLRA Changes

SLRA Section B2.1.28 and Table A4.0-1, Item 28 are supplemented, as shown in Enclosure 3, to include the revision to Enhancement #7 described above. (Note that Enhancement #7 is renumbered to Enhancement #8 due to the addition of a new enhancement as a result of the response to RAI B2.1.28-7a)

An editorial change has also been made in the last paragraph of the Program Descriptioin of SLRA Section B2.1.28 to indicate NUREG-1801 as the NRC approved NUREG with the exception, used with similar justification, and documented in the Safety Evaluation Report Related to the License Renewal of Fermi 2.

RAI B2.1.28-7a

Background:

As amended by letter dated April 2, 2019, the "operating experience (OE) summary" section of SLRA Section B2.1.28 states "[t]he component cooling heat exchanger channel heads are epoxy-coated carbon steel exposed to raw water (service water).

Inspections are performed yearly, which allows early detection of degradation of coatings and underlying metal." The OE summary also states that an inspection of the 1B component cooling water heat exchanger inlet and outlet endbells in 2016 revealed 25 areas requiring coating repair and 3 locations requiring weld repair.

GALL-SLR Report Table XI.M42-1 recommends that internal coatings/lining for piping, piping components, heat exchangers, and tanks are inspected every 4 or 6 years based on the inspection category.

The response to RAI B2.1.28-6 dated June 27, 2019 ADAMS Package Accession No. ML19183A440), states the following:

> *There is no current licensing basis requirement for annual inspection of the components cooling water heat exchangers but the technical basis for inspection on an annual frequency is to monitor flow blockage due to biological growth as a preventive measure, not degradation of the coatings. Flow blockage of the component cooling water heat exchangers is managed by the Open-Cycle Cooling Water System program (B2.1.11). The service water flow is reduced in colder months because the incoming water is much colder. The reduced service water flow velocities allow mud and sediments, which would tend to remain in suspension during periods of higher flow, to come out of suspension and contribute to fouling the tubes. Eventually, the tubes are fouled so much that full flowing the heat exchangers during testing does not improve conditions. Under the preventive maintenance program, scraping and cleaning the heat exchanger tubes is performed once per year in the winter months.*

Issue:

The response to RAI B2.1.28-7 does not address the component cooling water heat exchanger channel heads which are inspected on an annual basis to allow early detection of degraded coatings and underlying metal. The response to RAI B2.1.28-7 only addresses flow blockage of the component cooling water heat exchangers.

GALL-SLR AMP XI.M42 recommends a 4-year inspection interval for coatings that that do not meet Inspection Category A. However, the extent of degradation identified in the plant-specific operating experience calls into question whether consistency with Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers," can provide reasonable assurance that the intended function of the component cooling water heat exchangers will be met.

Request:

State the basis for why the annual inspections of the component cooling heat exchanger channel heads to detect degradation of coatings and underlying metal is not reflected in *the current licensing basis for the SPEO or provide a basis for a plant-specific inspection interval for these heat exchangers.*

Dominion Response:

Based on a review of the component cooling heat exchanger channel heads coating repairs and weld repairs of the underlying metal, the component cooling heat exchanger channel head coatings will continue to be inspected on a one-year inspection interval by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. If two subsequent inspections demonstrate no change in coating condition (i.e. at least three consecutive inspections with no change in condition), inspection frequencies at those locations may be conducted consistent with inspection Category B of NUREG-2191, Table XI.M42-1.

SLRA Changes

SLRA Section B2.1.28 and Table A4.0-1 item 28 are supplemented, as shown in Enclosure 3, to include a new enhancement for the component cooling heat exchanger channel head coating inspection frequency, as described above.

RAI B3.2-1-a

Background:

SLRA Section B3.2 describes Dominion's Neutron Fluence Monitoring Aging Management Program (AMP). In this AMP, Dominion stated that the program does not include neutron fluence monitoring activities for reactor internal (RVI) components. In RAI B3.2-1, the staff asked for clarification whether Surry-specific neutron fluence values for the RVI components have been projected to 80 years of licensed operation. By letter dated June 27, 2019 (ADAMS Accession No. ML19183A386) Dominion's response to RAI B3.2-1 cited report WCAP-18353-NP, Revision 0, "Reactor Internals Fluence Evaluation for a Westinghouse 3-Loop Plant with Two Units – Subsequent License Renewal," October 2018 for the Surry-specific neutron fluence projections of the RVI components to 80 years of licensed operation. Dominion has included WCAP-18353-NP, Revision 0, in Dominion's SLRA document portal. The SLRA portal also includes another referenced WCAP report for assessing neutron fluences in RVI components, which is WCAP-18205-NP, Revision 0.

Issue:

In its response to RAI B3.2-1, Surry stated that WCAP-18353-NP contained the information requested by the staff. The staff reviewed this and other WCAP documents *and believes that the needed information is in WCAP18205-NP. The staff's observation appears to be inconsistent with the RAI response. Irrespective of the appropriate document, the staff will need to rely upon the information in the document to reach its regulatory conclusion. As such, NRC processes require that the document be docketed.*

Request:

Please identify the necessary document and submit to the NRC on the docket.

Dominion Response:

The response to RAI B3.2-1 provided in Dominion letter, "Response to Requests for Additional Information – Set 1," dated June 27, 2019 (ADAMS Accession No. ML19183A386) is revised herein as follows:

WCAP-18205-NP, "*Reactor Internal Fluence Evaluation for a Westinghouse 3-Loop Plant With Twin Units - Subsequent License Renewal*", is provided in Enclosure 4.

WCAP-18205-NP describes an 80 year (72 EFPY) neutron fluence assessment on reactor internals performed for a Westinghouse 3- Loop plant with two units in support of subsequent licensing renewal based on the guidance specified in Regulatory Guide 1.190, "*Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence*".

WCAP-18205-NP, Table 2.2-1 and Table 2.2-2 present the DORT code transport calculations in the analysis in comparison with the previous transport calculations in WCAP-18028-NP, at the pressure vessel inner surface at the beltline region. The comparisons in Table 2.2-1 and Table 2.2-2 demonstrate that the results presented in WCAP-18205-NP are consistent with those used for reactor vessel integrity for 54 EFPY and 72 EFPY in WCAP-18205-NP.

In the WCAP-18205-NP assessment, the previously developed reactor models for the reactor pressure vessel extended beltline have been modified to include a more detailed representation of the reactor internals, mainly for the reactor internals components above and below the active core. Using the updated models, radiation transport calculations have been performed on a fuel-cycle-specific basis, using fuel cycle information specific for the two units located at the selected Westinghouse 3-Loop plant site to calculate reactor internals fast neutron fluences. A slightly different fluence rate synthesis technique was used in WCAP-18205-NP than what was used in WCAP-18028-NP to provide additional conservatism for the reactor vessel internals components above and below the active core. Two sets of DORT r, z model runs were performed in WCAP-18205-NP. One set used the actual axial power distribution. The other set used a flat axial power distribution with the downcomer reactor coolant density for the bottom half of the core and the outlet plenum reactor coolant density for the top half of the core. It is well known that the axial power distribution from the core design calculations have large uncertainties in the regions close to the top and bottom of the core. It is also well known that the top and bottom reactor internals components are only sensitive to the top and bottom six inches to one foot of the core and source conditions, due to their proximity to the core. The flat axial power distribution ensures that conservatism has been included where the simulated source conditions with large uncertainties are encountered, especially above and below the active core. For the radial reactor internals components, however, the actual axial power distribution has been used, because it provides best estimate fast neutron fluence for the radial reactor internals near the core midplane. Once the two sets of 2D/1D SYNTHESIS transport solutions are calculated, the solution with higher fluence rate from the two sets of solutions is used to generate the final three-dimensional solution for the reactor internals components.

Using the SYNTHESIS technique described above, WCAP-18205-NP determined which fast neutron fluence range (E > 1.0 MeV) applied to each reactor internals component and support binning of the selected Westinghouse 3-Loop plant units' reactor internals components for MRP-191, "*Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Design (MRP-191),*" screening purposes. Screening criteria for fast neutron fluence are taken from MRP-175, "*Materials Reliability Program: PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values (MRP-175).*"

- 1.3×10^{20} n/cm^2 (per MRP-175, screening threshold for stress relaxation in bolts)
- 6.7×10^{20} n/cm^2 (per MRP-175, screening threshold IE in CASS)
- 1.0×10^{21} n/cm^2 (per MRP-175, screening threshold for IE in austenitic stainless steel)
- 2.0×10^{21} n/cm^2 (per MRP-175, minimum dose for IASCC (requires 89 ksi stress))
- 1.3×10^{22}n/cm^2 (per MRP-175, screening threshold for void swelling)

The reactor internals components at the selected Westinghouse 3-Loop plant Units 1 and 2 were reviewed and compared against the fluence maps presented in Sections 2.4 and 2.5 of WCAP-18205-NP. The fluence results were used for subsequent screening, FMECA, functionality analysis, and categorization for the 60 years (54 EFPY) and 80 years operation (72 EFPY) in support of SLR. The fluence maps for 54 EFPY and 72 EFPY are similar, as can be seen by comparing the figures in WCAP-18205-NP, Section 2.4 and 2.5. The evaluated fluence ranges for the various components are the same between 54 EFPY and 72 EFPY, except for the following components:

- Control Rod Assemblies and Flow Downcomers Subassembly
  See Table C2.2-1: C-tubes (region 3), Flanges-Lower (region 4), Sheaths (region 3), and Support Pin Nuts (region 4)
- Mixing Devices Subassembly
  See Table C2.2-1: Mixing devices (region 4)
- Upper Support Column Assemblies Subassembly
  See Table C2.2-1: Bolts (at upper core plate)(region 4), Lock Keys (at upper core plate) (region 3)

WCAP-18028-NP, Table 2.6-1 and Table 2.6-2 document the figures of merit (FOM) and power densities of the selected Westinghouse 3-Loop plant units 1 and 2 for the purpose of MRP-227-A applicability evaluation. WCAP-18028-NP assumed fuel cycles 24 through 26 for both units have a full power of 2597 MWt. The fluence calculations in WCAP-18205-NP used 2546 MWt for Cycle 23, and 2597 MWt for Cycle 24 and beyond for both units, which are consistent with WCAP-18028-NP calculations. .

Enclosure 2

RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION
SET 4
REGARDING SPS SLRA

Virginia Electric and Power Company
(Dominion Energy Virginia or Dominion)
Surry Power Station Units 1 and 2

RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION SET 4 - REGARDING SPS SLRA

By letter dated October 15, 2018 (Agencywide Documents Access and Management System (ADAMS Accession No. ML18291A842), as supplemented by letters dated January 29, 2019 (ADAMS Accession No. ML19042A137), and April 2, 2019 (ADAMS Accession No. ML19095A666), Virginia Electric and Power Company (Dominion Energy Virginia or Dominion) submitted to the U.S. Nuclear Regulatory Commission (NRC or staff) an application to renew the Renewed Facility Operating License Nos. DPR-32 and DPR-37 for the Surry Power Station, Unit Nos. 1 and 2. Dominion submitted the application pursuant to Title 10 of the *Code of Federal Regulations* Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," for subsequent license renewal.

From August 6, 2019 through August 8, 2019, the U.S Nuclear Regulatory Commission (NRC) staff sent Dominion draft Requests for Additional Information (RAIs) for various technical review packages (TRP). Dominion subsequently informed the NRC staff that clarification calls were needed to discuss the information requested. Between August 8, 2019 through August 12, 2019, clarification calls were completed for all the draft RAIs unless Dominion declined having a call. The Set 4 RAIs resulting from these calls were received in an email from the NRC to Dominion dated August 14, 2019.

The response to the Set 4 RAIs are provided below in this Enclosure.

RAI B2.1.28-5a

Background:

As amended by letter dated April 2, 2019, SLRA Section B2.1.28, Enhancement No. 1 provides a list of components, including tanks, which will be inspected as part of the program. This list did not include the security diesel fuel oil tank, which is within the scope of the Fuel Oil Chemistry program.

As amended by letter dated April 2, 2019, SLRA Section B2.1.18, "Fuel Oil Chemistry," Exception No. 1 states the following regarding the security diesel fuel oil tank: "[t]he wall of the interior tank is provided with a solvent-based rust preventive film (not considered a coating)."

The "scope of program" program element of GALL-SLR Report XI.M42, "Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," recommends that internally coated tanks exposed to fuel oil, where loss of coating or lining integrity could prevent satisfactory accomplishment of any of the *component's or downstream component's current licensing basis intended functions, are included within the scope of the program.*

The response to RAI B2.1.28-5 dated June 27, 2019 (ADAMS Accession No. ML19183A440), states the following:

> *As required by the Fuel Oil Chemistry program (B2.1.18), the security diesel generator fuel oil tank is sampled quarterly and the samples are analyzed for particulates consistent with ASTM D6217-98, "Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration." Since the security diesel generator fuel oil tank was originally installed in 2011, quarterly test results noted below demonstrate fuel oil particulate levels have remained below the 10 mg/L acceptance limit over the installed life of the tank.*

Issue:

1. *The response to RAI B2.1.28-5 did not provide any information regarding the specific type of film used on the internal surfaces of the security diesel fuel oil tank, or information regarding potential age-related failure modes outside of particulate generation (e.g. failure into sheets). The staff notes that all coatings (e.g., epoxy) are either water-based or solvent-based.*
2. *An adequate basis was not provided for why particulate testing would be an effective indicator of film degradation. It is unclear how a coating, or film, which could potentially degrade into large sheets (i.e., as opposed to small particles) would be detected through particulate testing. Additionally, it isn't clear where the fuel oil filter is located.*

Request:

1. *State the specific type of film used on the internal surfaces of the security diesel fuel oil tank (e.g., product data sheet), and potential age-related failure modes that might impact the intended function of the security diesel fuel oil tank, or downstream components.*
2. *State the basis for why any potential age-related failure modes (e.g., accumulated particulate in the bottom of the tank) would not lead to flow blockage in the fuel oil filter or injectors sufficient to impact the intended function of the diesel.*

Dominion Response:

Response to RAI B2.1.28-5a, Request 1

As stated in SLRA Section B2.1.18, the security diesel generator fuel oil tank cannot be internally cleaned and is not accessible for bottom thickness measurements due to the tank location below the security diesel and the floor of the structure.

The reference to a solvent-based rust preventive film reflected in SLRA Section B2.1.18 was based upon the vendor specification sheet for dual wall sub-base tanks. The specification generally describes the tank exterior to be painted black and the interior to be coated with a "solvent-based rust preventative." The solvent-based protective film was intended as a temporary layer to prevent oxidation of the internal surface prior to installation and designed to dissolve when placed in-service in the presence of diesel fuel oil. The diesel manufacturer was unable to confirm the material constituents of the solvent-based rust preventative material.

The fuel oil tank was visually inspected using a borescope to identify if any material remained on the tank internal surfaces. A limited borescope inspection was performed through a spare two inch fuel oil sampling port on portions of the tank bottom and surfaces above the fuel oil level. The results of the visual inspection confirmed that the fuel oil tank internal surface is bare metal. Therefore, there are no adverse impacts on the license renewal intended function of the security diesel fuel oil tank or the downstream components.

<u>Response to RAI B2.1.28-5a, Request 2</u>

The security diesel fuel oil filter is located between the security diesel fuel oil tank and the diesel engine. The position of the fuel oil filter provides protection from any unexpected debris that may be contained in the tank. Chemistry sample results previously provided in response to RAI B2.1.28-5 [ML19183A440] reflected low levels of particulates. This is consistent with the findings of the borescope inspection which confirmed the fuel oil tank is a bare metal surface.

As such, the confirmed bare metal surface on the internal surfaces of the fuel oil tank, low particulate levels in fuel oil samples and the installation of the fuel filter between the fuel oil tank and the engine provides reasonable assurance that the license renewal intended function will be maintained through the subsequent period of operation.

RAI B2.1.34-1a

<u>Background:</u>

Dominion addressed the age-related degradation of loss of material and change in material properties for wooden power poles by including a plant-specific enhancement to the "detection of aging effects" program element of the Structures Monitoring Program (SLRA Section B2.1.34). This enhancement specifies that wooden power poles will be inspected on a 10-year frequency. However, the staff needed additional *information to evaluate the adequacy of the proposed 10-year inspection frequency for wooden poles which resulted in the issuance of RAI B2.1.34-1.*

In its response to RAI B2.1.34-1, dated July 17, 2019 (ADAMS Accession No. ML19204A357), Dominion stated that the 10-year inspection period was appropriate for the chromate copper arsenate (CCA) treated southern pine poles at Surry by considering the fifty-year durability evaluation from the USDA Forest Products Laboratory. Dominion also stated that there are 14 CCA wooden poles installed at Surry that were manufactured in 1981 or later.

SRP-SLR Section A.1.2.3.4 recommends that the discussion for the "detection of aging effects" program element should provide, in part, justification, including codes and standards referenced, to demonstrate that the technique and frequency are adequate to detect the aging effects before a loss of intended function.

Issue:

Dominion's response to RAI B2.1.34-1 does not provide adequate justification for the proposed 10-year inspection frequency of wooden poles, because the service life of at least some of the poles would exceed 50 years prior to entering the subsequent period of extended operation and no previous inspections would have been performed. The staff notes that the durability study referenced by Dominion for the CCA-treated southern pine poles specifically establishes the basis for the fifty-year durability of treated wood products; however, it does not establish inspection frequency criteria for use with treated wood poles after the fifty years of service. Furthermore, the response did not clearly provide the criteria, based on the expected decay at the site's location (deterioration zone), to establish the 10-year inspection frequency, and when the initial inspection that would establish the baseline condition will be performed at the site. Treated poles are expected to eventually lose resistance to decay (e.g., after the treatment service life) and their vulnerability and inspection criteria should be proportioned to the level of decay that is expected at the site's location (deterioration zone) to ensure that the aging effects can be detected before a loss of intended function.

Request:

Provide justification that would demonstrate, pursuant to 10 CFR 54.21(a)(3), that the proposed inspection frequency for wooden poles will be adequate to detect the associated aging effects before a loss of intended function considering the site's location. Also, clarify when the initial baseline inspection will occur, the type of inspection that will be performed to assess the poles' current condition, and its role, if any, in determining subsequent inspection frequency.

Dominion Response:

The wooden poles were manufactured in 1981 or later. A baseline inspection will be performed prior to January 1, 2031, to ensure that the poles are inspected within fifty years of their manufacture/treatment date and prior to entering the subsequent period of extended operation. The results of the baseline inspections will be evaluated to determine the frequency of subsequent inspections, not to exceed every eight years, as recommended by the USDA Rural Utilities Service Bulletin 1730B-121 for wooden poles located in Decay Zone 4.

Visual examinations will detect loss of material and change in material properties. Visual examinations will be augmented, as required to detect changes in material properties, with soundings or other techniques appropriate for the type, condition, and treatment of the wooden poles, including borings and excavations. Sounding can detect internal decay and voiding. Boring can detect and quantify internal decay, allow for analysis of preservative penetration and retention, and allow for shell thickness measurements to be taken for evaluating strength reduction. Excavation allows for inspection below grade at areas most susceptible to moisture damage and allows for below grade boring activities. The parameters typically monitored during wood pole inspections include shell rot, decay pockets, heart rot, rotten butt, cracked or broken arms or braces, mechanical damage, ground line decay, and split tops.

If an inspection identifies a degraded condition, the Corrective Action Program will be utilized to evaluate the adverse condition and implement the required actions needed to maintain the license renewal intended function throughout the subsequent period of extended operation.

The baseline inspection, subsequent aging management inspections, and any necessary evaluations/corrective actions provide reasonable assurance that loss of material and change of material properties of wooden poles will be managed so that the license renewal intended function will be maintained throughout the subsequent period of extended operation.

SLRA Changes

SLRA Section A.1.34, Section B2.1.34 and Table A4.0-1 item 34 are supplemented, as shown in Enclosure 3, to include the wooden pole inspection frequency, and the revision to Enhancement #6 as described above.

An editorial clarification has also been made to Enhancement #4 in SLRA Section B2.1.34 to indicate that it applies to AMP Element 3, Parameters Monitored or Inspected, as shown in Enclosure 3.

RAI B2.1.8-1a

Background:

In SLRA, Section B2.1.8, "Flow-Accelerated Corrosion," the applicant claimed consistency with the GALL-SLR Report AMP XI.M17, "Flow-Accelerated Corrosion." SLRA Section B2.1.8 states that the erosion activity implements the recommendation of EPRI 3002005530, "Recommendations for an Effective Program Against Erosive Attack." The "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements for GALL-SLR Report AMP XI.M17 discuss recommendations to monitor, detect, and trend degradation due to erosion mechanisms (e.g. cavitation, flashing, etc.).

During the In-Office audit, the staff reviewed the program basis document ETE-SLR-2018-1311, "Surry Subsequent License Renewal Project – Aging Management Program Evaluation Report – Flow-Accelerated Corrosion," Revision 1, to evaluate whether the applicant is consistent with the GALL-SLR Report AMP XI.M17 recommendations for the flow-accelerated corrosion (FAC) program. In the document, the applicant stated that the FAC erosion module in CHECWORKS will be used to assist in the development of the inspection plan for the Erosion Control program.

Issue:

In its response to RAI B2.1.8-1, dated July 17, 2019 (ADAMS Accession No. ML19204A357), the applicant stated that EPRI 3002005530 is referenced in its Erosion Control Program implementing procedure, and provides the basis used in the erosion module for component inspection, inspection techniques, determination of wear rate and service life, and determination of component replacement. However, the applicant's RAI response does not appear to discuss specifically how the erosion module in CHECWORKS is used to plan inspections, determine wear rate, etc.

Additionally, the erosion module in CHECWORKS appears to have different predictive capabilities for different erosion mechanisms. It is unclear to the staff how the outputs from this software are used in the applicant's erosion program.

Request:

Provide a justification for how the FAC erosion module in the CHECWORKS software is used to model erosion, how the results will be used in planning erosion inspections, and how this meets the recommendations of the GALL-SLR with respect to monitoring effects of wall thinning due to erosive mechanisms, its use in planning inspections for erosive degradation, as well as for monitoring and trending potential degradation due to erosive mechanisms. Additionally, given that the FAC erosion module in CHECWORKS has different capabilities for different erosion mechanisms, the justification should *include a discussion that describes what outputs from the erosion module are used in the applicant's program and how the results from the erosion module are validated by applicant inspections.*

Dominion Response:

The Erosion Module is an analytical tool within the EPRI CHECWORKS-SFA software used to evaluate the potential for wall thinning due to erosion in piping. It is distinct and separate from the Flow Accelerated Corrosion (FAC) modeling in the software. The Erosion Module is listed in Section 6.4 of EPRI Report 3002005530 as an option for evaluating the potential for erosion in a piping run. Appendix F of the EPRI Report describes calculational approaches for evaluating each type of erosion and describes how those approaches are implemented in CHECWORKS. The predictive capabilities of the Erosion Module address the erosion mechanisms of cavitation, flashing, and liquid droplet impingement (LDI). Solid particle erosion (SPE) modeling is not included in the Erosion Module, but is evaluated by the risk-ranking process for the Erosion Susceptibility Evaluation (ESE).

Each run of the CHECWORKS Erosion Module is developed separately from the FAC model, even if a line is modeled in CHECWORKS for both FAC and erosion. The Erosion Module considers the piping geometry and operating conditions to predict the occurrence of erosive damage in the modeled piping. Due to differing conditions that lead to each of three modeled erosion mechanisms, the outputs from the Erosion Module are different for each type of erosion. Each modeled line is evaluated for all three mechanisms – cavitation, flashing, and LDI – as described below:

- The potential for cavitation is evaluated only at flow restrictions (such as an orifice or a valve) in a modeled line. The module calculates the predicted degree of cavitation at each restriction, and reports a calculated "Cavitation Index" and a "Cavitation Regime", which is a qualitative measure of the predicted severity of cavitation. The module does not predict a wear rate for cavitation.
- The potential for flashing is also evaluated only at flow restrictions (such as an orifice or a valve) in a modeled line. The module reports a simple "yes/no" for predicted flashing at each restriction. It does not calculate a degree or level of severity of flashing, and it does not calculate a predicted wear rate for flashing.
- The output for LDI differs from the first two mechanisms. The potential for LDI is evaluated at each piping component in a modeled line, not just flow restrictions. The module reports a predicted wear rate due to LDI at each component on the piping run, with a rate of 0.00 indicating LDI is not predicted to occur.

Several important differences exist between the Erosion Module and the FAC Model in CHECWORKS. As previously mentioned the Erosion Module does not predict a wear rate for cavitation and flashing; however, it does predict a wear rate for LDI. The module does not calculate a remaining life or projected wall thickness for any component or line for any of the three modeled erosion mechanisms. It predicts only the occurrence of erosion as discussed above, based on the inputs of piping geometry and operating conditions. Lastly, there is no "model calibration" built into the Erosion Module. The module does not incorporate inspection results into the outputs of the erosion modeling.

The CHECWORKS Erosion Module will be used as one of a number of inputs to identify the erosion inspection scope. The Erosion Module is not being used to determine susceptibility, as all lines modeled in the Erosion Module were already determined to be susceptible in the ESE. The outputs of the Erosion Module will be used to help identify predicted erosion locations to be inspected on susceptible lines. The predicted magnitudes of erosive damage in the module are not considered, and any location where the module predicts erosion will be inspected. Outputs from the Erosion Module are not used to exclude lines from the inspection scope, although it will inform the priority of inspections.

The CHECWORKS Erosion Module currently covers only a small portion of the total scope of erosion control. Lines currently included in the Erosion Module were chosen based on the extent of information that was available for the preparation of the ESE. It is possible that more lines may be modeled in the future if inspection results prove the Erosion Module to be a valuable tool for directing inspection locations.

While the Erosion Module will provide input to the inspection scope, the primary source for selecting inspection locations will be the ESE. The erosion control procedure provides direction for developing the inspection plan. The procedure identifies the Erosion Module as the first source for the inspection scope, and the following step gives direction to include appropriate components from "Susceptible Non-modeled" (SNM) lines based on relative level of susceptibility. There is no bias in the selection of inspection locations based on whether that component is modeled. Further considerations for the selection process include components replaced at other units, operating experience reviews, re-inspections of previously inspected components, input from other internal inspections, and previously replaced components. Overall, the majority of the erosion inspection scope will be determined in a manner similar to the SNM process used in the FAC Program. Lines will be risk ranked based on the level of plant safety, erosion susceptibility, and consequence of failure. Since the CHECWORKS Erosion Module does not analyze solid particle erosion (SPE), lines susceptible to SPE will be incorporated into the inspection scope via the SNM risk ranking.

The recommendation from NUREG-2191, Section XI.M17, Element 1, Scope of Program, to monitor wall thinning of components subject to erosion mechanisms is accomplished by wall thickness measurements, which also address the recommendation from NUREG-2191, Section XI.M17, Element 3, Parameters Monitored or Inspected. Acquisition of wall thickness information for susceptible components is described in the erosion control procedure.

The recommendation from NUREG-2191, Section XI.M17, Element 4, Detection of Aging Effects, is accomplished using guidance from the erosion control procedure that gives direction for inspections to include appropriate components from SNM lines based on relative level of susceptibility. Also, components are identified as candidates for inspection based on components being replaced at other units, OE reviews (industry), re-inspections of previously inspected components, input from other internal inspections (plant-specific OE), and previously replaced components.

The Erosion Module of CHECWORKS does not include a feedback mechanism to adjust the modeling based on inspection results. Inspection results are retained in the CHECWORKS database (but are not used as input to the Erosion Module), or in FAC Manager. FAC Manager is a database used to compile inspection results and list completed inspections, but does not predict wear or identify components to be inspected. Results from erosion inspections are used to update the ESE, which identifies components to be inspected.

The erosion control procedure includes an evaluation of the wall thickness readings taken during component inspections to determine the need for replacement of piping or for further monitoring and trending to address the recommendations from NUREG-2191, Section XI.M17, Element 5, Monitoring and Trending,. This determination is not part of the CHECWORKS Erosion Module. Each inspected component is dispositioned in one of three ways:

- Component requires immediate replacement. The piping will be replaced, and further evaluation of the issue performed in order to remediate the cause of the wear.
- Component will be re-inspected in a future outage. For these components, a wear rate will be calculated by Engineering as the difference of the nominal pipe thickness (T_{nom}) and the minimum measured thickness (T_{min}), divided by the length of time the component has been in service. A Safety Factor of at least 2.0 will be used as recommended by industry guidance for this calculation. This wear rate, with the applied safety factor, will be used to determine the remaining

life of the component. The component will be re-inspected at an interval that confirms the wear rate and allows for the planning of component replacement and remediation of the cause of the wall thinning.

- Component requires no further inspection. This designation is only to be used if no significant wall thinning is detected.

This dispositioning of inspected components is done outside the CHECWORKS Erosion Module, since none of that functionality exists within the module. Extent-of-condition is addressed by re-inspections of previously inspected components, and inspections of previously replaced components, when establishing the inspection scope.

The outputs of the Erosion Module are used to help identify predicted erosion locations to be inspected on susceptible lines. The predicted magnitudes of erosive damage in the module are not considered, but any location the module predicts to be wearing will be inspected. Outputs from the Erosion Module are not used to exclude lines from the inspection scope, although it helps determine priority of inspections. Lines currently included in the Erosion Module were chosen based on the extent of information that was available to support the preparation of the ESE. Lines are identified for inspection based on risk ranking and consequence of failure rather than output from the Erosion Module.

As noted above, the Erosion Module does not include a feedback mechanism to adjust the modeling based on inspection results. The Erosion Module from CHECWORKS is not the primary tool used to identify components for inspection so the output from the Erosion Module does not indicate the expected magnitude of wall thinning due to erosion and is not intended to be validated. The output from the Erosion Module is used to identify potential wear locations on lines that already have been classified as susceptible by the ESE so that those locations can be considered for inspection.

SLRA Changes

SLRA Section B2.1.8 is supplemented, as shown in Enclosure 3, to include an Erosion Control Program Description discussion in the Program Description Section of the *Flow Accelerated Corrosion* program (B2.1.8).

RAI B2.1.8-3a

Background:

As supplemented by letter dated April 2, 2019, SLRA Table 3.3.2-6 "Bearing Cooling," was modified to address the potential for erosion in valve bodies constructed of several different materials. The supplement also states that cavitation in this system could be *caused by valve throttling. Additionally, condition report CR1031398, "BC Valve – Indication of Cavitation," describes cavitation in a Unit 1 bearing cooling valve and notes that the valve was previously replaced in 2013 due to a pin hole leak in the valve body. This CR also notes that the current non-destructive examination strategy doesn't evaluate the valve body for wall thinning. The staff notes that condition report CR1026621, "2-BC-505 Has a Through-Wall Leak," describes a through-wall leak for the corresponding Unit 2 valve; however, the cause of the leak was not included in the summary documentation.*

The applicant's erosion susceptibility evaluation (ESE) (ETE-CME-2018-1002, Revision 1, "Transmittal of True North Consulting Technical Report BP-2017-0045-TR-01, Erosion Susceptibility Evaluation – Surry," September 2018) designated the bearing cooling system as not being susceptible to cavitation because the cavitation index is greater than 2.5. The ESE states that the bearing cooling system is a closed-loop system which does not have large enough pressure drops for cavitation to occur. The staff notes that comments for other systems in the ESE identify the potential for cavitation and flashing downstream of throttle valves and orifices. The ESE indicates that the criteria for the cavitation index greater than 2.5 is "a rule of thumb" and cites a reference to a valve manufacturer publication. The associated implementing procedure, ER-AA-FAC-105, "Erosion Control Program," Section 3.1.1 states that the ESE is to be periodically updated based on relevant operating experience.

The response to RAI B2.1.8-3 dated July 17, 2019 (ADAMS Accession No. ML19204A357), states that the input for the erosion susceptibility evaluation included a review of plant operating experience to determine locations with a history of erosion failure, and that the bearing cooling system was determined to not be susceptible based on the absence of erosion failures.

<u>Issue:</u>

In its initial request the NRC staff requested information regarding whether other systems (i.e. in addition to the bearing cooling system) determined to not be susceptible to erosive mechanisms could be affected in a similar manner as the bearing cooling system (i.e. change of operating conditions lead to higher erosion susceptibility). In its response to RAI B2.1.8-3 the applicant stated that plant information has not indicated other systems that may have higher erosion susceptibility than was stated in the ESEs.

Although the response to RAI B2.1.8-3 states that the bearing cooling system was determined to not be susceptible based on the absence of erosion failures, the two CRs referenced above (CR1031398 and CR1026621) describe erosive failures (i.e. cavitation) in the bearing cooling system.

The staff noted the residual heat removal and chemical and volume control (CVCS) systems are identified in the current ESE as not susceptible to cavitation although NRC Information Notices 89-01 and 98-45 describe these systems as potentially susceptible. Additionally, EPRI 3002005530, which is referenced by the applicant's Erosion Control Program, states that the CVCS system is potentially susceptible to erosion. These are some examples of instances where the exclusion criteria as noted in the applicant's ESE may not apply and where the staff may need additional explanation for why these criteria are applied. These examples are used to demonstrate that systems not frequently in service may be susceptible to erosion, and plant operations (IN 98-45 cites an incorrectly adjusted blowdown setting of a pressure relief valve) can impact susceptibility to erosion. Additionally, EPRI Report TR-112657, "Revised Risk-Informed Inservice Inspection Evaluation Procedure," Revision B-A, December 1999, discusses a lower threshold for erosion susceptibility than the 2% cited in the applicant's ESE.

Request:

1. *Provide a description of what plant information was reviewed and how it was determined that no other systems may have higher erosion susceptibility than was initially stated in the ESEs.*
2. *Also, justify use of the exclusion criteria for susceptibility to cavitation related to pressure drops as well as the service time exclusion criterion given the discussion in the 'Issue' section above.*
3. *Additionally, describe how the initial ESE included and performed a review of site-specific operating experience as part of the susceptible evaluation, given that the bearing cooling system had experienced erosion.*

Dominion Response:

Response to RAI B2.1.8-3a, Request 1

The Corrective Action Program database was extensively searched to identify erosion issues from mid-2006 through mid-2016. Operating Experience (OE) information resulting from that search was provided to a third party as input during the development of the Erosion Susceptibility Evaluations (ESEs) for SPS Units 1 and 2. If erosion OE existed for a particular system, that system was classified as susceptible to erosion. If the issue was resolved with a modification, thus preventing erosion-induced wall thinning in the future, then it screened out as non-susceptible.

While developing the aging management programs for Units 1 and 2, previously unidentified OE associated with the Bearing Cooling (BC) system became evident during the evaluation of the aging management program for Closed Treated Water Systems. The BC valves that had experienced erosion were not originally intended to be used as throttle valves, but were subsequently used to throttle flow in order to meet operational needs, thereby causing through-wall pin-hole leaks. The OE was not initially identified and thus was not communicated to the third party developing the ESEs. Without the subsequent OE, the Bearing Cooling system was screened out as not susceptible. The newly-identified OE for the BC system has been used for updating the ESEs to indicate that the BC system is susceptible to erosion. A separate review of OE did not identify any other systems for which a reclassification of susceptibility was required. A review was performed to confirm there are no other situations involving changes in plant operation that could lead to component erosion.

Response to RAI B2.1.8-3a, Request 2

Regarding the exclusion criterion for susceptibility to cavitation related to pressure drop, the ESE identifies that cavitation is possible when the Cavitation Index is < 2.5. Cavitation Index (σ) is defined as follows:

$$\sigma = P_u - P_v / P_u - P_d$$

where:

P_u is the upstream pressure
P_v is the vapor pressure
P_d is the downstream pressure

The ESE identified susceptibility for systems with components having a Cavitation Index < 2.5.

Regarding the exclusion criterion for non-susceptibility due to service time, the current ESE excludes systems that are in service less than 2% of the time the plant is operating. Guidance from EPRI Report TR-112657, "Revised Risk Informed Inservice Inspection Evaluation Procedure," indicates that piping conditions for which flow occurs less than 100 hours per year are not considered to be susceptible to erosion-cavitation degradation. Based on that guidance, a re-evaluation for susceptibility to erosion will be performed using 100 hours per year as the criterion, unless the criterion of less than 2% plant operating time is justifiable.

Response to RAI B2.1.8-3a, Request 3

As mentioned in the response to Request 1 above, the Corrective Action Program database was searched to identify OE for the period mid-2006 through mid-2016 for development of the aging management program (AMP) documents. That OE information was provided to a third party who prepared the ESEs. Due to the specific timing of AMP preparation and development for the various programs, the OE for the BC system was not identified until after the ESEs were developed. A subsequent review did not identify any similar situations of changes in plant operation that affected erosion. However, a separate evaluation will be performed to provide additional confirmation that no changes exist in plant configuration or operation which have the potential to increase susceptibility for erosion.

SLRA Changes

SLRA Section B2.1.8 and Table A4.0-1, Item 8 are supplemented, as shown in Enclosure 3, to add enhancements to perform an evaluation for systems that can be excluded from erosion control susceptibility as described above and perform an evaluation to determine whether changes in plant configuration or operation affect flow conditions such that there is the potential to increase susceptibility for erosion.

Enclosure 3

SLRA MARK-UPS – SET 3 and SET 4 RAIs

Virginia Electric and Power Company
(Dominion Energy Virginia or Dominion)
Surry Power Station Units 1 and 2

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	15. Procedures will be revised to require visual examinations (EVT-1), and will include associated acceptance criteria, for 100% of one side of the accessible surfaces of the core barrel lower girth weld and ¾" of adjacent base metal (minimum 50% examination coverage). (Primary component) 16. Procedures will be revised for contingency tasks to inspect the following expansion components if necessitated by relevant indications being found for associated primary components, and will include associated acceptance criteria: a. Core barrel upper, middle, and lower axial welds (100% of weld length – 50% examination coverage; EVT-1) b. Core barrel upper girth weld (100% of weld length – 50% examination coverage; EVT-1) c. Core barrel lower flange weld (100% of weld length – 50% examination coverage; EVT-1) d. Lower support forging (25% of bottom surface; VT-3) e. Upper core plate (25% of accessible surfaces; VT-3) 17. A procedure for visual examinations will be revised to identify the examiner qualifications which are applicable for EVT-1 examinations.	B2.1.7	Program, accounting for the impacts of a gap analysis, will be implemented 6 months prior to the subsequent period of extended operation, or alternatively, a plant-specific program may be implemented 6 months prior to the subsequent period of extended operation.
8	*Flow-Accelerated Corrosion* program	The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that will be enhanced as follows: 1. ~~Procedures will be revised to include a re-evaluation of~~An engineering evaluation will be performed for systems ~~currently~~ that have been excluded from the FAC program due to no flow or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time, ~~to ensure that an adequate basis exists to justify continuing this exclusion.~~The purpose of the engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The engineering evaluation and modeling changes for the FAC program will be completed prior to entering the subsequent period of extended operation.(Revised - Change Notice 2) 2. A re-evaluation of the erosion susceptibility determination that identified plant systems in the scope of subsequent license renewal that were previously excluded from monitoring will be performed to re-affirm that the appropriate basis for exclusion either is in-service operational and testing time less than 100 hours per year, or is a technical evaluation specifically developed to exclude a system. (Added - Set 4 RAIs) 3. A re-evaluation will be performed to determine whether plant conditions (e.g., valve throttling) have changed such that susceptibility to erosion has increased for plant systems within the scope of subsequent license renewal. (Added - Set 4 RAIs)	B2.1.8	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
		4. Procedure will be revised to confirm that inspection scope expansions include the items noted below and to confirm that independent reviews of inspection scope expansions are independently reviewed by a qualified FAC engineer. (Added - Set 2 RAIs) • Any component within two pipe diameters downstream of the component displaying significant wear, or within two pipe diameters upstream if that component is an expander or expanding elbow. • The two most susceptible components from the CHECWORKS relative wear rate ranking in the same train containing the piping component displaying significant wear. • Corresponding components from other trains. • Inspections of additional components until no additional components with significant wear are detected.		
9	*Bolting Integrity* program	The *Bolting Integrity* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to provide inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet to four feet (or less) will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. 2. Procedures will be revised for inspections of pressure-retaining closure bolting in locations that preclude detection of joint leakage, such as in submerged environments or where the piping system contains air for which leakage is difficult to detect. The inspections will be performed to detect loss of material. A requirement will be included to inspect bolt heads when made accessible, and bolt threads if joints are disassembled. At a minimum, in each 10-year interval during the subsequent period of extended operation, inspections shall be completed for a representative sample of at least 20% of the population, up to a maximum of nineteen, for each material/environment combination. 3. A new procedure will be developed to provide guidance for a situation in which an acceptance criterion for allowable degradation is exceeded, and the aging effect causing the degradation for the material/environment combination is not corrected by repair or replacement, thus requiring that additional inspections be performed. The number of additional inspections will be determined in accordance with the Corrective Action Program; however no fewer than five additional (or 20%, whichever is less) inspections of different components having the same material/environment/aging effect combination are required for each inspection that did not meet the acceptance criterion. For a two-unit site, the additional inspections include inspections at the same unit, and at the opposite unit, for components having the same material, environment, and aging effect combination. The additional inspections are to be completed within the same interval (e.g., refueling outage or 10-year inspection interval). If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies are adjusted as determined by the Corrective Action Program.	B2.1.9	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
11	*Open-Cycle Cooling Water* program	The *Open-Cycle Cooling Water* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that will be enhanced as follows: 1. Selected fiberglass reinforced plastic (FRP) piping in the service water system will be replaced with a more degradation resistant material such as copper-nickel (Cu-Ni) prior to entering the subsequent period of extended operation. FRP piping associated with the Units 1 and 2 charging pump cooling water subsystems, service water rotating strainers, and the control room chillers may be replaced as part of a time-phased program. 2. Modifications necessary to provide new chemical injection site upstream of the service water rotating strainers will be completed prior to entering the subsequent period of extended operation. 3. The internal lining of ~~24~~30 inch and larger service water inlet piping with carbon fiber reinforced polymer, with the exception of the recirculation spray heat exchanger piping downstream of the inlet motor-operated valves, will be completed prior to entering the subsequent period of extended operation. (Revised - Set 2 RAIs) 4. ~~Procedures will be revised to remove reference to the carbon steel piping that was replaced and will include the replacement material.~~(Completed - Change Notice 1) 5. Procedures will be revised to provide additional guidance for identifying and evaluating applicable concrete aging effects such as loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; and cracking due to chemical reaction, or corrosion of reinforcement. 6. Procedures will be revised to require two soil corrosivity samples be performed: one adjacent to the Unit 1 circulating water inlet piping and another adjacent to the Unit 2 circulating water inlet piping. Sampling will be performed on a 10 year interval. Data collected at each location will include: soil resistivity, soil consortia (bacteria), pH, moisture, chlorides, sulfates, and redox potential. In addition to evaluating each individual parameter, corrosivity of carbon steel reinforcement and concrete degradation in high sulfate and acidic environments will be evaluated. (Added - Set 3 RAIs) 7. Procedures will be revised to provide guidance for internal inspection of carbon fiber reinforced polymer piping for aging effects such as voids, blistering, bubbles, cracking, crazing and delamination. (Added - Set 1 RAIs) 8. Procedures will be revised to require personnel who perform inspections and evaluation of concrete components to be qualified consistent with the qualifications identified in the Structures Monitoring program (B2.1.34) that are consistent with the requirements of ACI 349.3R. 9. Procedures will be revised to require personnel who perform visual inspections and evaluation of carbon fiber reinforced polymer piping to be VT-1 qualified consistent with IWA-2300 of ASME Section XI and Mandatory Appendix II of ASME Code Case N-871. Personnel who perform acoustic examinations of CFRP lined piping will be qualified consistent with mandatory Appendix VI of ASME Code Case N-871. (Added - Set 1 RAIs) 10. Procedures will be revised to require installed CFRP linings be 100% visually examined in accordance with ASME Code Case N-871 section 5213 during an inspection period between four and six years following return of the repaired area to service; and a minimum of once per 10 year inservice inspection interval thereafter in the same inspection period of each succeeding inspection interval. (Added - Set 1 RAIs) 11. Procedures will be revised to require accessible surfaces of the CFRP linings at each terminal end to be acoustically impact tap examined in accordance with ASME Code Case N-871 section 5250(a) and 5250(c). The expansion rings need not be removed for this examination provided examinations of adjacent surfaces do not indicate the presence of new unacceptable indications that could extend beneath the rings. (Added - Set 1 RAIs)	B2.1.11	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
11	*Open-Cycle Cooling Water* program	12. Procedures will be revised to periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The program will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. One hundred percent of the accessible circulating water line internal surfaces will be inspected in a ten year period. (Added - Set 1 RAIs) 13. Procedures will be revised to require trending of charging pump lube oil cooler and emergency service water pump engine heat exchanger inspection results by Engineering. 14. Procedures will be revised to require trending of wall thickness measurements. The frequency and number of wall thickness measurements will be based on trending results. 15. Procedures will be revised to require all areas previously documented in accordance with ASME Code Case N-871 Section V-1100(b) shall be re-examined, measured, and compared with the previous inspection records. Any indications of flaw growth will be required to be repaired consistent with ASME Code Case N-871. Documentation of the repair, location and dimensions will be required. Any new flawed areas shall be evaluated consistent with ASME Code Case N-871. (Added - RAI Set 2) 16. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses. 17. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions. 18. Procedures will be revised to identify acceptance criteria for visual inspection of concrete piping and components such as the absence of cracking and loss of material, provided that minor cracking and loss of material in concrete may be acceptable where there is no evidence of leakage, exposed rebar or reinforcing "hoop" bands or rust staining from such reinforcing elements. 19. Procedures will be revised to include the following CFRP defect inspection acceptance criteria for air voids, bubbles, blisters, delaminations and other defects (such as cracking and crazing): (Added - RAI Set 2) Air Voids For embedded air voids of area less than or equal to 25 square inches that have been visually detected in layers beneath the topcoat, they shall be repaired in accordance with ASME Code Case N-871 section 4390 (b)(1) and (b)(2) unless otherwise specified in the design documents. All other defects and all voids larger greater than 25 square inches shall be rejected, and a repair designed to maintain water tightness of the system. Bubbles, blisters or other defects If bubbles or blisters with major dimension exceeding 1 inch are detected anywhere within the protective epoxy topcoat, they shall be removed and repaired in accordance with ASME Code Case N-871 Section 4380(d). Delaminations or Voids Unless permitted by design documents, acceptance criteria for acoustic tap examination of terminal ends shall be consistent with ASME Code Case N-871 section 5350 (a) and (b)	B2.1.11	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
11	*Open-Cycle Cooling Water* program	20. Procedures will be revised to include the following defect repair criteria as part of the corrective actions.: (Added - RAI Set 2) For air void defects Repairs shall be consistent with ASME Code Case N-871 section 4390 (b)(3) and (b)(4) For bubbles, blisters or other surface defects Repairs shall be consistent with ASME Code Case N-871 section 4390 (d) For all other defects and all voids larger than 25 square inches A repair shall be designed to maintain water-tightness of the system consistent with ASME Code Case N-871 section 4390 (d) A final visual inspection shall be performed to verify the CFRP system has achieved the percentage of cure corresponding to achievement of required mechanical properties before placing the repaired piping back in service. In no case shall the system be placed in service before achieving 85% cure. 21. Procedures will be revised to ensure that for ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections at susceptible locations are increased commensurate with the significance of the degradation. 22. Procedures will be revised to ensure that when measured parameters do not meet the acceptance criteria, additional inspections are performed, when the cause of the aging effect is not corrected by repair or replacement for components with the same material and environment combination. The number of inspections will be determined by the Corrective Action Program, but no fewer than five additional inspections will be performed for each inspection that did not meet the acceptance criteria, or 20% of the applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will include inspections at both Unit 1 and Unit 2 with the same material, environment, and aging effect combination.	B2.1.11	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
16	*Fire Water System* program	The *Fire Water System* program is an existing condition monitoring program that will be enhanced as follows: 1. ~~Procedures inspection guidance will be revised to require replacement of any sprinkler that shows any of the following: leakage, corrosion, physical damage, loading, painting unless painted by the sprinkler manufacturer, or incorrect orientation. Sprinklers at the following locations will be added to the test scope: The Radwaste Facility, Auxiliary Boiler, Maintenance Building, Condensate Polishing Building, Laundry Building, and Machine Shop Building.~~ (Completed - Change Notice 1) 2. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. Additional representative samples will be field-service tested every 10 years thereafter to ensure signs of aging are detected in a timely manner. For wet pipe sprinkler systems, a one-time test of sprinklers that have been exposed to water including the sample size, sample selection criteria, and minimum time in service of tested sprinklers will be performed. At each unit, a sample of 3% or a maximum of ten sprinklers with no more than four sprinklers per structure shall be tested. Testing is based on a minimum time in service of fifty years and severity of operating conditions for each population. (Revised - Change Notice 2) 3. Procedures will be revised to specify: a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five year interval to demonstrate the capability to provide the design pressure at required flow. b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action. c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination. d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures.	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that 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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	4. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following: (Relocated from Commitment 10 and corrected - Change Notice 2) a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected. b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. c. Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. 5. Procedures will be revised to perform system flow testing at flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests. (Renumbered - Change Notice 2) 6. ~~Procedures for hydrant flushing will be revised to require fully opening the hydrant and fully flowing the hydrant for no less than one minute and until foreign material has cleared. In addition, procedures will be revised to observe draining of the hydrant barrel and also require the barrel be pumped dry should it not drain within 60 minutes. Hydrants outside the protected area that are within the scope of subsequent license renewal will be added to the flush scope.~~(Completed - Change Notice 1 and renumbered - Change Notice 2)) 7. ~~The Fire Water System program will be revised to periodically inspect the insulated exterior surfaces of the fire water tanks on a 10 year frequency during the subsequent period of operation. Insulation is removed to provide a minimum inspection population of 25 one-square-foot samples. The samples will be distributed in such a way that inspections occur on the tank dome, near the tank bottom, at points where structural supports, pipe, or instrument nozzles penetrate the insulation and where water could collect. In addition, inspection locations will be based on the likelihood of corrosion under insulation occurring.~~ Prior to the subsequent period of extended operation, the insulation on the exterior surfaces of the fire water storage tanks (FWSTs) will be permanently removed. Wall thickness measurements will be performed on external tank areas exhibiting unexpected degradation. Refurbishment/recoating will be performed consistent with the severity of the degradation identified and commensurate with the potential for loss of intended function. Inspections of external tank surfaces will be on a refueling cycle frequency. (Renumbered - Change Notice 2 and revised - Change Notice 3)	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that 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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	8. ~~Procedures for mainline strainer flushing will be revised to require flushing until clear water is observed after each operation or flow test. In addition to flushing after operation, the Radwaste Facility mainline strainer will require an inspection every five years for damaged and corroded parts.~~(Completed - Change Notice 1 and renumbered Change Notice 2)) 9. A procedure will be created to provide a Turbine Building oil deluge systems spray nozzle air flow test to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. (Renumbered - Change Notice 2) ~~10. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow up volumetric examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following:~~(Old Enhancement 9 was relocated to Enhancement 4 - Change Notice 2) a. ~~Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected.~~ b. ~~Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.~~ c. ~~Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.~~ 10. Procedure will be revised to provide inspection guidance related to lighting, distance and offset for non-ASME Code inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. 11. The Unit 1 hydrogen seal oil system deluge sprinkler pipe and Unit 1 station main transformer '1A' deluge sprinkler piping will be reconfigured to allow drainage. As part of the drainage reconfiguration, visual inspections and wall thickness measurements will be performed on the Unit 1 hydrogen seal oil system deluge sprinkler pipe that does not drain. In addition, wall thickness examination of the Unit 1 main transformer deluge sprinkler piping that does not allow drainage will also be performed as part of the drainage reconfiguration. Piping with unexpected degradation will be replaced. (Revised - Change Notice 3)	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that 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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	12. The program will be revised to require inspections and tests be performed by personnel qualified in accordance with site procedures and programs for the specified task. (Added - Change Notice 2) 13. Procedures will be revised to require when degraded coatings are detected by internal coating inspections, acceptance criteria and corrective action recommendations consistent with the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers and Tanks (B2.1.28) program are followed in lieu of NFPA 25 section 9.2.7 (1), (2), and (4). When interior pitting or general corrosion (beyond minor surface rust) is detected, tank wall thickness measurements are conducted as stated in NFPA 25 Section 9.2.7(3) in vicinity of the loss of material. Vacuum box testing as stated in NFPA 25 Section 9.2.7(5) is conducted when pitting, cracks, or loss of material is detected in the immediate vicinity of welds. (Added - Change Notice 2) 14. The activity of the jockey pump will be monitored consistent with the "detection of aging effects" program element of NUREG-2191, Section XI.M41. (Added - Set 3 RAIs) 15. Procedures will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, the performance of opportunistic visual inspections of the fire protection system will be required whenever the fire water system is opened for maintenance.	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that 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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
27	*Buried and Underground Piping and Tanks* program	The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings. 2. ~~Procedures will be revised to include visual inspection requirements and acceptance criteria for:~~(Completed - Change Notice 2) a. ~~Absence of cracking in fiberglass reinforced plastic components and evaluation of blisters, gouges, or wear~~ b. ~~Minor cracking and loss of material in concrete or cementitious material provided there is no evidence of leakage exposed or rust staining from rebar or reinforcing "hoop" bands~~ 3. 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. (Added - Set 1 RAIs) 4. Procedures will be revised to require uncoated buried stainless steel tubing segments in the fuel oil system be inspected prior to the subsequent period of extended operation. After inspection, each uncoated stainless steel segment will be coated consistent with Table 1 of NACE SP0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Systems."~~"Standard Recommended Practice, Cathodic Protection of Prestressed Concrete Cylinder Pipelines."~~ (Added - Set 1 RAIs) (Revised - Set 3 RAIs) 5. A cathodic protection system will be installed for protection of the 24-inch service water piping at the Low Level Intake Structure five years before entering the subsequent period of operation. (Added - Set 3 RAIs) 6. Procedures will be revised to specify that cathodic protection surveys use the -850mV 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 include the -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate. ~~Alternatives will be demonstrated to be effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured.~~	B2.1.27	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that 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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
27	*Buried and Underground Piping and Tanks* program	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 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years. 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). When using the electrical resistance corrosion rate probes: a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data (Revised - Change Notice 2 and Set 1 RAIs)	B2.1.27	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that 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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
28	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require ~~additional~~baseline inspections (100% of accessible coatings/linings) of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection ~~frequencies will be modified, as necessary, to ensure consistency with NUREG-2191~~ intervals will not exceed those specified in NUREG-2191, Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers." (Revised - Change Notice 2 and Set 1 RAIs) • Circulating water system waterbox air separating tanks • Condensate polishing outlet piping (short segment; entire length is inspected) • Vacuum priming tanks • Vacuum priming seal water separator tanks • Auxiliary steam drain receiver tank • Water treatment piping (short segment; entire length is inspected) • Flash evaporator demineralizer isolation valve • Brominator mixing tank • Pressurizer relief tanks 2. Programs will be revised to consistently reference coating aging mechanisms and add definitions for rusting, wear/erosion, and physical damage. 3. Procedures will be revised to require alignment of the internal coating/lining inspection criteria with the inspection criteria and aging mechanisms specified in the Coatings Condition Assessment Program. 4. Procedures will be revised to require inspections of cementitious coatings/linings and include aging mechanisms associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation. 5. Procedures will be revised to require cementitious coatings/linings inspectors to have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of one year of experience. 6. Procedures will be revised to require opportunistic inspections of piping internally lined with concrete and include aging associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation. (Added - Change Notice 2) 7. Component cooling heat exchanger channel head coatings are inspected on a one-year inspection interval. Procedures will be revised to require that if two subsequent inspections demonstrate no change in coating condition (i.e. at least three consecutive inspections with no change in condition), inspection frequencies at those locations may be conducted consistent with inspection Category B of NUREG-2191 Table XI.M42-1. (Revised - Set 3 RAIs)	B2.1.28	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that 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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
28	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	8. ~~Procedures will be revised to require a pre-inspection review of the previous "two" condition assessment reports, when available, be performed, to review the results of inspections and any subsequent repair activities.~~Procedures will be revised to require a coatings specialist to prepare the coatings post-inspection condition assessment report. A pre-inspection review will be performed of the coating inspections and any subsequent repair activities from the previous two coatings post-inspection condition assessment reports, when available. (Revised - Set 3 RAIs) 9. Procedures will be revised to require inspection results are evaluated against acceptance criteria to confirm that the components' intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate and extent of degradation. Where practical, (e.g., wall thickness measurements, blister size and (frequency), degradation is projected until the next scheduled inspection. (Added - Change Notice 2) 10. Procedures will be revised to: a. Specify there are no indications of peeling or delamination. (Revised - Change Notice 2) b. Require inspection of cementitious coatings/linings. Minor cracking and spalling is acceptable provided there is no evidence that the coating/lining is debonding from the base material. c. Require, as applicable wall thickness measurements, projected to the next inspection, meet design minimum wall requirements. (Revised - Change Notice 2) 11. Procedures will be revised to permit the "removal" of coatings/linings that do not meet acceptance criteria, with the required evaluation and documentation. 12. Procedures will be revised to include as an alternative to repair, rework, or removal, internal coatings/linings exhibiting indications of peeling and delamination. The component may be returned to service if: a. Physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal b. ~~The~~the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered) ~~adhesion testing (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of three sample points adjacent to the defective area~~(Revised - Change Notice 2) c. adhesion testing using ASTM International Standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of 3 sample points adjacent to the defective area. (Revised - Change Notice 2 d. ~~An~~an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component and (Revised - Change Notice 2) e. ~~Follow-up~~follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, or until the degraded coating is repaired or replaced.(Revised - Change Notice 2)	B2.1.28	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that 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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
28	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	13. Procedures will be revised to require ~~additional inspections if one of the license renewal inspections does not meet acceptance criteria due to current or projected degradation.~~ when a blister does not meet acceptance criteria, and it is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain inservice should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister.(Revised - Change Notice 2) 14. Procedures will be revised to require additional inspections be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of increased inspections will be determined in accordance with the Corrective Action Program. However, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. When inspections are based on the percentage of piping length, an additional 5% of the total length will be inspected. The timing of the additional inspections will be based on the severity of the degradation identified and will be commensurate with the potential for loss of intended function. However, in all cases, the additional inspections will be completed within the interval in which the original inspection was conducted, or if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to provide reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections will include inspections with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. (Added - Change Notice 2) 15. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material. (Added - Change Notice 2)	B2.1.28	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that 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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
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: decontamination building, radwaste facility, health physics yard office building, laundry facility, and machine shop. Inspections for the added structures will be performed under the enhanced program in order to establish quantitative baseline inspection data prior to the subsequent period of extended operation. (Revised - Change Notice 1) 2. Procedures will be revised to add the oiled-sand cushion to the inspection of the fire protection/domestic water tank foundation.(Added - Change Notice 3) 3. Procedures will be revised to include preventive actions to ensure 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using High-Strength Bolts," will be used. 4. The checklist for structural and support steel will be revised to indicate: "Are any connection members loose, missing or damaged (bolts, rivets, nuts, etc.)?". (Added - Change Notice 2) 5. ~~Procedures will be revised to require at least five years of experience (or ACI inspector certification) for concrete inspectors to be consistent with ACI 349.3R-002.~~ Procedures will be revised to require at least five years of experience (or ACI inspector certification) for concrete inspectors to be consistent with ACI 349.3R-002. Procedures will be revised to eliminate options for inspector qualifications that are not consistent with ACI 349.3R-002.(Revised - Change Notice 2) 6. ~~Procedures will be revised to inspect wooden power poles on a 10 year frequency.Procedures will be revised to specify that wooden pole inspections will be performed every ten years by an outside firm that provides wooden pole inspection services that are consistent with standard industry practice. Visual examinations may be augmented with soundings or other techniques appropriate for the type, condition, and treatment of the wooden poles, including borings to determine the location and extent of decay and excavation to determine the extent of decay at the groundline. (Revised - Change Notice 2)~~ Procedures will be revised to specify that wooden pole inspections will be performed at a frequency not to exceed every eight years. Visual examinations will detect loss of material and change in material properties. Visual examinations will be augmented, as required to detect change in material properties, with soundings or other techniques appropriate for the type, condition, and treatment of the wooden poles, including borings and excavations. (Revised - Set 4 RAIs) 7. Procedures will be revised to specify that 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. (Added - Change Notice 2)	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation. A baseline inspection for wooden poles will be performed prior to January 1, 2031.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
34	*Structures Monitoring* program	8. Procedures will be enhanced to specify VT-1 inspections to identify cracking on stainless steel and aluminum components. A minimum of 25 inspections will be performed every ten years during the subsequent period of extended operation from each of the stainless steel and aluminum component populations assigned to the Structures Monitoring program. If the component is measured in linear feet, at least one foot will be inspected to qualify as an inspection. For other components, at least 20% of the surface area will be inspected to qualify as an inspection. The selection of components for inspection will consider the severity of the environment. For example, components potentially exposed to halides and moisture would be inspected, since those environmental factors can facilitate stress corrosion cracking. (Added - Change Notice 2) 9. Procedures will be enhanced to specify that for the neutron shield tank (NST), loss of material due to corrosion, other than superficial corrosion, will be evaluated to ensure that the NST will continue to perform its intended functions, including structural support of the RPV. (Added - Set 2 RAIs) 10. Procedures will be enhanced to specify for the sampling-based inspections to detect cracking in stainless steel and aluminum components, additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. No fewer than five additional inspections for each inspection that did not meet acceptance criteria or 20 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. Additional inspections will be completed within the 10-year inspection interval in which the original inspection was conducted. The responsible engineer will initiate condition reports to generate work orders to perform the additional inspections. The responsible engineer will evaluate the inspection results, and if the subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted. The responsible engineer will then determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the Corrective Action Program. (Added - Change Notice 2) 11. Procedures will be enhanced to specify that evaluation of neutron shield tank findings consider its structural support function for the reactor pressure vessel. (Added - Change Notice 3) 12. Procedures will be enhanced to also include LOCAs as events that require evaluation for potentially degraded structures by Civil/Mechanical Design Engineering. (Added - Change Notice 3)	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

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-02, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.” The inspection of structural components, including masonry walls and water-control structures, are performed at intervals not to exceed five years, except for wooden poles, which are inspected on a ~~10 year frequency~~frequency not to exceed every eight years.

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).

ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel and aluminum components.

B2.1.16 Fire Water System

Program Description

The *Fire Water System* program is an existing condition monitoring program that manages loss of material, flow blockage, cracking and loss of coating integrity for in-scope water-based fire protection systems. This program manages aging effects by conducting periodic visual inspections, flow testing, and flushes. Testing and inspections are conducted on a refueling outage interval as allowed by NUREG-2191, Section XI.M27, Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations". There are no nozzle strainers, glass bulb sprinklers, fire pump suction strainers, or foam water sprinkler systems within the scope of subsequent license renewal.

The *Fire Water System* program will include testing a representative sample of the sprinklers prior to fifty years in service with additional representative samples tested at 10-year intervals. Sprinkler testing will be performed consistent with the 2011 Edition of NFPA 25, "Standard For The Inspection, Testing and Maintenance of Water-Based Fire Protection Systems," Section 5.3.1. The fifty year in-service date for sprinklers is October 26, 2021.

Portions of water-based fire protection system components that have been wetted, but are normally dry, such as dry-pipe or preaction sprinkler system piping and valves, were designed and installed with a configuration and pitch to allow draining. With the exception of two locations, Engineering walkdowns confirmed the as-built configuration that allows draining and does not allow water to collect. Corrective actions have been initiated for the two locations to verify a flow blockage condition does not exist and to restore the two locations to original configuration requirements that allow draining and do not allow water to collect. After corrective actions, portions of the water-based fire protection system that have been wetted, but are normally dry, will not be subjected to augmented testing and inspections beyond those required by NUREG-2191, AMP XI.M27, Table XI.M27-1.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. A low pressure condition is alarmed in the Main Control Room by the auto start of the electric motor driven fire pump, followed by the start of the diesel-driven fire pump if the low pressure condition continues to exist. The status of the fire pumps is indicated in the Main Control Room and at the fire pump control panels in the pump house. Both fire pumps may be manually started from the control room.

Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed and the source is detected and corrected.

Inspections and tests are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Non-code inspections and tests follow procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

If a flow test (i.e., NFPA 25, 2011 Edition, Section 6.3.1) or a main drain test (i.e., NFPA 25, 2011 Edition, Section 13.2.5) does not meet the acceptance criteria due to current or projected degradation, additional tests are conducted. The number of increased tests is determined in accordance with the site's corrective action process; however, there are no fewer than two additional tests for each test that did not meet the acceptance criteria. The additional inspections are completed within the interval (i.e., five years or annual/refueling) in which the original test was conducted. If subsequent tests do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests required. The additional tests will include at least one test at the other unit on site with the same material, environment, and aging effect combination.

In addition to piping replacement, actions will be taken to address instances of recurring corrosion due to microbiological induced corrosion. Low Frequency Electromagnetic Technique (LFET) or similar scanning technique will be used for screening 100 feet of accessible piping during each refueling cycle to detect changes in the wall thickness of the pipe. Thinned areas found during the LFET scan are followed up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

Aging of the external surfaces of buried and underground fire main piping is managed by the *Buried and Underground Piping and Tanks* program (B2.1.27). Loss of material and cracking of the internal surfaces of cement lined buried and underground fire main piping are managed by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28).

Aging of the fire water storage tank bottom surfaces exposed to oil soil are managed by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (B2.1.17).

When degraded coatings are detected during internal inspections of the fire water storage tanks, acceptance criteria, and corrective action recommendations of the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) are followed. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard.

NUREG-2191 Consistency

The *Fire Water System* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI M27, Fire Water System.

Exception Summary

The following program element(s) are affected:

1. (Deleted exception for fire water storage tanks insulated external surface inspections - Change Notice 3) NUREG-2191, Table XI.M27-1, note 10 recommends main drain tests at each water-based system riser to determine if there is a change in the condition of the water piping and control valves on an annual or refueling outage interval. Surry Power Station will perform the main drain tests on twenty percent of the standpipes and risers every refueling cycle.

Justification for Exception

As indicated by NUREG-2191 Table XI.M27-1, note 10, access for some inspections is feasible only during refueling outages which are scheduled every eighteen months. Main drain tests on twenty percent of the standpipes and risers every eighteen months provide adequate information to determine the condition of the fire water piping is maintained consistent with the design basis.

Enhancements

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

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

1. (Sprinkler inspections - Completed Change Notice 1)
2. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. Additional representative samples will be field-service tested every 10 years thereafter to ensure signs of aging are detected in a timely manner.

   For wet pipe sprinkler systems, a one-time test of sprinklers that have been exposed to water including the sample size, sample selection criteria, and minimum time in service of tested sprinklers will be performed. At each unit, a sample of 3% or a maximum of ten sprinklers with no more than four sprinklers per structure shall be tested. Testing is based on a minimum time in service of fifty years and severity of operating conditions for each population. (Revised - Change Notice 2)
3. Procedures will be revised to specify:

a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five year interval to demonstrate the capability to provide the design pressure at required flow.

b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action.

c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination.

d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures.

4. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect an unexpected level of degradation due to corrosion product deposition. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following: (Relocated from Enhancement 10 and Corrected - Change Notice 2)

   a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected.

   b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

c. Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)

5. Procedures will be revised to perform system flow testing at flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests.(Renumbered - Change Notice 2)

Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)

6. (Hydrant flushing Completed - Change Notice 1 and renumbered - Change Notice 2)
7. Prior to the subsequent period of extended operation, the insulation on the exterior surfaces of the fire water storage tanks (FWSTs) will be permanently removed. Wall thickness measurements will be performed on external tank areas exhibiting unexpected degradation. Refurbishment/recoating will be performed consistent with the severity of the degradation identified and commensurate with the potential for loss of intended function. Inspections of external tank surfaces will be on a refueling cycle frequency.(Renumbered - Change Notice 2 and revised - Change Notice 3)
8. (Strainer flushing completed - Change Notice 1 and renumbered - Change Notice 2)
9. A procedure will be created to provide a Turbine Building oil deluge systems spray nozzle air flow test to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. (Renumbered - Change Notice 2)

(Old Enhancement #9 was relocated to Enhancement 4 - Change Notice 2)

Detection of Aging Effects (Element4)

10. Procedure will be revised to provide inspection guidance related to lighting, distance and offset for non-ASME Code inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used.
11. The Unit 1 hydrogen seal oil system deluge sprinkler pipe and Unit 1 station main transformer '1A' deluge sprinkler piping will be reconfigured to allow drainage. As part of the drainage

reconfiguration, visual inspections and wall thickness measurements will be performed on the Unit 1 hydrogen seal oil system deluge sprinkler pipe that does not drain. In addition, wall thickness examination of the Unit 1 main transformer deluge sprinkler piping that does not allow drainage will also be performed as part of the drainage reconfiguration. Piping with unexpected degradation will be replaced.-(Revised – Change Notice 3)

12. The program will be revised to require inspections and tests be performed by personnel qualified in accordance with site procedures and programs for the specified task. (Added Change Notice 2)

13. Procedures will be revised to require when degraded coatings are detected by internal coating inspections, acceptance criteria and corrective action recommendations consistent with the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers and Tanks (B2.1.28) program are followed in lieu of NFPA 25 section 9.2.7 (1), (2), and (4). When interior pitting or general corrosion (beyond minor surface rust) is detected, tank wall thickness measurements are conducted as stated in NFPA 25 Section 9.2.7(3) in vicinity of the loss of material. Vacuum box testing as stated in NFPA 25 Section 9.2.7(5) is conducted when pitting, cracks, or loss of material is detected in the immediate vicinity of welds. (Added Change Notice 2)

14. The activity of the jockey pump will be monitored consistent with the "detection of aging effects" program element of NUREG-2191, Section XI.M41. (Added - Set 3 RAIs)

Detection of Aging Effects (Element4) and Acceptance Criteria (Element 6)

15. Procedures will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, the performance of opportunistic visual inspections of the fire protection system will be required whenever the fire water system is opened for maintenance.

Operating Experience Summary

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

1. In January 2012, an Engineering walkdown of the fire protection piping header along the north wall of the Unit 2 Turbine Building revealed a potential leak location on the supply line to a hose rack. The flanged connection and straight pipe were removed and replaced.
2. In January 2012, a section of 2-inch fire protection "drop" piping in the Turbine Building developed a leak. The investigation for extent of condition and determination for the extent of fire protection piping to be inspected and replaced, as necessary, involved inspections of three locations in the Turbine Building and three locations in the Auxiliary Building. Microbiologically induced corrosion (MIC) was evident in many locations, but the extent of corrosion was not as severe in the Auxiliary Building as it was in the Turbine Building. Despite the less severe corrosion in the Auxiliary Building, the three segments of piping that were inspected were replaced. Similarly, one of the three segments of piping in the Turbine Building was replaced.

   A capital project was proposed for a multi-year process of replacing segments of 2-inch, 4-inch, and 10-inch piping in the Turbine Building. The initial phase that was completed included replacing 200 feet of ten inch piping in the Turbine Building. Additional phases were proposed, and described in the Fire Protection Strategic Plan. See April 2013 and November 2015 operating experience.
3. In June 2012, during inspection of Auxiliary Building fire protection piping minor sediment was discovered in the supply header to the Unit 1 cable tunnel sprinklers. Debris and MIC nodules were discovered inside a spool piece and accessible four inch piping. The sediment and debris were removed, the visual inspection was performed, and the blind flanges and spool pieces were replaced. The necessary pipe replacement is included in the Fire Protection Strategic Plan.
4. In March 2013, NRC Information Notice 13-06, "Corrosion in Fire Protection Piping Due to Air and Water Interaction", identified industry operating experience involving the loss of function of fire protection water systems due to the potential for adverse air and water interactions in pre-action and dry-pipe systems. Engineering evaluated the potential for similar adverse conditions and associated degradation in deluge systems at Surry Power Station that are periodically flow tested. Subsequently, in January 2018, a walkdown was performed to confirm that plant design specifications on drainage features for piping downstream of all in-scope pre-action and deluge valves in the fire protection system continued to be in effect. Two locations, one relating to main transformer 1A and one relating to Unit 1 generator hydrogen seal oil system, were identified as having a potential for adverse air and water interactions and entered into the corrective action program.

5. In April 2013, a section of two 10-inch fire protection system piping in the Turbine Building developed a leak. A walkdown of six locations was performed to determine extent of condition in the Turbine Building and the Auxiliary Building. MIC was evident in four locations, but the extent of corrosion in the Auxiliary Building was not as severe. Replacement of 4-inch and 10-inch fire protection header is a like-for-like replacement. The replacement of the Turbine Fire Protection Header was split into four different phases. One phase was to be accomplished each year. The second phase is planned to replace approximately 400 feet of ten-inch header pipe and 200 feet of two-inch hose station pipe. The necessary pipe replacement is included in the Fire Protection Strategic Plan.

6. In February 2014, visual and volumetric inspections were performed for Fire Protection/domestic water storage tank 1A to determine the extent of additional degradation that had occurred since similar inspections were completed in December 2008. The most significant degradation was noted on the tank floor. The result of the visual inspection was that coating degradation was continuing, and that some bare metal was evident. Similarly, volumetric examinations found additional thinning for the tank floor. Follow-up visual examinations were performed in August 2018 and follow-up wall thickness examinations were performed in March 2019. Prior wall thickness measurements were confirmed to be attributed to laminations that existed from original steel plate fabrication. An engineering evaluation projected the tank floor plate would maintain acceptable wall thickness thoughout the subsequent period of extended operation. Work orders were generated to refurbish/recoat the FWST interior surfaces prior to the subsequent period of extended operation.

7. In August 2014, visual and volumetric inspections were performed for Fire Protection/domestic water storage tank 1B to determine the extent of additional degradation that had occurred since similar inspections were completed in December 2008. The most significant degradation was noted on the tank floor. Follow-up visual examinations were performed in August 2018 and follow-up wall thickness examinations were performed in March 2019. Prior wall thickness measurements were confirmed to be attributed to laminations that existed from original steel plate fabrication. An engineering evaluation projected the tank floor plate would maintain acceptable wall thickness thoughout the subsequent period of extended operation. Work orders were generated to refurbish/recoat the FWST interior surfaces prior to the subsequent period of operation.

8. In September 2014, a materials analysis was performed on buried cement lined grey cast iron fire main piping that was fractured during flow testing of hose station valves. The fracture was attributed to a latent material defect in the cast iron. The piping was removed and replaced with an equivalent spool piece. Based on the oxidation along the top segment of the crack, the pipe was cracked for a long period of time. High levels of calcium deposits on the fracture (from the cement lining) indicate that the pipe was partially cracked at the top segment before factory installation of the cement liner (manufacturing process). Material analysis of the pipe determined that the microstructure consisted of graphite flakes that were approximately 75%

ferrite and 25% pearlite. This resulted in a reduction in the supplied material hardness. Failure of pipe was not preventable through maintenance. The failure was caused by ground settling. During the pipe replacement it was observed that there was vertical misalignment between the replacement pipe and the existing buried pipe, which indicated that the buried side piping was exerting a large bending load at the anchor/foundation. This bending load along with the pre-existing crack and lower hardness value caused the pipe fracture. The balance of the failed pipe was found in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, or reduction of pipe interior diameter.

9. In November 2015, an effectiveness review of the Fire Protection Program aging management activity (AMA) (UFSAR Section 18.2.7) was performed. The AMA was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. A comprehensive fire water system assessment recommended a large scale piping replacement of turbine building and auxiliary building piping. The large scale piping replacement project to be performed over multiple refueling outages was identified as a measure to address degradation in carbon steel system piping and to ensure that system intended functions were maintained. Completed and closed phases of this effort have included replacement of approximately 400 feet of 4 inch piping and 200 feet of 2 inch piping in 2014 and approximately 567 feet of 4 inch piping and 303 feet of 2 inch piping in 2015. An additional phase replacing approximately 175 feet of 4 inch piping and 100 feet of 2 inch piping has been completed and is awaiting final testing. Work documents for additional phases are planned and issued for work extending into 2019.

10. In March 2019, results from fire protection system 2500 gpm flow tests with the motor driven fire pump from 2014 through 2019 consistently showed satisfactory system pressure for the corresponding flow rate. The trend from these results does not indicate significant degradation over the five-year interval, particularly considering the two most recent measurements. Results from fire protection system 2500 gpm flow tests with the diesel driven fire pump from 2014 through 2019 also consistently showed satisfactory system pressure for the corresponding flow rate. There is confidence that continued implementation of flow monitoring for the fire protection system using the three year interval required by the Technical Requirements Manual will effectively manage aging prior to a loss of intended function.

11. 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.

12. In November 2017, as part of oversight reviews of the Fire Protection Program AMA (UFSAR Section 18.2.7), an inconsistency was identified in the performance interval for system integrity demonstration by main drain testing. The test interval had been extended from quarterly to each 18 months but the extended interval had not been incorporated into program documents. An Engineering Assignment to review operating experience to trended performance data to 2011 has been completed with no significant degrading trends observed. The new interval is consistent with the test interval of NFPA 25 (2011 Edition) Table 13.1.1.2 modified by NUREG-2191, Section XI.M27, Table XI.M27-1, Note 10.

13. In January 2018 an aging management program effectiveness review was performed for the Fire Protection Program AMA (UFSAR Section 18.2.7). Information from the summary of that effectiveness review is provided below:

    The Fire Protection Program AMA is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the Fire Protection Program AMA that were reviewed include the inspection of components, the evaluation of inspection results, repairs/replacements, corrective actions, and AMA document updates. Engineering reports from 2006 to 2017 of inspections results were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of fire protection components within the scope of license renewal.

    In the past, multiple fire water piping leaks had been identified in the Unit 1 and Unit 2 Turbine Buildings. As a result, a five phase large scale fire protection piping replacement project has been underway since 2015 to replace Turbine Building header piping and hose station piping as well as the Unit 1 and Unit 2 Auxiliary Building Hose station piping. Two of the Turbine Building phases are complete and two are waiting on testing. Phase five includes the remaining scope in the turbine building and the entire scope in the Auxiliary Building and is planned to start in 2018. Once complete, a large majority of the above ground fire protection piping in the plant will have been replaced, including areas where reoccurring leaks were previously identified.

    The fire water/domestic water storage tanks are managed by the Tank Inspection Activities AMA (UFSAR Section 18.1.3); but, are also discussed here for overall fire protection performance considerations. The fire water/domestic water storage tanks were found to have failing internal coatings and loss of material on the tank floors. Estimates for projected useable tank lifetime and evaluations for additional monitoring were performed. Recommendations are being prepared for repair or replacement project considerations.

Multiple operating issues, and obsolescence of the diesel driven fire pump resulted in a design change that replaced the diesel driven fire pump and associated control panel. The new diesel driven fire pump has exhibited substantially improved performance compared to the original fire pump.

Activities to implement NFPA 25, 1998 Edition, Section 2-3.1.1 (1998 edition), testing of sprinklers that have been in service for fifty years have been initiated to prove continued functionality. The Unit 1 and Unit 2 turbine building sprinklers have been sampled and will be tested by 2021, when fifty years of service is reached.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to microbiological induced corrosion, has occurred on several occasions. Periodic fire protection system piping flushes, flow testing and piping thickness measurements will be performed to identify pipe degradation prior to loss of system intended function. Periodic visual inspections and tank bottom thickness measurements are performed on the fire water storage tanks. In addition to recent piping replacements in the Turbine Building and the Auxiliary Building to address instances of RIC due to microbiologically-influenced corrosion, Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. Thinned areas found during the LFET scan are followed-up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

The above examples of operating experience provides objective evidence that the *Fire Water System* program includes activities to perform periodic fire main and hydrant inspections and flushing, sprinkler inspections, functional test, and flow tests to identify loss of material, flow blockage, and loss of coating integrity for in-scope water-based fire protection systems within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fire Water System* 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. Appropriate 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 *Fire Water System* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Fire Water System* program, following enhancement, 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 loss of material, blistering, and cracking on external surfaces of piping and tanks in soil or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses piping and tanks composed of steel, stainless steel, copper alloys, fiberglass reinforced plastic, and concrete. 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 electrochemical verification of the effectiveness of cathodic protection, non-destructive evaluation of pipe or tank wall thicknesses, performance monitoring of fire mains, and visual inspections of the pipe from the exterior.

The buried carbon steel piping of the fuel oil system for emergency electrical power system is the only buried piping that is protected by an active CP system. Monthly periodic inspections confirm CP system availability and 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 balance of piping and tanks within the scope of subsequent license renewal are not provided with CP. Based on soil sampling and testing, it has been determined that installation and operation of CP is not necessary. Soil sampling and testing is performed during each excavation and a station-wide soil survey is also performed once in each 10-year period to confirm that the soil environment of components within the scope of license renewal is not corrosive 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."

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, the sample size is increased.

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 aging effects associated with the external surfaces of buried concrete piping in the circulating water system will be managed by the *Open-Cycle Cooling Water System* program (B2.1.11). The *Open-Cycle Cooling Water System* program (B2.1.11) will periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The *Open-Cycle Cooling Water System* program (B2.1.11) will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. 100% of the accessible circulating water line internal surfaces will be inspected in a ten year period. The *Buried and Underground Piping and Tanks* program will opportunistically inspect the buried concrete circulating water lines when scheduled maintenance work permits access.

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

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 elements:

Preventive Actions (Element 2)

1. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings.

2. (Completed Change Notice 2)

~~Parameters Monitored or Inspected (Element 3)~~

3. 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. (Added - Set 1 RAIs)

Preventive Actions (Element 2) and Detection of Aging Effects (Element 4)

4. Procedures will be revised to require uncoated buried stainless steel tubing segments in the fuel oil system be inspected prior to the subsequent period of extended operation. After inspection, each uncoated stainless steel segment will be coated consistent with Table 1 of NACE SP0169-2007, "~~Standard Recommended Practice, Cathodic Protection of Prestressed Concrete Cylinder Pipelines.~~Control of External Corrosion on Underground or Submerged Metallic Systems" (Added - Set 1 RAIs) (Revised - Set 3 RAIs)

5. A cathodic protection system will be installed for protection of the 24-inch service water piping at the Low Level Intake Structure five years before entering the subsequent period of operation. (Added - Set 3 RAIs)

Acceptance Criteria (Element 6)

6. Procedures will be revised to specify that cathodic protection surveys use the -850mV 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 -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate.

   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 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.

     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).

When using the electrical resistance corrosion rate probes:

a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar

b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data (Revised - Change Notice 2 and Set 1 RAIs)

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In June 1994, leakage was identified in buried, carbon steel, emergency diesel generator (EDG) fuel oil lines. The leak was discovered through external visual inspection, internal boroscope inspection, and pressure drop air testing, and considered to be due to internal pitting corrosion. The 1½ inch schedule 80 carbon steel piping system was replaced with 2½ inch schedule 160 carbon steel lines in 1995. Excavation, fill placement, compaction, and testing of the soil were done in accordance with design specifications. The bedding material for the fuel oil lines is a select granular fill consisting of clean well graded sand. The coating material provided is a synthetic elastomeric tape wrap. A passive cathodic protection system was installed in 1995 to protect the buried fuel oil piping from corrosion. This passive system became degraded as the sacrificial anodes were increasingly being drained off to station grounds.

   In May 2015, an impressed current cathodic protection system was installed and placed in service to replace the passive cathodic protection system on the buried, carbon steel, EDG fuel oil lines. One of the two new rectifier units was in a degraded condition from August 2015 through February 2016, until it was restored to operation by corrective maintenance. The NACE annual inspection completed in April 2016 concluded that the system was providing adequate cathodic protection consistent with NACE criteria. Monthly inspections confirm rectifier operation.

2. In May 2004, portions of the Unit 2 auxiliary feedwater system experienced leakage in the buried carbon steel recirculation piping. The primary cause of the leak was pitting corrosion due to poorly applied coating. As a corrective action, the Unit 1 and Unit 2 AFW recirculation system piping is no longer buried and was rerouted through the safeguards building basement. The extent of condition assessment portion of the root cause evaluation noted the following:
   - The corresponding auxiliary feedwater recirculation line on Unit 1 had been discovered to be leaking and was subsequently bypassed and abandoned as part of a design change,
   - Stainless steel liquid waste piping in excellent condition,
   - Carbon steel chilled water piping with wrap intact and no indication of corrosion,
   - Carbon steel auxiliary feedwater piping with wrap in good condition and no indication of corrosion, and
   - Leaking fuel oil pipe with indications of localized pitting that was replaced and re-routed.
3. In June 2010, while removing coating from the Unit 2 condensate makeup buried carbon steel piping, pitting was identified on several areas of the pipe where the coating had been removed. The pitting was seen at three locations and was characterized as shallow. The as-found condition of the pipe was within code requirements and determined to be fit for service. Following inspection the coating was restored.
4. In July 2012, excavation revealed leakage from a buried Unit 2 ten inch stainless steel condensate supply line. There appeared to be an approximate three to four inch circumferential crack in the line that had started along the outside diameter of the pipe. The crack was determined to be caused by transgranular stress corrosion cracking due to mechanical damage by excavation equipment. The replacement pipe is not buried and has been rerouted through the turbine building.
5. In June 2016, a Dominion Energy fleet self-assessment was performed on the Underground Piping and Tank Integrity (UPTI) Program to ensure the program is supporting the goal of providing long term reliability of buried and underground piping and tanks; to ensure consistency with NEI 09-14, Guideline for the Management of Underground Piping and Tank Integrity, and NSIAC requirements; and ensure the program meets industry best practices. Implementation of the UPTI Program was reviewed to confirm performance of inspections, effectiveness of scheduling and tracking, and program optimization based on inspection results.

   This self-assessment identified one performance deficiency in that the 2015 UPTI Life Cycle Management Plan (LCMP) was issued by engineering transmittal without being approved at Plant Health Steering Committee. The 2016 UPTI LCMP was approved by Plant Health Steering Committee.

A strength was noted in that the inspections required by the UPTI LCMP are being scheduled, tracked, and performed as expected; and the results are being used appropriately to determine the next inspection. The UPTI team reviews operating experience during fleet calls and incorporates the experience into the program and inspections as appropriate.

6. 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.
7. In May 2017, during the as-found coating inspection on Unit 2 buried carbon steel condensate makeup piping, coating was missing on approximately 270 degrees of the pipe circumference from the center of the excavated area into the soil on the east side. Coating on the bottom was remaining. There was no visible leakage from this condensate makeup line piping segment. Ultrasonic testing of the piping segment demonstrated that the minimum wall thickness requirement was met or exceeded at each location tested. The protective coatings were restored.
8. In November 2017, as part of oversight review activities, the Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.
9. In January 2018, an aging management program effectiveness review was performed of the initial license renewal Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1). Information from the summary of that effectiveness review is provided below:

   The Buried Piping and Valve Inspection Activities is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the Buried Piping and Valve Inspection Activities that were reviewed included the selection of components to be inspected, the inspection of components, the evaluation of inspection results, repairs/replacements, and AMA document updates. Engineering reports of inspections results from 2004 to 2016 were reviewed to confirm inspections were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of buried components within the scope of license renewal.

A living Life Cycle Management Plan (LCMP) that identifies inspection plans at the next five year interval is maintained based on piping wall thickness calculations, risk ranking and internal/industry operating experience. In 2004, leakage from a buried auxiliary feedwater pipe and in 2012 leakage from a buried condensate pipe resulted in design changes to reroute the piping through non-buried environments. Observed coating degradations during recent inspections resulted in coating repairs and pipe wall thickness evaluations to anticipate rates of change and confirm fitness for service. Quarterly reviews by the fleet UPTI program owners review industry and plant operating experience, including corrective actions, to identify adjustments to the program. Recent fleet operating experience from North Anna Power Station for a service water to auxiliary feedwater pipe resulted in accelerated inspection schedules for similar carbon steel piping at SPS.

In 2014, based on industry feedback, the EDG fuel oil sacrificial anode cathodic protection (CP) system was replaced with an impressed current system. Recent program reviews identified required updates to the maintenance procedures for the impressed CP system. In June 2017, as part of an Industry Material Review Visit, no adverse findings were noted for the UPTI program. Recent industry research and development is reviewed and incorporated into the program as appropriate. New soil survey studies consistent with EPRI 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," will identify any areas of soil corrosivity.

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 loss of material, cracking, and blistering 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, 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.

B2.1.8 Flow-Accelerated Corrosion

Program Description

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

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

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

Flow Accelerated Program Description

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

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

Erosion Control Program Description

The basis for erosion monitoring is an Erosion Susceptibility Evaluation (ESE) that identifies components that require inspection due to potential wall thinning caused by cavitation, flashing, liquid droplet impingement (LDI), or solid particle erosion (SPE). The ESE includes each system that could be degraded by any of these four mechanisms. The majority of the erosion monitoring inspection scope is based on the ESE, and is determined in a manner similar to the process for "Susceptible Non-modeled" (SNM) lines used for the FAC program. Lines are risk ranked based on the level of plant safety, erosion susceptibility, and consequence of failure.

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

The CHECWORKS Erosion Module is not used to determine susceptibility, or select systems for inspection, as all lines modeled in the Erosion Module are identified using the ESE. The outputs from the Erosion Module are used to help identify predicted erosion locations to be inspected on susceptible lines. Those outputs are not used to exclude lines from the inspection scope, but are used to help establish the priority of inspections. The Erosion Module does not calculate a remaining service life or projected wall thickness. Those determinations occur as engineering evaluations performed outside of the Erosion Module.

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

NUREG-2191 Consistency

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

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) and Detection of Aging Effects (Element 4)

1. An engineering evaluation will be performed for systems that have been excluded from the FAC program due to no flow or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time. The purpose of the engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The engineering evaluation and modeling changes for the FAC program will be completed prior to entering the subsequent period of extended operation.
2. A re-evaluation of the erosion susceptibility determination that identified plant systems in the scope of subsequent license renewal that were previously excluded from monitoring will be performed to re-affirm that the appropriate basis for exclusion either is in-service operational and testing time less than 100 hours per year, or is a technical evaluation specifically developed to exclude a system. (Added - Set 4 RAIs)
3. A re-evaluation will be performed to determine whether plant conditions (e.g., valve throttling) have changed such that susceptibility to erosion has increased for plant systems within the scope of subsequent license renewal. (Added - Set 4 RAIs)

Detection of Aging Effects (Element 4)

4. Procedure will be revised to confirm that inspection scope expansions include the items noted below and to confirm that independent reviews of inspection scope expansions are independently reviewed by a qualified FAC engineer.
   - Any component within two pipe diameters downstream of the component displaying significant wear, or within two pipe diameters upstream if that component is an expander or expanding elbow.
   - The two most susceptible components from the CHECWORKS relative wear rate ranking in the same train containing the piping component displaying significant wear.
   - Corresponding components from other trains.
   - Inspections of additional components until no additional components with significant wear are detected.

Operating Experience Summary

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

FAC Operating Experience

1. In April 2009, FAC inspections were performed during the refueling outage using the ultrasonic testing technique. Those inspections found that two 1.5 inch nominal OD sections of piping in the main steam system had minimum wall thickness below 65% of nominal, and required replacement. That replacement effort was completed using FAC-resistant piping prior to resuming power operation. A review of the inspection history for the associated lines and for parallel trains was conducted, and a scope expansion of six extra main steam lines was identified. The completion of the follow-on scope expansion and evaluation demonstrated an ongoing focus within the *Flow-Accelerated Corrosion* program for susceptible components.

2. Industry Operating Experience: In August 2009, industry OE described a steam piping failure that caused a plant shutdown. A FAC review revealed a similar small-bore piping arrangement at Unit 2. No similar finding was identified for Unit 1. Accordingly, those pipe sections were replaced during the subsequent Unit 2 refueling outage.

3. In November 2009, as part of the *Flow-Accelerated Corrosion* program, an 18" diameter section of feedwater system piping was UT inspected and found to have inadequate wall thickness, thus requiring replacement during the current refueling outage. A work order was completed to replace the piping section using CrMo material prior to resuming power operation.

4. In November 2010, after a main steam trip valve was removed to allow replacement due to erosion at the lower gasket seat, Engineering performed a visual FAC inspection of the upstream and downstream components. Wall thinning was found on the downstream elbow. The three inch carbon steel elbow was replaced using CrMo material.

5. In April 2011, several components on a ten inch condensate polishing line were UT inspected during the refueling outage as part of the *Flow-Accelerated Corrosion* program. The measured wall thickness for a nozzle was projected to be below the minimum allowable wall thickness prior to the next refueling outage, thus requiring replacement or repair during the current outage. Weld buildup repairs were completed for the nozzle and associated elbow prior to resuming power operation.

6. In December 2015, an effectiveness review of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) was performed. The AMA was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. The results of that review indicated that license renewal references were not included in the Flow Accelerated Corrosion Activity procedures. Resolution was achieved by revising the controlling procedures for the Flow Accelerated Corrosion Activity to provide references to the technical reports or pertinent section of the license renewal application for the license renewal commitments.
7. In November 2016, a fleet self-assessment of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) was completed. The assessment included a review, with industry peers, of standard processes for the Flow Accelerated Corrosion Activity to identify whether they were as efficient and effective as possible. No Areas for Improvement were identified, but it was determined that efficiencies could be gained by implementing more modern technologies. Opportunities for procedure enhancements also were identified. Since 2016, FAC Manager software has been placed in service to automate the process of transferring component evaluation results into CHECWORKS-SFA™. Procedure enhancements continue to be processed.
8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
9. In November 2017, as part of oversight review activities, the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

10. In January 2018, an AMP effectiveness review was performed of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16). Information from the summary of that effectiveness review is provided below:

    The Flow Accelerated Corrosion Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. The activity uses ultrasonic testing (UT) to perform wall thickness measurements of piping that is susceptible to FAC in either single or two-phase flow conditions. Visual inspections of the internals of plant piping systems are performed as the equipment is opened for other repairs and/or maintenance to detect flow accelerated corrosion (FAC) degradation. Condition Reports (CRs) for a 10-year period (July 2006-June 2016) have been reviewed to identify examples of degradation resulting from FAC.

    Reviews of FAC inspection results determine whether the component needs to be replaced during the outage in which it was inspected, or whether the remaining wall thickness and measured wear rate justify continued operation until the next inspection opportunity or planned replacement. Inspection results are used to determine whether examination frequencies are appropriate, and whether additional components need to be inspected or replaced to address the extent of degradation in similar components. The application of both visual and UT inspections have been confirmed to be appropriate. CRs are monitored by the Flow Accelerated Corrosion activity owner to identify potential impacts for the Flow Accelerated Corrosion Activity.

    Industry Operating Experience (OE) is discussed during fleet conference calls, and reviews are performed to determine whether a revision of the Flow Accelerated Corrosion Activity is needed. As an example, an OE item from a U.S. nuclear power plant describes an extraction steam drain line failure that caused a unit shutdown. A FAC OE review identified a similar small-bore piping arrangement at Unit 2. Accordingly, those pipe sections were replaced during the subsequent refueling outage. NRC generic communications also are monitored to identify the need for any changes to the Flow Accelerated Corrosion Activity or additions for the scope of inspections.

Erosion Operating Experience

11. In October 2006 the 14" combined recirculation line for the Unit 2 Main Feed Pumps was discovered to have four through-wall, pin-hole leaks, near the top of the pipe in a bend section near the condenser. An evaluation noted that, while FAC issues in this line were addressed under an earlier design change in 2003 and FAC-resistant piping was installed, cavitation-erosion scenarios were not adequately considered or addressed in that design change. In May 2008, as part of a design change to address several problems in feedwater recirculation flow and pump operations, changes were made in the design and arrangement of this affected line, and a diffuser was added to mitigate the cavitation-erosion that was occurring in the recirculation line pipe bend.

12. In December 2007, an NDE inspection was performed on a service water line (Cu-Ni piping) to a safety-related HVAC chiller to monitor degradation (erosion) as a result of previous failure evaluations. The NDE inspection provided additional wall thinning information until a design change could be implemented. The results of NDE indicated that wall thinning due to erosion (likely cavitation) was continuing, however the readings at that time were above the minimum allowable acceptance criterion. Measured wall loss rates indicated that replacement or repairs were needed in the next six to 12 months. A design change was completed in 2008 to install different pumps and globe valves that significantly reduce the flow velocity.

13. In May 2008 during a preventive maintenance activity, UT thicknesses measurements were taken on the Auxiliary Feedwater pumps' recirculation piping downstream of the orifices at Unit 2. This was based upon an event at Millstone in 2006, where a pinhole leak was discovered in the mini-flow recirculation lines downstream of the restricting orifice (RO). Although there was no through-wall leakage for this piping, the results revealed wall thinning. One Unit 2 line was below the code minimum, so the affected piping was replaced in May 2008. Unit 1 NDE inspections were found acceptable.

14. In December 2008, an engineering inspection of a main control room chiller revealed condenser tube erosion, but no leaks. Per Engineering recommendation, Plastocor coating was placed on the tubes of 'A' main control room chiller in June 2009, and on the tubes of 'C' main control room chiller in July 2010.

The above examples of operating experience provide objective evidence that the *Flow-Accelerated Corrosion* program includes activities to (a) identify all susceptible piping systems and components; (b) develop FAC predictive models to reflect component geometries, materials, and operating parameters; (c) perform analyses of models and, with consideration of operating experience, select a sample of components for inspections to identify wall thinning caused by flow-accelerated corrosion to be managed for susceptible components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Flow-Accelerated Corrosion* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Flow-Accelerated Corrosion* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Flow-Accelerated Corrosion* program, following enhancement, 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.

B2.1.11 Open-Cycle Cooling Water System

Program Description

The *Open-Cycle Cooling Water System* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that manages loss of material, reduction of heat transfer, flow blockage, cracking, and loss of coating or lining integrity of the piping, piping components, and heat exchangers identified by the Virginia Electric and Power Company responses to NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The program is comprised of the aging management aspects of the Virginia Electric and Power Company response to GL 89-13 and includes: (a) surveillance and control to reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of safety-related heat exchangers, (c) routine inspection and maintenance so that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems serviced by the open-cycle cooling water system. Additionally, recurring internal corrosion (RIC) is addressed in the Corrective Action Program through design modifications that have replaced materials more susceptible to degradation in raw water with materials that are less susceptible to degradation in raw water. This program includes enhancements to the guidance in GL 89-13 that address operating experience such that aging effects are adequately managed.

The open-cycle cooling water system includes those systems that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in GL 89-13.

The guidelines of GL 89-13 are utilized for the surveillance and control of biofouling for the open-cycle cooling water system. Procedures provide instructions and controls for chemical and biocide injection. Periodic sampling procedures monitor free available oxidant at heat exchangers. In addition, periodic flushing, cleanings and/or inspections are performed for the presence of biofouling.

Periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the site commitments to GL 89-13 to verify heat transfer capabilities. Titanium tubes and tubesheets are scraped in combination with as found visual inspection of the tubesheet for cracking and eddy current testing for tube denting, pits and cracks with additional annual cleaning to minimize pit/crack initiation points.

Safety-related piping segments are examined (i.e. ultrasonic testing) periodically to ensure that there is no significant loss of material, which could cause a loss of intended function.

Routine inspections and maintenance ensure that corrosion, erosion, sediment deposition (silting), and biofouling do not degrade the performance of safety-related systems serviced by open-cycle cooling water. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) manages the aging effects of the internal surface coatings except those metallic surfaces lined with carbon fiber reinforced polymer (CFRP) that are used as a pressure boundary. The CFRP lined components in the circulating water system and service water system piping will be inspected consistent with ASME Code Case N-871.

Aging effects associated with elastomers and flexible polymeric components in the open-cycle cooling water system are managed by the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25).

The *Buried and Underground Piping and Tanks* program (B2.1.27) manages the aging effects of external surfaces of buried and underground piping and components. The external surface of the aboveground raw water piping and heat exchangers is managed by the *External Surfaces Monitoring of Mechanical Components* program (B2.1.23). The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging effects of internal surface coatings.

The aging effects associated with the external surfaces of buried concrete piping in the circulating water system will be managed by the Open-Cycle Cooling Water System program (B2.1.11). The Open-Cycle Cooling Water System program (B2.1.11) will periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The Open-Cycle Cooling Water System program (B2.1.11) will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. 100% of the accessible circulating water line internal surfaces will be inspected in a ten year period. The *Buried and Underground Piping and Tanks* program (B2.1.27) will opportunistically inspect the buried concrete circulating water lines when scheduled maintenance work permits access.

NUREG-2191 Consistency

The *Open-Cycle Cooling Water System* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M20, Open-Cycle Cooling Water System.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4)

1. Section XI.M20 of NUREG-2191, Open-Cycle Cooling Water, indicates that testing intervals can be adjusted to provide assurance that equipment will perform the intended function between test intervals, but should not exceed five years. The *Open-Cycle Cooling Water System* program takes exception to the NUREG-2191 requirement to perform testing of the recirculation spray heat exchangers (RSHXs) at an interval not to exceed five years.

Justification for Exception:

As described in the plant responses to GL-89-13, heat transfer performance testing of the RSHXs is not performed due to system configuration that would require significant design modifications to support such testing. Alternatively, the RSHXs are visually inspected to confirm the absence of indications of degradation. To further reduce the potential for degradation, the internal environment of the RSHXs and the portion of the connected piping that cannot be isolated from the RSHXs is maintained in dry layup (i.e., maintained in an air environment) and the internals of the portion of the inlet piping that is not in dry layup is maintained in wet layup (i.e., a treated water environment that has been chemically treated to maintain a basic pH) to minimize corrosion. The open-cycle cooling water side of the RSHXs are periodically flow tested and visually inspected.

The plant GL 89-13 responses stated that the RSHXs would be flow tested and visually inspected every fourth refueling outage (i.e., every six years) and that the testing and inspection intervals may be modified based on the results of further testing. Based on the results of further testing, the RSHXs are currently flow tested and visually inspected at an interval of eight refueling outages (i.e., every twelve years).

The change in frequency to once every eight refueling outages for RSHXs flow testing and visual inspection was evaluated by Engineering. The evaluation included a review of prior operating experience (flow testing and visual inspection results). Prior flow test results documented between 1997 and 2010 were reviewed. The test results identified little or no blockage, with the exception of a test performed in 2003. The 2003 results revealed 5% blockage, which was still less than the 10% blockage acceptance criteria. RSHXs service water inlet and outlet piping cleaning and inspection are performed on a frequency consistent with RSHXs flow testing. A review of prior piping inspection results between 1996 and 2014 showed the piping to be in satisfactory condition. Although coating defects and areas of corrosion were identified during the piping inspections, the RSHXs were capable of performing their intended function. Required coating and weld repairs were entered in the Corrective Action Program.

Enhancements

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

Preventive Actions (Element 2)

1. Selected fiberglass reinforced plastic (FRP) piping in the service water system will be replaced with a more degradation resistant material such as copper-nickel (Cu-Ni) prior to entering the subsequent period of extended operation. FRP piping associated with the Units 1 and 2 charging pump cooling water subsystems, service water rotating strainers, and the control room chillers may be replaced as part of a time-phased program.

2. Modifications necessary to provide new chemical injection site upstream of the service water rotating strainers will be completed prior to entering the subsequent period of extended operation.
3. The internal lining of 30 inch and larger service water inlet piping with carbon fiber reinforced polymer, with the exception of the recirculation spray heat exchanger piping downstream of the inlet motor-operated valves, will be completed prior to entering the subsequent period of extended operation. (Revised - Set 2 RAIs)

Parameters Monitored and Inspected (Element 3)

4. (Completed Change Notice 1)
5. Procedures will be revised to provide additional guidance for identifying and evaluating applicable concrete aging effects such as loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; and cracking due to chemical reaction, or corrosion of reinforcement.
6. Procedures will be revised to provide guidance for internal inspection of carbon fiber reinforced polymer piping for aging effects such as voids, blistering, bubbles, cracking, crazing and delamination. (Added - Set 2 RAIs)
7. Procedures will be enhanced to perform two soil corrosivity samples: one adjacent to the Unit 1 circulating water inlet piping and another adjacent to the Unit 2 circulating water inlet piping. Sampling will be performed on a 10 year interval. Data collected at each location will include: soil resistivity, soil consortia (bacteria), pH, moisture, chlorides, sulfates, and redox potential. In addition to evaluating each individual parameter, corrosivity of carbon steel reinforcement and concrete degradation in high sulfate and acidic environments will be evaluated. (Added Set 3 RAIs)

Detection of Aging Effects (Element 4)

8. Procedures will be revised to require personnel who perform inspections and evaluation of concrete components to be qualified consistent with the qualifications identified in the *Structures Monitoring* program (B2.1.34) that are consistent with the requirements of ACI 349.3R.
9. Procedures will be revised to require personnel who perform visual inspections and evaluation of carbon fiber reinforced polymer piping to be VT-1 qualified consistent with IWA-2300 of ASME Section XI and Mandatory Appendix II of ASME Code Case N-871. Personnel who perform acoustic examinations of CFRP lined piping will be qualified consistent with mandatory Appendix VI of ASME Code Case N-871. (Added - Set 2 RAIs)
10. Procedures will be revised to require installed CFRP linings be 100% visually examined in accordance with ASME Code Case N-871 section 5213 during an inspection period between

four and six years following return of the repaired area to service; and a minimum of once per 10 year inservice inspection interval thereafter in the same inspection period of each succeeding inspection interval. (Added - Set 2 RAIs)

11. Procedures will be revised to require accessible surfaces of the CFRP linings at each terminal end to be acoustically impact tap examined in accordance with ASME Code Case N-871 section 5250(a) and 5250(c). The expansion rings need not be removed for this examination provided examinations of adjacent surfaces do not indicate the presence of new unacceptable indications that could extend beneath the rings. (Added - Set 2 RAIs)

12. Procedures will be revised to periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The program will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. One hundred percent of the accessible circulating water line internal surfaces will be inspected in a ten year period. (Added - Set 1 RAIs)

Monitoring and Trending (Element 5)

13. Procedures will be revised to require trending of charging pump lube oil cooler and emergency service water pump engine heat exchanger inspection results by Engineering.

14. Procedures will be revised to require trending of wall thickness measurements. The frequency and number of wall thickness measurements will be based on trending results.

15. Procedures will be revised to require all areas previously documented in accordance with ASME Code Case N-871 Section V-1100(b) shall be re-examined, measured, and compared with the previous inspection records. Any indications of flaw growth will be required to be repaired consistent with ASME Code Case N-871. Documentation of the repair, location and dimensions will be required. Any new flawed areas shall be evaluated consistent with ASME Code Case N-871. (Added - Set 2 RAIs)

Acceptance Criteria (Element 6)

16. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses.

17. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions.

18. Procedures will be revised to identify acceptance criteria for visual inspection of concrete piping and components such as the absence of cracking and loss of material, provided that minor cracking and loss of material in concrete may be acceptable where there is no evidence

of leakage, exposed rebar or reinforcing “hoop” bands or rust staining from such reinforcing elements.

19. Procedures will be revised to include the following CFRP defect inspection acceptance criteria for air voids, bubbles, blisters, delaminations and other defects (such as cracking and crazing): (Added - Set 2 RAIs)

    Air Voids

    For embedded air voids of area less than or equal to 25 square inches that have been visually detected in layers beneath the topcoat, they shall be repaired in accordance with ASME Code Case N-871 section 4390 (b)(1) and (b)(2) unless otherwise specified in the design documents. All other defects and all voids larger greater than 25 square inches shall be rejected, and a repair designed to maintain water tightness of the system.

    Bubbles, blisters or other defects

    If bubbles or blisters with major dimension exceeding 1 inch are detected anywhere within the protective epoxy topcoat, they shall be removed and repaired in accordance with ASME Code Case N-871 Section 4380(d).

    Delaminations or Voids

    Unless permitted by design documents, acceptance criteria for acoustic tap examination of terminal ends shall be consistent with ASME Code Case N-871 section 5350 (a) and (b)

Corrective Actions (Element 7)

20. Procedures will be revised to include the following defect repair criteria as part of the corrective actions: (Added - Set 2 RAIs)

    For air void defects

    Repairs shall be consistent with ASME Code Case N-871 section 4390 (b)(3) and (b)(4)

    For bubbles, blisters or other surface defects

    Repairs shall be consistent with ASME Code Case N-871 section 4390 (d)

    For all other defects and all voids larger than 25 square inches

    A repair shall be designed to maintain water-tightness of the system consistent with ASME Code Case N-871 section 4390 (d)

    A final visual inspection shall be performed to verify the CFRP system has achieved the percentage of cure corresponding to achievement of required mechanical properties before placing the repaired piping back in service. In no case shall the system be placed in service before achieving 85% cure.

21. Procedures will be revised to ensure that for ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections at susceptible locations are increased commensurate with the significance of the degradation.
22. Procedures will be revised to ensure that when measured parameters do not meet the acceptance criteria, additional inspections are performed, when the cause of the aging effect is not corrected by repair or replacement for components with the same material and environment combination. The number of inspections will be determined by the Corrective Action Program, but no fewer than five additional inspections will be performed for each inspection that did not meet the acceptance criteria, or 20% of the applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will include inspections at both Unit 1 and Unit 2 with the same material, environment, and aging effect combination.

Operating Experience Summary

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

1. In September 2001, a through wall leak was identified in an eight inch carbon steel control room chiller service water supply line. A through wall leak in similar piping occurred again in September 2005. In May 2006, volumetric inspections measurements identified a location in an eight inch carbon steel control room chiller service water supply line that was less than the minimum allowable wall thickness. A design change was implemented, which replaced the eight inch carbon steel piping with copper-nickel piping.
2. Between August 2007 and July 2009, biofouling of the control room chillers Y-strainers and rotating strainers occurred on multiple occasions. The initial cause was thought to be insufficient backwash flow to the rotating strainers during periods of elevated service water temperatures with one control room chiller operating. Procedure changes were implemented to start an additional pump and backwash the rotating strainers when differential pressure reaches one psid. Further clogging of the Y-strainers resulted in compensatory actions being established. These measures included increased monitoring of control room chiller and service water operating parameters when service water temperature was greater than 80°F, weekly flushing of control room chiller service water lines, and securing the chiller and cleaning the chiller suction strainers when pump suction pressure approached the minimum required net positive suction head.

In July 2009, repeated clogging of the control chiller suction Y-strainers occurred. Additional compensatory measures included more frequent flushing of the control room chiller service water piping, and running a minimum of two control room chillers to minimize system transients, which was determined to exacerbate biofouling of the strainers. In the fall of 2009, a modification was completed that provided additional chemical (biocide) injection into the service water system downstream of the rotating strainers and upstream of the Y-strainers to control biofouling. Chemical injection has proven effective in reducing biofouling of the Y-strainers and associated piping.

3. In October 2009, following sampling of the service water side of the component cooling heat exchangers, chemistry personnel determined the free available oxidant (FAO) readings were below minimum acceptable values, which could jeopardize control of biofouling in the system. The chemical injection pump settings were adjusted to restore the pump discharge pressure. Samples taken following adjustments revealed that the FAO levels were acceptable.
4. In February 2010, augmented volumetric inspections of the component cooling heat exchanger service water supply and discharge piping identified piping wall thicknesses that were less than minimum allowed. A weld repair was performed and the calculation of record was updated to reflect the results of the wall thickness readings. Pipe stresses were determined to be within code allowable. Subsequent wall thickness measurements taken following repairs were acceptable.
5. In October 2010, five through-wall holes were identified in a piping elbow of the Unit 1 "B" main condenser circulating water discharge piping. The piping contained raw water, and the material of construction was epoxy-coated carbon steel. Repairs were performed on the holes, and epoxy coating reapplied in February 2011.Subsequent inspections and repairs were performed in September 2016 with epoxy coating and March 2018 with the installation of the CFRP lining.
6. In January 2012, during the performance of a license renewal inspection of a component cooling heat exchanger, pitting, defective coatings, barnacles, and river debris were identified in the heat exchanger. Corrective actions included replacement of a manway, removal of debris from the heat exchanger, coating repairs, and performance of a weld repair. Inspections performed in April 2013 and February 2016 also identified needed weld repairs to the heat exchanger end bell. A surface examination and system pressure test were performed satisfactorily following weld repairs.
7. In October 2013, during surface preparation and weld inspections, a through wall leak was observed in the 42 inch service water piping adjacent to the motor-operated valve supplying service water to the component cooling water heat exchangers from the '1B' condenser water box tunnel. The cause of pipe wall thinning was determined to be non-application of the pipe internal coating. Historically, the motor-operated valve exhibited seat leakage since original

installation. In an effort to control leakage, a blank and a hose were used to divert the leakage. As a result, the piping at the blank was unable to be properly coated. Over time, the lack of coating resulted in significant wall loss. Corrective actions included replacement of the valve with a design which would minimize valve leakage, weld repairs to the piping, and internal coating of the piping. A post-weld surface examination and system pressure test were performed satisfactorily.

8. In November 2013, three through wall leaks were identified in the 42 inch piping upstream of the motor-operated valve supplying service water to the component cooling water heat exchangers from the '1D' condenser water box tunnel. The leaks were identified following sand blasting of the piping in preparation for application of internal coating. Weld repairs were performed to correct the deficiencies. A surface examination and system pressure test were performed satisfactorily subsequent to the repairs.

9. In April 2015, circulating and service water Carbon Fiber Reinforced Polymer (CFRP) pipe repair was performed on the interior surface of circulating water and discharge service water piping to repair and strengthen the existing pipe systems. The service water and circulating water systems piping are constructed of carbon steel piping that was originally internally coated with a coal tar epoxy coating. Over the years of operation, the coating has experienced localized failures exposing the pipe wall to brackish water and resulting in corrosion of the exposed pipe material. Since 1990 there has been a long-term service water pipe repair project which replaced the coal tar coating with a coating system using a multi-functional epoxy coating product to improve the corrosion protection. This project was completed in July 1998. The new coating system did improve the corrosion protection; however, it still has a limited service life approximately 15 to 25 years which results in localized coating failures. This coating approached the end of its expected service life and has been only marginally successful in protecting the steel pipe from the corrosive effects of the brackish cooling water system.

   A permanent repair of the service and circulating water systems piping that restores the system pressure boundaries and provides a corrosion resistant barrier to the existing system was applied to sections of the service water and circulating water piping system. This design change addresses service water piping downstream of the component cooling heat exchangers and circulating water piping downstream of the Unit 1 condenser outlet valves.

10. Between September 2015 and September 2016, five leaks occurred in the service water system due to cracking of fiberglass piping. The leaks were either repaired or new piping segments installed in accordance with the work order process. The fiberglass piping in the service water system may be replaced with corrosion resistant material such as copper-nickel as part of a time-phased program.

11. In December 2015, an effectiveness review of the Service Water System Inspections Activity (UFSAR Section 18.2.17) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

12. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMA 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.

13. In September 2017, as part of oversight activities, of the Service Water Inspections Activity (UFSAR Section 18.2.17) it was noted that commitments for the low level intake screenwell (LLIS) and emergency service water pump suction end bell cleaning/inspections were not being performed and documented consistent with the original License Renewal commitment. The License Renewal commitments for the LLIS cleaning and pump inspections were originally incorporated into the procedure that dewatered the LLIS. The recent license renewal cleaning/inspections were performed by divers using a recurring work activity without dewatering the LLIS. A corrective action was initiated for engineering and outage planning to resolve the inconsistency. It was determined that the cleaning and inspection commitments were satisfactorily completed without dewatering the LLIS. Update of the maintenance strategy and associated documents to allow performance of the license renewal commitments with or without dewatering the LLIS is in progress.

14. In January 2018, an aging management program effectiveness review was performed for the Service Water System Inspections Activity (UFSAR Section 18.2.17). Information from the summary of that effectiveness review is provided below:

    The Service Water System Inspections Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the AMA that were reviewed include the selection of components to be inspected, the inspection of components, the evaluation of inspection results, repairs/replacements, and AMA document updates. Engineering reports from 2004 to 2016 of inspections results were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of open-cycle cooling water system components within the scope of license renewal.

The key aspects of the *Open-Cycle Cooling Water System* program involve controlling biofouling, testing critical heat exchangers, inspecting and cleaning the system, and designing with robust materials. The program is implemented using an active Service Water System Inspection and Maintenance Program and has a well-established Generic Letter 89-13 Program. These programs govern the approach to compliance with the Nuclear Regulatory Commission (NRC) Generic Letter 89-13, Service Water Problems Affecting Safety-Related Equipment. The Program is inspected every three years by the NRC using Inspection Procedure 71111.07, Heat Sink Performance. The most recent inspection did not identify any findings. Additionally, station effectiveness is assessed by implementing INPO SOER 07-2, Intake Cooling Water Blockage every three years. The assessment reviews operating experience, condition reports, and equipment performance for the three year period. The most recent assessment, completed in September 2016, concluded that open-cycle cooling water equipment has been performing satisfactorily.

Over the summers of 2007 through 2009, a series of events involving an influx of biological growth from the James River prompted the creation of the Service Water Excellence Plan. The plan has resulted in numerous improvements designed to greatly reduce the adverse effects of biofouling and aging. For example, a biocide injection system has been installed to reduce biological growth, key pieces of safety-related piping have been converted to corrosion and fouling resistant materials, and new monitoring and flushing procedures have been instituted. More recently, since entering the first period of extended operation, the interior of the large diameter open-cycle cooling water piping has begun to be lined with carbon fiber reinforced polymer (CFRP). Surry Power Station is first in the industry to employ this technology. It is predicted that the CFRP will add 50 years of effective service life to the asset. The biocide injection point on the safety-related service water piping will also be relocated to maximize effectiveness.

<u>Recurring Internal Corrosion</u> (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and internal fouling of components, has occurred on several occasions. Corrective actions have been taken previously, and additional actions are scheduled to minimize the likelihood of piping and component degradation due to flow blockage and loss of material in the open-cycle cooling water system. The physical modifications completed or scheduled, and enhancements to operating practices and system design to improve OCCW system resistance to recurrence of internal corrosion are noted below:

The Open-Cycle Cooling Water (OCCW) System program will manage aspects of RIC in the service water system and the circulating water system that are within the scope of the program. The

Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28) will manage loss of material on the internal surfaces of service water system and circulating water system piping and heat exchanger channel heads that has been coated with epoxy coatings. The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25) will manage loss of material on the internal surfaces of service water system and circulating water system piping not covered by NRC Generic Letter 89-13.

Flow Blockage:

Flow blockage in OCCW system piping and components is managed by periodically monitoring control room chiller Y-strainer differential pressure and periodically flushing affected piping flow paths. During times when service water temperatures are elevated, above 80°F, the operations surveillance frequency of monitoring service water suction pressure and rotating strainer differential pressures are increased to intervals as short once every 4 hours and piping flush frequency increased to once daily. As a preventive measure, biocide injection points have been added downstream of the rotating suction strainers and the biocide injection has significantly reduced hydroid attachment and growth. A plant modification is in progress to add additional injection points to the upstream portion of the service water rotating strainers.

Loss of Material in Uncoated Steel Piping:

Loss of material has resulted in recurrent wall thinning and through wall leakage in service water piping in uncoated steel service water piping associated with main control room chillers. Replacement of uncoated steel piping with corrosion resistant copper-nickel piping reduced the susceptibility of the OCCW systems to recurring internal corrosion. There has been no documented recurring internal corrosion on the control room chillers copper-nickel piping or other copper-nickel service water system piping within the scope of subsequent license renewal.

Loss of Material in Copper-Nickel Alloy Heat Exchanger Tubing:

Recurring internal corrosion (loss of material) was experienced in the copper-nickel alloy heat exchanger tubing at and beyond the tube sheet for the main control room chiller condensers, including a condenser that had been recently replaced. The affected heat exchanger components have been cleaned and coated with a protective epoxy coating with the coating extending six inches into the heat exchange tubes. The Corrective Action Program apparent cause evaluation identified that the heat exchanger management program did not require flow to be maintained for an extended period in new 90-10 copper-nickel alloy heat exchangers to permit a protective oxide film to form on the tubes prior to the placement of the heat exchangers into a stagnant wet lay-up condition. Implementing documents have been modified to incorporate this lesson-learned. After epoxy coating and modification of wet layup practices, there has been no documented recurring internal corrosion in the control room chiller condenser copper-nickel alloy tubing at and beyond the tube sheet.

Loss of Material in Coated Steel Piping and Heat Exchanger Channel Heads:

Corrosion-resistant Carbon Fiber Reinforced Polymer (CFRP) liner will be installed in the 96-inch circulating water inlet piping, and 24-, 30-, 36-, 42-, and 48-inch service water supply from the circulating water system to the recirculation spray and supply to the component cooling water heat exchangers. The CFRP system is designed to take the place of the existing carbon steel pipe and will form a repaired pipe within the existing piping that is capable of meeting the design requirements of the station piping. The appropriate relief has been granted for this repair by the NRC. For epoxy coated piping sections and heat exchanger channel heads that do not yet have the CFRP lining installed, the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging of the existing epoxy-coated steel piping.

The above examples of operating experience provide objective evidence that the *Open-Cycle Cooling Water System* program includes activities to perform surveillance and control, heat exchanger testing, and routine inspection and maintenance to identify loss of material, reduction of heat transfer, flow blockage, and cracking of the piping, piping components, and heat exchangers within the scope of subsequent license renewal, as identified by the Virginia Electric and Power Company responses to NRC GL 89-13, and to initiate corrective actions. Occurrences identified under the *Open-Cycle Cooling Water System* 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 *Open-Cycle Cooling Water System* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Open-Cycle Cooling Water System* 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 for 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 loss of material, blistering, and cracking on external surfaces of piping and tanks in soil or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses piping and tanks composed of steel, stainless steel, copper alloys, fiberglass reinforced plastic, and concrete. 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 electrochemical verification of the effectiveness of cathodic protection, non-destructive evaluation of pipe or tank wall thicknesses, performance monitoring of fire mains, and visual inspections of the pipe from the exterior.

The buried carbon steel piping of the fuel oil system for emergency electrical power system is the only buried piping that is protected by an active CP system. Monthly periodic inspections confirm CP system availability and 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 balance of piping and tanks within the scope of subsequent license renewal are not provided with CP. Based on soil sampling and testing, it has been determined that installation and operation of CP is not necessary. Soil sampling and testing is performed during each excavation and a station-wide soil survey is also performed once in each 10-year period to confirm that the soil environment of components within the scope of license renewal is not corrosive 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."

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, the sample size is increased.

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 aging effects associated with the external surfaces of buried concrete piping in the circulating water system will be managed by the *Open-Cycle Cooling Water System* program (B2.1.11). The *Open-Cycle Cooling Water System* program (B2.1.11) will periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The *Open-Cycle Cooling Water System* program (B2.1.11) will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. 100% of the accessible circulating water line internal surfaces will be inspected in a ten year period. The *Buried and Underground Piping and Tanks* program will opportunistically inspect the buried concrete circulating water lines when scheduled maintenance work permits access.

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

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 elements:

Preventive Actions (Element 2)

1. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings.

2. (Completed Change Notice 2)

~~Parameters Monitored or Inspected (Element 3)~~

3. 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. (Added - Set 1 RAIs)

Preventive Actions (Element 2) and Detection of Aging Effects (Element 4)

4. Procedures will be revised to require uncoated buried stainless steel tubing segments in the fuel oil system be inspected prior to the subsequent period of extended operation. After inspection, each uncoated stainless steel segment will be coated consistent with Table 1 of NACE SP0169-2007, "~~Standard Recommended Practice, Cathodic Protection of Prestressed Concrete Cylinder Pipelines.~~Control of External Corrosion on Underground or Submerged Metallic Systems" (Added - Set 1 RAIs) (Revised - Set 3 RAIs)

5. A cathodic protection system will be installed for protection of the 24-inch service water piping at the Low Level Intake Structure five years before entering the subsequent period of operation. (Added - Set 3 RAIs)

6. The activity of the jockey pump will be monitored consistent with the "detection of aging effects" program element of NUREG-2191, Section XI.M41. (Added - Set 3 RAIs)

Acceptance Criteria (Element 6)

7. Procedures will be revised to specify that cathodic protection surveys use the -850mV 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 -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate.

   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 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.

     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).

When using the electrical resistance corrosion rate probes:

a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar

b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data (Revised - Change Notice 2 and Set 1 RAIs)

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In June 1994, leakage was identified in buried, carbon steel, emergency diesel generator (EDG) fuel oil lines. The leak was discovered through external visual inspection, internal boroscope inspection, and pressure drop air testing, and considered to be due to internal pitting corrosion. The 1½ inch schedule 80 carbon steel piping system was replaced with 2½ inch schedule 160 carbon steel lines in 1995. Excavation, fill placement, compaction, and testing of the soil were done in accordance with design specifications. The bedding material for the fuel oil lines is a select granular fill consisting of clean well graded sand. The coating material provided is a synthetic elastomeric tape wrap. A passive cathodic protection system was installed in 1995 to protect the buried fuel oil piping from corrosion. This passive system became degraded as the sacrificial anodes were increasingly being drained off to station grounds.

   In May 2015, an impressed current cathodic protection system was installed and placed in service to replace the passive cathodic protection system on the buried, carbon steel, EDG fuel oil lines. One of the two new rectifier units was in a degraded condition from August 2015 through February 2016, until it was restored to operation by corrective maintenance. The NACE annual inspection completed in April 2016 concluded that the system was providing adequate cathodic protection consistent with NACE criteria. Monthly inspections confirm rectifier operation.

2. In May 2004, portions of the Unit 2 auxiliary feedwater system experienced leakage in the buried carbon steel recirculation piping. The primary cause of the leak was pitting corrosion due to poorly applied coating. As a corrective action, the Unit 1 and Unit 2 AFW recirculation system piping is no longer buried and was rerouted through the safeguards building basement. The extent of condition assessment portion of the root cause evaluation noted the following:
   - The corresponding auxiliary feedwater recirculation line on Unit 1 had been discovered to be leaking and was subsequently bypassed and abandoned as part of a design change,
   - Stainless steel liquid waste piping in excellent condition,
   - Carbon steel chilled water piping with wrap intact and no indication of corrosion,
   - Carbon steel auxiliary feedwater piping with wrap in good condition and no indication of corrosion, and
   - Leaking fuel oil pipe with indications of localized pitting that was replaced and re-routed.
3. In June 2010, while removing coating from the Unit 2 condensate makeup buried carbon steel piping, pitting was identified on several areas of the pipe where the coating had been removed. The pitting was seen at three locations and was characterized as shallow. The as-found condition of the pipe was within code requirements and determined to be fit for service. Following inspection the coating was restored.
4. In July 2012, excavation revealed leakage from a buried Unit 2 ten inch stainless steel condensate supply line. There appeared to be an approximate three to four inch circumferential crack in the line that had started along the outside diameter of the pipe. The crack was determined to be caused by transgranular stress corrosion cracking due to mechanical damage by excavation equipment. The replacement pipe is not buried and has been rerouted through the turbine building.
5. In June 2016, a Dominion Energy fleet self-assessment was performed on the Underground Piping and Tank Integrity (UPTI) Program to ensure the program is supporting the goal of providing long term reliability of buried and underground piping and tanks; to ensure consistency with NEI 09-14, Guideline for the Management of Underground Piping and Tank Integrity, and NSIAC requirements; and ensure the program meets industry best practices. Implementation of the UPTI Program was reviewed to confirm performance of inspections, effectiveness of scheduling and tracking, and program optimization based on inspection results.

   This self-assessment identified one performance deficiency in that the 2015 UPTI Life Cycle Management Plan (LCMP) was issued by engineering transmittal without being approved at Plant Health Steering Committee. The 2016 UPTI LCMP was approved by Plant Health Steering Committee.

A strength was noted in that the inspections required by the UPTI LCMP are being scheduled, tracked, and performed as expected; and the results are being used appropriately to determine the next inspection. The UPTI team reviews operating experience during fleet calls and incorporates the experience into the program and inspections as appropriate.

6. 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.

7. In May 2017, during the as-found coating inspection on Unit 2 buried carbon steel condensate makeup piping, coating was missing on approximately 270 degrees of the pipe circumference from the center of the excavated area into the soil on the east side. Coating on the bottom was remaining. There was no visible leakage from this condensate makeup line piping segment. Ultrasonic testing of the piping segment demonstrated that the minimum wall thickness requirement was met or exceeded at each location tested. The protective coatings were restored.

8. In November 2017, as part of oversight review activities, the Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

9. In January 2018, an aging management program effectiveness review was performed of the initial license renewal Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1). Information from the summary of that effectiveness review is provided below:

   The Buried Piping and Valve Inspection Activities is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the Buried Piping and Valve Inspection Activities that were reviewed included the selection of components to be inspected, the inspection of components, the evaluation of inspection results, repairs/replacements, and AMA document updates. Engineering reports of inspections results from 2004 to 2016 were reviewed to confirm inspections were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of buried components within the scope of license renewal.

A living Life Cycle Management Plan (LCMP) that identifies inspection plans at the next five year interval is maintained based on piping wall thickness calculations, risk ranking and internal/industry operating experience. In 2004, leakage from a buried auxiliary feedwater pipe and in 2012 leakage from a buried condensate pipe resulted in design changes to reroute the piping through non-buried environments. Observed coating degradations during recent inspections resulted in coating repairs and pipe wall thickness evaluations to anticipate rates of change and confirm fitness for service. Quarterly reviews by the fleet UPTI program owners review industry and plant operating experience, including corrective actions, to identify adjustments to the program. Recent fleet operating experience from North Anna Power Station for a service water to auxiliary feedwater pipe resulted in accelerated inspection schedules for similar carbon steel piping at SPS.

In 2014, based on industry feedback, the EDG fuel oil sacrificial anode cathodic protection (CP) system was replaced with an impressed current system. Recent program reviews identified required updates to the maintenance procedures for the impressed CP system. In June 2017, as part of an Industry Material Review Visit, no adverse findings were noted for the UPTI program. Recent industry research and development is reviewed and incorporated into the program as appropriate. New soil survey studies consistent with EPRI 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," will identify any areas of soil corrosivity.

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 loss of material, cracking, and blistering 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, 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.

B2.1.28 Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Program Description

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing condition monitoring program that manages loss of coating integrity of the in-scope components exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, and air-dry environments, that can lead to loss of base materials or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings degrade and become debris.

Periodic visual inspections are conducted for each coating/lining material and environment combinations of the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the components or downstream component's intended function(s). Inspection intervals will not exceed those specified in NUREG-2191, Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers."

For tanks, heat exchangers and piping, all accessible surfaces are inspected. If a baseline inspection has not been previously established, baseline coating/lining inspections will occur in the 10-year period prior to the subsequent period of extended operation. Subsequent inspection intervals are established by a coating specialist qualified in accordance with ASTM International Standards endorsed in RG 1.54, Revision 2, "Service Level I, II and III Protective Coatings Applied to Nuclear Power Plants," including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist. Blisters are limited to a few intact small blisters that are completely surrounded by sound material and with the size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. Other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed or physical testing is performed, where physically possible (i.e., sufficient room to conduct testing), in conjunction with repair or replacement of the coating/lining.

NUREG-2191 Consistency

The *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, to NUREG-2191, Section XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4).

(Exception 1 Deleted - Set 2 RAIs)

1.

(Exception 2 Deleted - Set 1 RAIs)

2. NUREG-2191 indicates that periodic visual examinations of a sample of piping internally lined with concrete be performed to verify degradation leading to loss of material or downstream effects such as reduction in flow and pressure. Opportunistic inspections of concrete lined fire protection system main loop piping will be performed. An exception is taken to perform periodic inspections.

Justification for Exception

Concrete lined cast iron fire protection system main loop piping is buried. Inspection of this piping is highly intrusive and would require excavation and implementation of a complex temporary modification to maintain a functional fire protection header. Management of the effects of aging for the fire protection system is described in AMP XI.M27, "Fire Water System." In accordance with the Fire Water System program (B2.1.16), the following tests and inspections will be performed:

- Fire protection system underground loop and main header flow test will be conducted at least once every five years. During the flow test, system hydraulic characteristics will be measured and evaluated for indication of internal piping degradation or flow obstructions. The flow test will measure system hydraulic resistance as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of internal piping degradation from significant corrosion, sediment buildup or fouling will be detected in a timely manner.
- Underground supply piping is flushed through each of the outdoor fire hydrants annually. Full flow of clean, clear water is confirmed during flushing of annual hydrant flushes.
- Wet pipe sprinkler main drain flow tests and inspector test flushes will be performed to assure adequate water supply and proper system performance. Main drain testing will be performed for wet pipe sprinkler systems with alarm control valves to monitor and trend system pressure during flow conditions and identify degraded water supply conditions should they occur.
- The motor and diesel driven fire pumps are flow tested at least every 5 years to assure flow and pressure requirements are met.

Together, these tests provide reasonable assurance that flow blockage would be detected just as effectively as if internal inspections were being periodically conducted on a portion of the piping consistent with NUREG-2191, AMP XI.M42, Table XI.M42-1. In addition, the fire water system is maintained at required operating pressure. Daily monitoring of the head and pressure in the hydro-pneumatic tank is performed. Alarm circuits monitor the system pressure, and low pressure is annunciated in the main control room via the motor driven and diesel driven fire pump start logic. A loss or decrease in system pressure would be noted and corrective actions initiated. This continuous monitoring is an effective means to detect potential through-wall flaws in the piping and piping components.

In August 2014, while conducting a fire hose station valve test, an underground fire main leak was suspected to have occurred. The suspected leak location was excavated and a circumferential break was noted in the pipe. The failed section of pipe was removed from the flanged end and submitted to the corporate materials lab for examination. Overall, the pipe section appeared to be in good condition. Visually, the pipe wall was sound, showing no signs of any extensive corrosion from the outside. Along the inner diameter, the cement lining had fractured away in the areas where the pipe was cut but the underlying metal was in excellent condition. In those areas outside the cuts, near the flange where the lining was still in place, cement lining was in good condition. The examination concluded that it is possible that a fabrication defect was present in this pipe. Away from the fracture, the overall condition of the pipe was good. No signs of any significant corrosion were seen along the outside or inside of the pipe. The heaviest corrosion noted in the form of pitting was along the outside of the pipe near the leak location.

The NRC approved a NUREG-~~2191~~1801 exception based on very similar justification as documented in the Safety Evaluation Report Related to the License Renewal of Fermi 2, Docket No. 50-341, dated July 2016 (ADAMS Accession No. ML16190A241).

Enhancements

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

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

1. Procedures will be revised to require baseline inspections (100% of accessible coatings/linings) of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection intervals will not exceed those specified in NUREG-2191, Table XI.M42-1, “Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers.” (Revised - Change Notice 2 and Set 1 RAIs)
    - Circulating water system waterbox air separating tanks
    - Condensate polishing outlet piping (short segment; entire length is inspected)

- Vacuum priming tanks
- Vacuum priming seal water separator tanks
- Auxiliary steam drain receiver tank
- Water treatment piping (short segment; entire length is inspected)
- Flash evaporator demineralizer isolation valve
- Brominator mixing tank
- Pressurizer relief tanks

Parameters Monitored/Inspected (Element 3)

2. Programs will be revised to consistently reference coating aging mechanisms and add definitions for rusting, wear/erosion, and physical damage.
3. Procedures will be revised to require alignment of the internal coating/lining inspection criteria with the inspection criteria and aging mechanisms specified in the Coatings Condition Assessment Program.
4. Procedures will be revised to require inspections of cementitious coatings/linings and include aging mechanisms associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation.

Detection of Aging Effects (Element 4)

5. Procedures will be revised to require cementitious coatings/linings inspectors to have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of one year of experience.
6. Procedures will be revised to require opportunistic inspections of piping internally lined with concrete and include aging associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation.
7. Component cooling heat exchanger channel head coatings are inspected on a one-year inspection interval. Procedures will be revised to require that if two subsequent inspections demonstrate no change in coating condition (i.e. at least three consecutive inspections with no change in condition), inspection frequencies at those locations may be conducted consistent with inspection Category B of NUREG-2191, Table XI.M42-1. (Added - Set 3 RAIs)

Monitoring and Trending (Element 5)

8. ~~Procedures will be revised to require a pre-inspection review of the previous "two" condition assessment reports, when available, be performed, to review the results of inspections and any subsequent repair activities.~~Procedures will be revised to require a coatings specialist to prepare the coatings post-inspection condition assessment report. A pre-inspection review will be performed of the coating inspections and any subsequent repair activities from the previous two coatings post-inspection condition assessment reports, when available. (Revised - Set 3 RAIs)

9. Procedures will be revised to require inspection results be evaluated against acceptance criteria to confirm that the components' intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate and extent of degradation. Where practical, (e.g., wall thickness measurements, blister size and (frequency), degradation will be projected until the next scheduled inspection.

Acceptance Criteria (Element 6)

10. Procedures will be revised to:
    a. Specify there are no indications of peeling or delamination.
    b. Require inspection of cementitious coatings/linings. Minor cracking and spalling is acceptable provided there is no evidence that the coating/lining is debonding from the base material.
    c. Require, as applicable wall thickness measurements, projected to the next inspection, meet design minimum wall requirements.

Corrective Action (Element 7)

11. Procedures will be revised to permit the "removal" of coatings/linings that do not meet acceptance criteria, with the required evaluation and documentation.

12. Procedures will be revised to include as an alternative to repair, rework, or removal, internal coatings/linings exhibiting indications of peeling and delamination. The component may be returned to service if:
    a. Physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal,
    b. the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered),
    c. adhesion testing using ASTM International Standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of 3 sample points adjacent to the defective area,

d. an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component, and

e. follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, or until the degraded coating is repaired or replaced.

13. Procedures will be revised to require when a blister does not meet acceptance criteria, and it is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain inservice should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister.

14. Procedures will be revised to require additional inspections be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of increased inspections will be determined in accordance with the Corrective Action Program. However, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. When inspections are based on the percentage of piping length, an additional 5% of the total length will be inspected. The timing of the additional inspections will be based on the severity of the degradation identified and will be commensurate with the potential for loss of intended function. However, in all cases, the additional inspections will be completed within the interval in which the original inspection was conducted, or if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to provide reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections will include inspections with the same material, environment, and aging effect combination at both Unit 1 and Unit 2.

15. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In December 2008, the interior surface of the Unit 1 ECST was inspected in the filled condition. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floor. The inspection of the Unit 1 ECST showed minor blistering and little evidence of corrosion that would impact minimum wall thickness.

2. In December 2008, the interior surface of the Unit 2 ECST was inspected in the filled condition. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floors. An internal inspection of the Unit 2 ECST was performed in May 2017. Small blistering and pinhole damage was identified in areas of the coating along the tank walls. Internal coating repairs are scheduled in work management.

3. In December 2008, an engineering inspection of the 'A' main control room chiller revealed condenser tube erosion, but no leaks were identified and Engineering had no operability concerns. Per Engineering recommendation, Plastocor coating was placed on the tubes of 'A' main control room chiller in June 2009, and on the tubes of 'C' main control room chiller in July 2010. In January 2010, inspection revealed that the coating on the 'C' main control room chiller condenser outlet tubes had started to degrade. Coating in the tubes started to flake, crack and bubble up. Inspections of the tubes with a borescope revealed that there were spots where the copper oxide layer was flaking off. There was no corrosion, pitting, or cracking in the tubes or tubesheet. Maintenance successfully removed the loose, flaking and cracking coating. Engineering performed Eddy Current Inspection of the condenser tubes and no tube degradation was identified. In June 2010 the condenser outlet tubes were re-coated. Subsequent inspection in January 2011 revealed that the tubes and tubesheet were free of cracking, separation, or delamination. Coating was flaking three to three and half inches inside the tubes. Coating was removed where it was flaking. Inspection in June 2011 revealed no signs of degradation, pitting or erosion. Inspection performed in January 2015 and February 2016 found the condenser tubes to be acceptable for service.

4. During the Fall 2010 refueling outage (RFO), Engineering inspected the outlet line from a Unit 1 recirculation spray cooler. The line was found to have general corrosion occurring beneath the coating at the outlet flange interface on the upper endbell of the heat exchanger. The degraded coating was removed; base metal/weld repairs and coating repairs were performed during the Unit 1 fall RFO. Ultrasonic testing examination on the outlet service water flange was performed in November 2010. Exfoliation had not extended past the raised edge of the slip-on flange. Service water piping wall loss was not evident. Follow-up inspection of the outlet line was performed and coating degradation was found at the outlet flange interface on the upper end bell of the heat exchanger. Coating and weld repair were completed in November 2010. Another follow-up inspection in January 2011 noted areas of coating delamination, including the first four to six inches of pipe downstream from a service water motor operated valve, the area around the tap for a service water flow element and the tap for a service water resistance temperature detector. The areas of pipe where the delamination of coatings occurred were blasted and recoated in January 2011. Inspection of the recirculation spray cooler and ultrasonic testing of the service water vent piping is scheduled in work management.

5. In October 2010, five through wall holes were identified in a piping elbow of the Unit 1 "B" main condenser circulating water discharge piping. The piping contained raw water, and the material of construction was epoxy-coated carbon steel. Repairs were performed on the holes, and epoxy coating reapplied in February 2011.Subsequent inspections and repairs were performed in September 2016 with epoxy coating and March 2018 with the installation of the CFRP lining.

   The Open Cycle Cooling Water (OCCW) program (B2.1.11) will manage aging effects of CFRP linings in OCCW systems using ASME Code Case N-871.

6. In November 2010, while removing a Unit 1 service water motor operated valve from the system to replace the an adjacent service water expansion joint, it was noted that the coating on the inner diameter of the pipe flange was not intact and the weld metal in the pipe to flange connection had corroded. The service water was in direct contact with the carbon steel pipe. Base metal/weld repairs and coating repairs were performed in November 2010. The weld repairs were visually inspected for a minimum acceptable wall thickness. The visual inspections were completed satisfactorily.

7. In November 2012, during the weld inspection of a Unit 2 main condenser outlet waterbox, eight areas for repair were identified due to degradation of the epoxy coating, including two through-wall areas. The waterbox contains raw water, and the material of construction is epoxy-coated carbon steel. Repairs were performed on the holes, and epoxy coating reapplied in November 2012. This is an example of recurring internal corrosion in the circulating water system. Subsequent inspections and repairs were performed in April 2014, October 2015, and April 2017.

8. In September 2014, a materials analysis was performed on buried cement lined grey cast iron fire main piping that was fractured during flow testing of hose station valves. The fracture was attributed to a latent material defect in the cast iron. The piping was removed and replaced with an equivalent spool piece. Based on the oxidation along the top segment of the crack, the pipe had been cracked for a long period of time. High levels of calcium deposits on the fracture (from the cement lining) indicate that the pipe was partially cracked at the top segment before factory installation of the cement liner (manufacturing process). Material analysis of the pipe determined that the microstructure consisted of graphite flakes that were approximately 75% ferrite and 25% pearlite. This resulted in a reduction in the supplied material hardness. Failure of pipe was not preventable through maintenance. The failure was caused by ground settling. During the pipe replacement it was observed that there was vertical misalignment between the replacement pipe and the existing buried pipe, which indicated that the buried side piping was exerting a large bending load at the anchor/foundation. This bending load along with the pre-existing crack and lower hardness value caused the pipe fracture. The balance of the failed pipe was found in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, or reduction of pipe interior diameter.

9. In April 2015, circulating and service water Carbon Fiber Reinforced Polymer (CFRP) pipe repair was performed on the interior surface of circulating water and discharge service water piping to repair and strengthen the existing pipe systems. The service water and circulating water systems piping are constructed of carbon steel piping that was originally internally coated with a coal tar epoxy coating. Over the years of operation, the coating has experienced localized failures exposing the pipe wall to brackish water and resulting in corrosion of the exposed pipe material. Since 1990 there has been a long-term service water pipe repair project which replaced the coal tar coating with a coating system using a multi-functional epoxy coating product to improve the corrosion protection. This project was completed in July 1998. The new coating system did improve the corrosion protection; however, it still has a limited service life approximately 15 to 25 years which results in localized coating failures. This coating approached the end of its expected service life and has been only marginally successful in protecting the steel pipe from the corrosive effects of the brackish cooling water system.

   A permanent repair of the service and circulating water systems piping that restores the system pressure boundaries and provides a corrosion resistant barrier to the existing system was applied to sections of the service water and circulating water piping system. This design change addresses service water piping downstream of the component cooling heat exchangers and circulating water piping downstream of the Unit 1 condenser outlet valves. The CFRP system is used to repair any degraded piping sections. The CFRP relining began in 2015 and is expected to be complete in future refueling outages. The repair process used CFRP composite designed to take the place of the existing carbon steel pipe, and as such, becomes a pipe that is capable of meeting the original design requirements of this pipeline formed within the discharge piping. The outlet piping from the component cooling heat exchangers (CCHXs) that has been relined with CFRP is rated for full system pressure, design temperature, transient load, weight effects, and vacuum pressures combined with external ground water static pressure.

In a relief request dated December 20, 2017 the NRC staff concluded that the proposed CFRP composite system provides reasonable assurance of the buried circulating water and service water piping structural integrity and leak tightness. The NRC staff stated in correspondence to Dominion dated December 20, 2017, "The CFRP repair system alternative will remain in place for the life of the plant." The NRC further concluded, that based on operating experience, there is reasonable assurance to expect the CFRP repaired pipes to perform successfully and the maintenance and inspection programs will confirm acceptable performance during future inspection intervals. CFRP relining is expected to be complete in future refueling outages.

CFRP systems have been utilized in brackish water environments for over 25 years, and it is a common environment for application. This includes exposure to harsh freeze-thaw environments in bridge and pile applications within the transportation industry, upgrade to concrete infrastructure within power generation and industrial facilities, and pipeline repair and upgrade with CFRP - these types of applications are and have been completed in brackish environments with successful performance of the CFRP system.

The Open Cycle Cooling Water (OCCW) program (B2.1.11) will manage aging effects of CFRP linings in OCCW systems using ASME Code Case N-871.

10. In February 2016, engineering performed a coating/welding inspection inside the Unit 1 'B' component cooling heat exchanger inlet and outlet endbells. The inspection revealed fifteen areas inside the inlet endbell and ten areas on the outlet endbell requiring coating repairs. The outlet endbell also had three areas requiring base/metal weld repairs. There were no through-wall holes discovered. The weld repairs and coating were performed in February 2016. A quality inspector visually inspected the final repaired areas and a magnetic particle examination was performed on the final weld repairs. The work was completed and inspected satisfactorily.

<u>Recurring Internal Corrosion</u> (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and general corrosion, has occurred in the coated/lined service water system piping, plumbing system piping, main condenser waterboxes and the 96-inch circulating water discharge piping. Corrective actions such as circulating water and service water liner installation that was started in April 2015 are in progress, and additional actions are scheduled to minimize the likelihood of piping and component degradation due to pitting and general corrosion in systems monitored by the *Internal Coatings/Linings For In-Scope Piping, Piping*

Components, Heat Exchangers, and Tanks program (B2.1.28). Periodic system walkdowns in accordance with plant procedure will monitor for leakage. Additional corrective actions will be determined by the Corrective Action Program if significant loss of material is detected. Work orders have been created to replace affected portions of the plumbing system piping. Future occurrences of RIC will be documented in accordance with the Corrective Action Program. Corrective actions include:

a. Prior to the subsequent period of extended operation, the 96-inch circulating water outlet piping will be lined with CFRP. The design changes for both units are in progress, and no documented aging effects for CFRP coated sections of the 96-inch circulating water outlet piping have been identified. The CFRP design changes will be completed over the next several refueling outages. Separate design changes will install CFRP in the 96 inch circulating water inlet piping and the 30-, 36-, 42-, and 48-inch service water piping from the circulating water system to the recirculation spray and supply for the component cooling heat exchangers. Since the initial installation of the CFRP system in April 2015, there have been no condition reports to date indicating a loss of coating integrity in CFRP lined components. The CFRP system has a 50-year service life.

   The component cooling heat exchanger channel heads are epoxy-coated carbon steel exposed to raw water (service water). Inspections are performed yearly, which allows early detection of degradation of coatings and underlying metal. Inspection of the component cooling heat exchangers (CCHXs) in January 2011 discovered coating failures. Coating repairs were performed. A multi-functional epoxy coating system was applied to the Unit 1 CCHXs starting Unit 1 RFO 2013.

b. The CFRP lining is designed to meet the existing design requirements for the lines in which it will be installed and will serve as the system pressure boundary. In contrast to the existing carbon steel pipe, CFRP is not susceptible to pitting in a raw water environment. Therefore, augmented inspections will not be necessary on piping lined with CFRP.

   Plant operating experience has demonstrated that the yearly inspections of the component cooling heat exchanger channel heads are frequent enough to detect degradation before causing a loss of intended function.

   The Open Cycle Cooling Water (OCCW) program (B2.1.11) will manage aging effects of CFRP linings in OCCW systems using ASME Code Case N-871.

The above examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program includes activities to perform visual inspections of internal surfaces to identify deficient or degraded coatings/linings for piping, piping components, heat exchangers and tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the

Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, 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 *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program, following enhancement, 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.

B2.1.34 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 material
- Cracking, loss of bond, and loss of material (spalling, scaling)
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- Loss of material
- Loss of material, loss of form
- Loss of material (spalling, scaling) and cracking
- Loss of material, change in material properties
- 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 (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 scope of the *Structures Monitoring* program includes structures and components in the scope of subsequent license renewal. The program relies on periodic visual inspections to monitor and maintain the condition of structures and components within the scope of subsequent license renewal. Inspections are conducted by qualified personnel at a frequency not to exceed five years, except for wooden poles, which will be inspected on a ~~10 year frequency~~frequency not to exceed every eight years. The interval between successive recurring inspections may be decreased based on conditions discovered in previous inspections.

Structural monitoring inspections consist primarily of periodic visual examination of accessible structures and components performed by qualified personnel. 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 in the 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 will include preventive actions to provide reasonable assurance of structural bolting integrity, as discussed in Electric Power Research Institute (EPRI) documents (such as EPRI NP-5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel," and TR-104213, "Bolted Joint Maintenance & Application Guide"), American Society for Testing and Materials (ASTM) standards, and AISC specifications, as applicable.

In order to evaluate the potential of water to cause degradation of inaccessible below-grade concrete, samples of groundwater will be 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, inaccessible areas are assessed for aging when aging degradation exists in accessible areas and opportunistically inspected when excavated.

Ground water monitoring has shown the ground water to be non-aggressive, except for one sampling point. In 2007, a sample with a significantly high chloride level was obtained from the Turbine Building sump. Subsequent sample results from this sump have found additional chloride levels above the acceptance limit. An inspection was performed to assess the structure for any degradation that could be attributed to the elevated levels of chloride. The inspection found no evidence of significant degradation. There have been no indications of concrete degradation due to elevated chloride levels anywhere in the plant. Engineering continues quarterly monitoring of the ground water in this sump.

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.

ASME Code, Section XI visual examinations (VT-1) or surface examinations will be conducted to detect cracking of stainless steel and aluminum components exposed to aqueous solutions or air environments containing halides. A minimum sample of 25 inspections will be performed from each of the aluminum and stainless steel component populations every ten years.

If any sampling-based inspections to detect cracking in aluminum and stainless steel do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (i.e., 10 year inspection interval) in which the original inspection was conducted. Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in-service, severity of operating conditions, and lowest design margin.

Concrete inspection results are 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). In 1988, a research study was performed to evaluate the degradation processes that could affect the reinforced concrete structures. Concrete core samples were secured from the intake canal, Unit 1 Condensate Storage Tank Missile Shield, Unit 2 Safeguards Building and Unit 2 Containment. Based on testing of these samples, the study concluded that there was no evidence of ASR.

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.

Structural sealants, seismic gap joint filler, vibration isolation elements, and other elastomeric materials are 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 is supplemented by tactile inspection to detect hardening if the intended function is suspect.

Procedures will include preventive actions to ensure 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural

Connections publication, "Specification for Structural Joints Using High-Strength Bolts," will be used.

Spent fuel pool (SFP) liner leakage through the leak chase channels is monitored. An alarm is provided on the SFP to sound at a level loss of approximately 0.5 feet (UFSAR Section 9.5.3.3). A review of recent leak chase channel monitoring reports shows acceptable leakage rates with no tell-tale drains being completely blocked.

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: decontamination building, radwaste facility, health physics yard office building, laundry facility, and machine shop. Inspections for the added structures will be performed under the enhanced program in order to establish quantitative baseline inspection data prior to the subsequent period of extended operation. (Revised Change Notice 1)
2. Procedures will be revised to add the oiled-sand cushion to the inspection of the fire protection/domestic water tank foundation. (Added Change Notice 3)

Preventive Actions (Element 2)

3. Procedures will be revised to include preventive actions to ensure 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using High-Strength Bolts," will be used.

Parameters Monitored/Inspected (Element 3)

4. The checklist for structural and support steel will be revised to indicate: "Are any connection members loose, missing or damaged (bolts, rivets, nuts, etc.)?". (Added Change Notice 2)

Detection of Aging Effects (Element 4)

5. Procedures will be revised to eliminate options for inspector qualifications that are not consistent with ACI 349.3R-002. (Revised Change Notice 2)

6. ~~Procedures will be revised to specify that wooden pole inspections will be performed every ten years by an outside firm that provides wooden pole inspection services that are consistent with standard industry practice. Visual examinations may be augmented with soundings or other techniques appropriate for the type, condition, and treatment of the wooden poles, including borings to determine the location and extent of decay and excavation to determine the extent of decay at the groundline. (Revised Change Notice 2)~~Procedures will be revised to specify that wooden pole inspections will be performed at a frequency not to exceed every eight years. Visual examinations will detect loss of material and change in material properties. Visual examinations will be augmented, as required to detect change in material properties, with soundings or other techniques appropriate for the type, condition, and treatment of the wooden poles, including borings and excavations. (Revised - Set 4 RAIs)

7. Procedures will be revised to specify that 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. (Added Change Notice 2)

8. Procedures will be enhanced to specify VT-1 inspections to identify cracking on stainless steel and aluminum components. A minimum of 25 inspections will be performed every ten years during the subsequent period of extended operation from each of the stainless steel and aluminum component populations assigned to the Structures Monitoring program. If the component is measured in linear feet, at least one foot will be inspected to qualify as an inspection. For other components, at least 20% of the surface area will be inspected to qualify as an inspection. The selection of components for inspection will consider the severity of the environment. For example, components potentially exposed to halides and moisture would be inspected, since those environmental factors can facilitate stress corrosion cracking. (Added Change Notice 2)

9. Procedures will be enhanced to specify that for the neutron shield tank (NST), loss of material due to corrosion, other than superficial corrosion, will be evaluated to ensure that the NST will continue to perform its intended functions, including structural support of the RPV. (Added - Set 2 RAIs)

Corrective Actions (Element 7)

10. Procedures will be enhanced to specify for the sampling-based inspections to detect cracking in stainless steel and aluminum components, additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. No fewer than five additional inspections for each inspection that did not meet acceptance criteria or 20 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. Additional inspections will be completed within the 10-year inspection interval in which the original inspection was conducted. The responsible engineer will initiate condition reports to generate work orders to perform the additional inspections. The responsible engineer will evaluate the inspection results, and if the subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted. The responsible engineer will then determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the Corrective Action Program. (Added Change Notice 2)
11. Procedures will be enhanced to specify that evaluation of neutron shield tank findings consider its structural support function for the reactor pressure vessel. (Added Change Notice 3)
12. Procedures will be enhanced to also include LOCAs as events that require evaluation for potentially degraded structures by Civil/Mechanical Design Engineering. (Added Change Notice 3)

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2007, a condition report (CR) was written to document a ground water monitoring sample with a chloride level of 1210 ppm, which exceeded the acceptance limit of <500 ppm. This sample was obtained from the Turbine Building sump. Corporate and site Engineering continue to monitor the quarterly sample results from the Turbine Building sump and have found additional chloride levels above the acceptance limit, as high as 2700 ppm. An inspection of the Turbine Building sump was performed in July 2008 to assess the sump structure for any degradation that could be attributed to the elevated level of chlorides. The inspection found no evidence of significant degradation to the interior concrete. There are no safety-related components in the vicinity of the Turbine Building sump, and there have been no indications of concrete degradation due to elevated chloride levels anywhere in the plant.

   The source of the chlorides has not been determined. The Turbine Building sump is the deepest dewatering point and closest to the Intake Canal where expected underground leakage from the canal could influence the chloride level. The potential for in-plant sources of chlorides reaching the sump via secondary drains or local ground water was studied and determined to be unlikely. An Engineering evaluation concluded that, while the chloride level has remained high in the Turbine Building sump, the other sumps/piezometer well locations, some of which are located in close proximity to the Turbine Building sump, have been found to be consistently within acceptable levels. Engineering will continue to monitor the chloride levels in the Turbine Building sump on a quarterly basis. The plant procedure has been revised to maintain sampling requirements so that trending may continue but eliminate the comparison to the acceptance criterion for this sampling point.

2. In May 2011, a spall was found on the inside concrete surface of the bioshield wall of the Unit 2 Containment 'C' steam generator cubicle. The spall was approximately six inches long by six inches wide and 1-1/4 inches deep. The reinforcing steel was not exposed. It was determined that the bioshield wall remained fully functional, but the spalled concrete required repair prior to unit startup to prevent potential degradation of the reinforcing steel. A work order was submitted and the spalled concrete has been repaired.

3. In December 2011, several embedded anchor bolts for the condenser unit of a Unit 1 Control Room chiller were found to be degraded. The anchor bolts displayed signs of corrosion and material loss. A work order was submitted and the anchor bolts were repaired in December 2011, which consisted of chipping the existing concrete around the anchor bolts until sound metal was reached, performing a weld repair of each anchor bolt, and repairing the concrete slab.

4. In October 2012, leakage (approximately one gpm) was identified in the bottom portion of the steel to concrete joint (interface between the steel elbow and the concrete pipe) of the Unit 2 'D' 96-inch circulating water line. Corrosion and coating failure on the bottom third of the pipe was observed at this location. The urethane seal around the leading (upstream) edge of the joint was also missing and degraded. A work order was submitted and the Unit 2 'D' 96-inch circulating water line joint has been repaired.

5. In January 2013, the Service Building roof was leaking, causing water to collect in two locations on the floor of the Service Building hallway. The first location was near the #1 EDG room. The second location was approximately halfway between the doors to the health physics area and the door to the operations annex. A work order was submitted and degraded roof areas were repaired.

6. In December 2014, a CR was written to document a ground water monitoring sample that showed a chloride level of 610 ppm. The sampling point that exhibited unacceptable chloride levels is located adjacent to the Intake Canal, which draws water from the river. Three months later the same sampling point was found to have chlorides at 676 ppm. These values exceeded the acceptance limit of <500 ppm. The CR evaluation determined that the elevated chloride level was probably due to unusually low rain fall on the James River, temporarily increasing its natural salinity. Results from subsequent monitoring of ground water have been acceptable, and no degradation of concrete due to elevated chloride levels has been identified.

7. In December 2015, an effectiveness review of the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

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

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

9. In November 2017, as part of oversight review activities, the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6) AMA owners confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments required in UFSAR Chapter 18. Security lighting poles were within the scope of license renewal but were not inspected during the Civil Engineering Structural Inspection Activity cycle completed in 2012. The omission of the security lighting poles from the 2012 inspection cycle was entered in the Corrective Action Program. In December 2017, Civil Engineering inspected the light poles and noted no degradation. The License Renewal Application and supporting documentation were reviewed for in-scope structures requiring inspection, and that information was cross-referenced with the implementing procedure to confirm aging management program commitments required by UFSAR Chapter 18 were satisfied. The security lighting poles are identified in the implementing procedure as being within scope of license renewal and will be inspected during subsequent structural inspections.

10. In January 2018, an aging management program effectiveness review was conducted for the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6), which include the *Structures Monitoring* program (B2.1.34), *Masonry Walls* program (B2.1.33) and the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35). Information from the summary of that effectiveness review is provided below:

    The Civil Engineering Structural Inspection Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the AMA that were reviewed included structural inspections for aging management that have been incorporated into the periodic inspections performed for Maintenance Rule compliance. Maintenance Rule inspections, along with trending and evaluation for evidence of aging effects, ensure the continuing capability of civil engineering structures to meet their intended functions consistent with the current licensing basis. A 10-year review of inspection results and corrective actions did not identify any aging that resulted in a loss of intended function(s).

11. In March 2018, the existing Structures Monitoring program was revised to improve the inspection techniques and to adopt new inspection techniques to manage aging effects associated with ASR degradation of concrete structures and components consistent with industry operating experience IE Notice 2011-20 (IN 2011-20), "Concrete Degradation by Alkali-Silica Reaction," and EPRI Report #3002005389 (2015), "Tools for Early Detection of ASR in Concrete Structures."

The above examples of operating experience provide objective evidence that the *Structures Monitoring* program includes activities to perform volumetric and 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, 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.

In addition, the applicable RV flange and closure head initial RT_{NDT} values are bounding and the P-T limit curves flange notch requires no change or further consideration. Finally, the lowest service temperature requirements are not applicable to Units 1 and 2, because the plants are Westinghouse-designed per ASME Code, Section III, and utilize stainless steel reactor coolant system piping.

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

Since the P-T limits will be updated through the 10 CFR 50.90 process at a later, appropriate date, the effects of aging on the intended function(s) of the RVs will be adequately managed for the subsequent period of extended operation. The *Reactor Vessel Material Surveillance* program (B2.1.19) and plant Technical Specifications will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the period of applicability for Units 1 and 2.

4.2.6 LOW TEMPERATURE OVERPRESSURE PROTECTION

TLAA Description:

Low temperature overpressure protection (LTOP) system (sometimes referred to as the Reactor Coolant System Overpressure Mitigating System, or the RV Overpressure Mitigating System) at Unit 1 and Unit 2 is required by Technical Specification Limited Condition for Operation 3.1.G. Two pressurizer power operated relief valves (PORV) provide the automatic relief capability during the design basis mass input and the design basis heat input transients to automatically prevent the reactor coolant system pressure from exceeding the P-T limit curves based on 10 CFR 50, Appendix G.

LTOP system setpoints are based on the P-T limits calculation which is a TLAA.

TLAA Evaluation:

The LTOP enabling temperature has been determined for 68 EFPY as discussed in Appendix D of WCAP-18243-NP. Using Code Case N-514, the LTOP enabling temperature is 283°F. The Surry Technical Specification ~~3.1.G.1.c.(4)~~3.1.G.1.a specifies an arming temperature of 350°F which is conservative and remains valid for the subsequent period of extended operation.

In WCAP-18243-NP the maximum allowable LTOP system PORV setpoint was calculated to be 399.6 psig for the Units 1 and 2 subsequent period of extended operation. The calculation was performed in accordance with the WCAP-14040-A methodology using LTOP input parameters and the limiting axial flaw steady state ASME Code, Section XI, Appendix G limits calculated for the subsequent period of extended operation at 68 EFPY.

The evaluation showed that the current Technical Specification 3.1.G.1.c.(4) value of ≤ 390.0 psig is bounding and will remain valid for the subsequent period of extended operation. Since the maximum allowable PORV setpoint was determined using the methodology in WCAP-14040-A, this demonstrates that the current licensing basis PORV setpoint that was developed using K_{Ia} ASME Code, Section XI, Appendix G limits without applying uncertainties was sufficiently conservative.

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

The LTOP system setpoint and enabling temperature have been projected to the end of the subsequent period of extended operation.

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Moisture separator assembly	FD	Steel	(E) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	D
				Wall thinning	Steam Generators (B2.1.10)	IV.D1.RP-49	3.1.1-074	A
					Water Chemistry (B2.1.2)	IV.D1.RP-49	3.1.1-074	B
			(I) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	D
				Wall thinning	Steam Generators (B2.1.10)	IV.D1.RP-49	3.1.1-074	A
					Water Chemistry (B2.1.2)	IV.D1.RP-49	3.1.1-074	B
Primary inlet nozzle and outlet nozzle (and cladding)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	B
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.R-436	3.1.1-127	E;42
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	D
Primary inlet nozzle safe end and outlet nozzle safe end	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	B
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A

This program is based on the Surry response to NRC GL 88-14, "Instrument Air Supply Problems;" and utilizes guidance and standards provided in EPRI TR 108147 "Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079," and ANSI/ISA-S7.3-1975, "Quality Standard for Instrument Air." The *Compressed Air Monitoring* program activities implement the moisture content and contaminant criteria of ANSI/ISA-S7.3-1975 (incorporated into ISA-S7.0.01-1996).

Program activities include air quality checks at various locations to ensure that dew point, particulates, and hydrocarbons are maintained within the specified limits. Opportunistic inspections of the internal surfaces of select compressed air system components for signs of loss of material will be performed.

A1.15 FIRE PROTECTION

The *Fire Protection* program is an existing condition and performance monitoring program comprised of functional tests and visual inspections. The program manages:

- loss of material for fire-rated doors, fire damper ~~housings~~assemblies, the halon systems, RCP oil collection system, steel seismic gap covers and the low-pressure carbon dioxide systems
- loss of material (spalling) or cracking for concrete structures, including fire barrier walls, ceilings, and floors
- hardening, shrinkage, and loss of strength for elastomer fire barrier penetration seals and seismic gap elastomers
- loss of material, change in material properties, cracking/delamination, and separation for non-elastomer fire barrier penetration seals, fire stops, fire wraps, and coatings cracking/delamination, and separation
- loss of material and cracking for aluminum seismic gap covers

This program includes fire barrier inspections. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, fire damper ~~housings~~assemblies, and periodic visual inspection and functional tests of fire-rated doors to demonstrate that their operability is maintained. The program also includes periodic inspections and functional tests of the halon systems and low-pressure carbon dioxide systems.

A1.16 FIRE WATER SYSTEM

The *Fire Water System* program is an existing condition monitoring program that manages cracking, loss of material, flow blockage due to fouling, and loss of coating integrity for in-scope water-based fire protection systems. This program manages aging effects by conducting periodic visual inspections, flow testing, and flushes consistent with provisions of the 2011 Edition of National Fire Protection Association (NFPA) 25. Testing of sprinklers that have been in place for 50 years is performed consistent with NFPA 25, 2011 Edition. With exception of two locations,

B2.1.15 Fire Protection

Program Description

The *Fire Protection* program is an existing condition and performance monitoring program comprised of functional tests and visual inspections. The program manages:

- Loss of material for fire-rated doors, fire damper ~~housings~~assemblies, the halon systems, RCP oil collection system, steel seismic gap covers and the low-pressure carbon dioxide systems
- Loss of material (spalling) or cracking for concrete structures, including fire barrier walls, ceilings, and floors
- Hardening, shrinkage, and loss of strength for elastomer fire barrier penetration seals and seismic gap elastomers
- Loss of material, change in material properties, cracking/delamination, and separation for non-elastomer fire barrier penetration seals, fire stops, fire wraps, and coatings cracking/delamination, and separation
- Loss of material and cracking for aluminum seismic gap covers

This program includes fire barrier inspections. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, fire damper ~~housings~~assemblies, and periodic visual inspection and functional tests of fire-rated doors to demonstrate that their operability is maintained. The program also includes periodic inspections and functional tests of the halon systems and low-pressure carbon dioxide systems.

The *Fire Protection* program requires visual inspections of not less than 20% of the penetration seals every 12 months, such that 100% of the seals are inspected every five years. The program specifies visual inspections of the fire barrier walls, ceilings and floors in structures within the scope of subsequent license renewal every five years. The visual inspections of fire barriers include determining the condition of fire wraps every eighteen months. The eighteen month frequency also is applicable for visual inspections of fire doors and damper assemblies. Periodic functional checks are performed on the fire doors.

The program will also provide for aging management of external surfaces of the halon systems and low-pressure carbon dioxide fire systems components that are within the scope of license renewal through periodic visual inspections for corrosion that may lead to loss of material. The program includes functional testing of the halon systems and low-pressure carbon dioxide fire suppression systems components in accordance with the Technical Requirements Manual.

Personnel performing inspections are qualified and trained to perform the inspection activities. Unacceptable conditions are entered into the Corrective Action Program for proper disposition.

NUREG-2191 Consistency

The *Fire Protection* program is an existing program that,following enhancement, will be consistent with NUREG-2191, Section XI.M26, Fire Protection.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement will be implemented in the following program elements:

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

1. Procedures will be enhanced to require fire damper assemblies (rather than fire damper housings) to be visually inspected for loss of material and determined to be acceptable if there are no signs of degradation that could result in loss of fire protection capability due to loss of material.

Monitoring and Trending (Element 5) and Acceptance Criteria (Element 6)

2. Carbon dioxide and halon systems air flow testing procedures will be enhanced to trend air flow test data. In addition, procedures will be enhanced to specify that inspection results for the halon and CO2 systems meet the acceptance criteria if there are no indications of excessive loss of material.

Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

3. Procedures will be revised to require an assessment for additional inspections to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation. For sampling-based inspections, results are 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. If degradation is detected within the inspection sample of penetration seals, the scope of the inspection is expanded to include additional seals in accordance with the plant's corrective action program. Additional inspections would be 20% of each applicable inspection sample; however, additional inspections would not exceed five. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's corrective action program.

Operating Experience Summary

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

1. In January 2010, an original K-10 mortar fire barrier in the Turbine Building/Auxiliary Building pipe tunnel was determined to be damaged and non-functional. The instance was corrected by providing a new installation of Rectorseal BIO K-10+ Fire Rated Mortar having a 3-hour rating, and providing the required train separation in accordance with 10 CFR 50, Appendix R, Section III.G.2(a).
2. In July 2012, during the performance of a periodic maintenance procedure for inspection (functional check) of a swinging safety-related special purpose fire door, the gum rubber seal on the latch side of the door frame was found to be deteriorated. The seal was replaced as determined by engineering evaluation.
3. 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.
4. In January 2018, an aging management program effectiveness review was performed for the Fire Protection Program Activity (UFSAR Section 18.2.7). Information from the summary of that effectiveness review is provided below:

    The Fire Protection Program Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the Fire Protection Program Activity that were reviewed include the inspection of fire doors, fire barriers, fire detection, fire suppression, fire protection system integrity, RCP oil collection system, and Appendix R equipment as well as the evaluation of inspection results, repairs/replacements, corrective actions, and AMA document updates. A review of Engineering inspection result reports from 2006 to 2017 confirmed inspections were conducted at appropriate intervals and corrective actions were taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective

Action Program from 2006 through 2017 for age related degradation of fire protection components within the scope of license renewal.

Problems that included equipment obsolescence, false alarms, operator distraction, and potential single point failures were arising with the old fire detection system, which resulted in installation of a new fire detection system in 2015. Not all of the old fire panels were replaced. A new design change is currently being developed to address obsolescence of the remaining fire panels as well as make enhancements to the new fire detection system.

5. In March 2018, the NRC completed a triennial fire protection inspection. One finding was determined to have very low safety significance (Green). The finding involved failure to adequately protect fiberglass pipe that is susceptible to fire damage and required for safe shutdown. This finding was treated as a non-cited violation and closed. The subject pipe was replaced on both units with part fiberglass protected by Pyrocrete and part copper-nickel. Both portions of replacement pipe will withstand a three-hour fire.

The above examples of operating experience provide objective evidence that the *Fire Protection* program includes activities to perform visual inspections to identify cracking, loss of material, spalling, hardening, shrinkage and loss of strength for structures and components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fire Protection* 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 are 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 *Fire Protection* program will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Fire Protection* program,following enhancement, 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.

Serial Nos.: 19-344/344A/344B
Docket Nos.: 50-280/281

Enclosure 4

WCAP-18205-NP
REVISION 0
DECEMBER 2016

REACTOR INTERNALS FLUENCE EVALUATION FOR A WESTINGHOUSE 3-LOOP PLANT WITH TWIN UNITS - SUBSEQUENT LICENSE RENEWAL

NON-PROPRIETARY

Virginia Electric and Power Company
(Dominion Energy Virginia or Dominion)
Surry Power Station Units 1 and 2

Enclosure 5

DOMINION AFFIDAVIT FOR WITHHOLDING CONFIDENTIAL INFORMATION: DATED SEPTEMBER 4, 2019

Virginia Electric and Power Company
(Dominion Energy Virginia or Dominion)
Surry Power Station Units 1 and 2

Affidavit in Support of Request to Withhold Information From Public Disclosure Pursuant to 10 CFR 2.390

I, Mark D. Sartain, Vice President - Nuclear Engineering and Fleet Support, state that:

1. I have been specifically delegated and am authorized to execute this affidavit on behalf of Virginia Electric and Power Company (Dominion).

2. I am requesting WCAP-18205-NP be withheld from public disclosure in its entirety under 10 CFR 2.390.

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

2. Dominion is submitting information that contains confidential information that is privileged as part of response to a request for additional information by the Nuclear Regulatory Commission (Commission).

3. The information being submitted as part of a response to a request for additional information by the Commission that contains company confidential information is appropriate to be withheld from public disclosure in its entirety in accordance with 10 CFR 2.390(a)(4) and 9.17(a)(4).

4. The following factors specified in 10 CFR 2.390(b)(4) justify withholding this information from public disclosure in its entirety:

    a. The information sought to be withheld from public disclosure is owned and has been held in confidence by Dominion and is not customarily disclosed to the public.

    b. This information is a type that is customarily held in confidence by Dominion, and there is a rational basis for doing so because the information contains privileged commercial information related to the evaluation of neutron fluence in support of subsequent license renewal.

    c. This information is being transmitted to the NRC in confidence.

d. This information is not available in public sources and could not be gathered readily from other publicly available information.

e. Public disclosure of this confidential information is likely to cause substantial harm to the competitive position of Dominion 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. Accordingly, Dominion request that the designated information be withheld from public disclosure pursuant to the policy reflected in 10 CFR 2.390(a)(4) and 9.17(a)(4).

Mark D. Sartain

Vice President – Nuclear Engineering and Fleet Support

Executed on: 9/3/2019