VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

October 31, 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.: 19-438
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 (SLRA)
SUPPLEMENT TO SUBSEQUENT LICENSE RENEWAL APPLICATION
CHANGE NOTICE 5

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 attachment to an October 18, 2019 meeting invitation from Angela Wu (NRC) to Paul Aitken (Dominion) (Serial No. 19-438), "DMLR Comments on Dominion's October 15, 2019 Annual Update Letter," the NRC staff provided nine comments regarding the SPS SLRA for which additional information was needed to support their review of the SLRA.

On October 18, 2019 and October 21, 2019, Angela Wu (NRC) provided emails to Paul Aitken (Dominion), "Surry SLRA - Typo of Section 4.7.8 vs Section 4.7.9?," (Serial No. 19-439) and "SURRY TRP 033 Selective Leaching RAI - Gardner," (Serial No. 19-455), respectively, for which additional information was needed.

Teleconferences were held on October 21, 24, 28, and 29, 2019, between Dominion Energy and NRC staff to clarify the comments and determine the NRC staff information needs.

Change Notice 5, provided in Enclosure 1, includes additional information and clarification for the eleven comments to assist the NRC staff with their review of Dominion's responses to previous requests for information.

Enclosure 2 contains SLRA mark-ups that are a result of Change Notice 5 as described in Enclosure 1.

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 and Fleet Support

GARY DON MILLER
Notary Public
Commonwealth of Virginia
Reg. # 7629412
My Commission Expires August 31, 2023

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 Operations and Fleet Support of Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 31st day of October, 2019.

My Commission Expires: August 31, 2023

Notary Public

Commitments made in this letter: None

Enclosures:

1. SLRA Supplement – Change Notice 5
2. SLRA Mark-ups – Change Notice 5

cc: (w/o Enclosures except *)

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Enclosure 1

SLRA SUPPLEMENT – CHANGE NOTICE 5

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

SLRA SUPPLEMENT – CHANGE NOTICE 5

CHANGE NOTICE 5

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.

Change Notice 5, provided in Enclosure 1, includes additional information and clarification related to eleven comments received from the NRC staff. These comments required additional information and/or SLRA revisions to assist the NRC staff with their review of responses to requests for information that were previously submitted.

Revisions to the SLRA are provided in Enclosure 2.

NRC Comment 1

Buried and Underground Piping and Tanks / Open Cycle Cooling Water

It is unclear which AMP is managing the aging effects for the concrete CW piping. The description on page 4 states the Structures Monitoring program, the AMR Table 3.3.2-5 on page 26 states Buried and Underground Piping, and the Buried and Underground Piping AMP on page 108 still states the Open-Cycle Cooling Water AMP.

Commitment 11, item 6 continues to include the soil corrosivity samples. Because the Open-Cycle Cooling Water AMP is no longer managing the aging effects associated with the external surfaces of the concrete piping, the enhancement for the soil corrosivity is no longer applicable to the OCCW AMP. Soil corrosivity sampling and testing is addressed in the Buried Piping program, but it is not addressed in the OCCW program.

Dominion Response

The internal surfaces of the 96-inch concrete circulating water (CW) piping will continue to be managed by the *Open-Cycle Cooling Water System* program (B2.1.11). Aging effects of the external surfaces for the 96-inch concrete CW piping will be managed by both the *Structures Monitoring* program (B2.1.34) and *Buried and Underground Piping and Tanks* program (B2.1.27). The *Buried and Underground Piping and Tanks* program (B2.1.27) will perform the one-time inspection (one excavation) for evidence of concrete aging (below grade) associated with the south side of the Turbine Building (See response to Comment 4).

Regarding soil corrosivity samples, in Table A4.0-1, Item 11, Commitment No. 7 associated with the *Open-Cycle Cooling Water System* program (B2.1.11) will be relocated to Item 27, Commitment No. 7 associated with the *Buried and Underground Piping and Tanks* program (B2.1.27).

Additionally, in SLRA Section B2.1.11, *Open-Cycle Cooling Water* program (B2.1.11), Enhancement # 7 will be relocated to Enhancement # 7 of the *Buried and Underground Piping and Tanks* program (B2.1.27).

SLRA Changes

Based on the above discussion the following SLRA Sections are supplemented as shown in Enclosure 2:

Section 3.3.2.1.5
Table 3.3.2-5
Table 3.5.1
Table A4.0-1, Item 11
Table A4.0-1, Item 27
Section B2.1.11
Section B2.1.27

NRC Comment 2

Open Cycle Cooling Water

(p16/183) Discussion about ASME Code Case N-871

For Section V-2500, in addition to the "acoustic tap examination" from -5250(a), Surry previously stated it would also do metallic substrate thickness measure in accordance with -5250(c). The current discussion does not include the -5250(c) aspect and the only justification provided is that the metallic substrate thickness was measured prior to installation to confirm minimum wall thickness requirements.

Commitment 11, Item 11 deleted 5250(c) regarding the metallic substrate measurement.

Dominion Response

Although Section 5250(c), metallic substrate thickness measurements, were deleted from Table A4.0-1, Item 11 and Section B2.1.11, *Open-Cycle Cooling Water System* program (B2.1.11), Dominion intends to perform thickness measurements in accordance with ASME Code Case N-871, Section 5250(c) in order to confirm the adequacy of the anchor load transfer region.

SLRA Changes

Based on the above discussion, SLRA Table A4.0-1, Item 11 and Section B2.1.11 are supplemented to include ASME Code Case N-871, Section 5250(c), as shown in Enclosure 2.

NRC Comment 3

Open Cycle Cooling Water

Discussion cites CC N-871 Section 5211(d); however, there is no such section associated with ambient noise levels. The associated enhancement cites the correct section of the code case.

Dominion Response

The description of Change #1, "ASME Code Case N-871 Changes in the Open-Cycle Cooling Water program," provided in Enclosure 2 of Dominion letter dated October 14, 2019 (Serial No. 19-385), incorrectly sited Section 5211(d) of ASME Code Case N-871 in regards to ambient noise levels. However, the correct section of the code case, 5111(d), was referenced in SLRA Section B2.1.11, *Open-Cycle Cooling Water System* program (B2.1.11).

NRC Comment 4

Buried and Underground Piping and Tanks

Commitment No. 7 for the B&UPT program states, "For the selected structure, a minimum 50 ft^2 concrete surface area below the frost line will be inspected by the one-time inspection." A review of the elevation information in the letter yields the following:

- Frost line 18-inch below grade
- Top of the concrete piping could be from 17-feet to 25 1/2 -feet below grade
- Bottom of concrete piping could be 25-feet to 33 ½-feet below grade

Groundwater level data collected from June 2014 shows groundwater ranging from 16 ½ -feet to 18 ½ -feet below grade. The applicant needs to clarify (in their commitment) whether the inspected surrogate structure surface area to be inspected will be exposed to the same groundwater soil environment/material combination as the CW concrete piping.

Dominion Response

As required by Enhancement No. 8 (previously Enhancement No. 7) of the *Buried and Underground Piping and Tanks* program (B2.1.27), the one-time inspection (one excavation) for evidence of concrete aging (below grade) associated with the south side of the Turbine Building will be a minimum surface area of 50 ft^2 and will be located below groundwater level.

UFSAR Section 15.2.5 states that exterior surfaces of walls of Class I structures with floor levels below Elevation 26 ft. 6 in. are covered with a bitumastic coating. UFSAR Table 15.2-1 specifies that the High Level Intake Structures are Class I structures; therefore, the High Level Intake Structures have been eliminated as surrogate structures. Additionally, the Fire Pump House has been removed as a surrogate structure because the foundation is not at the depth of the groundwater level.

As shown in UFSAR Table 15.2-1, the Turbine Building is not classified as a Class I structure.

Based on the above, there is reasonable assurance that the surrogate structure subject to a one-time inspection will be equivalent to the buried concrete piping. At this time, Dominion cannot affirm if a coating is applied to below grade concrete of the Turbine Building. Therefore, a condition for confirmation will be included in Enhancement # 8 (previously Enhancement # 7) of the *Buried and Underground Piping and Tanks* program (B2.1.27), to make that determination prior to the one-time inspection (one excavation) of the Turbine Building below grade concrete.

If a coating is not identified, then:

- A minimum of 50 ft^2 concrete surface area located below groundwater level will be inspected by the one-time inspection.
- The one-time inspection results shall be used to evaluate the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349.3R.
- If observed age-related degradation exceeds ACI 349.3R Tier-1 criteria, then the area containing the degradation will be evaluated for acceptability by a responsible Civil Engineer using the Corrective Action Program. The evaluation shall determine the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349.3R.
- If observed age-related degradation exceeds ACI 349.3R Tier-1 criteria, a subsequent inspection will be performed within ten years to determine if the previously observed degradation remains within the parameters evaluated during the previous inspection. If the degradation during the subsequent inspection more than marginally exceeds the evaluated parameters from the previous inspection, then within 5 years an excavation of one 96-inch CW pipe will be performed to inspect a surface area of 50 ft^2 located below groundwater level.

If a coating is identified, then:

- Excavation of one 96-inch CW pipe will be performed to inspect a surface area of 50 ft^2 located below groundwater level.

SLRA Changes

SLRA Table A4.0-1, Item 27 and Section B2.1.27, Enhancement No. 8 (previously Enhancement No. 7) are supplemented to include the above condition for confirmation, as shown in Enclosure 2.

NRC Comment 5

Buried and Underground Piping and Tanks

The text of the response cites use of first and second tier acceptance criteria from ACI-349.3R. One portion of the response narrows to first tier criteria, "Observed conditions that exceed first-tier criteria are entered into the Corrective Action Program. The Responsible Civil Engineer will evaluate..." However, Commitment No. 7 lacks specificity in regard to the use of first or second tier criteria.

Dominion Response

An enhancement has been added to the *Buried and Underground Piping and Tanks* program (B2.1.27) to specify that if observed age-related degradation exceeds ACI 349.3R Tier-1 criteria, then the area containing the degradation will be evaluated for acceptability by a Responsible Civil Engineer using the Corrective Action Program. The evaluation shall include the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349.3R. A subsequent inspection will be performed within ten years to determine if the observed degradation identified remains within the parameters evaluated during the previous inspection. If the degradation identified during the subsequent inspection more than marginally exceeds the evaluated parameters from the previous inspection, then a 96-inch circulating water pipe will be scheduled for inspection within five years.

SLRA Changes

Based on the above discussion, SLRA Table A4.0-1, Item 27 and Section B2.1.27, Enhancement No. 8 (previously Enhancement No. 7) are supplemented as shown in Enclosure 2.

NRC Comment 6

Buried and Underground Piping and Tanks

The response states the following in regard to potential corrective actions associated with adverse inspection results of the surrogate structure.

> any further actions required are determined by the Responsible Civil Engineer, based on the conditions observed. The evaluation determines the significance of the degradation as it pertains to the CW pipe. The further evaluation required by the Corrective Action Program considers the apparent cause of the degradation, and the applicability of that cause to the CW pipe. Further actions may include additional analysis, expanded inspections, or testing (e.g., destructive testing), if warranted.

The staff has concluded that if first tier criteria are not met, then additional inspections or testing should be cited in the commitments. The staff recognizes that the extent of not meeting the acceptance criteria could form the basis for the extent and time span prior to followup inspections; however, the applicant should provide a lower limit on extent and timing of followup inspections; and the basis.

Dominion Response

The NRC staff concern associated with this comment is addressed in the response and the associated SLRA mark-ups provided with the response to NRC Comment 5 above.

NRC Comment 7

Buried and Underground Piping and Tanks

As amended by letter dated October 14, 2019, SLRA Section B2.1.27, "Buried and Underground Piping and Tanks," Commitment No. 27, item 6 states:

A cathodic protection system will be installed for protection of each unit's buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building five years before entering the subsequent period of operation. (Added - Change Notice 4)

However, SLRA Section B2.1.27 and the associated UFSAR description include the following statements regarding cathodic protection:

- 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.

- The balance of piping and tanks within the scope of subsequent license renewal are not provided with CP.

The staff is certain of Dominion's intent in regard to installing cathodic protection; however, the internal discrepancies with the program and UFSAR need to be corrected. This is particularly critical for the UFSAR section as this will represent a portion of the CLB upon entry into the SPEO.

Dominion Response

SLRA Section A1.27 and Section B2.1.27, *Buried and Underground Piping and Tanks* program (B2.1.27) have been revised to clarify that the fuel oil system for the emergency power system is protected by an active cathodic protection (CP) system. Dominion previously committed to install CP for buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building and the 24-inch service water piping at the Low Level Intake Structure. Consequently, SLRA Sections A1.27 and B1.2.27 have been revised to indicate that 5 years prior to entering the subsequent period of extended operation, each unit's buried carbon steel piping within the scope of subsequent license renewal will be cathodically protected. The statement indicating the balance of piping and tanks within the scope of subsequent license renewal are not provided with CP based on soil sampling and testing has also been deleted.

SLRA Changes

Based on the above discussion, SLRA Sections A1.27 and B2.1.27 are supplemented as shown in Enclosure 2.

NRC Comment 8

Buried and Underground Piping and Tanks

Clarification is needed regarding how EPRI Report 3002005294 will determine if soil is "non-corrosive" (e.g., 10 points or less using EPRI Report 3002005294). This clarification was provided to Dominion after the clarification call.

Dominion Response

An enhancement has been added to the *Buried and Underground Piping and Tanks* program (B2.1.27) to specify that soil sample results indicating corrosivity of greater than 10 points using the "carbon steel" column in Table 9-4, "Soil Corrosivity Index from BPWORKS," of EPRI Report 3002005294, "Soil Sampling and Testing Methods to

Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," require evaluation of potential scope expansion or category transition.

SLRA Changes

Based on the above discussion, SLRA Table A4.0-1, Item 27 and Section B2.1.27 are supplemented as shown in Enclosure 2.

NRC Comment 9

Buried and Underground Piping and Tanks

Additional further evaluation/inspections/testing should also be conducted if aggressive soil/groundwater (i.e., pH<5.5, chlorides>500ppm, sulfates>1,500 ppm) is identified at any of the 5 sampling locations. This is not reflected in the commitment, which only discusses the surrogate inspection.

Dominion Response

Groundwater samples are monitored to confirm a non-aggressive groundwater/soil environment. If groundwater values increase above the established thresholds then the condition will be entered into the Corrective Action Program for further evaluation and appropriate corrective actions. Corrective actions will include a confirmatory groundwater resampling, as well as groundwater sampling on a quarterly basis for at least one year (i.e., four quarters). The results of the quarterly groundwater samples will be trended, and if groundwater chemistry continues to exceed the aggressive environment thresholds, additional corrective actions will be determined. The additional corrective actions may include further sampling, installation of additional wells, more frequent inspections of the surrogate structure, and/or the development of a plant specific aging management activity.

SLRA Changes

Based on the above discussion, SLRA Table A4.0-1, Item 27 and Section B2.1.27 are supplemented as shown in Enclosure 2.

NRC Comment 10

Surry SLRA Table 3.1.1, Item 3.1.1-077 and TLAA 4.7.9, "Steam Generator Tube Wear Evaluation," address loss of material due to wear and fretting for nickel alloy steam generator u-tubes exposed to treated water >60 ^{o}C (140 ^{o}F). For the SLRA Table 2 AMR item that cites generic note E, the plant-specific Note 1 currently credits the TLAA in Section 4.7.8 of the SLRA, "Steam Generator Tube High Cycle Fatigue Evaluation," to manage the aging effect for nickel alloy exposed to treated water.

Did Dominion intend to reference the evaluation of loss of material in steam generator tubes at tube support plates, which is a plant-specific TLAA, evaluated in Section 4.7.9, "Steam Generator Tube Wear Evaluation?

Dominion Response

SLRA Table 3.1.2-4, Note 1 has been revised to reflect Section 4.7.9 as the appropriate reference.

SLRA Changes

Based on the above discussion, SLRA Table 3.1.2-4 is supplemented as shown in Enclosure 2.

NRC Comment 11

1. What is the corrosion mechanism that contributed to the ruptures that were mentioned in the annual update?
2. What is the extent of the adverse results of the corrosion mechanism on the fire protection system? Include the following: (a) results of follow-on inspections; (b) what portions of the system did not meet their intended function; and (c) what portions of the system might not have met their intended function based on projecting inspection results.
3. What is the cause of the rupture of the fire protection (e.g. ground water or leakage from piping)? What are the results of the soil analysis taken for soil chemistry in the vicinity of the ruptured piping?
4. If loss of material due to selective leaching was the applicable aging effect/mechanism that caused the ruptures, what augmented requirements that will be incorporated into the Selective Leaching program?

Dominion Response

1. In July 2019, Surry experienced leakage from two adjacent pipe sections of the fire protection yard loop piping. Metallurgical analysis concluded failure of the 12" cast iron fire protection piping was a result of graphitic corrosion (i.e. selective leaching). The analysis determined that the identified graphitic corrosion was a result of groundwater exposure of the cast iron fire protection piping between roughly the 5 o'clock to 7 o'clock positions.

2a. Following the fire protection yard loop piping leakage event, a fire protection yard loop isolation valve located south of the failure, was unearthed and replaced in accordance with a previously scheduled work order. A section of piping was removed with the fire protection yard loop isolation valve because the fire protection piping was joined by bell and spigot connections. Accordingly, that portion of the piping was replaced along with the isolation valve. Follow-on destructive examination identified graphitic corrosion on this pipe section and the associated isolation valve. Because graphitic corrosion is a long-term corrosion mechanism, it is believed the corrosion resulted from extended contact with groundwater and was not due to the packing leak identified 1 year prior.

2b. Following the failure of the 12" fire protection loop piping, the affected sections of piping were isolated. The boundary between the fire protection yard loop isolation valves isolating the affected sections of piping includes one hose house and is currently "CAUTION" tagged. Due to the loop design of the fire main header and additional redundancies no additional sections of the fire header or equipment were determined to be nonfunctional due to the failure. The failed sections of pipe at this location were repaired, but remain isolated and available if needed.

2c. During subsequent evaluations performed as part of the corrective action process, materials analysis was performed on the failed fire protection piping and determined that graphitic corrosion was the cause of the failure. The most significant corrosion was limited to the bottom section of piping between roughly the 5 o'clock to 7 o'clock positions. It was determined through metallurgical analysis that the identified graphitic corrosion was a result of the cast iron fire protection piping exposure to groundwater.

In order to determine which areas of the fire protection main loop had been exposed to groundwater, exploratory holes approximately 10" in diameter were dug at strategic locations. Specifically, a review of several previous buried pipe inspection results was conducted to identify any instances of groundwater that were identified during other excavations. This review provided insights as to where groundwater may be present and a methodology to plot where exploratory holes should be dug to determine if groundwater is in contact with fire main piping. The holes were then dug to a depth of seven feet or until water was located. Seven feet was chosen because it is below the depth of the fire protection piping which is buried at six feet on centerline. The water found in the holes was sampled. The samples were analyzed and determined to not include chlorides, which eliminates the possibility that the higher than expected groundwater level is leakage from the station intake canal.

As a result of not having physically verified the condition of fire protection yard loop piping in the areas where groundwater is known to have contacted the cast iron fire protection piping, the fire protection yard loop was conservatively declared non-functional in accordance with the Technical Requirements Manual (TRM). Backup fire suppression has been established such that the TRM action statements are satisfied using the evaluated portions of the existing loop piping.

Currently, the motor driven fire pump is operating at full pressure (~135 psig) to support outage related maintenance activities. The motor driven fire pump is currently in operation, which reduces pressure transients on the system. No additional fire protection header leakage has been identified with the header pressurized. With the exception of a section of the loop in the vicinity of the original failure, which is currently isolated, the loop is pressurized. Compensatory measures are in place to isolate sections of the yard loop which are known to have been exposed to groundwater and to start a pre-staged high flow capacity pump if needed. The high flow capacity pump is staged, but not running, with administrative controls to provide the required backup fire suppression supply.

Corrective actions are in place to track the extent of condition of groundwater monitoring, and a repair plan to restore the affected piping.

3. Upon excavation of the rupture site, it was identified that there were two 18-foot to 20-foot long sections of 12-inch diameter fire protection loop piping that were cracked and leaking. The northern section of fire protection loop pipe had a longitudinal crack approximately ten feet long. This pipe was removed and examined by the Corporate Materials Laboratory. Graphitic corrosion was identified at the outside diameter of the cast iron fire protection loop pipe. The corrosion reduced the strength of the fire protection loop pipe which failed due to hoop stress from internal pressure. The corrosion pockets were primarily located at the bottom of the fire protection loop pipe.

   The southern section of fire protection loop pipe had a circumferential crack approximately eight feet south of the northern fire protection loop pipe mechanical connection. This type of crack is typically associated with bending stress and an overload condition. The crack propagated from a large pocket of external graphitic corrosion located at the bottom of the fire protection loop pipe. The cause evaluation concluded that the circumferential crack occurred as a result of the initial longitudinal crack and rupture. The initial rupture created an uplifting force and motion which caused the circumferential crack at the weakened location.

   The piping along with the fire protection loop isolation valve was also examined and the presence of graphitic corrosion confirmed. While the valve body had

had considerable internal and external graphitic corrosion, the damage was not considered significant when compared to the overall thickness of the casting. As a result, the structural integrity was not compromised at the time of the discovery.

Information provided within the corporate failure analysis provides additional insights into the cause. Graphitic corrosion is generally a slow process, so the exterior corrosion noted along the pipe and isolation valve would suggest these locations had been exposed to groundwater for an extended period of time.

The evaluated failure was graphitic corrosion caused by exposure to groundwater over an extended period of time. Water intrusion into the excavation sites during pipe repair and several exploratory wells dug in selected areas indicate the presence of groundwater. Sampling of the water at the excavation site indicated the source was chemically consistent with groundwater and not from another chemically treated source or the Intake Canal.

Soil analysis was performed at the northern and southern pipe section was performed with the results located in the table below. In accordance with EPRI guidance the soil in the northern location would be graded as moderately corrosive and the southern section would be mildly corrosive.

Sample Parameter	Northern sample	Southern Sample
Extractable Chlorides	120	19
Sulfides	Not detected above reporting limits	Not detected above reporting limits
pH	4.24	7.36
ORP	160	160
Resistivity	1983	3806
%Moisture	23	6.1

4. Based on the above, the *Selective Leaching* program (B2.1.21) will be augmented to include a requirement to dig exploratory holes to confirm the presence of groundwater around the buried fire water main loop piping, excavate/examine to identify selective leaching, project any identified degradation, and determine necessary future inspections based on the following:

   Exploratory Holes for Groundwater

   - A minimum of 25 exploratory holes will be drilled prior to the subsequent period of extended operation (SPEO) and during each 10-year inspection interval in the

SPEO to identify suspected system leakage or elevated groundwater. The selection of exploratory hole sample locations will take into account recent soil sample results, piping most susceptible to aging based on time-in-service, and the severity of piping operating conditions.

- Exploratory holes will be drilled in areas of suspected system leakage or elevated groundwater.
- Exploratory holes will be drilled to the maximum depth of the fire protection loop piping.
- When water is detected, as a minimum it will be analyzed for pH, chlorides and sulfates.
- Fire protection loop piping will be excavated and inspected at each hole where groundwater has been confirmed and corrective actions implemented based on the inspection results. Each excavation will also include a soil sample, in accordance with the *Buried and Underground Piping and Tanks* program (B2.1.27) that will be analyzed and the results evaluated with the excavation inspection results.

<u>Corrective Actions for Presence of Groundwater</u>

- If water in an exploratory hole is identified to be a result of fire protection system leakage or other plant system leakage and not due to elevated groundwater, then corrective actions consistent with the *Selective Leaching* program (B2.1.21) will be initiated.
- If water in an exploratory hole is identified to be a result of elevated groundwater, then five additional exploratory holes will be drilled to confirm the extent of the elevated groundwater area. If the additional exploratory holes discover groundwater, an extent of condition analysis will be conducted to determine the extent of additional drillings required. Fire protection loop piping at the additional exploratory holes with groundwater will be excavated for examination.
- If no additional areas of elevated groundwater are identified beyond the area initially confirmed to have elevated groundwater during July 2019 or during the first SPEO 10 year exploratory hole sample location inspections, an extent of condition analysis will be conducted to determine the extent of excavations required for the first and second SPEO inspection intervals. The extent of condition analysis will take into account corrective actions (e.g., piping replacement) and inspection projections conducted for the initial area of confirmed elevated groundwater (which occurred in July 2019).

<u>Sample Expansion (Selective Leaching due to Elevated Groundwater)</u>

- For each excavation, a minimum of ten feet of buried fire protection main loop piping will be excavated, cleaned using aggressive cleaning techniques sufficient to remove de-alloyed material and visually examined for evidence of selective leaching.

- A minimum of five destructive exams will be performed in separate one foot sample sections of fire protection pipe that exhibit signs of selective leaching.
- Acceptance criteria will be consistent with the *Selective Leaching* program (B2.1.21).
- An extent of condition analysis will be conducted to determine extent of further inspections.
- Timing of the additional inspections will be based on the severity of the degradation identified and commensurate with the potential for loss of intended function.

SLRA Changes

Based on the above discussion, SLRA Section B2.1.21 is supplemented as shown in Enclosure 2.

Enclosure 2

SLRA MARK-UPS
CHANGE NOTICE 5

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

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
U-tube	HT;PB	Nickel alloy	(I) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.R-44	3.1.1-070	A
					Water Chemistry (B2.1.2)	IV.D1.R-44	3.1.1-070	B
				Cumulative fatigue damage	TLAA	IV.D1.R-46	3.1.1-002	A
			(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.R-47	3.1.1-069	A
					Water Chemistry (B2.1.2)	IV.D1.R-47	3.1.1-069	B
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-233	3.1.1-077	A
					TLAA	IV.D1.RP-233	3.1.1-077	E, 1
				Reduction of heat transfer	Steam Generators (B2.1.10)	IV.D1.R-407	3.1.1-111	A
					Water Chemistry (B2.1.2)	IV.D1.R-407	3.1.1-111	B

Table 3.1.2-4 Plant-Specific Notes:

1. Wear of steam generator tubes at tube support plates is a plant-specific TLAA, evaluated in ~~Section 4.7.8, Steam Generator Tube High Cycle Fatigue Evaluation~~Section 4.7.9, Steam Generator Tube Wear Evaluation.
2. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used to manage loss of material for the primary inlet and outlet nozzles exposed to reactor coolant.
3. The One-Time Inspection (B2.1.20) program will verify the effectiveness of the Water Chemistry (B2.1.2) program to manage loss of material for the new transition cone closure weld.

3.3.2.1.5 Circulating Water

Materials

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

- Concrete
- Copper Alloy (>15 percent Zn)
- Copper Alloy with internal coating
- Ductile iron with internal coating
- Elastomer
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating
- Steel with internal lining
- Titanium

Environment

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

- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Condensation
- Raw water
- Soil
- Treated water

Aging Effects Requiring Management

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

- Cracking
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of bond
- Loss of coating or lining integrity
- Loss of material
- Loss of material (spalling, scaling)
- Loss of preload

Aging Management Programs

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

- Bolting Integrity (B2.1.9)
- Buried and Underground Piping and Tanks (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)
- Structures Monitoring (B2.1.34)
- Water Chemistry (B2.1.2)

Table 3.3.2-5 Auxiliary Systems - Circulating Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (circulating water condenser - channel head)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C, 8
			(I) Raw water	Loss of coating or lining integrity; loss of material or cracking (for cementitious coatings/linings)	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-400	3.3.1-127	E, 6
						VII.C1.A-414	3.3.1-139	A
Heat exchanger (circulating water condenser - tube)	PB	Titanium	(I) Raw water	Cracking (titanium only); reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-736	3.3.1-207	A, 4
			(E) Treated water	Cracking; reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.C1.A-765	3.3.1-236	A, 4
					Water Chemistry (B2.1.2)	VII.C1.A-765	3.3.1-236	B, 4
Heat exchanger (circulating water condenser - tubesheet)	PB	Copper alloy with internal coating	(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	A, 5
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-414	3.3.1-139	A, 5
			(E) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	C, 5
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	D, 5
Piping, piping components	LB;PB	Concrete	(I) Raw water	Cracking; loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-250	3.3.1-030	B
			(E) Soil	Cracking; loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-157	3.3.1-103	A
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 9

Table 3.3.2-5 Plant-Specific Notes:

1. Internal coating: coal tar epoxy.
2. Internal lining: carbon fiber reinforced polymer.
3. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.
4. Reduction of heat transfer is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for components with only a pressure boundary function.
5. Material is aluminum-bronze (ASTM B171 Alloy 614) with less than 8% aluminum.
6. The Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program is used instead of the Open-Cycle Cooling Water System (B2.1.11) program to manage recurring internal corrosion for internally-coated steel heat exchangers.
7. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
8. Cited GALL item VII.I.A-405a includes "cracking" aging effect that is only applicable for copper alloy (>15% Zn or >8% Al). Cracking is not an applicable aging effect for steel with internal lining components.
9. ~~The Open-Cycle Cooling Water System (B2.1.11) program will manage aging of the external surfaces of buried cementitious piping.~~The Structures Monitoring (B2.1.34) program provides guidance for managing the aging of buried concrete structures to supplement the requirements in the Buried and Underground Piping and Tanks (B2.1.27) program.
10. The Open-Cycle Cooling Water System (B2.1.11) program will manage aging effects for the internal surfaces of carbon fiber reinforced piping exposed to raw water.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-065	Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Groups 1-3, 5, 7-9: concrete (accessible areas): below-grade exterior; foundation, Groups 6: concrete (inaccessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, Structures Monitoring	No	~~Consistent with NUREG-2191.~~ Consistent with NUREG-2191. In addition to Structures and Component Supports, concrete components in Auxiliary Systems (circulating water) are aligned to this item.
3.5.1-066	Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-067	Groups 1-5, 7, 9: Concrete: interior; above-grade exterior, Groups 1-3, 5, 7-9 - concrete (inaccessible areas): below-grade exterior; foundation, Group 6: concrete (inaccessible areas): all	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-068	High-strength steel structural bolting	Cracking due to SCC	AMP XI.S3, ASME Section XI, Subsection IWF	No	Consistent with NUREG-2191.
3.5.1-070	Masonry walls: all	Cracking due to restraint shrinkage, creep, aggressive environment	AMP XI.S5, Masonry Walls	No	Consistent with NUREG-2191.

A1.27 BURIED AND UNDERGROUND PIPING AND TANKS

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 components 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 CP, nondestructive 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. 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.

Five years prior to entering the subsequent period of extended operation, each unit's buried carbon steel piping within the scope of subsequent license renewal will be cathodically protected. This will include the buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building and the 24-inch service water piping at the Low Level Intake Structure on each unit.

~~The balance of piping and tanks within the scope of subsequent license renewal are not provided with CP.~~ 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 subsequent license renewal is not corrosive for the installed material types.

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 (A1.16).

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 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)~~(Deleted - Change Notice 5) 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. Examination procedures and personnel who perform acoustic examinations of CFRP lined piping will be qualified consistent with mandatory Appendix VI and section 5400 of ASME Code Case N-871. (Added - Set 2 RAIs) (Revised - Change Notice 4) 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~~three 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) (Revised - Change Notice 4)	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	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 Mandatory Appendix V, "Inservice Examination", Section V-2500, ASME Code Case N-871 section 5250(a), section ~~and ,~~5250(c),~~-~~and Section 5350. The acoustic examination of terminal ends will be capable of detecting and sizing delaminations and voids in any composite or bonding layer with dimensions equal to or less than those permitted by Section 4390(b)(3). The acoustic impact tap examination procedure sections will also be enhanced to add Section 5111(d), that provides consideration of the impact of in-situ ambient noise levels on application of the procedure and qualification of procedures and personnel. The qualification testing will be conducted in an area where the ambient noise level is equal to or higher than the noise level where the in-situ testing will be performed. 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) (Added - Set 2 RAIs) (Revised - Change Notice 4) (Revised - Change Notice 5) 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) (Revised - Change Notice 4) 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.	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	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 one 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) 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
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 Piping 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. A cathodic protection system will be installed for protection of each unit's buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building five years before entering the subsequent period of operation. (Added - Change Notice 4) 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 ten 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, high chlorides, and acidic environments will be evaluated. (Added - Change Notice 5)	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	8. Procedure(s) will be developed to perform a one-time inspection (one excavation) for evidence of concrete aging (below grade) associated with ~~either the Unit 1 or Unit 2 High Level Intake Structures, or~~ the south side of the Turbine Building~~.~~, with the following requirements: (Revised - Change Notice 5) a. Prior to excavation, it shall be confirmed that the south side of the Turbine Building is not covered with a bitumastic coating below grade. b. If a coating is not identified, then: • ~~or the Fire Pump House~~A minimum of 50 ft^2 concrete surface area below ~~the frost level~~ groundwater level will be inspected by the one-time inspection. • The ~~procedure will require that, as a surrogate location, the~~ evaluation of the one-time inspection results ~~also~~ shall include evaluation of the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349.3R. • If observed age-related degradation exceeds ACI 349.3R Tier-1 criteria, then the area containing the degradation will be evaluated for acceptability by a responsible Civil Engineer using the Corrective Action Program. The evaluation shall include the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349.3R. • If observed age-related degradation exceeds ACI 349.3R Tier-1 criteria, a subsequent inspection will be performed within ten years to determine if the previously observed degradation remains within the parameters evaluated during the previous inspection. If the degradation during the subsequent inspection more than marginally exceeds the evaluated parameters from the previous inspection, then witihin five years an excavation of one 96-inch CW pipe will be performed to inspect a surface area of 50 ft^2 located below groundwater level. c. If a coating is identified, then: • Excavation of one 96-inch CW pipe will be performed to inspect a surface area of 50 ft^2 located below groundwater level.	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	9. 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.~~ 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) 10. Procedures will be revised to specify that soil sample results indicating corrosivity of greater than 10 points using the “carbon steel” column in Table 9-4, “Soil Corrosivity Index from BPWORKS,” of EPRI Report 3002005294, “Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants,” require evaluation of potential scope expansion or category transition. (Added - Change Notice 5) 11. Procedures will be revised to specify that when an aggressive groundwater/soil environment is confirmed, corrective actions are required, including confirmatory groundwater resampling, as well as groundwater sampling on a quarterly basis for at least one year (i.e., four quarters). The results of the quarterly groundwater samples will be trended, and if groundwater chemistry continues to exceed the aggressive environment thresholds, additional corrective actions will be determined. The additional corrective actions may include items such as further sampling, installation of more wells, more frequent inspections of the surrogate structure, and/or the development of a plant specific aging management activity. (Added - Change Notice 5)	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.

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)~~(Deleted - Change Notice 5)

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. Examination procedures and personnel who perform acoustic examinations of CFRP lined piping will be qualified consistent with mandatory Appendix VI and section 5400 of ASME Code Case N-871. (Added - Set 2 RAIs) (Revised - Change Notice 4)

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 three 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) (Revised - Change Notice 4)

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 Mandatory Appendix V, “Inservice Examination”, Section V-2500, ASME Code Case N-871 section 5250(a), ~~-~~section ~~and ,~~5250(c) and Section 5350. The acoustic examination of terminal ends will be capable of detecting and sizing delaminations and voids in any composite or bonding layer with dimensions equal to or less than those permitted by Section 4390(b)(3). The acoustic impact tap examination procedure sections will also be enhanced to add Section 5111(d), that provides consideration of the impact of in-situ ambient noise levels on application of the procedure and qualification of procedures and personnel. The qualification testing will be conducted in an area where the ambient noise level is equal to or higher than the noise level where the in-situ testing will be performed. 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) (Added - Set 2 RAIs) (Revised - Change Notice 4) (Revised - Change Notice 5)

12. Procedures will be revised to periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. One hundred percent of the accessible circulating water line internal surfaces will be inspected in a ten year period. (Added - Set 1 RAIs) (Revised - Change Notice 4)

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.

B2.1.21 Selective Leaching

Program Description

The *Selective Leaching* program is a new condition monitoring program that will manage loss of material of the susceptible materials located in a potentially aggressive environment. The materials of construction for these components may include gray cast iron, ductile iron, and copper alloys (greater than 15% zinc or greater than 8% aluminum).

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

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

For two unit sites the periodic visual and mechanical inspections can be reduced from ten to eight because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Past power up-rates were implemented for both units at approximately the same time. Historically, water chemistry conditions between the two units have been very similar. The raw water source for both units is the James River. Emergency diesel generator runs are managed to equalize total run times among the diesels, so as to equalize wear and aging. Operating experience for each unit demonstrates no significant difference in aging effects of systems in the scope of this program between the two units.

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

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

- For copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide,
- For gray cast iron and ductile iron, the absence of a surface layer that can be easily removed by chipping or scraping or identified in the destructive examinations,
- The presence of no more than a superficial layer of dealloying, as determined by removal of the dealloyed material by mechanical removal, and
- The components meet system design requirements such as minimum wall thickness, when extended to the end of the subsequent period of extended operation.

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

The *Selective Leaching* program (B2.1.21) will be augmented to include a requirement to dig exploratory holes to confirm the presence of groundwater around the buried fire water main loop piping, excavate/examine to identify selective leaching, project any identified degradation, and determine necessary future inspections based on the following:

Exploratory Holes for Groundwater

- A minimum of 25 exploratory holes will be drilled prior to the subsequent period of extended operation (SPEO) and during each 10 year inspection interval in the SPEO to identify suspected system leakage or elevated groundwater. The selection of exploratory hole sample locations will take into account recent soil sample results, piping most susceptible to aging based on time-in-service, and the severity of piping operating conditions.

- Exploratory holes will be drilled in areas of suspected system leakage or elevated groundwater.
- Exploratory holes will be drilled to the maximum depth of the fire protection loop piping.
- When water is detected, as a minimum it will be analyzed for pH, chlorides and sulfates.
- Fire protection loop piping will be excavated and inspected at each hole where groundwater has been confirmed and corrective actions implemented based on the inspection results. Each excavation will also include a soil sample, in accordance with the Buried and Underground Piping and Tanks program (B2.1.27) that will be analyzed and the results evaluated with the excavation inspection results.

Corrective Actions for Presence of Groundwater

- If water in an exploratory hole is identified to be a result of fire protection system leakage or other plant system leakage and not due to elevated groundwater, then corrective actions consistent with the *Selective Leaching* program (B2.1.21) will be initiated.
- If water in an exploratory hole is identified to be a result of elevated groundwater, then five additional exploratory holes will be drilled to confirm the extent of the elevated groundwater area. If the additional exploratory holes discover groundwater, an extent of condition analysis will be conducted to determine the extent of additional drillings required. Fire protection loop piping at the additional exploratory holes with groundwater will be excavated for examination.
- If no additional areas of elevated groundwater are identified beyond the area initially confirmed to have elevated groundwater during July 2019 or during the first SPEO 10-year exploratory hole sample location inspections, an extent of condition analysis will be conducted to determine the extent of excavations required for the first and second SPEO inspection intervals. The extent of condition analysis will take into account corrective actions (e.g., piping replacement) and inspection projections conducted for the initial area of confirmed elevated groundwater (which occurred in July 2019.)

Sample Expansion (Selective Leaching due to Elevated Groundwater)

- For each excavation, a minimum of ten feet of buried fire protection main loop piping will be excavated, cleaned using aggressive cleaning techniques sufficient to remove de-alloyed material and visually examined for evidence of selective leaching.
- A minimum of five destructive exams will be performed in separate one foot sample sections of fire protection pipe that exhibit signs of selective leaching.
- Acceptance criteria will be consistent with the Selective Leaching program (B2.1.21).
- An extent of condition analysis will be conducted to determine extent of further inspections.
- Timing of the additional inspections will be based on the severity of the degradation identified and commensurate with the potential for loss of intended function.

NUREG-2191 Consistency

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

Exception Summary

None

Enhancements

None

Operating Experience Summary

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

1. In Spring 1988, inspection of butterfly valves located in the main condenser inlet and outlet piping and in the service water piping associated with the component cooling heat exchangers identified degradation due to graphitic corrosion. IE Notice 84-71 (IEN 84-71) "Graphitic Corrosion of Cast Iron in Salt Water," informed licenses of a potentially significant corrosion problem in salt or brackish water environments. Unit 1 and Unit 2 are located on the salinity line of the James River. This water falls within the brackish category. Both units were designed with a number of cast iron components in the circulating water and service water systems. In response to IEN 84-71, a graphitic corrosion evaluation was performed. The evaluation resulted in the examination of a large sample of components, valves, strainers, and pumps which revealed various degrees of graphitic corrosion. Wall thickness measurements were obtained by ultrasonic testing and verified by mechanical measurements. Destructive measurements were made on some valves. The conclusion of the evaluation was that various valves in the circulating water and service water system would be replaced. The originally installed butterfly valves were uncoated gray cast iron. Due to the brackish water environment, these valves had reduced wall thickness due to graphitic corrosion. In order to ensure seismic qualification, the valves were replaced with valves manufactured from ductile iron due to its mechanical properties. In order to provide extended service life, the wetted portion of the ductile iron (valve disc and body inside surface) had a liquid epoxy coating applied.
2. In January 1996, a materials analysis was performed of the inlet end and approximately five inches of a vacuum priming seal recirculating pump heat exchanger. The inlet end of the heat exchanger was degraded as a result of flow accelerated corrosion. Cross sections taken at the tube to tubesheet interface also revealed signs of dealloying of the copper-zinc tubesheet on the service water side. A definite decrease in the percentages of zinc was detected in these areas. The tubes appeared to be a copper-nickel alloy with a small amount of iron and

manganese present. The six originally installed heat exchanger assemblies with copper-nickel alloy tubes and copper-zinc tubesheets were replaced with heat exchanger assemblies with 316 stainless steel tubes and 316L stainless steel tubesheets. To minimize tube fouling, corrosion damage and tube leaks experienced by service water, the heat exchangers were removed from the turbine building service water subsystem by a design change in 1997 and are now cooled by bearing cooling water.

3. In October 2006, circulating water system inlet motor operated valve (MOV) butterfly valves were inspected and found to have numerous coating failures and valve body corrosion degradation. The valves were made from cast A536 ductile iron. The corrosion damage was described as galvanic and graphitic corrosion due to coating failure. A design modification replaced the circulating water Inlet MOV valves with new valves manufactured from a material not susceptible to selective leaching, passivated 316L stainless steel and no problems have been identified since replacement.

4. In 2010, graphitic corrosion was evident when two bearing cooling heat exchanger service water valves, gray cast iron, ASTM A 126, were found to have metal loss after about fifteen years of in service operation. Neither valve had through-wall leakage. The replacement valves are manufactured of ASTM A-536 ductile iron and were coated prior to installation. Replacement work orders were established to replace the valves every fifteen years. The component cooling heat exchanger service water inlet valves are also coated ductile iron valves that were replaced during the fall 2013 Unit 1 refueling outage. The old valves were observed to have limited coating degradation and no noticeable metal loss. Based on engineering observations, ductile iron has exhibited a better performance in service water applications.

The above examples of operating experience provide objective evidence that the *Selective Leaching* program will include activities to perform visual and mechanical inspections or destructive examinations to identify loss of material for piping, valve bodies and bonnets, pump casings, and heat exchanger components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Selective Leaching* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Selective Leaching* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Selective Leaching* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.27 Buried and Underground Piping and Tanks

Program Description

The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that manages 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.

Five years prior to entering the subsequent period of extended operation, each unit's buried carbon steel piping within the scope of subsequent license renewal will be cathodically protected. This will include the buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building and the 24-inch service water piping at the Low Level Intake Structure on each unit.

~~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)~~*Buried and Underground Piping and Tanks* program (B2.1.27) and the *Structures Monitoring* program (B2.1.34). 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.

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)
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, "Control of External Corrosion on Underground or Submerged Metallic Piping 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. A cathodic protection system will be installed for protection of each unit's buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building five years before entering the subsequent period of operation. (Added - Change Notice 4)

Parameters Monitored/Inspected (Element 3)

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 ten 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, high chlorides and acidic environments will be evaluated. (Added - Change Notice 5)

Detection of Aging Effects (Element 4)

8. Procedure(s) will be developed to perform a one-time inspection (one excavation) for evidence of concrete aging (below grade) associated with ~~either the Unit 1 or Unit 2 High Level Intake~~

~~Structures, or~~ the south side of the Turbine Building with the following requirements: (Revised - Change Notice 5)

a. Prior to excavation, it shall be confirmed that the south side of the Turbine Building is not covered with a bitumastic coating below grade.

b. If a coating is not identified, then:

- ~~, or the Fire Water Pump House. For the selected structure,~~ A~~a~~ minimum of 50 ft^2 concrete surface area below ~~the frost line~~ groundwater level will be inspected by the one-time inspection.
- ~~The procedure will require that, as a surrogate location, t~~The evaluation of the one-time inspection results ~~also~~shall include evaluation of the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349.3R.
- If observed age-related degradation exceeds ACI 349.3R Tier-1 criteria, then the area containing the degradation will be evaluated for acceptability by a responsible Civil Engineer using the Corrective Action Program. The evaluation shall include the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349.3R.
- If observed age-related degradation exceeds ACI 349.3R Tier-1 criteria, a subsequent inspection will be performed within ten years to determine if the previously observed degradation remains within the parameters evaluated during the previous inspection. If the degradation during the subsequent inspection more than marginally exceeds the evaluated parameters from the previous inspection, then within 5 years an excavation of one 96" CW pipe will be performed to inspect a surface area of 50 ft^2 located below groundwater level. (Added - Change Notice 4)

c. If a coating is identified, then:

- Excavation of one 96" CW pipe will be performed to inspect a surface area of 50 ft^2 located below groundwater level.

Acceptance Criteria (Element 6)

9. 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)

10. Procedures will be revised to specify that soil sample results indicating corrosivity of greater than 10 points using the "carbon steel" column in Table 9-4, "Soil Corrosivity Index from BPWORKS," of EPRI Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," require evaluation of potential scope expansion or category transition. (Added - Change Notice 5)

Acceptance Criteria (Element 6) and Corrective Actions (Element 7)

11. Procedures will be revised to specify that when an aggressive groundwater/soil environment is confirmed, corrective actions are required, including confirmatory groundwater resampling, as well as groundwater sampling on a quarterly basis for at least one year (i.e., four quarters). The results of the quarterly groundwater samples will be trended, and if groundwater chemistry continues to exceed the aggressive environment thresholds, additional corrective actions will be determined. The additional corrective actions may include items such as further sampling, installation of more wells, more frequent inspections of the surrogate structure, and/or the development of a plant specific aging management activity. (Added - Change Notice 5)

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.