VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

May 27, 2021

10 CFR 50
10 CFR 51
10 CFR 54

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

Serial No.: 21-184
NRA/DEA: R0
Docket Nos.: 50-338/339
License Nos.: NPF-4/7

VIRGINIA ELECTRIC AND POWER COMPANY
NORTH ANNA POWER STATION (NAPS) UNITS 1 AND 2
SUBSEQUENT LICENSE RENEWAL APPLICATION (SLRA)
RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION
SAFETY REVIEW - SET 3
AND ADMINISTRATIVE CHANGE TO SLRA TABLE A4.0-1, ITEM 25

By letter dated August 24, 2020 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML20246G697), Virginia Electric and Power Company (Dominion Energy Virginia or Dominion) submitted an application for the subsequent license renewal of Renewed Facility Operating License Nos. NPF-4 and NPF-7 for North Anna Power Station (NAPS) Units 1 and 2, respectively. The US Nuclear Regulatory Commission (NRC) has been reviewing the NAPS SLRA and has identified areas where additional information is needed to complete their review. In an email from Lois M. James (NRC) to Daniel G. Stoddard (Dominion) dated May 3, 2021, the NRC staff transmitted specific requests for additional information (RAIs) to support completion of the Safety Review.

Enclosure 1 provides Dominion's response to the NRC RAIs.

A mark-up of SLRA Table A4.0-1, Item 25, is provided in Enclosure 2 to show the deletion of duplicate text (Commitments 4.a and 4.b are same as Commitments 5.a and 5.b). The remaining Commitments for Item 25 are renumbered.

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

Sincerely,

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

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

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

Acknowledged before me this 27th day of May, 2021.

My Commission Expires: 12/31/24

Notary Public

Commitments made in this letter: None

Enclosures:

1. Response to NRC Request for Additional Information NAPS SLRA Safety Review Set 3
2. SLRA Mark-up Administrative Change to SLRA Table A4.0-1, Item 25

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Enclosure 1

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION
NAPS SLRA SAFETY REVIEW - SET 3

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

Response to NRC Request for Additional Information
NAPS SLRA Safety Review - Set 3

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

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

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

1. Buried and Underground Piping and Tanks, AMP B2.1.27

Regulatory Basis:

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

RAI 2.1.27 2a

Background

As amended by letter dated April 1, 2021, SLRA Section B2.1.27, "Buried and Underground Piping and Tanks," states "[t]he Buried and Underground Piping and Tanks program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks."

Dominion's response to RAI B2.1.27-2 dated April 1, 2021 (ADAMS Accession No. ML21091A187) states the following in part:

- *"NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks program, allows examinations either to be conducted from the external surface of the tank using visual techniques or from the internal surface of the tank using volumetric techniques, in lieu of cathodic protection. As such, the Buried and Underground Piping and Tanks program (B2.1.27) conducts internal tank surface examinations of the buried EDG [emergency diesel generator] FOSTs [fuel oil storage tanks] consistent with the guidance in NUREG-2191, Section XI.M41, as an alternative to cathodic protection."*
- *"[t]he EDG FOSTs are cleaned and inspected on a 10-year frequency. During the 2013 EDG FOST inspections, a visual of the interior coating and an ultrasonic thickness examination from inside each tank were performed. Approximately 60 spot ultrasonic thickness readings were obtained from inside each tank, along the length of the tanks. Thickness readings on both tanks were acceptable and showed no degrading trend from the previous data recorded in 2002. Some minor coating degradation was identified within each tank and repairs were completed prior to returning the tanks to service."*

GALL-SLR Report AMP XI.M41 recommends inspections and cathodic protection for buried steel tanks.

<u>Issue</u>

GALL-SLR Report AMP XI.M41 recommends inspections and cathodic protection for buried steel tanks (i.e., inspections are not performed in lieu of providing cathodic protection).

As part of its basis for not providing cathodic protection for the buried EDG FOSTs, Dominion Energy provided a qualitative summary of the previous two 10-year interval inspections (i.e., ultrasonic thickness readings were acceptable, no degrading trend from the previous inspection). However, no quantitative inspection results (e.g., ultrasonic thickness measurements in comparison to T_{min}, T_{nom}, or original thickness; corrosion rates; etc.) were provided. The staff seeks more detailed (i.e., quantitative) inspection results to substantiate Dominion Energy's claim that cathodic protection is not necessary for the buried EDG FOSTs during the subsequent period of extended operation (SPEO).

<u>NRC Request</u>

Provide quantitative inspection results from the 2002 and 2013 EDG FOST inspections (i.e., ultrasonic thickness measurements in comparison to T_{min}, T_{nom}, and original thickness (if available); a drawing or sketch indicated where the ultrasonic thickness measurements were taken, corrosion rates, etc.) to substantiate the claim that cathodic protection is not necessary for the buried EDG FOSTs during the SPEO.

Dominion Response

Cathodic protection of the buried emergency diesel generator (EDG) fuel oil storage tanks (FOSTs) was not included in the original design and would be a hardship to backfit into the existing EDG FOSTs configuration. Several design features such as a sloped concrete missile shield covering to facilitate water drainage, an external tank coating, and an oil-sand barrier between the tank and the surrounding select granular compacted backfill provide preventive measures that limit the exposure of the tank external surface to a potentially aggressive environment. As noted in SLRA Section B2.1.18, Operating Experience 6, the 2013 thickness measurement readings on both EDG FOSTs were acceptable and showed no degrading trend from the previous data recorded in 2002.

The two FOSTs for the EDG system are located between the Fuel Oil Pump House and the dike wall that surrounds the above-ground fuel oil storage tank. A trench was excavated into the bedrock between the two structures for placement of the EDG FOSTs. The two EDG FOSTs are buried and supported by compacted select granular fill. A four-inch layer of oil-sand is between the exterior tank walls and the compacted fill. A two-foot thick reinforced concrete missile shield, supported by the compacted fill, is located above the EDG FOSTs. The concrete missile shield is sloped and sealed to adjacent structures with a pre-molded joint filler and a bituminous seal to allow water drainage from the missile shield surface.

In lieu of a sketch, a description of the thickness measurements performed on the EDG FOSTs in 2002 and 2013 is provided below.

- 2002, 2A EDG FOST and 2B EDG FOST: A total of 24 thickness measurements evenly distributed in eight regions (three thickness measurements in each region) of the barrel and head with an additional reading in each head of the two tanks were performed. The three thickness measurements were evenly distributed in the bottom half in each of the eight regions of the barrel and head. The additional head region thickness measurement was in the center of each head of the two tanks.
- 2013, 2A EDG FOST: A total of 60 thickness measurements evenly distributed in 12 regions (five thickness measurements in each region) of the barrel and head with an additional three readings in each head were performed. The five thickness measurements were evenly distributed in the bottom half in each of the 12 regions of the barrel and head. The three additional head region thickness measurements were evenly distributed in the center of each head.
- 2013, 2B EDG FOST: A total of 60 thickness measurements evenly distributed in 12 regions (five thickness measurements in each region) of the barrel and head were performed. The five thickness measurements were evenly distributed in the bottom half in each of the 12 regions of the barrel and head.

Each of the EDG FOST 2002 and 2013 inspection tank thickness measurements for the EDG FOSTs (1-EG-TK-2A and 1-EG-TK-2B) were greater than the minimum acceptable thickness of 0.324 inches. The 2013 thickness readings on both tanks were acceptable and showed only minor wall thickness loss from the previous data recorded in 2002. A comparison of the 2002 and 2013 minimum and maximum tank thickness measurements for the EDG FOSTs barrel and heads is provided below.

2013/2002 Inspections	2A		2B	
	Minimum	Maximum	Minimum	Maximum
2002 Barrel Thickness (in.)	0.513	0.555	0.517	0.565
2013 Barrel Thickness (in.)	0.506	0.568	0.503	0.527
Maximum Corrosion (in./yr.)	0.00445		0.00564	
2002 Head Thickness (in.)	0.654	0.689	0.674	0.690
2013 Head Thickness (in.)	0.662	0.670	0.653	0.699
Maximum Corrosion (in./yr.)	0.00245		0.00336	

The conservative maximum corrosion rate for each tank's 1/2 inch carbon steel barrel and each tank's 9/16 inch carbon steel heads was calculated using the 2002 maximum thickness and the 2013 minimum thickness over the 11 year interval between inspections. A projection of each tank's head and barrel thickness measurements using the conservative maximum corrosion rate confirms that the minimum acceptable thickness of 0.324 inches will be maintained until the next 10 year periodic inspection of each EDG FOST.

The above design and inspection information demonstrates with reasonable assurance that the intended function of the EDG FOSTs will be maintained throughout the subsequent period of extended operation.

RAI B2.1.27 3a

Background

In the "background" section of RAI B2.1.27 3, the staff identified plant specific operating experience indicating that portions of in-scope buried steel and stainless steel piping are not externally coated. Specifically, the staff noted (a) inspections have shown buried in scope stainless steel piping has been found without coating or with significantly disbonded coating; and (b) a leak due to external corrosion on a buried carbon steel service water line identified that the piping was not coated and wrapped in accordance with the installation specification.

Dominion Energy's response to RAI B2.1.27-3 dated April 1, 2021, states the following in part: "[b]uried steel piping coating applications include coal tar epoxy, coal tar enamel, or tape wrap. Buried stainless steel piping coating applications include coal tar enamel or tape wrapped."

GALL-SLR Report Table XI.M41 1 recommends that buried steel and stainless steel piping are externally coated in accordance with the "preventive actions" program element of GALL-SLR Report AMP XI.M41. In addition, GALL-SLR Report AMP XI.M41 states "[a]dditional inspections, beyond those in Table XI.M41-2[, "Inspection of Buried and Underground Piping and Tanks,"] may be appropriate if exceptions are taken to program element 2, "preventive actions," or in response to plant specific OE [operating experience]."

Issue

Although buried steel and stainless steel piping are specified to be externally coated, plant specific operating experience indicates that coatings were not always provided. Based on this plant specific OE, the seeks additional clarification regarding why additional inspections of buried steel and stainless steel piping are not appropriate.

NRC Request

Please provide additional OE to demonstrate that State the basis for why additional inspections, beyond those recommended in GALL-SLR Table XI.M41-2, are not appropriate for buried steel and stainless steel piping.

Dominion Response

Stainless Steel and Carbon Steel Piping Coatings

Buried steel and stainless steel piping within the scope of subsequent license renewal is coated as indicated by information in the table included with Dominion Energy's response to RAI B2.1.27-3, dated April 1, 2021 (ADAMS Accession No. ML21091A187). Buried steel piping coating applications include coal tar epoxy, coal tar enamel, or tape wrap. Buried stainless steel piping coating applications include coal tar enamel or tape-wrapped. No exclusion from the external coating of buried steel or stainless steel piping preventive actions was claimed in the response to RAI B2.1.27-3.

Parameters Monitored, Inspection Categories, and Corrective Actions

Monitoring the condition of external coatings is conducted by the Buried and Underground Piping and Tanks program (B2.1.27) to determine if the coatings are intact, well-adhered, and otherwise sound such that aging effects would not be expected for the base material of the component.

As previously described in SLRA Table A4.0-1, Item 27, Commitment 2, the Buried and Underground Piping and Tanks program (B2.1.27) will be enhanced to allow achievement of NUREG-2191 Table XI.M41-2, Inspection Category C, extent of inspections for buried carbon steel piping based on cathodic protection system performance. Based on carbon steel inspection categories specified by NUREG-2191 Table XI.M41-2, use of Category E (cathodic protection system performance is not consistent with Category C) requires coatings and backfill consistent with NUREG-2191 preventive measures and acceptable operating experience (i.e., no leaks in buried piping due to external corrosion, no significant coating degradation or metal loss in more than 10% of inspections conducted) in addition to acceptable soil survey results. An increase in the extent of inspection from Category E to Category F would be required for unacceptable operating experience associated with coatings or buried piping leakage.

Where coatings, backfill, or the condition of exposed piping do not meet acceptance criteria, the degraded condition is repaired or the affected component is replaced. In addition, where 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 expanded.

<u>Buried Stainless Steel Piping Operating Experience:</u>

The Buried and Underground Piping and Tanks program (B2.1.27) operating experience (OE) #10 assessment in SLRA Section B2.1.27 reviewed and evaluated 31 buried stainless steel opportunistic piping inspections performed in 2011 and 2012 on the quench spray, recirculation spray, safety injection, chemical & volume control, residual heat removal, and condensate systems. The assessment identified no significant pitting, corrosion or degradation of the stainless steel piping. Inspection results included coatings fully covering pipes' surfaces, coatings substantially intact, coatings degraded, and brittle or tape wrap loosely adhered. Degraded coatings and tape wraps were corrected prior to backfill. A portion of coating in a quench spray system piping segment was identified as missing. The affected piping was recoated prior to backfill. It is reasonable to assume that the missing coating may have been loose or degraded and was inadvertently removed during the inspection excavation (it was raining during excavation) or during prior maintenance activities. This assumption is supported by 17 other quench spray opportunistic piping inspections where coatings were found to have been installed and 13 other stainless steel piping inspections where the piping was found with intact coatings.

<u>Buried Steel Piping Operating Experience</u>

With exception of the three OE items noted below, a review and evaluation of 27 buried steel piping inspections conducted from 2011 to 2018 on the fire protection, condensate, fuel oil, and service water systems did not identify any significant pitting, corrosion or degradation of the steel piping.

1. In March 2014, coating blisters and defects were identified on the external surface of the buried 36-inch carbon steel service water piping (t_{nom} = 0.375 in) between the Service Water Pump House and the Tie-In Vault. Engineering inspections identified three minor corrosion pits requiring weld buildup. The maximum pit depth observed was 0.13 inch. With a minimum allowable wall thickness of 0.179 inch, the remaining wall thickness (0.198 in) was conservatively determined to allow the pipe to remain in service until December 2019. In March 2015 an ASME Code weld repair was completed that restored the piping to the previous design thickness. Coating repairs were completed prior to backfilling the pipe.
2. In 2016, Buried and Underground Piping and Tanks program (B2.1.27) OE #12 indicated leakage of 1-2 gallons per minute was observed from a direct buried carbon steel service water pipe elbow. The metallurgical report determined the failure mechanism to be external corrosion concentrated in a three-inch square area around the leakage point. As with most buried pipe failures that result from external corrosion

of coated piping, there is reasonable assurance that the service water pipe elbow was damaged during installation; however, evidence to support that conclusion was destroyed as a result of the external corrosion. The service water pipe elbow was replaced, protective coating and wrap applied to the external surfaces, and the system was returned to service. The metallurgical report also noted another section of the service water pipe elbow which had exterior coating present. The presence of exterior coating indicates this OE event is an isolated, unexpected occurrence of coating degradation most likely due to damage during installation.

3. In 2016, Buried and Underground Piping and Tanks program (B2.1.27) OE #13 indicated leakage in the buried carbon steel piping from the Fuel Oil Pump House to the '2H' emergency diesel generator (EDG) room due to localized corrosion on the outside diameter of the pipe due to coating / tape wrap degradation (direct cause). The extent of condition included the buried carbon steel fuel oil lines between the Fuel Oil Pump House and each EDG room, as well as the buried carbon steel fuel oil lines between the Fuel Oil Pump House and the SBO EDG room. These buried carbon steel fuel oil lines have been replaced with stainless steel and placed in service.

The above examples of operating experience demonstrate when coatings, backfill, or the condition of exposed piping do not meet acceptance criteria, the degraded condition is repaired or the affected component is replaced. The above information also demonstrates with reasonable assurance that the intended function of the buried steel and stainless steel piping will be maintained throughout the subsequent period of extended operation.

Enclosure 2

SLRA MARK-UP
ADMINISTRATIVE CHANGE TO SLRA TABLE A4.0-1, ITEM 25

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

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
24	*Flux Thimble Tube Inspection* program	The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that is credited.	B2.1.24	Ongoing
25	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program	The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require inspection of elastomeric and flexible polymeric components for the following: • Surface crazing, scuffing, loss of sealing, blistering, and dimensional change (e.g., "ballooning" and "necking") • Loss of wall thickness • Exposure of internal reinforcement (e.g., reinforcing fibers, mesh, or underlying metal) for reinforced elastomers 2. Procedures will be revised to specify that visual inspection of elastomeric and flexible polymeric components is supplemented by tactile inspection to detect hardening or loss of suppleness. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area. 3. Procedures will be revised to specify that follow-up volumetric examinations are performed where irregularities that could be indicative of an unexpected level of degradation are detected for steel components exposed to raw water, raw water (potable), or waste water. 4. Procedure(s) will be revised or developed to specify the following: a. In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 19 components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions. b. The rate of degradation will be evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.	B2.1.25	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
25	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program	~~5. Procedure(s) will be revised or developed to specify the following:~~ a. ~~In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 19 components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions.~~ b. ~~The rate of degradation will be evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.~~ (Deleted duplicate text - RAI Set 3) c. Additional inspections will be performed if any sampling-based inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. 5. The existing inspections of the Unit 1 and Unit 2 bearing cooling system, performed under the Corrective Action Program, will be enhanced to require performance of a minimum of 10 piping wall thickness measurements at each Unit with a frequency not to exceed two refueling cycle intervals. Locations with a wall thickness of less than 50% will be selected and augmented as necessary considering prior inspection results, extent of degradation, rate of degradation, and timing of the next inspection. (Renumbered - RAI Set 3) 6. Procedure(s) will be revised or developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions. (Renumbered - RAI Set 3)	B2.1.25	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.