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April 15, 2021

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Serial No.	20-328D
NRA/SS	R0
Docket No.	50-336
License No.	DPR-65

DOMINION ENERGY NUCLEAR CONNECTICUT, INC.
MILLSTONE POWER STATION UNIT 2
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION FOR PROPOSED LICENSE AMENDMENT REQUEST TO REVISE THE MILLSTONE UNIT 2 TECHNICAL SPECIFICATIONS FOR STEAM GENERATOR INSPECTION FREQUENCY

By letter dated October 8, 2020 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML20282A594), and as supplemented by letter dated December 8, 2020 (ADAMS Accession No. ML20343A259), Dominion Energy Nuclear Connecticut, Inc. (DENC), submitted a license amendment request for Millstone Power Station, Unit No. 2 (MPS2). The proposed amendment would revise MPS2 Technical Specification (TS) 6.26, "Steam Generator (SG) Program," Item d.2, to reflect a proposed change to the required SG tube inspection frequency from every 72 effective full power months (EFPM), or at least every third refueling outage, to every 96 EFPM.

In an email dated February 26, 2021, the NRC issued a draft request for additional information (RAI) related to the proposed LAR. On March 9, 2021, the NRC staff conducted a conference call with DENC staff to clarify the request. In an email dated March 18, 2021, the NRC transmitted the final version of the RAI (ADAMS Accession No. ML21078A033). DENC agreed to respond to the RAI within 30 days of issuance, or no later than April 19, 2021.

Attachment 1 provides DENC's response to the RAI. Attachment 2 provides a revised mark-up of the TS.

If you have any questions or require additional information, please contact Shayan Sinha at (804) 273-4687.

Sincerely,

Mark D. Sartain
Vice President – Nuclear Engineering & Fleet Support

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Mr. Mark D. Sartain, who is Vice President – Nuclear Engineering and Fleet Support of Dominion Energy Nuclear Connecticut, Inc. 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 15th day of April, 2021.

My Commission Expires: August 31, 2023.

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

Notary Public

Attachments:

1. Response to Request for Additional Information for the Proposed LAR to Revise TSs for Steam Generator Inspection Frequency

2. Revised Technical Specification Mark-up

Commitments made in this letter: None

cc: U.S. Nuclear Regulatory Commission
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ATTACHMENT 1

Response to Request for Additional Information for the Proposed LAR to Revise TSs for Steam Generator Inspection Frequency

MILLSTONE POWER STATION UNIT 2
DOMINION ENERGY NUCLEAR CONNECTICUT, INC.

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Background

In Appendix A of 10 CFR Part 50, General Design Criteria 14, 15, 30, 31, and 32 define requirements for the structural and leakage integrity of the reactor coolant pressure boundary (RCPB). As part of the RCPB, the SG tubes must also meet the requirements of 10 CFR 50.55a with respect to inspection and repair requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code. All pressurized water reactors have TS according to 10 CFR 50.36 that include a SG Program with specific criteria for the structural and leakage integrity, repair, and inspection of SG tubes. For Millstone Unit 2, the requirements for performing SG tube inspections and repair are in TS Section 6.26, while the requirements for reporting the SG tube inspections and repair are in TS Section 6.9.1.9.

RAI-1

There are several apparent inconsistencies between the proposed Insert A to TS Section 6.9.1.9 in Attachment 2, "Marked-up Technical Specification Pages," of Reference 1 and the proposed changes in TSTF-577 (Reference 3) from which the licensee states it is proposing to model (for example, c.3, c.4. e. and f. of TS 6.9.1.9). The staff also noted that the editorial changes from Section 2.4.4, "Editorial Improvements," of Reference 3, which is currently under review, were not incorporated in the proposed mark-up TS pages. Please provide the correct proposed changes and new proposed mark-up TS pages. If not, provide an explanation for the apparent inconsistencies.

DENC Response to RAI-1

DENC has revised the proposed TS markup for MPS2 TS 6.26, "Steam Generator (SG) Program," to incorporate the editorial changes from Section 2.4.4, "Editorial Improvements," of TSTF-577 that use the acronym "SG" rather than the term "Steam Generator." DENC has also revised the proposed TS markup for MPS2 TS 6.9.1.9, "Steam Generator Tube Inspection Report," to modify the punctuation and grammar to align with the conventions used in the TS markup from TSTF-577. Attachment 2 provides the revised TS mark-up pages, with additions from the previous TS markup shown in italicized, bold font, and deletions from the previous TS markup shown in struck-through, bold font.

RAI-2

The Millstone Unit 2 spring 2017 SG tube inspection report (Reference 4) states, "Steam drum visual inspections to evaluate the material condition and cleanliness of key components such as moisture separators, drain systems, and interior surfaces," were performed in both SGs during refueling outage 24 (2R24). Reference 4 goes on to state, "The results of all secondary-side visual examinations performed were satisfactory, with no degradation detected." However, Section 4.3.1, "Steam Drum," of the Attachment to Reference 2 states, "Evidence of early stage flow assisted corrosion of the secondary moisture separators was noted." Figure 4-3, "Steam Drum Components," in the Attachment to Reference 2 includes a picture of early stage flow assisted corrosion in a separator baseplate. Section 4.3.1 goes on to state, in part, "...based on limited operational wear observed through 2R24, significant structural degradation is not expected to occur over the next five cycles of operation." The staff has the following requests regarding the flow assisted corrosion of the secondary moisture separators:

a. *Please discuss the discrepancy between Reference 2 and Reference 4 related to the results of the secondary-side visual examinations.*

b. *Please describe each location where flow assisted corrosion was observed in all SGs.*

c. *Please discuss how the flow assisted corrosion was evaluated to determine that "significant structural degradation is not expected to occur over the next five cycles of operation." In addition, please discuss how the condition will be monitored during future outages, for example, visual inspections, thickness measurements.*

DENC Response to RAI-2

RAI-2, part a. Response

Reference 4 summarizes the MPS2 Steam Generator Integrity Condition Monitoring and Operational Assessment (CMOA) report (Attachment to Reference 2), which documented the results of secondary side inspections performed during the 2R24 outage. The author of the CMOA was a contracted Tube Integrity Engineer (TIE), who developed the material degradation assessment captured in Section 4.3.1 after reviewing still images of discolored secondary separator components and who used very conservative terminology in his assessment of the material condition. The summary captured in Reference 4 was developed by DENC's site program owner. Based on oversight of the SG inspections identified in Table 1, DENC's site program owner confirmed that the regions of discoloration identified in the secondary moisture separators reflected an absence of magnetite, which has not changed appreciably over multiple operating cycles. Based on this information, the site program owner was able to conclude the photographic evidence was insufficient to diagnose the discoloration as an early stage of flow accelerated corrosion.

RAI-2, part b. Response

No flow assisted corrosion has been observed in either SG. DENC has performed extensive visual examinations of the MPS2 steam drum components since SG replacement in 1992. Table 1 provides a summary of the most recent examination history.

Table 1 – Recent Steam Drum Examinations

Outage	Date	Steam Generator
EOC18	Spring 2008	Both SGs
EOC20	Spring 2011	SG-1
EOC22	Spring 2014	SG-2
EOC23	Fall 2015	SG-1
EOC24	Spring 2017	Both SGs
EOC25	Fall 2018	Both SGs

The secondary separators have been the primary focus of recent steam drum examinations due to operating experience from other stations with similar BWXT secondary SG designs and concerns that degradation of steam separators could adversely impact moisture carryover performance. Based on this recent operating experience, additional scrutiny was applied to any anomaly associated with the BWXT secondary separators during the End of Cycle (EOC) 25 inspection.

Secondary separators in both SGs have been inspected from the top (above the secondary deck, looking down into the secondary separators) and the bottom (looking

up at the baseplate from below the secondary deck). Some regions of the separators exhibit a lack of magnetite, with no apparent loss of material thickness. This occurs most notably on the lower cylinder sidewalls and skimmer slots and occurs to a lesser extent on the baseplates and swirl vanes. These are the locations where the formation of orange oxides has been noted. These findings affect a small population of the secondary separators, mostly on the hot-leg side of the SGs. Figures 1 thru 4 below provide examples of these locations:

Figure 1 – Orange Oxide on SG-2 Baseplate

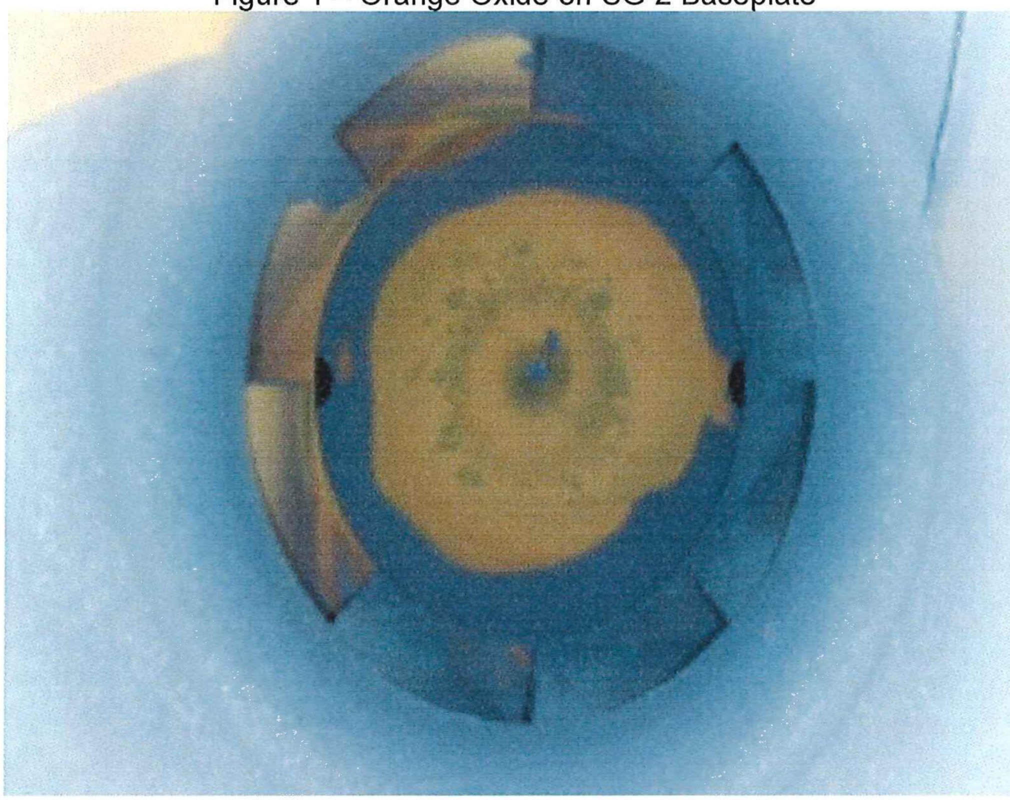


Figure 2 – Orange Oxide on SG-1 Swirl Vanes

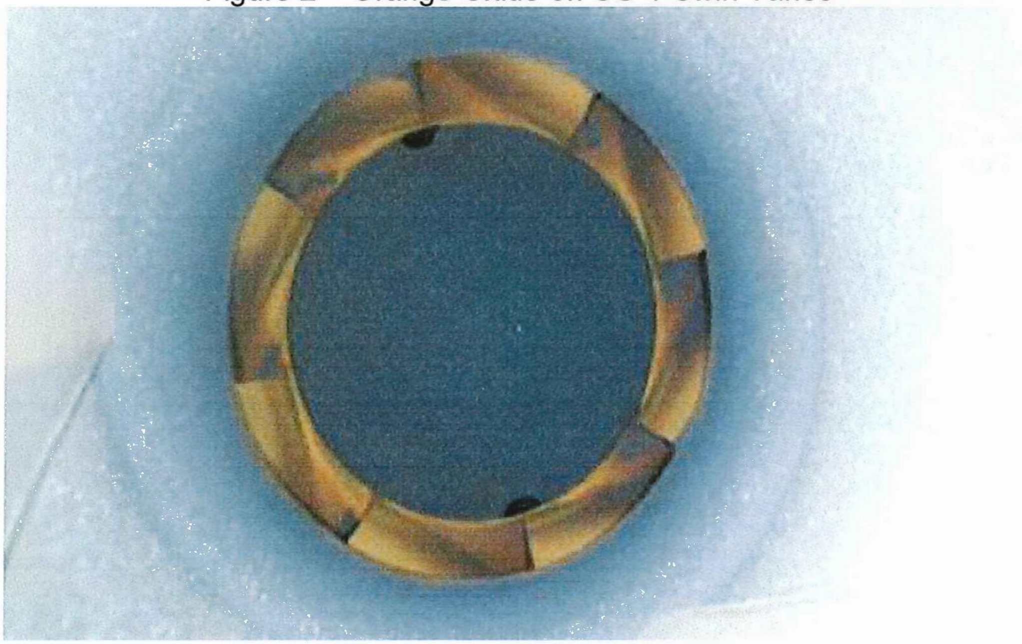


Figure 3 – Closeup SG-2 Visual Examination from EOC25

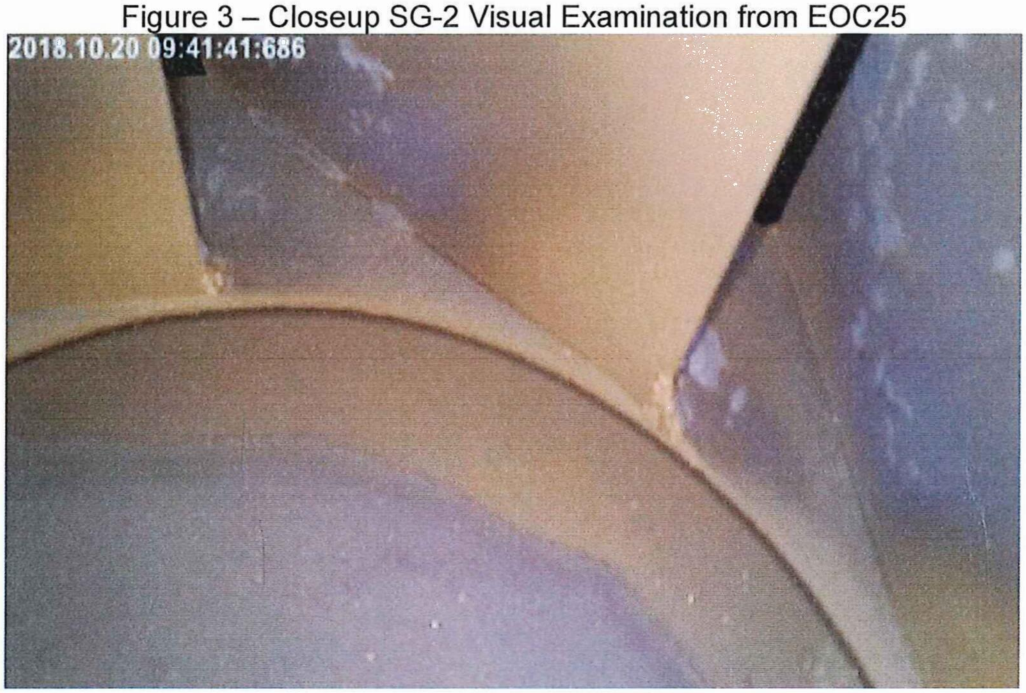


Figure 4 – Closeup SG-2 Visual Examination from EOC25

Video images were obtained of all secondary separators from above the secondary deck during EOC25. Of the 170 separators (per SG) inspected, approximately 25 showed a lack of tightly adhering magnetite (as evidenced by orange discoloration). Where discoloration was observed on the skimmer vanes, lower cylinder assembly sidewalls, swirl vanes, or baseplates, the visual inspectors scrutinized the discolored location for evidence of perforations or visible material loss. No perforations or visible material loss were evident, and the affected sidewalls and baseplates were smooth.

<u>RAI-2, part c. Response</u>

The contracted TIE reached the conclusions documented in Reference 4 based on review of still images of the discolored secondary separators. Minor material loss is difficult to assess based on photo images alone, and concluding that the existence of orange oxide represents "evidence of early state flow assisted corrosion" is considered an overly conservative conclusion by DENC, as the existence of orange oxide alone does not indicate a condition that is either unsatisfactory or degraded.

As discussed in the response to part "b." above, visual inspectors scrutinized areas of discoloration identified on the skimmer vanes, lower cylinder assembly sidewalls, swirl vanes, and baseplates for evidence of perforations or visible material loss while performing the EOC25 secondary side inspections. No perforations or visible material loss were evident, and the affected sidewalls and baseplates were smooth. Based on lack of evidence that flow assisted corrosion is actively degrading secondary side component material after 26 years of replacement SG operation, it is reasonable to

conclude significant structural degradation of the secondary separators is not expected to occur over five cycles of operation between secondary side inspections.

According to the SG manufacturer (BWXT), the robust design of MPS2 secondary separators makes them less susceptible to perforation resulting from baseplate degradation when compared to other secondary separator designs. Figure 5 and Figure 6 below show the robustness of the MPS2 secondary separator baseplates.

Figure 5 – SG-1 Secondary Separator Baseplate

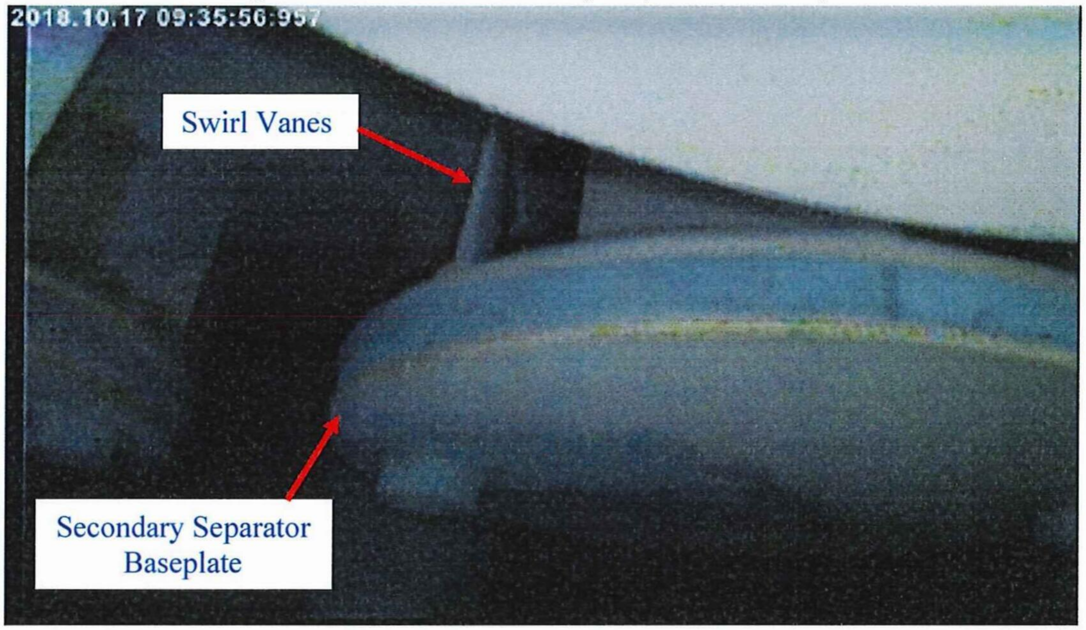
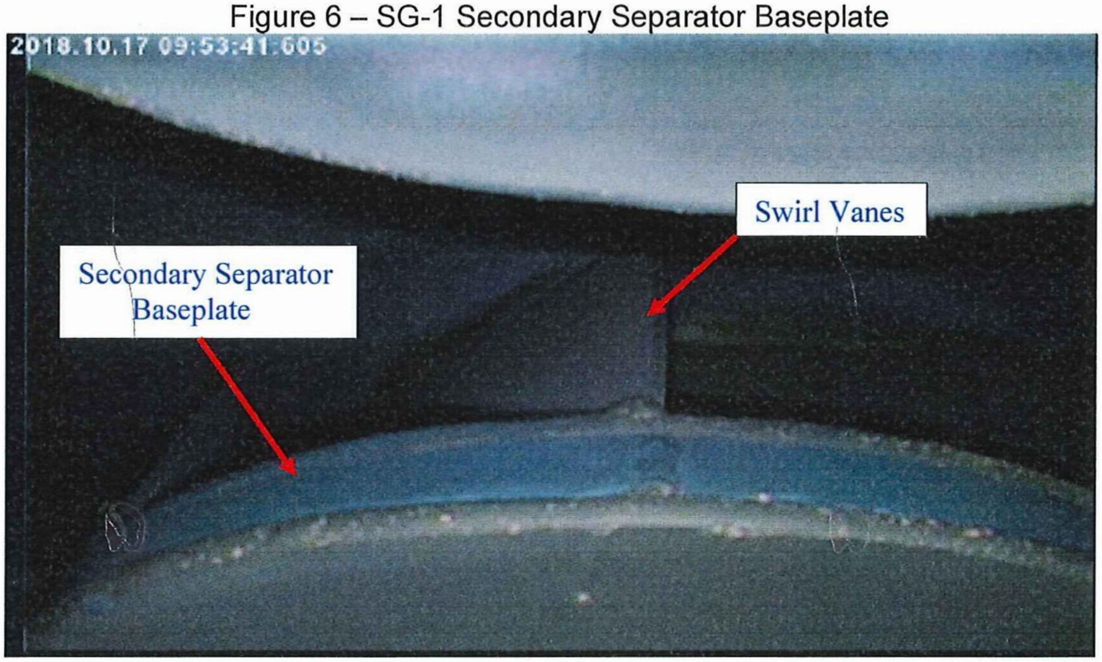


Figure 6 – SG-1 Secondary Separator Baseplate



In the unlikely event that perforations develop in the future, they are not expected to significantly affect moisture carryover and will not affect the structural integrity of the secondary separators due to the robust design aspects of the MPS2 SGs. DENC intends to continue to monitor the condition of the MPS2 secondary separators each inspection interval through visual inspection and implement more quantitative methods to monitor material degradation as warranted by visual inspection results.

RAI-3

Table 4-2, "DMT Deposit Removal Quantities," of the Attachment to Reference 2 indicates identical amounts of magnetite and copper (e.g., 1,963 lbs. of magnetite and 16.2 lbs. of copper) were removed from SG 25 (2,608 lbs. of total deposit) and SG 26 (2,584 lbs. of total deposit). This appears to be in error as the staff would not expect the deposit removal quantities to be identical for the two SGs. Please provide the correct values for both SGs in Table 4.2, or provide an explanation for the apparent error.

DENC Response to RAI-3

Soft chemical cleaning was performed on both SGs simultaneously during the 2R24 outage, and the total deposition was removed and filtered collectively. For purposes of estimating the total inventory removed through deposit minimization treatment (DMT) and water lancing, the total deposition removed from the two SGs was divided evenly between SG1 and SG2. The data presented in Reference 2, Attachment 1, Table 4-2 have been verified to be correct for both SGs.

At MPS2, no operational difficulties have been reported which would potentially relate to support blockage. Also, no systematic change in the growth or distribution of support structure wear indications have been identified which would suggest secondary side flow redistribution resulting from deposit accumulation. DMT was performed expressly for the purpose of increasing SG thermal performance.

RAI-4

Reference Identification 2610 in the table entitled, "SG26 [SG 2] PLP [possible loose parts] / Foreign Objects Detected in 2R24," of the Attachment to Reference 2 states that the historical foreign object (nut) appears to have moved closer to the periphery. The table further states that no wear was identified in the vicinity and that the part was not visually monitored by secondary side inspection. Please discuss the decision not to visually monitor the foreign object and attempt to remove the foreign object during 2R24.

DENC Response to RAI-4

The Degradation Assessment prepared prior to the 2R24 outage contained a detailed primary side examination scope (eddy current and visual), and a detailed secondary side examination scope (visual and foreign object search and retrieval). Foreign object 2610, which had been first detected in EOC13 (2000), and continuously monitored since that time, was included in the preplanned secondary side examination scope. However, the secondary side inspection crew reported that no part was visible at that location, and thus could not be removed or further visually monitored. A subsequent eddy current examination identified that there was a possible loose part (PLP), in a nearby location, which prompted the TIE to assume that the part had moved during the water lancing activities. Since no wear has ever been detected in any tube adjacent to this PLP in 17 years, there is reasonable confidence that no parts capable of causing significant tube degradation remain in the tube bundle.

RAI-5

The staff identified the following apparent discrepancies. Confirm the correct information.

a. *Table 3-2, "Summary of SG Inspection Sampling Through the 2R24 Outage (TS 6.26)," in the Attachment to Reference 2 refers to fan bar and foreign object wear as potential degradation mechanisms rather than existing degradation mechanisms.*

b. *Section 5, Condition Monitoring Assessment," of the Attachment to Reference 2 states, "Figures 5-1 through 5-4 provide the CM [condition monitoring] limit curves for flaws sized with ETSSs [examination technique specification sheets] 96004.3, 27901.1, 27902.1, and 27903.1[,] respectively." However, Figure 5-1, "Acceptance Limits for Fan Bar Wear," references ETSS 96041.3. The staff also notes that ETSS 96004.3 is not referenced in any other section in Reference 2.*

DENC Response to RAI-5

RAI-5, part a. Response

Fan bar wear and foreign object wear are existing degradation mechanisms identified for the MPS2 SGs, but this wear has only been observed in a limited subset of the SG tubes. In Table 3-1 of the Reference 2 Attachment, the term "potential" is used to indicate the number of tubes susceptible to each degradation mechanism and the number of tubes that were examined for that degradation mechanism.

RAI-5, part b. Response

The reference to ETSS 96004.3 was an error. The correct document to be referenced throughout Section 5 of the Reference 2 Attachment is ETSS 96041.3.

REFERENCES

1. *Proposed License Amendment Request to Revise the Millstone Unit 2 Technical Specifications for Steam Generator Inspection Frequency, dated October 8, 2020 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML20282A594).*

2. *Supplement to Proposed License Amendment Request to Revise the Millstone Unit 2 Technical Specifications for Steam Generator Frequency, dated December 8, 2020 (ADAMS Accession No. ML20343A259).*

3. *TSTF-577, "Revised Frequencies for Steam Generator Tube Inspections," Revision 0, dated June 8, 2020 (ADAMS Accession No. ML20160A359).*

4. *Millstone, Unit 2, End of Cycle 24 Steam Generator Tube Inspection Report, dated September 18, 2017 (ADAMS Accession No. ML17269A030).*

ATTACHMENT 2

Revised Technical Specification Mark-up

MILLSTONE POWER STATION UNIT 2
DOMINION ENERGY NUCLEAR CONNECTICUT, INC.

STEAM GENERATOR TUBE INSPECTION REPORT

6.9.1.9 A report shall be submitted within 180 days after initial entry into MODE 4 following completion of an inspection performed in accordance with TS 6.26, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG~~;~~ ,

Insert A

~~b. Degradation mechanisms found,~~

~~c. Nondestructive examination techniques utilized for each degradation mechanism,~~

~~d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,~~

~~e. Number of tubes plugged during the inspection outage for each degradation mechanism,~~

~~f. The number and percentage of tubes plugged to date, and the effective plugging percentage in each steam generator.~~

~~g. The results of condition monitoring, including the results of tube pulls and in-situ testing.~~

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555, one copy to the Regional Administrator, Region I, and one copy to the NRC Resident Inspector within the time period specified for each report. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification:

a. Deleted

b. Deleted

c. Deleted

d. ECCS Actuation, Specifications 3.5.2 and 3.5.3.

e. Deleted

f. Deleted

g. RCS Overpressure Mitigation, Specification 3.4.9.3.

Insert A:

b. The nondestructive examination techniques utilized for tubes with increased degradation susceptibility;

c. For each degradation mechanism found:

1. The nondestructive examination techniques utilized;

2. The location, orientation (if linear), measured size (if available), and voltage response for each indication. For tube wear at support structures less than 20 percent through-wall, only the total number of indications needs to be reported;

3. A description of the condition monitoring assessment and results, including the margin to the tube integrity performance criteria and comparison with the margin predicted to exist at the inspection by the previous forward-looking tube integrity assessment; ***and***

4. The number of tubes plugged during the inspection outage~~;~~**.**

d. An analysis summary of the tube integrity conditions predicted to exist at the next scheduled inspection (the forward-looking tube integrity assessment) relative to the applicable performance criteria, including the analysis methodology, inputs, and results;

e. The number and percentage of tubes plugged to date, and the effective plugging percentage in each SG; ***and***

f. The results of any SG secondary side inspections~~;~~**.**

An SG

6.26 STEAM GENERATOR (SG) PROGRAM

SG

~~A Steam Generator~~ Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the ~~Steam Generator~~ Program shall include the following:

a. Provisions for condition monitoring assessments: Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during a SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Provisions for performance criteria for SG tube integrity: SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

SG

1. Structural integrity performance criterion: All in-service ~~steam generator~~ tubes shall retain structural integrity over the full range of normal operating conditions (including STARTUP, operation in the power range, HOT STANDBY, and cool down), all anticipated transients included in the design specification, and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 150 gpd per SG.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.6.2, "Reactor Coolant System Operational LEAKAGE."

6.26 STEAM GENERATOR (SG) PROGRAM (Continued)

c. Provisions for SG tube plugging criteria: Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

d. Provisions for SG tube inspections: Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1., d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

, which defines the inspection period. 100% of the tubes in

96

2. After the first refueling outage following SG installation, inspect each SG at least every ~~72~~ effective full power months ~~or at least every third refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, c, and d below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.~~

6.26 STEAM GENERATOR (SG) PROGRAM (Continued)

~~a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;~~

~~b) During the next 120 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period;~~

~~c) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the third inspection period; and~~

~~d) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the fourth and subsequent inspection periods.~~

3. If crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall ~~not exceed 24 effective full power months or one~~ be at the next refueling outage ~~(whichever results in more frequent inspections)~~. If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.