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October 8, 2020

Dominion Energy

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

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

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

Pursuant to 10 CFR 50.90, Dominion Energy Nuclear Connecticut, Inc. (DENC) requests an amendment to the Millstone Power Station Unit 2 (MPS2) Facility Operating License Number DPR-65, in the form of a change to the technical specifications (TSs). This license amendment request (LAR) proposes to revise MPS2 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. Because MPS2 has an 18-month operating cycle, a 96 EFPM frequency essentially requires the inspection to be performed every fifth refueling outage.

DENC is currently scheduled to perform the next MPS2 SG tube inspection during the MPS2 Cycle 27 refueling outage (RFO) in the fall of 2021. DENC has been involved in the development of Technical Specification Task Force (TSTF)-577, "Revised Frequencies for Steam Generator Tube Inspections," dated June 8, 2020 (ADAMS Accession No. ML20160A359), and has participated in meetings between the industry and the Nuclear Regulatory Commission (NRC) related to TSTF-577. DENC proposes to model the changes in TSTF-577. NRC approval of TSTF-577 and a follow-on, site-specific LAR to revise the MPS2 SG tube inspection schedule would be unlikely to occur prior to the fall 2021 MPS2 RFO.

The operational experience of the MPS2 SGs, as described in Attachment 1, demonstrates that the proposed change to the SG inspection schedule is acceptable and will result in a reduction of dose to personnel and risk to the plant. Furthermore, the MPS2 SG operational assessment and experience supports the proposed TS changes.

Attachment 1 provides DENC's description and assessment of the proposed change. Attachment 2 provides the marked-up TS pages for the proposed change. Attachment 3 contains the Steam Generator Integrity Condition Monitoring and Operational Assessment for MPS2 Spring 2017 Outage (2R24).

DENC has evaluated the proposed amendment and has determined it does not involve a significant hazards consideration as defined in 10 CFR 50.92. The basis for this determination is included in Attachment 1. DENC has also determined that operation with the proposed change will not result in a significant increase in the amount of effluents that may be released offsite or a significant increase in individual or cumulative occupational radiation exposure. Therefore, the proposed amendment is eligible for categorical exclusion from an environmental assessment as set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment is needed in connection with approval of the proposed change. The LAR has been reviewed and approved by the Facility Safety Review Committee.

DENC requests approval of the proposed change by October 8, 2021. Should you have any questions or require additional information, please contact Shayan Sinha at (804) 273-4687.

Respectfully,

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 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 8th day of October, 2020.

My Commission Expires: 12/31/20.

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

Notary Public

Commitments contained in this letter: None

Attachments:

1. Description and Assessment of Proposed Change
2. Marked-up Technical Specification Pages
3. Millstone Unit 2 Steam Generator Integrity Condition Monitoring and Operational Assessment, Refueling Outage (2R24)

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ATTACHMENT 1

DESCRIPTION AND ASSESSMENT OF PROPOSED CHANGE

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

DESCRIPTION AND ASSESSMENT OF PROPOSED CHANGE

1.0 SUMMARY DESCRIPTION

Pursuant to 10 CFR 50.90, Dominion Energy Nuclear Connecticut, Inc. (DENC) requests an amendment to the Millstone Power Station Unit 2 (MPS2) Facility Operating License Number DPR-65, in the form of a change to the technical specifications (TSs). This license amendment request (LAR) proposes to revise MPS2 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. Because MPS2 has an 18-month operating cycle, a 96 EFPM frequency essentially requires the inspection to be performed every fifth refueling outage.

DENC is currently scheduled to perform the next MPS2 SG tube inspection during the MPS2 Cycle 27 refueling outage (RFO) in the fall of 2021. DENC has been involved in the development of Technical Specification Task Force (TSTF)-577, "Revised Frequencies for Steam Generator Tube Inspections," and has participated in meetings between the industry and the Nuclear Regulatory Commission (NRC) related to TSTF-577. DENC proposes to model the changes proposed in TSTF-577. NRC approval of TSTF-577 and a follow-on, site-specific LAR to revise the MPS2 SG tube inspection schedule would be unlikely to occur prior to the fall 2021 MPS2 RFO.

The operational experience of the MPS2 SGs, as described in this attachment, demonstrates that the proposed change to the SG inspection schedule acceptable and will result in a reduction of dose to personnel and risk to the plant. Furthermore, the MPS2 SG operational assessment and experience supports the proposed TS changes.

2.0 DETAILED DESCRIPTION

2.1 System Design and Operation

The nuclear steam supply system (NSSS) utilizes two steam generators to transfer the heat generated in the reactor coolant system (RCS) to the secondary system and produce steam at the warranted steam pressure and quality.

The steam generator is a vertical U-tube heat exchanger. The steam generator operates with the reactor coolant in the tube side and the secondary fluid in the shell side.

Reactor coolant enters the steam generator through the inlet nozzle, flows through three-quarter inch outer diameter (OD) U-tubes, and leaves through two outlet nozzles. Vertical partition plates in the lower head separate the inlet and outlet plenums. The plenums are stainless steel clad, while the primary side of the tube sheet is Ni-Cr-Fe clad. The vertical U-tubes are Ni-Cr-Fe alloy. The tube-to-tube sheet joint is welded on the primary side.

2.2 Current Technical Specification Requirements

Applicable SG TS requirements are included in the following MPS2 TS sections:

TS 3.4.6.2 Item c, "Reactor Coolant System Operational LEAKAGE," limits primary to secondary leakage through any one SG to 75 gallons per day.

TS 3.4.5, "Steam Generator Tube Integrity," states that SG tube integrity shall be maintained and all SG tubes satisfying the tube plugging criteria shall be plugged in accordance with the SG Program.

TS Surveillance Requirement (SR) 4.4.5.1 requires verification of SG tube integrity in accordance with the Steam Generator Program. TS SR 4.4.5.2 requires verification that each inspected SG tube that satisfies the tube plugging criteria is plugged in accordance with the SG Program prior to entering hot shutdown following a SG tube inspection.

The SG inspection scope is governed by TS 6.26, "Steam Generator (SG) Program" requirements. TS 6.26, Item a, requires that a condition monitoring assessment be performed during each outage in which the SG tubes are inspected, to confirm that the performance criteria are being met. TS 6.26, Item b, ensures SG tube integrity is maintained by meeting specified performance criteria for structural and leakage integrity, consistent with the plant design and licensing basis. Meeting SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions. TS 6.26, Item c, provides SG tube plugging criteria and TS 6.26, Item d, includes provisions regarding the scope, frequency, and methods of SG tube inspections. Specifically, TS 6.26, Item d.2 states, in part, "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)."

TS 6.9.1.9, "Steam Generator Tube Inspection Report," states that a report shall be submitted within 180 days after initial entry into MODE 4 [Hot Shutdown] following completion of an inspection performed in accordance with TS 6.26, "Steam Generator (SG) Program". This section also provides requirements for the report.

2.3 Description of Proposed Change

The following is a detailed description of the proposed MPS2 TS changes (added text is shown below in bold type, deleted text is shown in strikethrough):

- TS 6.26, Item d.2 is revised as follows:

  After the first refueling outage following SG installation, inspect **100% of the tubes in each** SG at least every ~~72~~ **96** effective full power months, **which defines the inspection period.** ~~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 and 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 tube 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.~~

- TS 6.26, Item d.2 bullets a) thru d) are being deleted.

- TS 6.26, Item d.3 is revised as follows:

  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 **be at the next** ~~not exceed 24 effective full power months or one~~ 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.

- TS 6.9.1.9 is revised as follows:

  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;

  b. ~~Degradation mechanisms found,~~ **The nondestructive examination techniques utilized for tubes with increased degradation susceptibility;**
  c. ~~Nondestructive examination techniques utilized for each degradation mechanism~~, **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;

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

  d. ~~Location, orientation (if linear), and measured sizes (if available) of service induced indications,~~ **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**; ~~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.~~ **The results of any SG secondary side inspections;**

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

TS markups of the proposed changes are provided in Attachment 2.

2.4 Reason for Proposed Change

The MPS2 replacement SGs are in the second inspection period, which currently has a duration of 120 EFPM. One hundred percent (100%) of the tubes in each steam generator have been inspected twice during this inspection period. SG-2 was inspected during the 2R22 outage (April 2014), SG-1 was inspected during 2R23, (October 2015), and both steam generators were inspected during the 2R24 outage (April 2017). DENC is currently scheduled to perform the next MPS2 SG tube inspection during the MPS2 Cycle 27 RFO in the fall of 2021, based on the MPS2 TS 6.26, Item d.2 requirement to inspect each SG at least every 72 effective full power months or at least every third refueling outage (whichever results in more frequent inspections). DENC has been involved in the development of TSTF-577, "Revised Frequencies for Steam Generator Tube Inspections," and has participated in meetings between the industry and the NRC related to TSTF-577. DENC proposes to model the changes proposed in TSTF-577. NRC approval of TSTF-577 and a follow-on, site specific LAR to revise the SG tube inspection schedule would be unlikely to occur prior to the fall 2021 MPS2 RFO.

The operational experience of the MPS2 SGs, as described in Section 3.0 of this attachment, demonstrates that the proposed change to the SG inspection schedule is acceptable and will result in a reduction of dose to personnel and risk to the plant. Table 6 shows the proposed schedule for future SG inspections. Overall, the proposed change will result in two fewer SG inspections before the expiration of the current operating license, while still accomplishing the 100 percent (%) inspection of the tubing within the sequential periods.

A reduction in dose will be achieved through fewer SG inspections during refueling outages. Typical dose values for SG inspections can vary depending on outage scope and activities. However, during the MPS2 2R24 outage, the SG inspection and associated activities accounted for 5.5 person-rem.

Many of the evolutions associated with SG inspections pose an increased risk to the plant and personnel (e.g., heavy lifts, confined space activities). An example of plant configuration improvement and risk reduction, as a result of not performing an SG inspection, is the elimination of the need for a plant mid-loop hold for installation of SG nozzle dams. This evolution is performed by personnel in a confined space inside the SG channel head under a high radiation environment with the plant at a reduced primary water inventory. For SG inspections, there are heavy lifts associated with moving equipment onto the refuel floor, into containment, and to the SG platforms. The primary and secondary manways must also be removed and reinstalled on the SGs using rigging. Personnel performing these activities could potentially be working in a locked high radiation area. Work on in the upper internals of the SGs also requires placing personnel inside a confined space.

While risk is minimized as much as possible through plant processes and procedures, performing 100% SG inspection scope in a 96 EFPM sequential period will reduce the total number of outages that the above associated activities are performed. This will yield a corresponding reduction of personnel dose exposure while improving plant risk and maintaining personnel safety.

3.0 TECHNICAL EVALUATION

3.1 Component Safety Functions

The SG tubes in pressurized water reactors (PWRs) have a number of important safety functions. SG tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. As part of the RCPB, the SG tubes are unique in that they act as a heat transfer surface between the primary and secondary systems to remove heat from the primary system. In addition, the SG tubes isolate the radioactive fission products in the primary coolant from the secondary system.

The steam generator tube rupture (SGTR) accident is the limiting design basis event for a SG. The analysis of an SGTR event assumes a bounding primary-to-secondary leakage rate equal to the TS limit for operational leakage rate, plus the leakage rate from a double-ended rupture of a single tube. The analysis for design basis accidents and transients other than SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture). In these analyses, the radiological release from a steam discharge to the atmosphere is based on the total primary-to-secondary leakage from all SGs or is assumed to increase to the limit as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level is assumed to be equal to the TS limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel.

SG tube integrity is necessary to ensure the tubes are capable of performing their intended safety functions. Concerns relating to the integrity of the tubing stem from the fact that the SG tubing can be subject to a variety of degradation mechanisms. SG tubes have experienced tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as wear.

These degradation mechanisms can impair tube integrity if they are not managed effectively. When the degradation of the tube wall reaches a prescribed criterion for action, the tube is considered defective and corrective action, such as plugging or repair, is taken.

The industry, working through the Electric Power Research Institute (EPRI) Steam Generator Management Program (SGMP), has implemented a generic approach to managing SG performance referred to as "Steam Generator Degradation Specific Management" (SGDSM).

The overall program is described in Nuclear Energy Institute (NEI) document 97-06, "Steam Generator Program Guidelines," (Reference 8.1) which is supported by a number of EPRI guidelines, such as:

- PWR Steam Generator Examination Guidelines
- Steam Generator Integrity Assessment Guidelines
- Steam Generator In-Situ Pressure Test Guidelines
- PWR Primary-to-Secondary Leak Guidelines
- PWR Primary Water Chemistry Guidelines
- PWR Secondary Water Chemistry Guidelines

NEI 97-06 and the EPRI Guidelines define a comprehensive, performance-based approach to managing SG performance.

3.2 Component Design

MPS2 is a two loop Asea Brown Boveri (ABB)-Combustion Engineering (CE) PWR with two Babcock and Wilcox (B&W) replacement SGs. Each SG was designed to contain 8523 U-bend thermally treated Inconel 690 tubes. One hot leg tubesheet hole in SG-1 was plugged during construction and the opposing cold leg hole was not drilled; thus SG-1 has 8522 tubes.

The tubing is nominally 0.750 inch outside diameter with a 0.0445-inch nominal wall thickness. During replacement SG fabrication, the tubes were installed using a two-step hydraulic expansion process over the full depth of the 21.06-inch thick tube sheet. The tubesheet was drilled on a triangular pitch with 1.0 inch spacing. There are 141 rows and 167 columns in each SG. To minimize small radius U-bends, tubes in rows one through three were installed using a staggered arrangement. This resulted in the termination of tubes at different locations between the hot and cold legs. For these rows, the tube identification follows the hot leg row/column naming convention.

Secondary side tube support structures include seven lattice grid supports on the vertical section of the tubes and twelve fan bar assemblies on the U-bend section of the tubes. All lattice grid supports are full supports. SG replacement was completed during the 2R11 outage (fall 1992). The most recent operational assessment was developed following inspections of both MPS2 SGs at the end of Cycle 24 (spring 2017). The new SGs have accrued approximately 20.5 Effective Full Power Years (EFPY) of operation as of the end of Cycle 26 (April 23, 2020). Considering an average cycle length of 1.371 EFPY since replacement, the SGs are expected to accrue approximately 24.6 EFPY by the end of Cycle 29 (fall 2024), at which time another inspection and Operational Assessment (OA) will be performed. The MPS2 replacement SGs are in the second inspection period as described in MPS2 TS 6.26, item d.2 bullet b), which has a duration of 120 EFPM. One hundred percent (100%) of the tubes in each steam generator have been inspected twice during the current inspection period. SG-2 was inspected during the 2R22 outage (April 2014), SG-1 was inspected during 2R23, (October 2015), and both steam generators were inspected during the 2R24 outage (April 2017). MPS2 operates with a licensed reactor power of 2700 MWth and a hot leg temperature between 591 to 595 degrees F.

3.3 Component Background

The design of the original MPS2 SGs had Alloy 600 mill annealed (Alloy 600MA) tube material. Alloy 600MA is susceptible to corrosion degradation mechanisms such as pitting and stress corrosion cracking under the operating conditions of most commercial nuclear units. These forms of degradation led to plugging significant numbers of tubes and shortening the useful life of the MPS2 original SGs to the point of early replacement, which occurred in 1992.

In light of the operating experience associated with the susceptibility of Alloy 600MA SG tube material to corrosion induced degradation, Alloy 690 thermally treated (Alloy 690TT) has emerged as the tube material of choice for both new and replacement pressurized water reactor SGs. This tube material has been found through laboratory studies and operating experience to have significantly greater resistance to corrosion induced degradation. The first commercial nuclear SGs with Alloy 690TT tubing were put into service in 1989. The Alloy 690TT tube material now has more than 30 years of domestic operating service experience. There are approximately 50 domestic nuclear units using Alloy 690TT SG tube material, and this population has operated, on average, for about 17 years with Alloy 690TT in service. The predominant degradation mechanism for SGs with Alloy 690TT tubing has been volumetric wear due to interaction with tube support structures. To date, no domestic or international commercial nuclear units have reported indications of stress corrosion cracking degradation in Alloy 690TT tubes.

Each of the replacement SGs at MPS2 have undergone a pre-service inspection (PSI) and eight in-service inspections (ISI), the results of which are described later in this attachment. There have only been two degradation mechanisms detected in the MPS2 replacement SGs, (i.e., wear at the tube bundle U-bend support structures or fan bar, and wear caused by foreign objects). No tubes have been plugged due to wear at support structures and seven tubes have been plugged due to foreign object wear. A total of thirty-two tubes have been plugged, including one plug installed pre-service and twenty-four tubes that have been plugged in-service due to foreign objects that were irretrievable.

3.4 Technical Specification Sequential Periods

The current MPS2 TS reflect an amendment (Reference 8.7) to incorporate TSTF-510, Revision 2, "Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection" (Reference 8.8). For ISI of SGs with Alloy 690TT tubing, in accordance with TSTF-510, Revision 2, the MPS2 TS permits an initial sequential period of 144 EFPM for 100% inspection of the SG tubes with techniques qualified for detecting existing and potential degradation. The accrual of service for this requirement begins after the first ISI examination and does not include the pre-service exam (PSI). Under the current TS requirements, the lengths of the sequential periods are 144 EFPM (first inspection period), 120 EFPM (second inspection period), 96 EFPM (third inspection period), and 72 EFPM (fourth and subsequent inspection periods). DENC completed the first inspection period for the MPS2 replacement SGs in the spring of 2011, the results of which are further described in Sections 3.10 and 3.11 of this attachment. MPS2 is currently in the second sequential inspection period.

The percentage of SG tubes that must be inspected is dependent on the number of scheduled inspections over the sequential period. Inspections must also be planned such that 100% of the tubing has been inspected by the end of the sequential period. If an active degradation mechanism associated with cracking is present, then the affected and all potentially affected SGs must be inspected at the subsequent refueling outage.

3.5 Technical Justification for Revising Tube Inspection Requirements

Significant operating experience has been gained over the course of 15 years since the current TS inspection frequencies were determined, and this experience provides justification for extending these frequencies.

For the Alloy 690TT SGs, wear at support structures is the primary concern. Twenty-one of the forty-four domestic units with Alloy 690TT tubing have experienced either a minimal number of structure wear indications or no indications. Fifteen of these domestic units (including MPS2) have never been required to plug a tube for structure wear. Among these are units with SGs that have been in service since the 1990's. The other six units have been required to plug fewer than 10 tubes for structure wear. Twelve of the units with Alloy 690TT tubing have moderate numbers of wear indications with low growth rates that tend to attenuate over time. Conservative initiation and growth rate projections out to 96 EFPM of operating time between inspections for these units has been easily justified, since the structural integrity and accident induced leakage performance criteria are met with margin. The 11 units with Alloy 690TT tubing in the US with higher numbers of wear indications or higher growth rates are limited to inspection frequencies dictated by the assessments required by the SG Program, as is the case with the current inspection frequencies. Based on this operating experience, the proposed TS change to require inspection of the SG tubes at periods not to exceed 96 EFPM is acceptable for MPS2.

The SG Program required assessments ensure safe SG inspection intervals, even considering the prescribed inspection frequencies in the proposed change. These intervals are based on measurable parameters that monitor SG performance, such as results of SG tube inspections and operational leakage. Objective criteria to assess performance are established based on risk insights, deterministic analyses, and performance history. In addition, the TS limits for operational leakage require a plant shutdown if the limits are exceeded. This ensures that the failure to meet a performance criterion, while undesirable, will not result in an immediate safety concern. Therefore, the proposed extension of the existing SG inspection frequencies is acceptable.

3.6 Inspection Techniques

The SG Program described in MPS2 TS 6.26, requires use of appropriate inspection techniques to detect flaws of any type (e.g., volumetric flaws, axial and circumferential cracks). In addition to the required inspections at the specified intervals, the SG Program requires that the inspection scope, the inspection methods, and the inspection intervals ensure that SG tube integrity is maintained until the next SG inspection. Furthermore, degradation assessments (DAs) are used to determine the type of flaws to which the tubes may be susceptible, the location of the flaws, and which inspection methods need to be employed and at what locations to detect such flaws. Therefore, the TS will continue to require a robust inspection program to support the proposed inspection intervals.

3.7 Operational Assessments

As described in the TS Bases for MPS2 TS 4.4.5.1, during shutdown periods the SGs are inspected as required by SR 4.4.5.1 and the SG Program. NEI 97-06 (Reference 8.1), and its referenced EPRI Guidelines, establish the content of the SG Program. Use of the SG Program ensures that the inspection is appropriate and consistent with accepted industry practices. The SG Program also specifies the inspection methods to be used to find potential degradation. NEI 97-06 provides guidance for performing OAs to verify that the tubes remaining in service will continue to meet the SG performance criteria.

During an SG inspection, any inspected tube that satisfies the SG Program plugging criteria is removed from service by plugging. The tube plugging criteria delineated in MPS2 TS 6.26 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube plugging criteria, in conjunction with other elements of the SG Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s).

OAs have been performed for each inspection, in accordance with the requirements of the SG Program. The OAs performed to date have been both accurate and appropriately conservative.

3.8 Degradation Assessments

DAs have been performed per the SG Program described in MPS2 TS 6.26. As previously noted, there have been only two degradation mechanisms detected in the MPS2 SGs, (i.e., wear at the tube bundle U-bend support structures or fan bar and wear caused by foreign objects). These mechanisms are discussed further in Sections 3.9 and 3.11.

Two additional degradation mechanisms are considered to have the potential to occur in the future. These degradation mechanisms are lattice support wear and tube-to-tube wear. Tube thinning adjacent to support structures was also identified as a degradation mechanism with a low likelihood of initiation and progression.

Lattice Support Wear

Tube wear has been detected on other B&W replacement steam generators at the lattice support structures. However, no tube wear has been detected as lattice support wear at MPS2.

Tube-to-Tube Wear

Tube-to-tube wear has been reported at Palisades Nuclear Plant, both units at the San Onofre Nuclear Generating Station (SONGS), and several of the replacement Once Through Steam Generators (OTSGs). Although the OTSG experience is not relevant to MPS2 due to the different design, the Palisades and SONGS experiences both have potential applicability to MPS2. The tube-to-tube wear reported at Palisades is believed to be related to tubes having less than the nominal gap from one tube to the other. The SONGS experience was caused by fluid elastic instability in the U-bend region. However, neither of these conditions are known to exist in MPS2 SGs and no tube-to-tube wear has been detected at MPS2.

Thinning

Thinning is a general term used to describe two different SG damage mechanisms. The first is a wastage mechanism resulting from the use of phosphate-based secondary chemistry controls. This mechanism has not been observed in plants that do not use phosphate chemistry (such as MPS2) and is therefore not a threat to the MPS2 SGs. The other is a type of thinning observed in Westinghouse Model 51 SGs caused by acid-sulfate crevice conditions within cold leg deposits. Under modern chemistry control regimes, this mechanism is unlikely to develop because sulfate limits are very low and resulting crevice pH is typically not acidic.

The other mechanisms evaluated in previous DAs were concluded to have a very low likelihood of initiation and progression.

3.9 Foreign Objects

Section 6.2 of Attachment 3 contains a detailed discussion on the topic of foreign object wear. An excerpt from that discussion is provided below.

"The 2R24 inspection scope for foreign objects and associated wear was extensive and included both visual and eddy current inspections. Visual inspections included both the annulus and no-tube lane at the top of the tubesheet in both steam generators. These visual inspections included looks into the tube bundle at all peripheral and no-tube lane locations. The eddy current examinations included full length bobbin probe examinations of all tubes, 50% rotating probe examinations of an approximate six tube deep periphery at the top of tubesheet (+/- 3 in) in both legs, and bounding rotating probe examinations of potential foreign object associated indications. All evidence of foreign objects and foreign object wear was tracked and evaluated in the BWXT Loose Parts Tracker (LPT), and objects were retrieved where possible. Tubes adjacent to irretrievable foreign objects had been stabilized and plugged during past

outages. Consequently, no foreign objects capable of causing tube degradation are known to remain adjacent to in-service tubes. This aggressive ECT and FOSAR campaign has significantly reduced the potential for future foreign object wear. With these extensive inspections and subsequent part removal, there is reasonable confidence that no parts capable of causing significant tube degradation remain in the tube bundle."

Since no foreign objects capable of causing tube degradation were known to remain in the MPS2 steam generators following the 2R24 inspection activities, it can be assumed that continued wear at tube locations where foreign objects were known to exist has been arrested.

Foreign objects may enter the steam generator tube bundle at any time during an operating cycle and cause wear on the tubes. DENC performs eddy current and visual inspections to identify objects and retrieve them; however, this cannot preclude foreign object events. Industry operating experience proves that wear from foreign objects initially leads to low level leakage. The primary-to-secondary leak monitoring program implemented at MPS2 is capable of identifying leakage at very low levels and MPS2 TS and procedures require a unit shutdown when necessary to avoid the potential of tube rupture.

Current EPRI guidance on development of forward-looking OAs has been incorporated in the SG Program, as described in MPS2 TS and Bases. The OA requires consideration of secondary side conditions that could affect SG tube integrity, such as foreign material in the SGs, material degradation that could generate foreign objects during operation, and degradation of support structures. There is also a requirement for the forward-looking OA to establish the acceptable inspection interval, to ensure that degraded secondary side components do not affect tube integrity during future operation.

3.10 MPS2 Inspection and Plugging History

Table 1 provides a tabulation of the previous examinations performed at MPS2 and shows that each in-service steam generator tube has been inspected at least twice during the current inspection period.

TABLE 1: Historical Examination Schedule

Outage	Date	Cycle EFPM	Total SG EFPM***	Inspection Period EFPM**	SG-1 Scope*	SG-2 Scope*	Inspection Period and Length
2R11	Jan-93	NA	0	NA	NA (SG Replacement)		NA
Start of 1st Inspection Period (144 EFPM)							
2R12 (First ISI)	Oct-94	15.744	15.744	0	2508 / 0 / 1	2380 / 0 / 0	1st Sequential Inspection Period 144 EFPM
Mid Cycle	May-97	6	21.744	6	6407 / 0 / 30	2563 / 0 / 31	
2R13	Apr-00	10.056	31.8	16.1	Skip Cycle	8523 / 0 / 77	
2R14	Feb-02	19.728	51.528	35.784	8522 / 0 / 57	Skip Cycle	
2R15	Oct-03	16.92	68.448	52.704	Skip Cycle	8523 / 172 / 82	
2R16	Apr-05	15.972	84.42	68.676	8522 / 142 / 144	Skip Cycle	
2R17	Oct-06	16.2	100.62	84.876	Skip Cycle	Skip Cycle	
2R18	Apr-08	16.5	117.12	101.376	8522 / 248 / 313	8523 / 297 / 374	
2R19	Oct-09	15.624	132.744	117	Skip Cycle	Skip Cycle	
2R20	Apr-11	16.032	148.776	133.032	8514 / 2552 / 374	8521 / 2557 / 479	
Start of 2nd Inspection Period (120 EFPM)							
2R21	Oct-12	16.02	164.796	5.052	Skip Cycle	Skip Cycle	2nd Sequential Inspection Period 120 EFPM
2R22	Apr-14	16.152	180.948	21.204	Skip Cycle	8510 / 2640 / 187	
2R23	Oct-15	16.236	197.184	37.44	8504/2579/94	Skip Cycle	
2R24	Apr-17	16.548	213.732	53.988	8504/2501/122	8510/2522/180	

* Bobbin / TTS using array or rotating / Other Rotating - Example: (8523 / 297 / 374) = 8523 Bobbin Exams; 297 TTS Exams; 374 Additional Rotating Exams

** The first inspection period begins at startup after the first ISI.

*** Total SG EFPM represents the cumulative EFPM since the SGs were replaced.

The extensive examinations performed over the past 27 years have resulted in the plugging of 31 tubes. In 2008, seven tubes were plugged for foreign object wear, and five of these tubes recorded minor wear but were removed from service due to the absence of a qualified sizing technique at the time. All remaining tube plugs were installed discretionarily, due to foreign objects that were deemed irretrievable at the time. Due to heightened FME awareness and prevention techniques, no tubes have been plugged since 2011.

TABLE 2: SG-1 Tube Plugging History

Outage	Tubes Plugged	RTS Tubes	Total Plugged	% Plugged	FSAR Table 14.6.5.1-3 % Plugging Limit
PSI	1	8522	1	0.01	5.9
2008/ 2R18	8	8514	9	0.11	5.9
2011/ 2R20	10	8504	19	0.22	5.9

TABLE 3: SG-2 Tube Plugging History

Outage	Tubes Plugged	RTS Tubes	Total Plugged	% Plugged	FSAR Table 14.6.5.1-3 % Plugging Limit
PSI	0	8523	0	0.00	5.9
2008/ 2R18	2	8521	2	0.02	5.9
2011/ 2R20	11	8510	13	0.15	5.9

3.11 Structure Wear

For the purposes of this evaluation, structure (fan bar) wear can be grouped into two categories:

- Wear that currently exists in in-service tubes, whether detected during the 2R24 outage or not.
- Wear which will initiate during the subsequent five fuel cycles.

The eddy current examination conducted during 2R24 included full length bobbin probe examinations of all tubes. As part of the technique qualification program using EPRI examination technique specification sheet (ETSS) 96041.3 (examining for wear utilizing a bobbin probe), all flaws ranging in depth from 4% TW to 90% TW were detected. Due to the high Probability of Detection (POD) for fan bar wear detection, undetected flaws are not a significant concern for structural integrity. Additionally, because wear which has already initiated will continue to grow, it is assumed to be more limiting in the future than wear which has not yet initiated. This evaluation will focus on wear flaws that have already initiated. This requires consideration of NDE sizing uncertainty, NDE POD, and the rate of future wear flaw growth.

As stated earlier, no tubes have been plugged at MPS2 for structure wear. Only four tubes, (two in each SG), have recorded any wear at support structures and all four wear indications are minor fan bar wear. No wear has been detected at the lattice grid support. Fan bar wear was first detected in SG-1 during 2R14 (March 2002), and in SG-2 during 2R15 (October 2003). Apparent growth rates of indications without prior detection could represent a detection issue and not a growth rate issue. In other words, these indications could have existed during previous examinations, but at degradation depths below detectability or the reporting threshold, making growth rate estimates erroneously high. Additionally, the sample of tubes exhibiting fan bar wear is too small to be statistically significant. Short cycle lengths can generate large NDE measured growth rates, simply because actual growth rates are small in comparison to the NDE sizing variability. Table 4 below provides wall loss measurement data for each MPS2 SG tube exhibiting structural wear to date. The effects of NDE sizing variability is evidenced by the apparent negative growth rates in some instances.

TABLE 4: SG Tube Wall Loss Measurement Data

			Percent Through Wall Each Outage							
Row	Column	S/G	2R14	2R15	2R16	2R18	2R20	2R22	2R23	2R24
40	155	1	9		9	11	11		12	13
140	93	1	9		9	12	12		14	19
37	120	2		6		9	9	8		12
99	80	2		11		11	15	15		13

It is more reliable to establish growth rates by trending the progression of the degradation over multiple inspections. Table 5 lists the average wear growth rates over the time period since the indications were first detected.

TABLE 5: Fan Bar Wear Growth Rates

SG	Row	Col	Location	Maximum Depth 2R24	Size When First Detected	Average Growth Rate Since Detection
1	40	155	F06	13% TW	9% TW (2002)	0.30% per EFPY
1	140	93	F08	19% TW	9% TW (2002)	0.74% per EFPY
2	37	120	F07	12% TW	6% TW (2003)	0.50% per EFPY
2	99	80	F06	13% TW	11% TW (2003)	0.17% per EFPY

Note the maximum depth of fan bar wear was 19% through-wall (TW), which was observed during the 2R24 outage. This depth is significantly below the required structural integrity criteria (50.2% allowable real depth structural limit, Reference 8.6) that is calculated based on the requirements of MPS2 TS 6.26. There is no industry published default growth rate recommended for structure wear. Wear rates tend to be site specific, especially for replacement steam generators. Operational assessments developed after each of the inspections performed at MPS2 have historically used excessively large growth rates to include adequate conservatism. A review of each OA since the fan bar wear was first detected shows that the growth rates used in these integrity assessments ranged from 10% TW/EFPY in 2R15 to 3% TW/EFPY in 2R18.

When the measured wear depth is adjusted upwards to account for technique uncertainty and conservative cycle lengths are assumed, these excessively large growth rates provide for overestimated projected wear depths over the ensuing operating interval. The 2R14 OA projected wear depth was 53% for 2-cycles of SG-1 operation and the 2R15 OA projected wear depth was 55% for 2-cycles of SG-2 operation. These projected wear depths are more than twice the measured depths after 15 more years of operation.

The OA documented during 2R24 used an excessively conservative growth rate of 5% TW/EFPY and easily justified three cycles of operation, even when including additional conservatism. However, if the same growth rate, uncertainty, and conservatism is applied for five cycles of operation, the resulting wear depth is unacceptable.

The highest average growth rate observed between the two MPS2 SGs over the time from first detection to the most recent inspection was 0.74% TW/EFPY. While the inspection results of the MPS2 SGs support the use of a 0.74% TW/EFPY growth rate value, the following reevaluation of the 2R24 OA will assume 3% TW/EFPY. This wear rate is conservative and easily bounds the wear observed in the small sample of tubes that exhibit fan bar wear.

The deepest fan bar wear indication returned to service measured 19% TW using a bobbin probe. The NDE (Non-Destructive Examination) sizing parameters for the bobbin technique (ETSS 96041.3) are a slope of 0.99 and an intercept of 2.73% TW. Using the slope and intercept, a best estimate depth of 21.5 % TW (19 x 0.99 + 2.73) is obtained for an indication with a measured depth of 19% TW.

A standard error of 3.36% TW is the uncertainty associated with this technique. Further adjusting this value upward to an upper 95th percentile gives an NDE uncertainty of 5.53% TW (3.36 x 1.645). Adding this uncertainty to the best estimate value of 21.5% TW yields a bounding real depth of 27% TW (21.5 + 5.5) for indications returned to service.

MPS2 utilizes an 18-month operating cycle. A 96-month operating interval will result in a maximum of four outages without SG examinations being performed, (i.e. an inspection every fifth refueling outage). MPS2 has averaged 1.371 EFPY per operating cycle. Conservatively assuming 1.4 EFPY per operating cycle and applying a growth rate of 3.0% TW/EFPY over a five-cycle bounding inspection interval of seven EFPY gives a total growth of 21.0% TW (3.0% x 7 EFPY) until the next planned inspection. Further applying this total growth to the bounding depth of 27% TW gives a projected 2R29 depth of 48% TW (27 + 21.0) for indications detected and returned to service during the 2R24 outage.

The allowable real depth Structural Limit (SL) for fan bar wear with a bounding length of 3.20" is 50.2% TW as shown in the ETSS 96041.3 OD Axial Thinning Evaluation found in Appendix C of the 2R24 DA (Reference 8.6). The projected real depth of 48.0 % TW was calculated with various conservatisms (as described above), and is within the allowable real depth of 50.2% TW; therefore, there is reasonable assurance that the structural integrity performance criterion will be met for this mechanism for the five cycles of operation (at which time, another inspection and OA will be performed).

3.12 Conclusions

The Alloy 690TT material used in the MPS2 replacement SGs has been found through laboratory studies and operating experience to have significantly greater resistance to corrosion induced degradation. There have been no reported indications of stress corrosion cracking degradation in any Alloy 690TT tube to date. As such, stress corrosion cracking is not considered a credible degradation mechanism for MPS2 SG tubing. However, DENC will continue to monitor industry operating experience regarding potential degradation mechanisms.

The DENC SG program prescribes that the number and portions of the tubes inspected, and methods of inspection are to be performed with the objective of detecting flaws of any type that may be present. Nondestructive examination scopes and methodologies employed during MPS2 SG inspections performed to date have effectively identified degradation mechanisms existing in MPS2 SGs and are appropriate for the identification of degradation mechanisms that may exist in SGs with A690TT tubing. Although the enhanced detection achieved by inspection with advanced probes provides improved probability of detection performance, for the two degradation mechanisms exhibited in MPS2 SGs, eddy current examination methodologies currently employed have proven effective in identification and monitoring degradation. Tube wear at support structure locations has proven to exhibit slow, stable wear rates which have been shown by analysis to accommodate an interval of five operating cycles between SG inspection activities. Similarly, the nondestructive examination methods employed to date have been effective in identifying the existence of and wear resulting from tube contact with foreign objects. Degradation rates for this mechanism are highly dependent on the attributes of the foreign object and the interaction mechanism with adjacent tubes. To address this degradation mechanism, identified foreign objects are either removed during secondary side inspection activities, or proactive actions such as plugging and/or staking of tubes adjacent to the foreign object are employed to arrest tube degradation and/or prevent tube failure. Should industry OE identify new degradation mechanisms for which A690TT tubing is proven susceptible, MPS2 SG inspection strategies will be assessed and modified, as needed to ensure existing degradation continues to be effectively identified and monitored.

The predominant degradation mechanism for most SGs with Alloy 690TT tubing, has been volumetric wear due to interaction with tube support structures. However, only four indications of tube wear at support structures, (fan bar wear), have been detected at MPS2 and none have exceeded 20% in almost 30 years of operation with the Alloy 690TT tubes in service. This operating experience supports the TS change to allow inspection of the SG tubes at periods not to exceed 96 EFPM is acceptable. The OAs and DAs performed to date have been both accurate and appropriately conservative.

To address degradation due to introduction of foreign material into an MPS2 SG between scheduled inspections, DENC has primary-to-secondary leak monitoring programs that are capable of identifying leakage at very low levels and MPS2 procedures require unit shutdown when necessary to avoid the potential of tube rupture. In addition, TS requirements on operational leakage require a plant shutdown if the limits are exceeded. This ensures that the failure to meet a performance criterion, while undesirable, will not result in an immediate safety concern.

Based upon the evaluations above, there is reasonable assurance that the structural and leakage performance criteria will not be exceeded at any time prior to the 2R29 outage (fall of 2024), and that adopting a 96-month inspection period is appropriate. Therefore, the proposed extension of the existing SG inspection frequencies is acceptable.

Table 6 details the proposed examination schedule after adopting a 96-month inspection interval.

TABLE 6: Proposed Examination Schedule

Outage	Date	Cycle EFPM	Total SG EFPM***	Inspection Period EFPM**	SG-1 Scope*	SG-2 Scope*	Inspection Period and Length
Start of 2nd Inspection Period (96 EFPM)							
2R21	Oct-12	16.02	164.796	5.052	Skip Cycle		2nd Sequential Inspection Period 96 EFPM
2R22	Apr-14	16.152	180.948	21.204	Skip Cycle	8510 / 2640 / 187	
2R23	Oct-15	16.236	197.184	37.44	8504/2579/94	Skip Cycle	
2R24	Apr-17	16.548	213.732	53.988	8504/2501/122	8510/2522/180	
2R25	Oct-18	16.716	230.448	70.704	Skip Cycle		
2R26	Apr-20	16.344	246.792	87.048	Skip Cycle		
End of 96 Month Period							
2R27	Oct-21	16.3	263.092	7.348	Skip Cycle		3rd Sequential Inspection Period 96 EFPM
2R28	Apr-23	16.3	279.392	23.648	Skip Cycle		
2R29	Oct-24	16.3	295.692	39.948	Robust Primary-side and Secondary-side Examinations		
2R30	Apr-26	16.3	311.992	56.248	Skip Cycle		
2R31	Oct-27	16.3	328.292	72.548	Skip Cycle		
2R32	Apr-29	16.3	344.592	88.848	Skip Cycle		
End of 96 Month Period							
2R33	Oct-30	16.3	360.892	9.148	Skip Cycle		4th Sequential Inspection Period 96 EFPM
2R34	Apr-32	16.3	377.192	25.448	Robust Primary-side and Secondary-side Examinations		
2R35	Oct-33	16.3	393.492	41.748	Skip Cycle		
2R36	Apr-35	16.3	409.792	58.048	Skip Cycle		
End of Current Operating License: July 31, 2035							

* Bobbin / TTS using array or rotating / Other Rotating - Example: (8523 / 297 / 374) = 8523 Bobbin Exams; 297 TTS Exams; 374 Additional Rotating Exams

** The first inspection period begins at startup after the first ISI.

*** Total SG EFPM represents the cumulative EFPM since the SGs were replaced.

4.0 REGULATORY EVALUATION

This LAR proposes to revise MPS2 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 EFPM, or at least every third refueling outage, to every 96 EFPM. The following regulatory requirements have been reviewed and the No Significant Hazards Consideration Determination is provided below.

4.1 Applicable Regulatory Requirements/Criteria

Technical Specifications - Section 50.36 of Title 10 of the *Code of Federal Regulations* (10 CFR), establishes the regulatory requirements related to the content of the TSs. Pursuant to 10 CFR 50.36, TSs are required to include items in the following five specific categories related to station operation: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) surveillance requirements; (4) design features; and (5) administrative controls. In 10 CFR 50.36(c)(5), administrative controls are stated to be, "the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure the operation of the facility in a safe manner." This also includes the programs established by the licensee and listed in the administrative controls section of the TS for the licensee to operate the facility in a safe manner. For MPS2, the requirements for performing SG tube inspections and repair are contained in TS 3/4.4.5, "Steam Generator Tube Integrity" and TS 6.26, "Steam Generator (SG) Program."

The TSs for pressurized-water reactor plants require that a SG program be established and implemented to ensure SG tube integrity is maintained. For MPS2, the SG inspection scope is governed by TS 6.26, "Steam Generator (SG) Program" requirements. TS 6.26, Item a, requires that a condition monitoring assessment be performed during each outage in which the SG tubes are inspected, to confirm that the performance criteria are being met. TS 6.26, Item b, ensures SG tube integrity is maintained by meeting specified performance criteria for structural and leakage integrity, consistent with the plant design and licensing basis. Meeting SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions. TS 6.26, Item c, provides SG tube plugging criteria and TS 6.26, Item d, includes provisions regarding the scope, frequency, and methods of SG tube inspections. Specifically, TS 6.26, Item d.2 states, in part, "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)."

10 CFR Requirements/General Design Criteria (GDC) - 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants," Criteria 14, 15, 30, 31, and 32, define the requirements for the RCS pressure boundary with respect to structural and leakage integrity. Steam generator tubing and tube repairs

constitute a major fraction of the RCS pressure boundary surface area. Steam generator tubing and associated repair techniques and components, such as plugs and sleeves, must be capable of maintaining reactor coolant inventory and pressure.

Criterion 14, "Reactor Coolant Pressure Boundary"
The reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, or rapidly propagating failure, and of gross rupture.

Criterion 15, "Reactor Coolant System Design"
The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

Criterion 30, "Quality of reactor coolant pressure boundary"
Components, which are part of the reactor coolant pressure boundary, shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

Criterion 31, "Fracture prevention of reactor coolant pressure boundary"
The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady state and transient stresses, and (4) size of flaws.

Criterion 32, "Inspection of reactor coolant pressure boundary"
Components, which are part of the reactor coolant pressure boundary, shall be designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leak-tight integrity, and (2) an appropriate material surveillance program for the reactor pressure vessel.

The reactor coolant system (RCS) pressure boundary is designed, fabricated and constructed to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. RCS pressure boundary components have provisions for the inspection, testing and surveillance of critical areas, by appropriate means, to assess the structural and leak-tight integrity of the boundary components during their service lifetime. The SG tubes function as an integral part of the RCS pressure boundary and, in addition, isolate fission products in the primary coolant from the secondary coolant and the environment. SG tube integrity means the tubes are capable of performing these safety functions in accordance with the plant design and licensing bases. All applicable regulatory requirements will continue to be satisfied as a result of the proposed license amendment.

As part of the plant licensing basis, applicants for operating licenses are required to analyze the consequences of postulated design-basis accidents (DBA) such as a SG tube rupture and a main steam line break (MSLB). These analyses consider primary-to-secondary leakage that may occur during these events and must show that the offsite radiological consequences do not exceed the applicable limits of the 10 CFR 50.67 guidelines for offsite doses, GDC 19 criteria for control room operator doses, or some fraction thereof, as appropriate, to the accident or the NRC-approved licensing basis. No accident analysis for MPS2 is being changed because of the proposed amendment; thus, no radiological consequences of any accident analysis are being changed. The proposed change to TS 6.26, Item d.2, stays within the GDC requirements for the SG tubes and maintains the accident analysis and consequences for the postulated DBAs for SG tubes.

4.2 No Significant Hazards Consideration Determination

Pursuant to 10 CFR 50.90, Dominion Energy Nuclear Connecticut, Inc. (DENC) is requesting an amendment to the Millstone Power Station Unit 2 (MPS2) Facility Operating License Number DPR-65, in the form of a change to the technical specifications (TSs). This license amendment request proposes to revise MPS2 TS 6.26, "Steam Generator (SG) Program," and TS 6.9.1.9 "Steam Generator Tube Inspection Report," 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.

DENC has evaluated whether a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of Amendment," as discussed below:

(1) Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No

The proposed change revises the inspection frequencies for SG tube inspections and associated reporting requirements. The SG inspections are conducted as part of the SG Program, as described in MPS2 TS 6.26, to ensure and demonstrate that performance criteria for tube structural integrity and accident leakage integrity are met. These performance criteria are consistent with the plant design and licensing basis. With the proposed changes to inspection frequencies, the SG Program must still demonstrate that the performance criteria are met. As a result, the probability of any accident previously evaluated is not significantly increased and the consequences of any accident previously evaluated are not significantly increased.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

(2) Does the proposed change create the possibility of a new or different accident from any accident previously evaluated?

Response: No

The proposed change does not alter the design function or operation of the MPS2 SGs or the ability of the SGs to perform their design function. The SG tubes continue to meet the SG Program performance criteria. No plant physical changes are being implemented that would result in plant operation in a configuration outside the plant safety analyses or design basis. The proposed change does not introduce any changes or mechanisms that create the possibility of a new or different kind of accident. Finally, no new effects on existing equipment are created, nor are any new malfunctions introduced.

Therefore, based on the above evaluation, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

(3) Does the proposed change involve a significant reduction in a margin of safety?

Response: No

Revising the MPS2 inspection schedule for SGs does not involve changes to any limit on accident consequences specified in the MPS2 licensing bases or applicable regulations, does not modify how accidents are mitigated, and does not involve a change in a methodology.

The steam generator tubes are an integral part of the reactor coolant pressure boundary and, as such, are relied upon to maintain the primary system pressure and inventory. Revising the SG tube in-service inspection frequency will not alter their function or design. Inspections of the SGs demonstrate that the SGs do not have an active damage mechanism. The improved design of the replacement SGs to use Alloy 690 thermally treated (Alloy 690TT) tubes, the in-service inspection data, and operational assessments also provide reasonable assurance that significant tube degradation is not likely to occur. Therefore, DENC concludes that this proposed change does not involve a significant reduction in a margin of safety.

Therefore, operation of the facility in accordance with the proposed change will not involve a significant reduction in a margin of safety.

Therefore, DENC concludes the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

5.0 ENVIRONMENTAL CONSIDERATION

The proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9) as follows:

(i) The proposed change involves no significant hazards consideration.

As described in Section 4.2 above, the proposed change involves no significant hazards consideration.

(ii) There are no significant changes in the types or significant increase in the amounts of any effluents that may be released off-site.

The proposed LAR revises MPS2 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 EFPM, or at least every third refueling outage, to every 96 EFPM. The proposed change does not alter the design function or operation of the MPS2 SGs or the ability of these SGs to perform its design function. As such, the proposed change does not involve the installation of any new equipment or the modification of any equipment that may affect the types or amounts of effluents that may be released off-site. The proposed change will have no impact on normal plant releases and will not increase the predicted radiological consequences of accidents postulated in the Updated Final Safety Analysis Report (UFSAR). Therefore, there are no significant changes in the types or significant increase in the amounts of any effluents that may be released off-site.

(iii) There is no significant increase in individual or cumulative occupational radiation exposure.

The proposed LAR revises MPS2 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. A reduction in dose will be achieved through fewer SG inspection outages. The proposed change does not alter the design function or operation of the

MPS2 SGs or the ability of these SGs to perform its design function. The proposed change does not implement plant physical changes or result in plant operation in a configuration outside the plant safety analyses or design basis. Therefore, there is no significant increase in individual or cumulative occupational radiation exposure associated with the proposed change.

Based on the above, DENC concludes that, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 CONCLUSION

DENC concludes, based on the considerations discussed herein, that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

7.0 PRECEDENTS

Similar LARs requesting SG tube inspection frequency change is currently under review by the NRC as noted below:

7.1 Letter from Tennessee Valley Authority to the NRC, dated February 24, 2020, Application for Revise Sequoyah Nuclear Plant (SQN) Unit 1 Technical Specifications for Steam Generator Tube Inspection Frequency (SQN-TS-20-01) (ADAMS Accession No. ML20056C857)

7.2 Letter from Tennessee Valley Authority to the NRC, dated July 17, 2020, Application for Revise Watts Bar Nuclear Plant (WBN) Unit 1 Technical Specifications for Steam Generator Tube Inspection Frequency and to Adopt TSTF-510, "Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection," (WBN-390-TS-20-012) (ADAMS Accession No. ML20199M346)

The following letters are recent precedence for one-time changes to SG inspection frequencies:

7.3 Letter from NRC to Florida Power and Light Company dated April 16, 2020, Turkey Point Nuclear Generating Unit No. 3 - Issuance of Exigent Amendment No. 291 Concerning the Deferral of Steam Generator Inspections (EPID L-2020-LLA-0067) (ADAMS Accession No. ML20104B527)

7.4 Letter from NRC to Exelon Generation dated May 1, 2020, Braidwood Station, Unit 2 – Issuance of Amendment No. 209 Re: One-Time Extension of Steam Generator Inspections [COVID-19] (EPID L-2020-LLA-0069) (ADAMS Accession No. ML20111A000)

7.5 Letter from NRC to Virginia Electric Power Company dated May 7, 2020, Surry Power Station, Unit Nos. 1 and 2, Issuance of Exigent Amendment Nos. 299 and 299 to Revise Technical Specification 6.4.Q, "Steam Generator (SG) Program," to Allow a One-Time Deferral of the Surry Unit No. 2 SG "B" Spring 2020 Refueling Outage Inspection (EPID No. L-2019-LLA-0071) (ADAMS Accession No. ML20115E237)

8.0 REFERENCES

8.1 Nuclear Energy Institute (NEI) 97-06 Revision 3, "Steam Generator Program Guidelines," January 2011

8.2 Electric Power Research Institute (EPRI) Report 3002007571, "Steam Generator Management Program: Steam Generator Integrity Assessment Guidelines," Revision 4, June 2016

8.4 Millstone Power Station Unit 2, Final Safety Analysis Report, Revision 38, June 30, 2020

8.5 DENC Letter 17-353, "Millstone Power Station Unit 2, End of Cycle 24 Steam Generator Tube Inspection Report," dated September 18, 2017 (ADAMS Accession No. ML17269A030)

8.6 ETE-MP-2017-1015, "Millstone Unit 2 Steam Generator Integrity Degradation Assessment (R24)," Revision 0

8.7 USNRC, Millstone Power Station Unit No. 2 – Issuance of Amendment Re: Adopt TSTF-510, "Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection (TAC No. ME9188)," dated January 4, 2013 (ADAMS Accession No. ML12340A291)

8.8 Technical Specification Task Force (TSTF) Traveler, Correction to TSTF-510, Revision 2, "Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection," dated March 1, 2011 (ADAMS Accession No. ML110610350)

8.9 Electric Power Research Institute (EPRI) Report 3002007572, "Steam Generator Management Program: Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 8, June 2016

8.10 ETE-MP-2017-1060, "Millstone Unit 2 Steam Generator Integrity Condition Monitoring and Operational Assessment Refueling Outage (2R24)," Revision 1

8.11 Technical Specification Task Force (TSTF) Traveler, Transmittal of TSTF-577, Revision 0, "Revised Frequencies for Steam Generator Tube Inspections," dated June 8, 2020 (ADAMS Accession No. ML20160A359)

Serial No. 20-328
Docket No. 50-336

ATTACHMENT 2

MARKED-UP TECHNICAL SPECIFICATION PAGES

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

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~~,~~ ;

~~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,~~

Insert A

~~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;

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;

f. The results of any SG secondary side inspections;

6.26 STEAM GENERATOR (SG) PROGRAM

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.

    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~~ 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.

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ATTACHMENT 3

MILLSTONE UNIT 2 STEAM GENERATOR INTEGRITY CONDITION MONITORING AND OPERATIONAL ASSESSMENT REFUELING OUTAGE (2R24)

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

Millstone Unit 2 Steam Generator Integrity Condition Monitoring and Operational Assessment

Refueling Outage (2R24)

April 2017

Revision 0

Total Pages: 38
(Including this page and attachments)

Preparer: [redacted] Date: 4/22/17

Preparer: [redacted] Date: 4/22/17

Reviewer: [redacted] Date: 4-24-17

Independent Reviewer: [redacted] Date: 4-24-17

Cross Discipline Reviewer: [redacted] Date: 4/27/17

Engineering Approval: [redacted] Date: 4-27-17

Management Approval: [redacted] Date: 4-27-17

Table of Contents

1. Executive Summary

This document evaluates the Millstone Unit 2 steam generator (SG) as-found condition (condition monitoring assessment) and the anticipated condition during the next operating period (operational assessment). This evaluation is based on the inspection activities performed in SG25 and SG26 during the 2R24 refueling outage. The condition monitoring (CM) assessment concludes that none of the three SG Program performance criteria were exceeded during the operating period prior to 2R24. The operational assessment (OA) concludes that there is reasonable assurance that operation of the Millstone Unit 2 SGs throughout the operating period preceding the next examination (up to three fuel cycles) will not cause any of the three performance criteria to be exceeded.

This evaluation was performed in accordance with the following Millstone and industry requirement documents:

- Millstone Technical Specifications (TS 6.26)
- Dominion fleet-wide steam generator (SG) program (Ref. [8.1])
- Dominion SG Condition Monitoring and Operational Assessment (CMOA) procedure (Ref. [8.2])
- EPRI Steam Generator Integrity Assessment Guidelines (IAG) (Ref. [8.7])
- April 2010 Interim Guidance on the IAG (Ref. [8.8])
- NEI 97-06 (Ref. [8.3])

Descriptions of specific SG activities performed during 2R24, and the degradation mechanisms targeted by the inspection program are provided in Section 3.0.

Key findings:

- Tube Degradation
  - The only tube degradation mechanisms detected were fan bar wear and foreign object wear
  - No degradation exceeded the 40 %TW technical specification plugging criteria
  - No indications of lattice support wear were reported
- Foreign Objects
  - A variety of foreign objects were located and removed from the SG secondary side
  - Some foreign objects could not be removed
- Tube Plugging
  - Plugging was not required or performed during the 2R24 outage
- Secondary Side Inspections
  - Identified no concerns relative to long-term performance and reliability

2. Introduction / Background

NEI 97-06 was developed to provide the industry with guidance and standards for assessing the structural and leakage integrity of steam generator tubes and to provide the basis for plant specific SG integrity programs. NEI 97-06 and the Millstone Unit 2 Technical Specifications (TS 6.26) establish three specific steam generator performance criteria:

- Structural Integrity – Margin of 3.0 against burst under normal steady state power operation and a margin of 1.4 against burst under the most limiting design basis accident. Additional requirements are specified for non-pressure accident loads.
- Operational Leakage – RCS operational primary-to-secondary leakage through any one steam generator shall not exceed 150 GPD.
- Accident Induced Leakage – Leakage shall not exceed the value assumed in the limiting accident analysis (150 GPD per SG).

This Technical Evaluation constitutes a condition monitoring and operational assessment of each tube degradation mechanism identified during the 2R24 primary and secondary side inspections. The CM assessment is performed to verify that the condition of the tubes, as reflected by the inspection results, meets the above performance criteria. Indications of degradation, if found, are evaluated to confirm that the safety margins against leakage and burst were not exceeded at the end of the previous operating cycle. The results of the condition monitoring evaluation are used as a basis for the OA which demonstrates that the anticipated performance of the steam generators, including any degraded tubes remaining in service, will not exceed the performance criteria for leakage and tube burst during the next operating period.

A pre-outage Degradation Assessment (Ref. [8.4]) was performed to identify existing degradation mechanisms as well as degradation mechanisms which could potentially occur in the near term within the Millstone Unit 2 steam generators. The assessment also identified the appropriate inspection scope, techniques to be utilized during the subject inspection, and applicable detection and sizing information for the identified degradation mechanisms. The 2R24 inspections were performed in accordance with the Degradation Assessment.

All of the acquired eddy current data was analyzed by two independent analysis paths: manual primary analysis and secondary computerized analysis (ZETEC RevospECT). All results were passed through a resolution process. Any discrepancies between the two analysis teams were resolved by a third team of analysts (primary and secondary resolution analysts). The BWXT Lead Level III coordinated the analysis process and provided additional analysis expertise as required. The Dominion ET Level III and an Independent Qualified Data Analyst (IQDA), a role defined within the EPRI PWR SG Examination Guidelines (Ref. [8.5]), served in oversight roles. The inspections were performed per the requirements of Ref. [8.5] and all inspection techniques utilized for degradation detection and/or sizing were qualified per these guidelines.

The Millstone Unit 2 Analysis Reference Manual (Ref. [8.6]), updated and approved prior to commencement of the inspection, served as the principal guidance document for data evaluation. As with past practice, Millstone Unit 2-specific examination technique summary sheets (ETSS) were used in conjunction with Ref. [8.6] to summarize instructions relative to acquisition and analysis setups and analysis screening parameters.

The naming convention of the steam generators in this report has been changed from what has been used in recent outages. The naming convention has been inconsistent in the past and this has caused some confusion among the various Dominion and vendor organizations. In recent outages, the steam generators have been called SG1 and SG2 in the various reports including the CMOA. The steam generators are now designated as SG25 (formerly SG1) and SG26 (formerly SG2). These designations are consistent with the original manufacturing naming convention.

3. Scope of Activities, Evaluated Degradation Mechanisms, Tube Plugging

3.1 Scope of Activities

The SG activities planned for 2R24 were described in the Degradation Assessment (Ref. [8.4]) and are summarized below.

3.1.1 Primary Side

The following primary side activities were performed in SG25 and SG 26 during the 2R24 outage.

- Visual examination of both channel heads (as-found / as-left), specifically including the divider plate / tubesheet interface, and previously installed tube plugs.
- Eddy current bobbin probe and rotating +Point™ probe examinations as described in Table 3-1. Table 3-1 provides a breakdown of the actual number of primary side tube examinations performed during the outage including additional tests necessary to bound foreign objects and to address unresolved bobbin indications. Table 3-1 also summarizes the results of the examination.

3.1.2 Secondary Side

The following secondary side activities were performed in SG25 and SG26 during the 2R24 outage.

- Chemical cleaning of the secondary side using AREVA's Deposit Minimization Treatment (DMT) process
- High pressure sludge lancing.
- Post-sludge lancing visual examination of top-of-tubesheet annulus and no-tube lane to assess as-left material condition and cleanliness, and to identify and remove any retrievable foreign objects (FOSAR).
- Visual investigation of accessible locations having eddy current indications potentially related to foreign objects, and removal of retrievable foreign objects.
- Steam drum visual inspections to evaluate the material condition and cleanliness of key components such as moisture separators, drain systems, and interior surfaces.

Table 3-1
Millstone 2R24 ECT Summary

	SG25	SG26	Total
Number of Installed Tubes	8523*	8523	17046
Number of Tubes In Service Prior to 2R24	8504	8510	17014
Number of Tubes Inspected F/L w/Bobbin Probe**	8504	8510	17014
Previously Plugged Tubes	19*	13	32
Number of Tubes Incomplete w/Bobbin Probe due to Obstruction	0	0	0
Number of Exams with +Point™ (Total)	2623	2702	5325
•Hot Leg Tubesheet TSH +3/-3 Periphery	1256	1269	2525
•Hot Leg Tubesheet PTE	1	0	1
•Hot Leg Tubesheet 01HTSH	3	7	10
•Hot Leg Tubesheet PLP Bounding	18	49	67
•Cold Leg Tubesheet TSC +3/-3 Periphery	1245	1253	2498
•Cold Leg Tubesheet 01CTSC	0	4	4
•Cold Leg Tubesheet TSC +10/-3	11	0	11
•Cold Leg Tubesheet PLP Bounding	22	30	52
•Hot Leg Special Interest	34	39	73
•U-Bend Special Interest	7	5	12
•Cold Leg Special Interest	6	11	17
•Hot Leg Additional RPC	20	22	42
•Cold Leg Additional RPC	0	13	13
Tubes with Max FB Wear ≥ 40 %	0	0	0
Tubes with Max FB Wear ≥20% but <40%	0	0	0
Tubes with Max FB Wear <20%	2	2	4
Tubes with Max SVI / VOL / WAR≥ 40 %	0	0	0
Tubes with Max SVI / VOL / WAR≥20% but <40%	1	13	14
Tubes with Max SVI / VOL / WAR<20%	0	2	2
Total Tubes Plugged as a Result of this Inspection	0	0	0

* One tubesheet location in SG25 (R57 C156) was not drilled in the cold leg tubesheet. The hot leg hole for this tube was plugged with a welded plug. Although this location was never tubed, it is included in the counts of installed tubes and plugged tubes.

** A number of tubes were examined in hot leg / cold leg segments to achieve full length coverage.

3.2 Evaluated Degradation Mechanisms

Prior to this outage, only fan bar wear and foreign object wear had been identified in the MP2 SGs, therefore these degradation mechanisms were the only mechanisms classified in the DA (Ref. [8.4]) as "existing." As discussed in Ref. [8.4], one other mechanism was classified as "potential" (lattice support wear). It is primarily "existing" and "potential" damage mechanisms that were targeted by the 2R24 inspection.

It is a requirement of the Millstone SG program that all tube locations identified as currently experiencing (i.e., "existing") or potentially susceptible to degradation (i.e., "potential"), be examined with qualified NDE techniques within specific time periods. These periods are prescribed in TS 6.26.d.2. The first inspection period of the MP2 SGs had a duration of 144 EFPM and ended after the 2R20 outage. The second inspection period has a duration of 120 EFPM and started during Cycle 21. This was the third steam generator inspection in the second inspection period, but was the second inspection of each SG.

Table 3-2 summarizes the examinations performed to date and their compliance with the inspection period requirements. For example, in the table an entry of 200 indicates that "200%" of the tubes were examined within the second period. More succinctly, it means that each tube was examined at least twice within the given period. As shown in the table, all tubes were inspected at least four times time during the first period. In addition, all in-service tubes have already been inspected twice during the second inspection period thus meeting the minimum sampling requirements for the second inspection period.

3.3 Tube Plugging

Based on the inspection results, tube plugging was not required or performed during the 2R24 outage. Table 3-3 provides a summary of the MP2 tube plugging to date.

Table 3-2 – Summary of SG Inspection Sampling Through the 2R24 Outage (TS 6.26)

Degradation Mechanism			FO Wear (potential)		Lattice Support Wear (potential)		FB Wear (potential)	
Location Affected			TSH to TSC		Support Intersections		FB Intersections	
Number of Tubes in Susceptible Region			8,523		8,523		8,523	
Principal ECT Probe for Detection			Bobbin[A]		Bobbin		Bobbin	
Steam Generator			SG25	SG26	SG25	SG26	SG25	SG26
Outage	Date	SG EFPM Since Period Start	CUMULATIVE SAMPLE EXAMINED **(PERCENT)**					
2R12	Oct-94	0.0	29	28	29	28	29	28
Mid Cycle 13	Jun-97	6.0	100	53	100	53	100	53
2R13	Apr-00	16.0		153		153		153
2R14	Mar-02	35.8	200		200		200	
2R15	Oct-03	52.7		253		253		253
2R16 (mid-period)	Apr-05	68.6	300		300		300	
2R17	Oct-06	84.8						
2R18	Apr-08	101.3	400	353	400	353	400	353
2R19	Oct-09	116.9						
2R20 (last in period)	Apr-11	133.0	500	453	500	453	500	453
2R21	Oct-12	5.0						
2R22	Apr-14	21.1		100		100		100
2R23	Oct-15	37.5	100		100		100	
2R24	Apr-17	54.0	200	200	200	200	200	200

A) FO and FO wear detection is augmented with secondary side visual exams and top of tubesheet (TTS) +Point/Array probe sampling.

Table 3-3 – Millstone SG Tube Plugging Attributes

DATE	Preservice 2R11		Oct-94 2R12		May-97 MCO13		Jun-00 2R13		Feb-02 2R14		Oct-03 2R15		Apr-05 2R16		Oct-06 2R17		Apr-08 2R18		Oct-09 2R19		Apr-11 2R20		Oct-12 2R21	
SG EFPY	0.0		1.3		1.8		2.6		4.3		5.7		7.0		8.4		9.8		11.1		12.4		13.7	
SG ID	25	26	25	26	25	26	25	26	25	26	25	26	25	26	25	26	25	26	25	26	25	26	25	26
FO Wear ≥40 %TW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0
Unretrieved FO with or w/o Wear <40 %TW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	0	0	10	11	0	0
FO Wear <40 %TW w/o FO Present	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	0	0	0
Lattice Support Wear & Fan Bar Wear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inspectability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	2	0	0	10	11	0	0
TOTAL	1		0		0		0		0		0		0		0		10		0		21		0	

DATE	Apr-14 2R22		Oct-15 2R23		Apr-17 2R24		Oct-18 2R25		Total per SG	
SG EFPY	15.1		16.4		17.8					
SG ID	25	26	25	26	25	26	25	26	25	26
FO Wear ≥40 %TW	0	0	0	0	0	0			2	0
Unretrieved FO with or w/o Wear <40 %TW	0	0	0	0	0	0			11	13
FO Wear <40 %TW w/o FO Present	0	0	0	0	0	0			5	0
Lattice Support Wear & Fan Bar Wear	0	0	0	0	0	0			0	0
Inspectability	0	0	0	0	0	0			0	0
Other	0	0	0	0	0	0			1	0
Sub-Total	0	0	0	0	0	0	0	0	19	13
TOTAL	0		0		0		0		32	

Total Plugging by Category

2	FO Wear >40 %TW
24	Unretrieved FO with or w/o Wear <40 %TW
5	FO Wear <40 %TW w/o FO Present
0	Lattice Support Wear & Fan Bar Wear
0	Inspectability
1	Other

☐ SG Inspected

4. Inspection Results

This section provides the results of both the primary and secondary side inspections performed during the 2R24 outage. In general, only the specific results that relate to the condition monitoring assessment and the operational assessment will be discussed herein. The implications of these results with respect to the CMOA are discussed in Sections 5.0 and 6.0, respectively.

4.1 Channel Head inspections

The hot and cold leg channel heads stay well welds and divider plate welds were visually examined in SG25 and SG26 prior to the installation of eddy current probe manipulators. The examination revealed no evidence of divider plate or staywell weld degradation, and no foreign objects were identified.

Plug visual examinations were performed on all previously installed plugs in SG25 and SG26. No indications of plug degradation, leakage, or misplacement were identified.

4.2 Primary Side Tube Inspections

The primary side inspection scope was performed, and a brief tally of the number of indications reported is provided in Section 3.1.1 and Table 3-1. Results of potential significance to SG integrity are discussed in this section. Table 4-1 identifies all indications of tube degradation identified during the 2R24 examination.

4.2.1 Inspectability Issues

No indications of signal interference prevented the effective examination of tube regions planned for examination during 2R24.

4.2.2 Geometric Discontinuities

Dents (DNTs), bulges (BLGs), and tubesheet overexpansions (OXPs and OVRs) result in elevated residual stresses and, in susceptible tube materials, have been implicated in the development of stress corrosion cracking (SCC). Although SCC is not considered to be a potential degradation mechanism in the MP2 A690TT tubing, sampling inspections of these geometric discontinuities with +Point probes were performed during 2R24. None of these examinations revealed tube degradation associated with the discontinuities.

4.2.3 Fan Bar Wear

The primary examination technique for fan bar wear detection and sizing is the bobbin coil probe (ETSS 96041.3). A total of four fan bar wear indications in four tubes were reported during the examination; two indications in each SG (Table 4-1). All four have been reported during previous outage inspections

Table 4-1 – 2R24 Tube Degradation Summary

SG	Row	Col	Location	ETSS	Axial Length (in)	Circ Length (in)	Maximum Depth 2R24	Depth Reported Prior Outage	Initially Reported	Signal Present Prior to Current Outage?	Cause	Foreign Object Remaining?	In-Situ Tested?	Plugged & Stabilized?
25	40	155	F06 - 1.76"	96041.3	3.15*	N/A	13% TW	12% TW 2R23	2R14	Yes	Fan Bar Wear	N/A	No	No
25	140	93	F08 - 0.66"	96041.3	3.15*	N/A	19% TW	14% TW 2R23	2R14	Yes	Fan Bar Wear	N/A	No	No
25	92	143	TSH + 10.91"	27901.1	0.24	0.37	23% TW	NDD 2R23	2R24	Yes	Foreign Object Wear	No	No	No
26	28	5	TSC + 21.65"	27901.1	0.28	0.43	25% TW	27% TW 2R22	2R15	Yes	Foreign Object Wear	No	No	No
26	29	4	TSC + 22.2"	27901.1	0.27	0.43	26% TW	25% TW 2R22	2R18	Yes	Foreign Object Wear	No	No	No
26	37	120	F07 - 0.83"	96041.3	3.15*	N/A	12% TW	8% TW 2R22	2R15	Yes	Fan Bar Wear	N/A	No	No
26	44	5	TSC + 17.91"	27902.1	0.43	0.38	10% TW	11% TW 2R22	2R20	Yes	Foreign Object Wear	No	No	No
26	59	10	TSC + 17.33"	27901.1	0.38	0.43	23% TW	24% TW 2R22	2R15	Yes	Foreign Object Wear	No	No	No
26	98	143	TSH + 8.76"	27901.1	0.33	0.37	20% TW	20% TW 2R22	2R18	Yes	Foreign Object Wear	No	No	No
26	99	80	F06 + 1.28"	96041.3	3.15*	N/A	13% TW	15% TW 2R22	2R15	Yes	Fan Bar Wear	N/A	No	No
26	118	41	TSH + 12.81"	27902.1	0.48	0.37	12% TW	12%TW 2R22	2R18	Yes	Foreign Object Wear	No	No	No
26	119	42	TSH + 12.97"	27903.1	0.38	0.43	29% TW	24% TW 2R22	2R18	Yes	Foreign Object Wear	No	No	No
26	122	123	TSH + 2.53"	27901.1	0.33	0.54	34% TW	NDD 2R22	2R24	No	Foreign Object Wear	No	No	No
26	123	46	TSH + 18.15"	27903.1	0.23	0.37	25% TW	22% TW 2R22	2R15	Yes	Foreign Object Wear	No	No	No
26	124	45	TSH + 19.27"	27903.1	0.38	0.32	31% TW	26% TW 2R22	2R18	Yes	Foreign Object Wear	No	No	No
26	124	123	TSH + 1.77"	27901.1	0.38	0.43	36% TW	NDD 2R22	2R24	No	Foreign Object Wear	No	No	No
26	125	48	TSH + 19.53"	27903.1	0.33	0.43	36% TW	32% TW 2R22	2R15	Yes	Foreign Object Wear	No	No	No
26	125	122	TSH + 1.36"	27902.1	0.53	0.37	23% TW	NDD 2R22	2R24	No	Foreign Object Wear	No	No	No
26	126	49	TSH + 19.97"	27903.1	0.49	0.48	39% TW	34% TW 2R22	2R15	Yes	Foreign Object Wear	No	No	No
26	128	107	TSH + 0.06"	27901.1	0.28	0.37	26% TW	29% TW 2R22	2R20	Yes	Foreign Object Wear	No	No	No

* Conservative assumed length

4.2.4 Foreign Objects and Foreign Object Wear

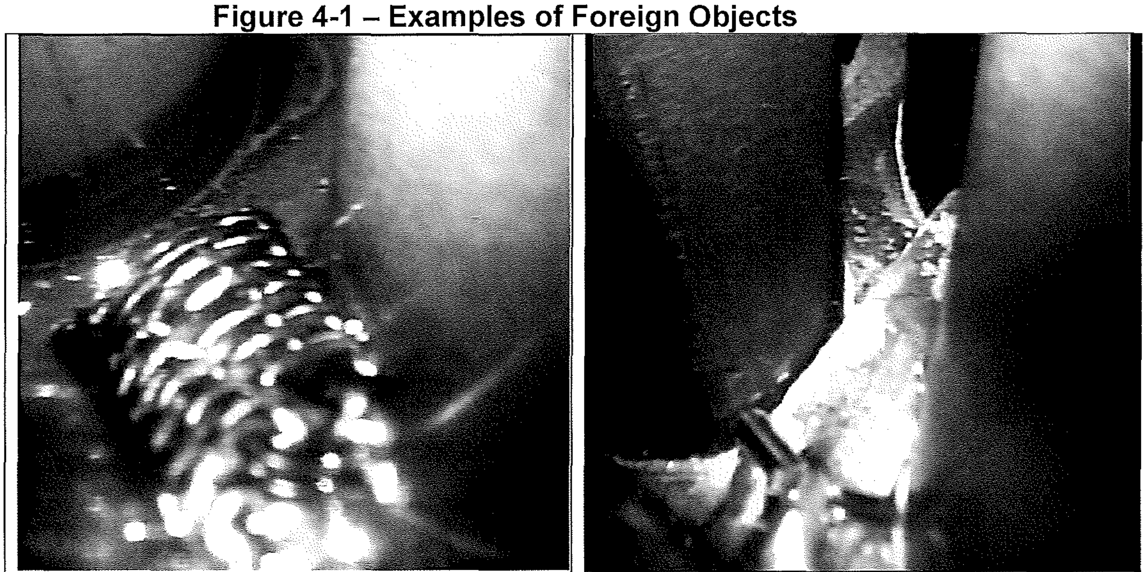
One of the most significant potential threats to tube integrity found during 2R24 was foreign object (FOs). This section provides a discussion of the FO degradation mechanism for 2R24.

A comprehensive approach was applied to foreign objects or foreign object wear during 2R24. The BWXT Loose Parts Tracker (LPT) database contains information on foreign objects detected by either eddy current or by visual examination techniques during 2R24. Prior to the 2R23 examination, the AREVA Foreign Objects Tracking System (FOTS) database for the Millstone Unit 2 SGs was used to develop a list of any foreign object locations that required evaluation during the examination. Based on history and the potential for wear, the appropriate examination scope was planned and documented in the DA.

The +Point™ probe was used to perform a 50% examination of the outer 6 rows of the hot and cold leg periphery and open tube lane. Since foreign objects normally contact more than a single tube, the +Point™ probe examination provided an improved probability of detecting foreign objects or foreign object wear within this band. Due to the tube spacing in the tri-pitch steam generator, few foreign objects are capable of traveling more than a few rows into the tube bundle. The cross flow velocity of the incoming feedwater, and consequently the potential for foreign object wear, is also highest within this zone. Compared to the bobbin exam, the +Point examination provides a significant improvement in the probability of detection of foreign objects that are most likely to cause wear and FO wear within this region.

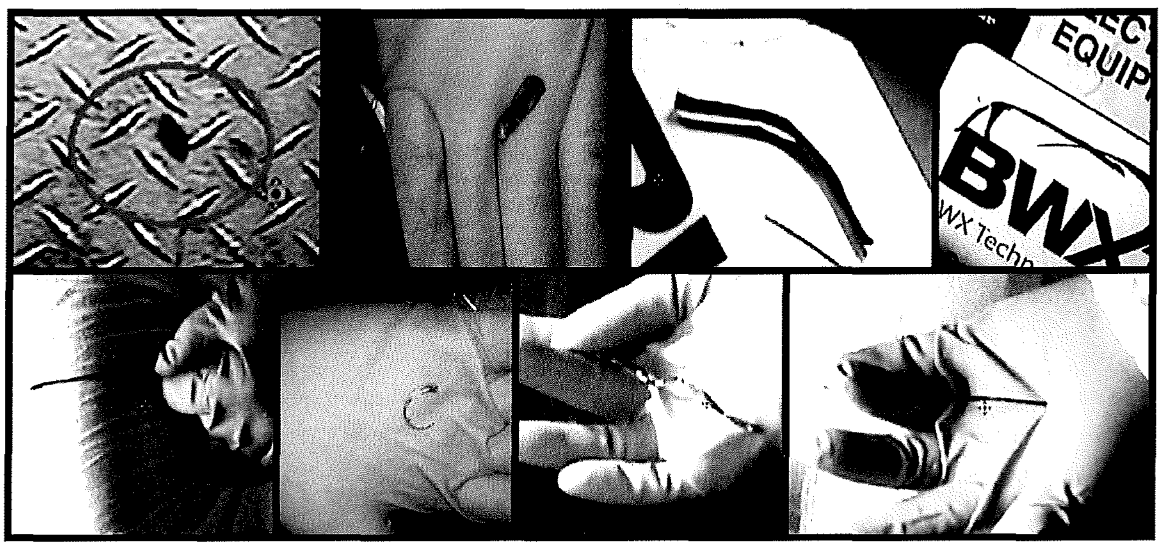
During the 2R24 examination, any new confirmed Possible Loose Part (PLPs), PLP related indications, or new FO wear indications reported by the eddy current examination were investigated by the Secondary Side Inspection (SSI) crew as far as possible and any new objects identified by SSI within the tube bundle region were tested by the +Point™ eddy current technique. When possible the FO's were removed by Foreign Object Search and Retrieval (FOSAR). The combined examinations were coordinated through the use of the LPT database. Some of the foreign objects identified during this inspection are shown in Figure 4-1 while Figure 4-2 shows foreign objects that were removed.

Figure 4-1 – Examples of Foreign Objects



Wire Screen	Metallic Object

Figure 4-2 –Foreign Objects Retrieved



Attachment 1 and 2 contain a full listing of the historical and emergent foreign object items addressed in SG 25 and SG26, respectively, during 2R24. A wide range of cases were addressed as will be presented below.

4.2.5 Summary of Foreign Object Wear

A comprehensive program was defined for detection of foreign objects and foreign object wear. This program consisted of planned examinations for known locations, a 50% examination of the outer six rows with the +Point™ probe, a 100% bobbin coil examination, bounding examinations with +Point™, SSI of the top of tubesheet annulus and bundle periphery and FOSAR as required.

Per Table 4-1, SG 25 had one tube wear location that was newly detected with a wear depth of 23% in tube R92 C143, located approximately 11" above the hot leg tubesheet.

- A review of previous bobbin data indicates that this wear has been present in this tube since 1997; however, this was the first time that a +Point probe had been used at this location.
- One tube adjacent to this tube, R90 C143, and a tube adjacent to that tube but not adjacent to the worn tube, R89 C144, both contained PLP indications at a similar elevation to the wear indication on R92 C143, but neither tube had any indications of wear identified by +Point™ coil. A review of previous +Point™ and bobbin data in these two tubes indicates that this loose part has been present at this location since 2008.
- A review of the location by SSI confirmed the presence of the part between R90 C143 and R89 C144. However, it could not be accessed for removal.
- Since the wear indication has been present since 1997, and the nearby PLP has been present since 2008 with no movement or initiation of wear in the associated tubes, this object does not represent a threat to tube integrity over the next three cycles.

Also per Table 4-1, SG 26 had 12 previously reported foreign object wear locations with no significant change in sized depth from 2R22. SG 26 also reported three new wear locations in R122 C123 (34% TW), in R124 C123 (36% TW) and in R125 C122 (23%tw). None of these locations had an indication of a foreign object and FOSAR found no part at any of these locations.

With no growth continuing in the historical foreign object wear locations and no part at the new foreign object wear locations, these tubes do not represent a threat to tube integrity over the next three cycles. The combination of the 100% bobbin coil examination of the full tube bundle, the +Point™ examination of the outer six rows of the periphery and open tube lane and the SSI examination of the tubesheet annulus and periphery, there is reasonable assurance that there are no currently existing parts within the tube bundle high flow region that could threaten tube integrity over the next three cycles.

4.2.6 Inspection Result Classification Category

The inspection results from SG 25 and SG26 were classified as category C1 per Section 3.7 of the Examination Guidelines (Ref [8.5]) with respect to fan bar wear. Specifically, there were no fan bar wear indications equal to or greater than 40 %TW and no previously reported fan bar wear indications grew more than 10%TW since the last inspection (Table 4-1). Less than 5% of the inspected tubes were degraded by fan bar wear.

Similarly, the inspection results for SG 25 and SG 26 were classified as C1 with respect to foreign object wear. Specifically, there were no foreign object wear indications equal to or greater than 40 %TW and no previously reported foreign object wear indications grew more than 10%TW since the last inspection (Table 4-1). Less than 5% of the inspected tubes were degraded by foreign object wear.

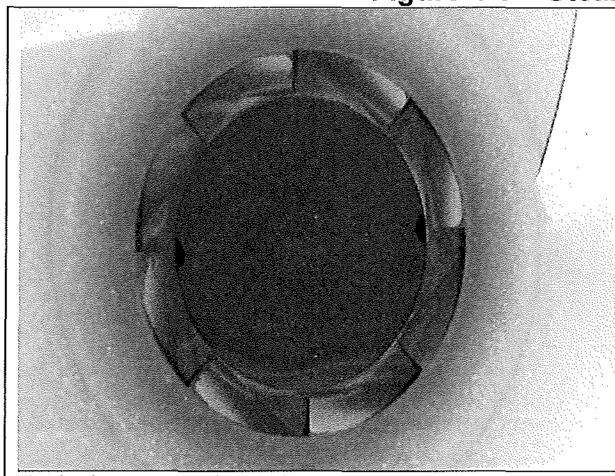
4.3 Secondary Side Inspections

Secondary side structures and material conditions must be evaluated to assess any potential impact on SG tube integrity. Any foreign objects, or degradation of internals that could produce foreign objects, are important because tube integrity could be impacted. Visual examinations were performed during this outage to develop the information needed for the evaluation. FOSAR results of potential significance to tube integrity were discussed above in Section 4.2.4. This section provides an overall summary of observations made during the secondary side examination.

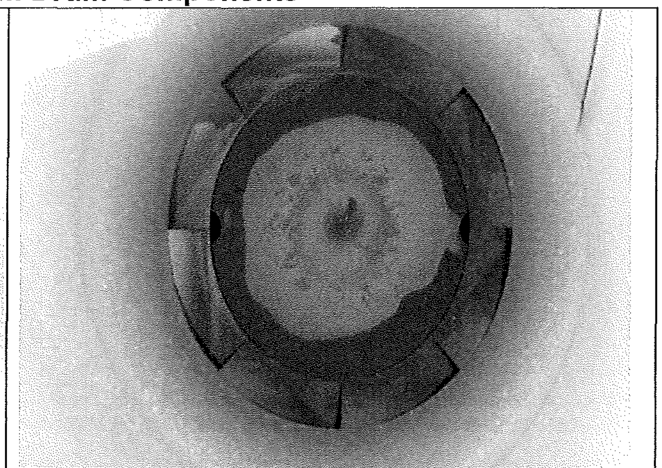
4.3.1 Steam Drum

A visual examination of steam drum components was performed in SG25 and SG26. In the areas examined, sludge accumulation was light, with a harder underlying crystalline coating of sludge noted. Due to water clarity issues following refill after DMT, visual inspection of the U-bend structures (arch bars, J-tabs and fan bars) was not possible. Sludge deposits on the primary and secondary moisture separators were light and tightly adhering. Very little deposit was removed from these surfaces when rubbed with a gloved hand. The primary separators examined were in good condition with no evidence of material degradation. The curved arm assemblies within the primary separators were inspected and found to be in good condition. The edges of the steam outlet to the assemblies were sharp, indicating no noticeable flow assisted corrosion. Evidence of early stage flow assisted corrosion of the secondary moisture separators was noted. Severe degradation of these separators can eventually lead to the introduction of loose parts that may migrate to the tube bundle. However, there was no evidence that this degradation has reached any significant depth in SG25 or SG26, and it will not progress to a state where loose parts could be introduced to the SGs over the next three cycles of operation. This condition should be monitored during future outages.

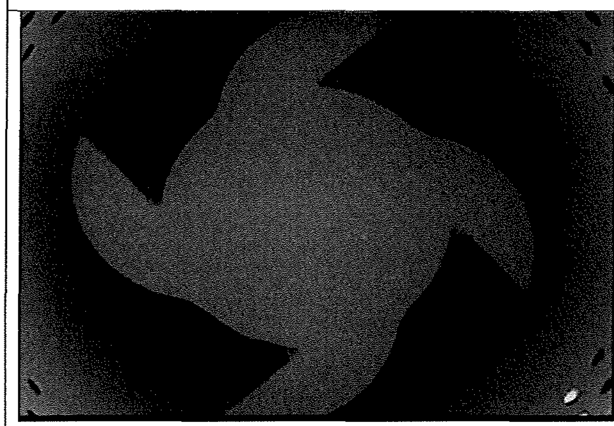
Figure 4-3 – Steam Drum Components



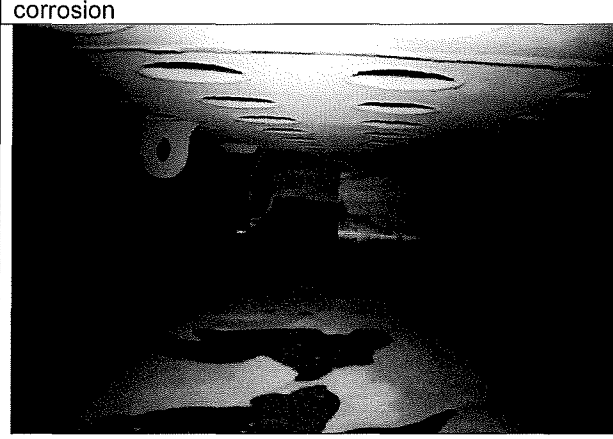
Typical separator baseplate



Separator baseplate with early stage flow assisted corrosion



Typical curved arm primary separator



Underside of primary deck

4.3.2 Top of Tubesheet Cleanliness

Post-lancing visual examinations in SG25 and SG26 identified no loose sludge in the annulus at the top of tubesheet. The no-tube lane and staywell regions were clear as well. The blowdown flow holes in the tubesheet showed no evidence of flow induced erosion. Due to the application of DMT, a total of 2608 pounds of deposit was removed from SG 25 and a total of 2584 pounds of deposit was removed from SG 26 (See Table 4-2). The 1st support lattice, shroud, and shroud support components examined were in good condition. Jacking studs showed no indication of movement between the shell and shroud. (See Figure 4-4)

Table 4-2 DMT Deposit Removal Quantities

		Fe Step	Pass Step	Cu Step	LVRs/FVR	TOTALS
SG 25	Magnetite Removed (lbs)	1442	291	213	16.1	1963
	Cu Removed (lbs)	0.6	3.3	11.6	0.7	16.2
	Lancing (lbs)					629
	Total (lbs)					2608.2
SG 26	Magnetite Removed (lbs)	1442	291	213	16.1	1963
	Cu Removed (lbs)	0.6	3.3	11.6	0.7	16.2
	Lancing (lbs)					605.5
	Total (lbs)					2584.7
	Grand Total (lbs)					5192.9

There was a light dusting of sludge noted in the annulus of both SGs. Discoloration of the outer surface of most tubes was noted. This was attributed to the application of DMT, and does not represent a deleterious condition. The no-tube lane and staywell area was clean and the blowdown flow holes showed no evidence of erosion. The 1st support lattice, shroud, and shroud support components examined were in good condition with no evidence of material degradation. Jacking studs showed no indication of movement.

4.4 Summary

Consistent with expectations documented in the DA (Ref. [8.4]), the only conditions of potential significance to SG integrity identified during the 2R24 SG examinations were secondary side foreign objects, foreign object tube wear, and fan bar tube wear. The significance of these findings with respect to the condition monitoring assessment and operational assessment are discussed in the sections that follow.

Figure 4-4 – Lower Bundle Components

Typical Top of Tubesheet	1st Lattice Components

5. Condition Monitoring Assessment

The condition monitoring (CM) assessment is an evaluation of tube structural and leakage integrity during the operating period since the last inspection. The CM is based on current inspection results. As discussed in Section 4.0 and presented in Table 4-1, the modes of tube degradation detected were foreign object wear and fan bar wear. The sizing techniques used to determine the dimensions of the flaws listed in Table 4-1 are also identified in the table. The sizing performance of the techniques, along with the reported flaw dimensions were used to evaluate the structural integrity of the tubes.

A review of the screening guidance of Ref. [8.7] provides the basis for concluding that non-pressure accident loads are not limiting for MP2 degradation located beyond the constraint of the tubesheet. The reference states that circumferential degradation and the circumferential component of volumetric degradation is limiting with respect to non-pressure loads and advises that non-pressure loads are not significant contributors to burst for tubes with flaws that are below the top tube support and which are less than 270° in circumferential extent, or for flaws located on the tube flanks within the u-bend (e.g., fan bar wear). All flaws identified during this outage, meet this criteria and therefore it is appropriate to use the EPRI Flaw Handbook (Ref. [8.9]) methods, which consider pressure loading only, to establish the structural limits for all of the MP2 tube degradation identified.

To perform the CM for fan bar wear and foreign object wear, the limiting degradation size must be compared with an appropriate structural integrity limit which accounts for the material property uncertainty, model uncertainties and NDE sizing uncertainties. Since the circumferential extent of all of the indications listed in Table 4-1 can be shown to be <135°, it is appropriate to use the EPRI Flaw Handbook (Ref. [8.9]) "Part-Throughwall Axial Volumetric Degradation" flaw model to evaluate the CM limit. Using this model as implemented by the EPRI FHC (Ref. [8.10]), CM limit curves were developed in the Degradation Assessment [8.4] for each flaw type and sizing ETSS.

Figures 5-1 through 5-4 provide the CM limit curves for flaws sized with ETSSs 96004.3, 27901.1, 27902.1, and 27903.1 respectively. The CM curves represent the structural performance criteria derived by conservatively accounting for material property uncertainties, model uncertainties, and NDE depth sizing uncertainties. The uncertainties were combined using Monte Carlo techniques as described in Ref. [8.7].

The figures also display the length and depth of each flaw. Because each flaw plotted in Figures 5-1 through 5-4 lies below the CM limit curve, it is concluded that the structural performance criteria set forth in the MP2 Technical Specifications was not exceeded by any of the evaluated flaws. This also provides reasonable assurance that none of these flaws would have leaked under accident conditions.

No primary-to-secondary SG tube leakage was reported during the previous operating period; therefore, the operational leakage performance criteria was not exceeded during the operating period preceding this outage.

5.1 Condition Monitoring Conclusion

Based upon the evaluations documented in this report, all degradation identified during the 2R24 inspection satisfied condition monitoring requirements for SG tube structural and leakage integrity. Further, the conditions observed during 2R24 also serve to validate the conclusions of all previous outage operational assessments with respect to projected compliance with technical specification SG performance criteria. Specifically, the 2R24 findings are consistent with the assumptions, expectations, and projections documented in previous operational assessments.

Figure 5-1

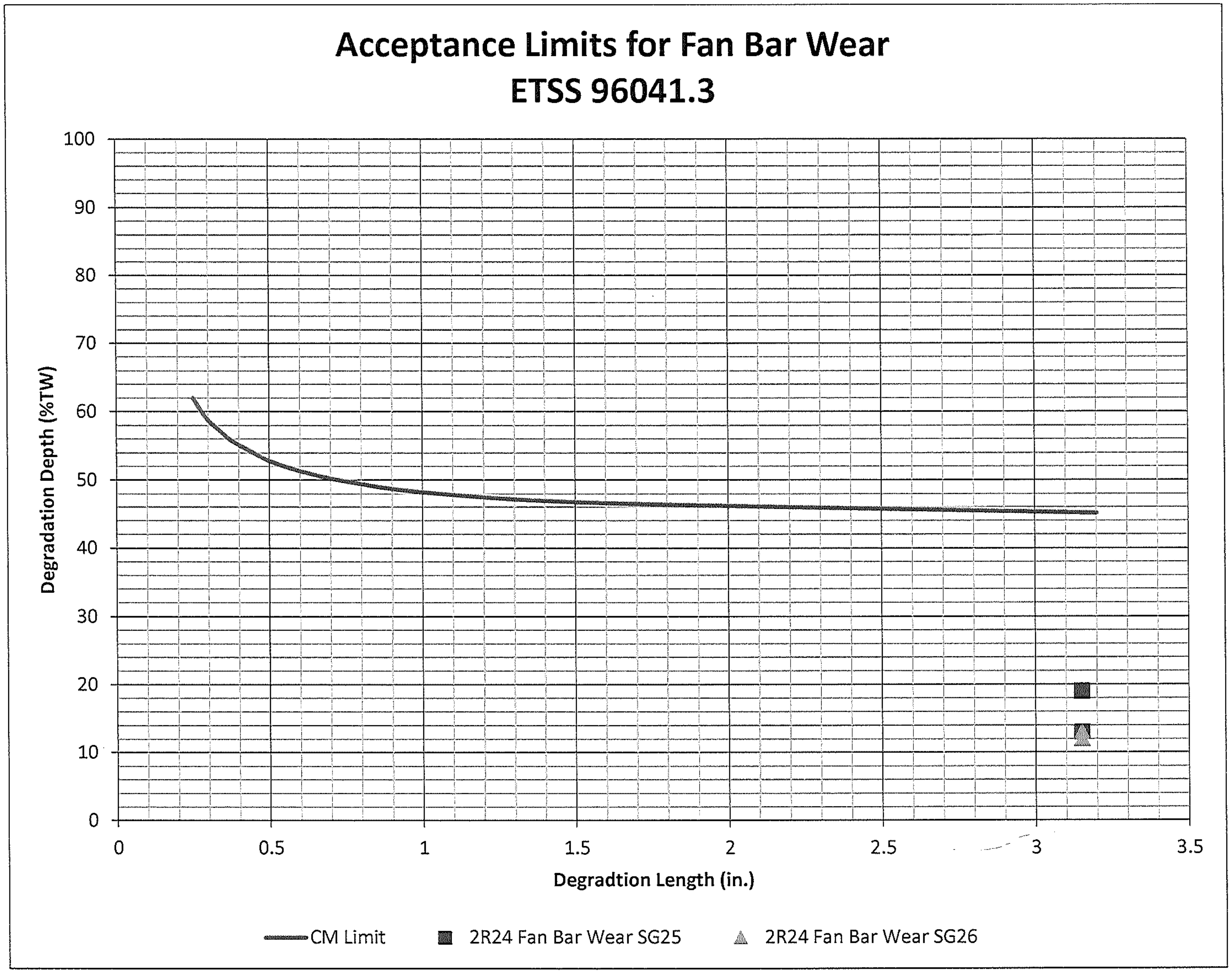

Acceptance Limits for Fan Bar Wear
ETSS 96041.3
Degradation Depth (%TW)
100
90
80
70
60
50
40
30
20
10
0
0
0.5
1
1.5
2
2.5
3
3.5
Degradtion Length (in.)
CM Limit
2R24 Fan Bar Wear SG25
2R24 Fan Bar Wear SG26

Figure 5-2

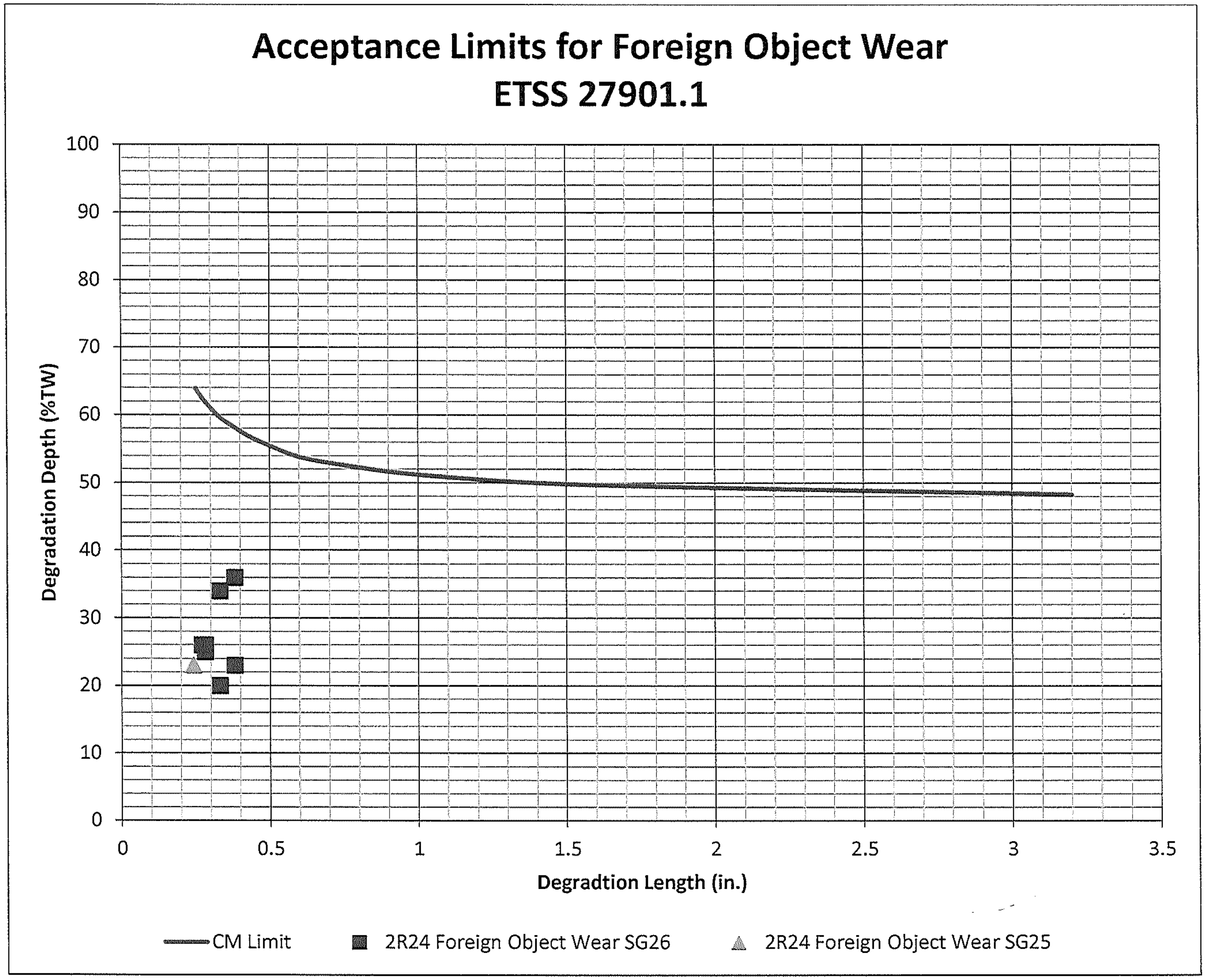

Acceptance Limits for Foreign Object Wear
ETSS 27901.1
Degradation Depth (%TW)
100
90
80
70
60
50
40
30
20
10
0
0
0.5
1
1.5
2
2.5
3
3.5
Degradtion Length (in.)
CM Limit
2R24 Foreign Object Wear SG26
2R24 Foreign Object Wear SG25

Figure 5-3

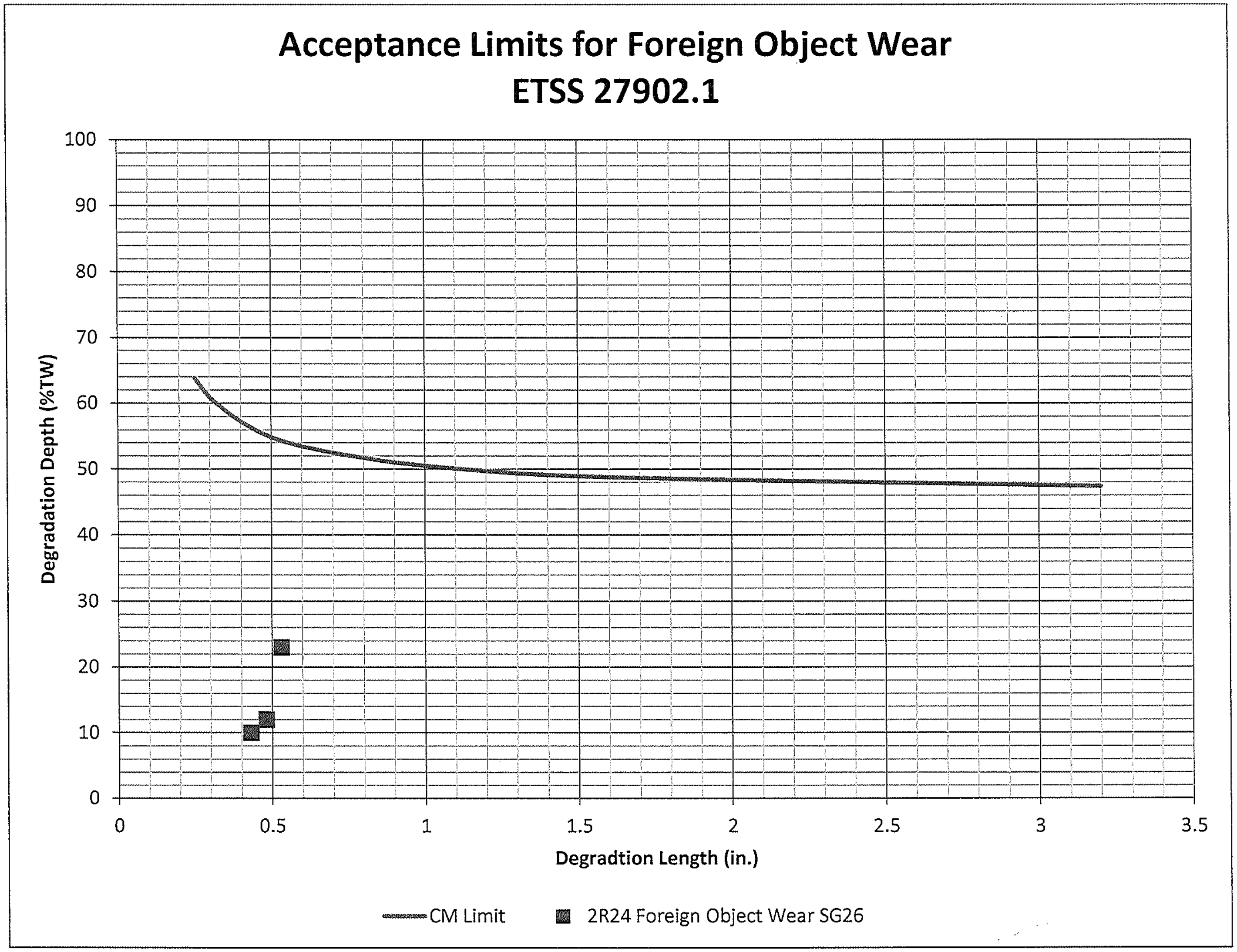
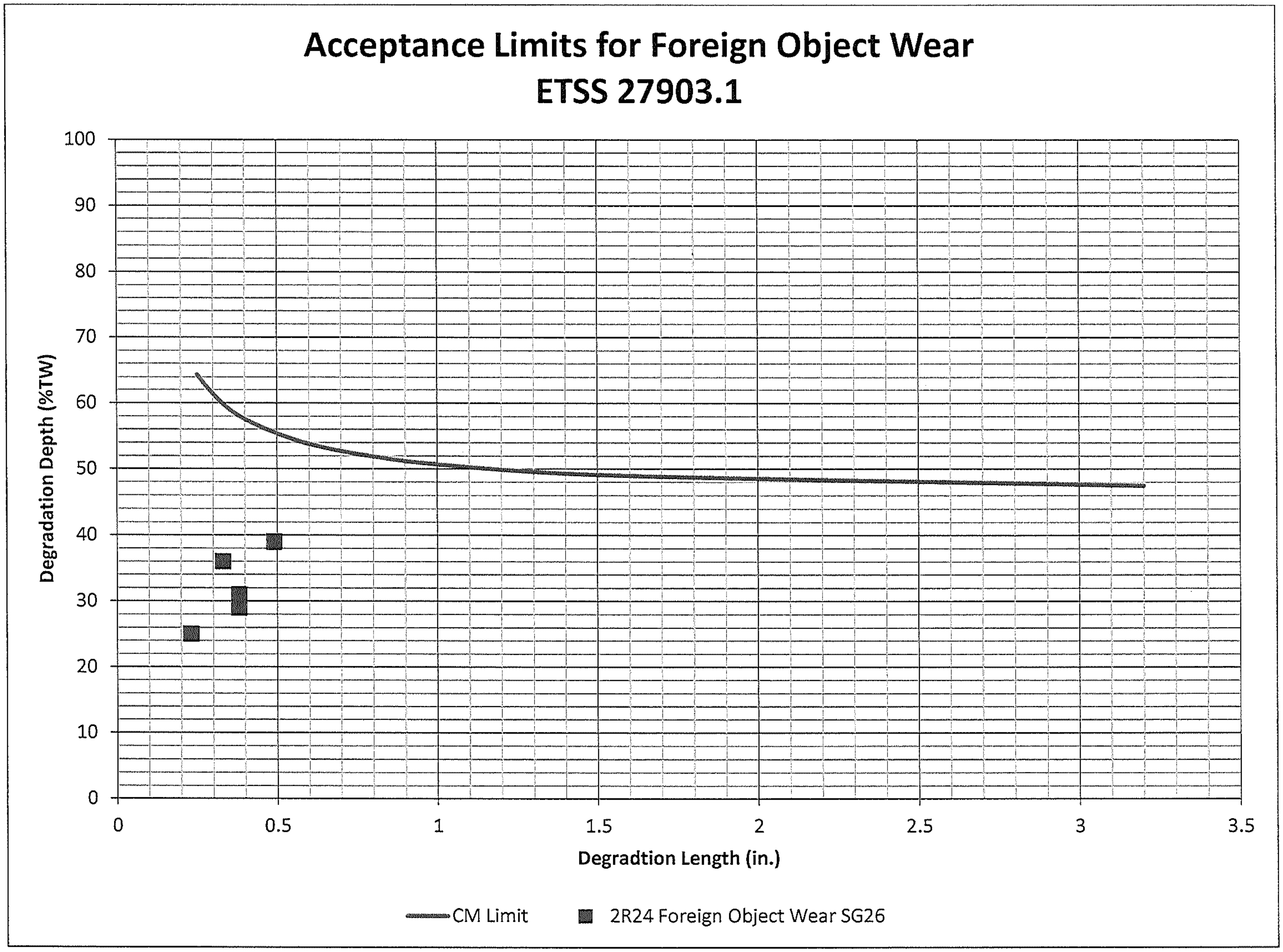

Acceptance Limits for Foreign Object Wear
ETSS 27902.1
Degradation Depth (%TW)
100
90
80
70
60
50
40
30
20
10
0
0
0.5
1
1.5
2
2.5
3
3.5
Degradtion Length (in.)
CM Limit
2R24 Foreign Object Wear SG26

Figure 5-4


Acceptance Limits for Foreign Object Wear
ETSS 27903.1
Degradation Depth (%TW)
100
90
80
70
60
50
40
30
20
10
0
0
0.5
1
1.5
2
2.5
3
3.5
Degradtion Length (in.)
CM Limit
2R24 Foreign Object Wear SG26

6. Operational Assessment

The operational assessment (OA) must demonstrate that the structural integrity performance criteria will not be exceeded prior to the next scheduled examination in either of the Millstone Unit 2 SGs. The MP2 technical specifications limit the period between inspections to a maximum of three fuel cycles for an individual SG. Hence, this OA evaluates the limiting operating interval (i.e., three fuel cycles) for both SGs based upon the current outage primary and secondary side inspection results. Per Table D-1 of the Degradation Assessment [8.4], the expected operating interval between 2R24 and 2R27 will be 46.6 EFPM or 3.9 EFPY. For this analysis, the three-cycle inspection interval will be conservatively assumed to be 4.2 EFPY.

Given the superior resistance of the A690TT tube material to corrosion and anticipated continued diligence in chemistry monitoring and control, there is minimal near term threat of corrosion initiation. Consistent with Ref. [8.7], this operational assessment addresses degradation mechanisms known to exist in the MP2 steam generators: fan bar wear and foreign object wear.

The first two subsections below assess future fan bar wear and foreign object wear against the structural performance criteria. The third subsection assesses future compliance with accident induced and operational leakage performance criteria and the fourth subsection considers secondary side internals degradation.

6.1 Fan Bar Wear

For the purposes of this OA, future fan bar wear can be grouped into two categories:

- Wear that currently exists in in-service tubes, whether detected during 2R24 or not
- Wear which will initiate during the next three fuel cycles.

Because wear which has already initiated will continue to grow, it is assumed to be more limiting in the future than wear which has not yet initiated. This evaluation will focus on wear flaws that have already initiated. This requires consideration of NDE sizing uncertainty, NDE probability of detection (POD), and the rate of future wear flaw growth.

6.1.1 Beginning of Cycle (BOC) Fan Bar Wear Depth

The beginning of cycle fan bar wear depth is an upper bound estimate of the depth of wear left in-service prior to the next operating interval. This value accounts for the fact that NDE techniques have an imperfect probability of detection, and must account for known flaws left in service following the tube inspection. Consistent with Ref. [8.7], Table 8-1, the most limiting BOC fan bar wear depth to be used in this analysis will be the largest flaw left in service. In the technique qualification program (ETSS 96041.3), all flaws, ranging in depth from 4 %TW to 90 %TW, were detected. Due to the high POD for fan bar wear detection, undetected flaws are not an issue for structural integrity.

The deepest fan bar wear indication returned to service measured 19%TW with a bobbin probe. As shown in Table A-1 of the Degradation Assessment [8.4], the NDE (Non-Destructive Examination) sizing parameters for the bobbin technique (ETSS 96041.3) are a slope of 0.99 and an intercept of 2.73%TW. Using the slope and intercept, a best estimate real depth of 21.5%TW (19 x 0.99 + 2.73) is obtained for an indication with a measured depth of 19%TW.

The standard error of 3.36%TW is the technique uncertainty only. Per the EPRI SG Integrity Assessment Guidelines [8.7], the analyst uncertainty can be assumed to be equal to one-half of the technique uncertainty. Combining the technique and analyst uncertainties using the "square root of the sum of the squares" method yields a combined standard error of 3.76%TW. Further adjusting this value upward to an upper 95th percentile gives an NDE uncertainty of 6.2%TW (3.76 x 1.645). Adding this uncertainty to the best estimate value of 21.5%TW yields a bounding real depth of 27.7%TW (21.5 + 6.2) returned to service.

6.1.2 Fan Bar Wear Growth

A summary of the growth rates for fan bar wear is provided in Table 6.1. The maximum growth rate observed from last inspections (SG26 in 2R22 or SG25 in 2R23) to 2R24 was 3.6%TW/EFPY. However, due to the low number of fan bar wear indications observed, a bounding estimate of 5 %TW/EFPY was used to evaluate the future impact of fan bar wear on SG integrity.

Table 6.1 – Fan Bar Wear Growth Rates

SG	Row	Col	Location	ETSS	Maximum Depth 2R24	Depth Reported Prior Outage	Cause	Delta %TW Growth	Delta EFPY	%TW Growth per EFPY
25	40	155	F06 - 1.76"	96041.3	13% TW	12% TW 2R23	Fan Bar Wear	1	1.375	0.7
25	140	93	F08 - 0.66"	96041.3	19% TW	14% TW 2R23	Fan Bar Wear	5	1.375	3.6
26	37	120	F07 - 0.83"	96041.3	12% TW	8% TW 2R22	Fan Bar Wear	4	2.74	1.5
26	99	80	F06 + 1.28"	96041.3	13% TW	15% TW 2R22	Fan Bar Wear	-2	2.74	-0.7

Applying a growth rate of 5.0%TW/EFPY over a three-cycle bounding inspection interval of 4.2 EFPY gives a total growth of 21.0%TW (5.0 x 4.2) until the next planned inspection. Further applying this total growth to the bounding real depth of 27.7%TW gives a projected 2R27 depth of 48.7%TW (27.7 + 21.0) for indications detected and returned to service in 2R24.

The allowable real depth (Structural Limit, SL) for fan bar wear with a bounding length of 3.20" is 50.2%TW as shown in the ETSS 96041.3 OD Axial Thinning Evaluation found in Appendix C of the Degradation Assessment [8.4]. Since the projected real depth of 48.7%TW is less than the allowable real depth of 50.2%TW, there is reasonable assurance that the structural integrity performance criterion will be met for this mechanism for the next three cycles of operation until 2R27.

6.2 Foreign Object Wear

Foreign object wear is the primary degradation mechanism of concern at Millstone Unit 2 based on previous plugging history. Although several new foreign object wear indications were reported during the 2R24 outage, many foreign objects were visually confirmed and removed. Many of these foreign objects were in locations where tube degradation is possible.

The 2R24 inspection scope for foreign objects and associated wear was extensive and included both visual and eddy current inspections. Visual inspections included both the annulus and no-tube lane at the top of the tubesheet in both steam generators. These visual inspections included looks into the tube bundle at all peripheral and no-tube lane locations. The eddy current examinations included full length bobbin probe examinations of all tubes, 50% rotating probe examinations of an approximate six tube deep periphery at the top of tubesheet (+/- 3 in) in both legs, and bounding rotating probe examinations of potential foreign object associated indications. All evidence of foreign objects and foreign object wear was tracked and evaluated in the BWXT Loose Parts Tracker (LPT), and objects were retrieved where possible. Tubes adjacent to irretrievable foreign objects had been stabilized and plugged during past outages. Consequently, no foreign objects capable of causing tube degradation are known to remain adjacent to in-service tubes. This aggressive ECT and FOSAR campaign has significantly reduced the potential for future foreign object wear. With these extensive inspections and subsequent part removal, there is reasonable confidence that no parts capable of causing significant tube degradation remain in the tube bundle.

Despite the extensive inspections and removal of multiple parts, the OA still has to consider the potential for tube degradation from parts remaining in the bundle or potentially entering the bundle during the next inspection interval. For the purposes of the OA, the discussion of foreign objects and associated wear will be segregated into the following categories:

1) foreign object wear without evidence of a part present,
2) eddy current PLPs (Potential Loose Parts) without wear,
3) foreign objects known to have remained in the steam generators, and
4) foreign objects that may enter the steam generators.

As discussed previously, the SG work activities performed during this refueling outage included secondary side visual inspections of the steam drum and upper tube bundle in SG25 and SG26. These examinations identified no foreign objects, or any conditions which could credibly generate foreign objects, capable of impacting tube integrity.

Based upon the following discussions, there is reasonable assurance that operation of SG25 and SG26 for three cycles will not generate foreign object wear flaws which exceed the structural integrity performance criteria.

6.2.1 Foreign Object Wear With No Part Present

The four new foreign object wear indications (maximum depth 36 %TW) identified during 2R24 were confirmed to have no foreign object remaining in the vicinity. A summary of the growth rates for new foreign object wear indications is provided in Table 6.2. Without the objects in-place continued degradation is not possible. Consequently, none of the new flaws in in-service tubes pose a future tube integrity threat.

Table 6.2 New Foreign Object Wear

SG	Row	Col	Location	ETSS	Maximum Depth 2R24	Depth Reported Prior Outage	Cause	Delta %TW Growth	Delta EFPY	%TW Growth per EFPY
26	122	123	TSH + 2.53"	27901.1	34% TW	NDD 2R22	Foreign Object Wear	34	2.74	12.4
26	124	123	TSH + 1.77"	27901.1	36% TW	NDD 2R22	Foreign Object Wear	36	2.74	13.1
26	125	122	TSH + 1.36"	27902.1	23% TW	NDD 2R22	Foreign Object Wear	23	2.74	8.4
25	92	143	TSH + 10.91"	27901.1	23% TW	NDD 2R23	Foreign Object Wear	23	1.375	16.7

The OA must also consider the growth of foreign object wear indications identified and left in service. Historical foreign object wear indications where the foreign objects had been previously removed were re-sized during 2R24 and were left in service. All of these historical indications are in SG 26. A summary of the growth rates for historical foreign object wear indications is provided in Table 6.3. Some variation in sizing can be expected from one inspection to the next. As expected, these indications exhibited virtually no growth as compared with previous outage sizing and considering technique sizing variability and uncertainty.

Table 6.3 Historical Foreign Object Wear Indications

SG	Row	Col	Location	ETSS	Maximum Depth 2R24	Depth Reported Prior Outage	Cause	Delta %TW Growth	Delta EFPY	%TW Growth per EFPY
26	28	5	TSC + 21.65"	27901.1	25% TW	27% TW 2R22	Foreign Object Wear	-2	2.74	-0.7
26	29	4	TSC + 22.2"	27901.1	26% TW	25% TW 2R22	Foreign Object Wear	1	2.74	0.4
26	44	5	TSC + 17.91"	27902.1	10% TW	11% TW 2R22	Foreign Object Wear	-1	2.74	-0.4
26	59	10	TSC + 17.33"	27901.1	23% TW	24% TW 2R22	Foreign Object Wear	-1	2.74	-0.4
26	98	143	TSH + 8.76"	27901.1	20% TW	20% TW 2R22	Foreign Object Wear	0	2.74	0
26	118	41	TSH + 12.81"	27902.1	12% TW	12%TW 2R22	Foreign Object Wear	0	2.74	0
26	119	42	TSH + 12.97"	27903.1	29% TW	24% TW 2R22	Foreign Object Wear	5	2.74	1.8
26	123	46	TSH + 18.15"	27903.1	25% TW	22% TW 2R22	Foreign Object Wear	3	2.74	1.1
26	124	45	TSH + 19.27"	27903.1	31% TW	26% TW 2R22	Foreign Object Wear	5	2.74	1.8
26	125	48	TSH + 19.53"	27903.1	36% TW	32% TW 2R22	Foreign Object Wear	4	2.74	1.5
26	126	49	TSH + 19.97"	27903.1	39% TW	34% TW 2R22	Foreign Object Wear	5	2.74	1.8
26	128	107	TSH + 0.06"	27901.1	26% TW	29% TW 2R22	Foreign Object Wear	-3	2.74	-1.1

6.2.2 Eddy Current PLPs without Wear

Thirty-two (32) cases of eddy current PLPs without wear were reported during the 2R24 inspections. Some of the PLPs were newly reported while others had been reported in previous outages. For some of the newly reported PLPs, reviews of the previous eddy current results showed that the suspected part was present in a previous outage(s), but was not reported. The eddy current PLPs with history (either previously reported or previously present based on lookup) were deemed acceptable based on their presence over multiple cycles without causing any detectable wear. Some of the PLP locations near the periphery of the bundle were visually inspected. Locations with no visual evidence of a part were considered acceptable based on the confirmed absence of a part. All PLP indications were further dispositioned as either PLM (monitor), PLR (part removed), or PLS (signal with no part observed). Based on these analyses, all eddy current PLP locations were acceptable for the next three cycles of operation.

6.2.3 Foreign Object Wear from Parts Remaining in the Steam Generators

Tables 2-8 and 2-9 of the Degradation Assessment [8.4] identified known parts remaining in SG25 and SG26 respectively. During 2R24, these locations were re-examined using eddy current and/or visual inspections to confirm that the part was still present and that no wear was caused by these parts. Attachments 1 and 2 of this document summarize the results of those inspections. No wear was observed caused by parts remaining in the SGs.

6.2.4 Foreign Objects That May Enter the Steam Generators

As summarized in Table 6.2, four locations had new foreign object wear although the parts are no longer present. The parts are assumed to have entered the SGs over the last operating interval between inspections. If a new foreign object is assumed to enter the steam generator at the beginning of the next operating period and is assumed to wear at similar rates over the planned three cycle operating period, the following is a projection of the expected depth at 2R27 compared to the structural allowable depth.

The deepest new foreign object wear indication found during 2R24 measured 36%TW with a rotating coil probe (SG26 R124C123 TSH+1.77"). As shown in Table A-1 of the Degradation Assessment [8.4], the NDE (Non-Destructive Examination) sizing parameters for the RPC technique (ETSS 27901.1) are a slope of 1.05 and an intercept of -1.97%TW. Using the slope and intercept, a best estimate real depth of 35.8%TW (36 x 1.05 – 1.97) is obtained for an indication with a measured depth of 36%TW.

The standard error of 2.30%TW is the technique uncertainty only. Per the EPRI SG Integrity Assessment Guidelines [8.7], the analyst uncertainty can be assumed to be equal to one-half of the technique uncertainty. Combining the technique and analyst uncertainties using the "square root of the sum of the squares" method yields a combined standard error of 2.57%TW. Further adjusting this value upward to an upper 95th percentile gives an NDE uncertainty of 4.2%TW (2.57 x 1.645). Adding this uncertainty to the best estimate value of 35.8%TW yields a bounding real depth of 40.0%TW (35.8 + 4.2) at 2R24.

Although no foreign object is currently at this location, a hypothetical three-cycle assessment can be performed by applying the growth rate exhibited by the indication at SG26 R124C123 TSH+1.77" (13.1%TW/EFPY) over one additional cycle inspection interval of 1.375 EFPY. This gives a total growth of 18.0%TW (13.1 x 1.375) after one additional cycle of operation until the next planned inspection.

Further applying this total growth to the bounding real depth of 40.0%TW gives a projected depth of 58.0%TW (40.0 + 18.0) after one additional cycle inspection interval.

The allowable real depth (Structural Limit, SL) for foreign object wear with a bounding length of 0.38" is 60.6%TW as shown in the ETSS 27901.1 OD Axial Thinning Evaluation found in Appendix C of the Degradation Assessment [8.4]. Since the projected real depth of 58.0%TW is less than the allowable real depth of 60.6%TW, the structural integrity performance criterion is expected to be met for this indication after a third cycle of operation.

Therefore, if a new foreign object is assumed to enter the steam generator at the beginning of the next operating period and is assumed to wear at similar rates over the planned three-cycle operating period, there is reasonable assurance that the structural integrity performance criterion will be met for this mechanism at 2R27.

6.3 Leakage Performance Criteria

No tube leakage was reported during the previous operating cycle. As discussed above, no degradation is expected to exceed SG tube structural integrity limits during the next inspection interval in either SG25 or SG26. Further, no degradation of the type, that can result in throughwall penetration while still meeting structural integrity limits (i.e., cracking), is expected. As a result, there is reasonable assurance that the accident induced leakage performance criteria and operational leakage performance criteria will not be exceeded during the operating period prior to the next SG tube inspection in either of the SGs.

6.4 Secondary Side Internals Degradation

No degradation of secondary side internals which could impact tube integrity prior to the next examination was identified during this outage. There were no reported difficulties during the insertion of sludge lance equipment into the secondary side handholes. Therefore, it can be concluded that wrapper drop has not occurred. The eddy current examination performed during 2R24 revealed no indication of missing support structures. The absence of secondary side structural degradation provides a high level of confidence that tube degradation caused by secondary support deterioration will not occur in any of the steam generators prior to the next inspection in each SG. A visual examination of internal components in SG25 and SG26 in the upper bundle and steam drum revealed no degradation and none is expected for the foreseeable future. Consequently, there is no expected degradation mechanism of secondary side components that could threaten tube integrity prior to the next inspection. These findings continue to support the planned secondary side inspection intervals incorporated into the long-term secondary management plan summarized in the MP2 DA (Ref. [8.4]).

6.5 Operational Assessment Conclusion

Based upon the evaluations above, there is reasonable assurance that the structural and leakage performance criteria will not be exceeded prior to the next planned inspection in either of the MP2 SGs; supporting an inspection interval of three operating cycles until 2R27.

7. Conclusions

As indicated by the results of the current outage primary side and secondary side examinations, the Millstone Unit 2 steam generators continue to satisfy the structural and leakage integrity requirements delineated in the Dominion SG Program and MP2 technical specifications. Specifically, no degradation exceeding the performance criteria was identified during this or any previous MP2 SG inspection.

This evaluation has demonstrated that there is reasonable assurance that operation of the MPS Unit 2 SGs for up to three fuel cycles between inspections will not cause the structural or leakage integrity performance criteria to be exceeded. In addition, the absence of conditions which challenge the SG program performance criteria validates prior outage operational assessment assumptions and conclusions regarding structural and leakage integrity.

8. References

8.1. Dominion Fleet Administrative Procedure, "Steam Generator Program," ER-AP-SGP-101, Revision 11

8.2. Dominion Fleet Administrative Procedure, "Steam Generator Condition Monitoring and Operational Assessments," ER-AP-SGP-103, Revision 6

8.3. NEI, "Steam Generator Program Guidelines," NEI 97-06, Rev. 3, January 2011

8.4. Dominion Engineering Technical Evaluation ETE-MP-2017-1015, "Millstone Unit 2 Steam Generator Integrity Degradation Assessment (2R24)", Revision 0, 2/23/2017

8.5. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 7," 1013706, October 2007

8.6. Unit 2 Steam Generator Eddy Current Data Analysis Reference Manual U2-24-SIP-REF01, Revision 8, April 2017

8.7. EPRI, "Steam Generator Integrity Assessment Guidelines: Revision 3," 1019038, November, 2009

8.8. EPRI, "Interim Guidance Regarding Steam Generator Integrity Assessment Guidelines, Revision 3", SGMP-IG-09-03, November 2009

8.9. EPRI, "SGMP: SG Degradation Specific Management Flaw Handbook, Revision 2," 3002005426, October 2015

8.10. EPRI Software, "Steam Generator Management Program: Flaw Handbook Calculator (SGFHC) for Excel 2010 v1.0", 3002003048, June 2014

ATTACHMENT 1 LPT SG25

SG25 PLP / Foreign Objects Detected in 2R24

Ref ID	Description	Affected Tube Locations	ECT Results	History/ Change?	2R24 Results/Disposition
2521	Newly Detected Metal Screen	R30 C97 R31 C98 R32 C97 TSC + 0”	No PLP or wear on bounding tubes	Newly detected, but likely present in system previously	ECT: No PLP or wear in bounding tubes SSI: Part could not be removed Part dispositioned to remain in the SG based on previous engineering assessment of metal screen
2522	Historical Weld Slag (2R20 FK7)	R41 C160 R42 C159 R40 C159 R43 C158 R41 C158 R44 C157 R42 C157 TSH +1”	PLP No Wear	Location unchanged since 2R16	ECT: PLPs detected with no wear SSI: Part confirmed to be in same location
2523	Historical Weld Slag (2R20 FK1)	R24 C101 R23 C102 R24 C103 R25 C102 TSC +0”	PLP No Wear	Location unchanged since 2R14	ECT: PLPs detected in four tubes with no wear SSI: Part confirmed to be in same location
2524	Historical Weld Slag (2R20 FK48)	R119 C66 R121 C66 R120 C67 TSC +0”	Tubes plugged in 2R20	Location unchanged since 2R20	ECT: No PLP or wear in bounding tubes SSI: Part confirmed to be in same location
2525	Historical Weld Slag (2R20 FK21)	R78 C141 R76 C141 R77 C142 TSC +0”	Tubes plugged in 2R18	Location unchanged since 2R18	ECT: No PLP or wear in bounding tubes SSI: Part confirmed to be in same location

Ref ID	Description	Affected Tube Locations	ECT Results	History/ Change?	2R24 Results/Disposition
2526	Rectangular Metallic Object (2R20 FK26)	R92 C27 R94 C27 TSH + 0"	PLP No Wear	Newly detected, but likely present in system previously	ECT: PLPs detected with no wear SSI: Part removed
2527	Machine Shaving	R109 C40 R110 C41 R111 C40	PLP No Wear	Newly detected	ECT: PLPs detected with no wear SSI: Part removed
2528	Historical Metallic Object	R89 C144 R90 C143	PLP Wear on adjacent tube	PLPs newly detected, but present in history back to 2008 WAR newly detected, but present back to 1997	ECT: PLPs detected with no wear SSI: Part could not be removed Part dispositioned to remain in the SG based on history back to 2008 with no change
-	ECT PLP (2R20 FK26)	R36 C5 R42 C5 R44 C5 01H +2"	PLP No Wear	Detected in 2R20	ECT: PLP with no wear; characterized as weld splatter conforming to tube surface SSI: Location not accessible
-	ECT PLP (2R20 FK30)	R122 C43 R121 C42 01H +2"	PLP No Wear	Detected in 2R20	ECT: INRs reported in same location as previous PLPs with no wear; previously characterized as weld splatter conforming to tube surface SSI: Location not accessible

Note: ET inspections were performed following first FOSAR campaign.

ATTACHMENT 2 LPT SG26

SG26 PLP / Foreign Objects Detected in 2R24

Ref ID	Description	Affected Tube Locations	ECT Results	History/ Change?	2R24 Results/Disposition
261	Flexitallic Gasket	R32 C5 R33 C4 TSH +1"	No PLP or wear on bounding tubes	Newly detected	ECT: No PLP or wear in affected and bounding tubes SSI: Part removed.
262	Flexitallic Gasket	R82 C19 R83 C18 R83 C20 R84 C19 R85 C20 TSH +0"	No PLP or wear on bounding tubes	Newly detected	ECT: No PLP or wear in affected and bounding tubes SSI: Part removed.
263	Flexitallic Gasket	R121 C114 R122 C113 R122 C115 R123 C112 R123 C114 R124 C111 R124 C113 R125 C112 TSH +1"	No PLP or wear on bounding tubes	Newly detected	ECT: No PLP or wear in affected and bounding tubes SSI: Part removed.

Ref ID	Description	Affected Tube Locations	ECT Results	History/ Change?	2R24 Results/Disposition
264	Wire	R135 C104 R136 C103 R136 C105 R137 C104 TSH +0"	No PLP or wear on bounding tubes	Newly detected	ECT: No PLP or wear in affected and bounding tubes. SSI: Part removed.
265	Flexitallic Gasket	R125 C98 R126 C97 R127 C98 R128 C97 TSH +0"	No PLP or wear on bounding tubes	Newly detected	ECT: No PLP or wear in affected and bounding tubes SSI: Part removed.
266	Rust slag	R138 C99 (in annulus) TSH +0"	No PLP or wear on bounding tubes	Newly detected	ECT: No PLP or wear in affected and bounding tubes SSI: Part removed.
267	Sludge Rock or Scale	R19 C104 R20 C103 R21 C104 TSH +1"	No PLP or wear on bounding tubes	Newly detected	ECT: No PLP or wear in affected and bounding tubes SSI: Removal not attempted Part dispositioned to remain in the SG based on sludge rock characterization. Sludge rocks do not lead to tube degradation based on OPEX.

Ref ID	Description	Affected Tube Locations	ECT Results	History/ Change?	2R24 Results/Disposition
268	Sludge Rocks	-	No PLP or wear in associate lanes	-	ECT: No PLP or wear in associated lanes SSI: Characterization identified observed features as likely relating to sludge rocks on the tubesheet
269	Historical Flexitallic Gasket (2R22 FK8)	R38 C81 R40 C81 TSH +0”	No PLP or wear on bounding tubes	Two tubes plugged in 2R18. Gasket no longer present.	ECT: No PLP or wear in bounding tubes; originally affected tubes already plugged SSI: Gasket no longer present.
2610	Historical Nut (2R22 FK22)	R93 C138 R94 C137 C95 C138 TSH +0”	PLP No Wear	Object has been monitored since 2000 with no wear. Part moved 1 row closer to the periphery, likely as a result of waterlancing	ECT: PLPs reported closer to the periphery. Part appears to have moved. No wear in the vicinity SSI: Part not monitored visually
2611	Historical Flexitallic Gasket (2R22 FK10)	R97 C144 R98 C143 R94 C143 R96 C141 R95 C144 R96 C143 R97 C142 R93 C144 R95 C142 R98 C141 TSC +0”	PLP No Wear	Eight tubes plugged in 2R20; Location unchanged since 2R22	ECT: No PLPs or wear in bounding tubes SSI: Gasket confirmed to be in same location

Ref ID	Description	Affected Tube Locations	ECT Results	History/ Change?	2R24 Results/Disposition
2612	Rectangular Metallic Object	R24 C67 R26 C67 TSH +0"	PLP No Wear	Newly detected	ECT: No PLP or wear in affected and bounding tubes SSI: Part removed.
2613	Sludge Rock	R20 C65 R22 C65 TSH +0"	No PLP or wear on bounding tubes	Newly detected	ECT: No PLP or wear in affected and bounding tubes SSI: Part could not be removed Part dispositioned to remain in the SG based on sludge rock characterization. Sludge rocks do not lead to tube degradation based on OPEX
-	Historical ECT PLP (2R22 FK4)	R66 C157 R67 C156 R68 C155 R69 C156 R72 C155 R75 C154 R78 C153 R81 C152 01H +2"	PLP No Wear	Unchanged since initial detection in 2R20	ECT: PLPs reported in same location with no wear; characterized as weld splatter conforming to tube surface SSI: Location not accessible
-	Historical ECT PLP (2R22 FK6)	R18 C165 R19 C166 R20 C165 R17 C166 R16 C167 01C +2"	INR No Wear	Location unchanged since initial detection in 2R20	ECT: INRs reported in same location as previous PLPs with no wear; characterized as weld splatter conforming to tube surface SSI: Location not accessible

Note: ET inspections were performed following first FOSAR campaign.