Dominion Nuclear Connecticut, Inc.
Millstone Power Station
Rope Ferry Road
Waterford, CT 06385

Dominion

November 9, 2004

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Serial No.: 04-673
LR/ELA R0
Docket Nos.: 50-336
50-423
License Nos.: DPR-65
NPF-49

DOMINION NUCLEAR CONNECTICUT, INC. (DNC)
MILLSTONE POWER STATION UNITS 2 AND 3
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
LICENSE RENEWAL APPLICATIONS

The Nuclear Regulatory Commission (NRC) requested additional information regarding the license renewal applications (LRAs) for Millstone Power Station Units 2 and 3 on June 25, 2004, June 26, 2004, and August 10, 2004. The response to these requests is being submitted as Attachment 1. Supplemental information was also requested by the staff regarding a response previously provided by letter dated July 26, 2004 (S/N: 04-405). The supplemented response is included as Attachment 2.

As a result of audits of the Aging Management Programs and Aging Management Reviews, additional information in support of the Millstone Power Station Units 2 and 3 LRAs is being submitted as Attachment 3.

Should you have any questions regarding this letter, please contact Mr. William D. Corbin, Director, Nuclear Projects, Dominion Resources Services, Inc., 5000 Dominion Blvd., Glen Allen, VA, 23060.

Very truly yours,

Leslie N. Hartz
Vice President – Nuclear Engineering

Attachments:

1. Request for Additional Information Responses
2. Supplemental Request for Additional Information Response
3. Additional Information in Support of Applications for Renewed Operating Licenses

Commitments made in this letter: None

A106

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SN: 04-673
Docket Nos.: 50-336/50-423
Subject: Response to RAI – License Renewal Applications

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Leslie N. Hartz, who is Vice President - Nuclear Engineering, of Dominion Nuclear Connecticut, Inc. She has affirmed before me that she 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 her knowledge and belief.

Acknowledged before me this 9TH day of November, 2004.

My Commission Expires: May 31, 2006.

Vicki L. Hull
Notary Public

(SEAL)

Attachment 1

Request for Additional Information Responses

Millstone Power Station Units 2 & 3
Dominion Nuclear Connecticut, Inc.

RAI 2.1-1

Based on a review of the LRA, the applicant's scoping and screening implementation procedures, and discussions with the applicant, the staff determined that additional information is required with respect to certain aspects of the applicant's evaluation of the 10 CFR 54.4(a)(2) criteria. Please address the following:

A. Section 2.1.3.6, "10CFR54.4(a)(2) Report," of the LRA, and the applicant's technical report prepared to address the (a)(2) issue, state that NSR piping that is attached to SR piping, and that is seismically designed and supported up to (emphasis added) the first equivalent anchor point beyond the SR/NSR boundary, is included within the scope of license renewal. However, NUREG-1800, Section 2.1.3.1.2, states that the scoping methodology includes both the NSR piping and the associated piping anchors (emphasis added) as being within the scope of license renewal pursuant to 10 CFR 54.4(a)(2).

   Based on the above, the staff requests that the applicant define the term "first equivalent anchor point" as it relates to the evaluation of NSR piping attached to SR piping and describe the methodology of its application. In cases where plant equipment credited with providing support to NSR piping within the scope of license renewal may be equivalent to an associated piping anchor as described in NUREG-1800, provide justification for not including this plant equipment within the scope of license renewal.

B. Describe the methodology and documentation sources used to perform walkdowns associated with the review of NSR fluid-containing components located near SR components (spatial interaction). Additionally, for low energy fluid-containing NSR components, describe the extent to which engineering judgement was used to identify NSR components which may affect SR components.

Dominion Response:

The response to RAI 2.1-1 is provided in two parts. First, the requested definition from Subpart A and the methodology descriptions requested in Subparts A and B are presented. Enhancements to the original methodologies are incorporated into the responses to Subparts A and B. Second, the additional systems and components added to the scope of license renewal as a result of the application of these methodologies enhancements, along with the results of the associated aging management reviews, are presented as "Supplemental Information."

A. As stated in LRA Section 2.1.3.6, the non-safety-related (NS) piping that is attached to safety-related (SR) piping, and that is required to be seismically designed and supported up to the first equivalent anchor beyond the SR/NS boundary, is included within the scope of the license renewal. The associated pipe supports are also included in the scope of license renewal as described in LRA Section 2.1.5.3 as a general structural supports commodity item. As further described in Section 2.1.3.6, the specific piping system components that are seismically designed beyond the SR/NS interface were not uniquely identified during the screening process. Based on discussions with the NRC staff, the piping and components that comprise these NS piping segments have been incorporated into the scope of license renewal in accordance with the methodology described below.

Since the determination of actual piping anchors used in the seismic analysis for each safety-related piping system for Millstone Units 2 and 3 would be labor intensive, Dominion developed a bounding approach that encompasses the equivalent anchor. For each SR/NS interface occurring for safety-related piping within the scope of license renewal, a set of criteria was applied to the attached NS piping system. For the purpose of license renewal, the first equivalent anchor is defined as when the piping has been restrained in each of the three orthogonal directions. Additionally, it is recognized that, in some cases, plant equipment may be credited as providing restraint in one or more directions in the piping system seismic evaluation. In these cases, the credited components are also included in the scope of license renewal.

The following criteria were applied in the determination of the license renewal boundary endpoints for NS piping attached to SR piping:

- The NS piping terminates at plant equipment that is mounted to a baseplate supported by a structure or mounted to a foundation (base-mounted component). In this instance, the base-mounted component and supporting structure are included in the scope of license renewal.
- The NS piping is attached to a SR piping run or component. This constitutes an endpoint for the purpose of this evaluation since the attached safety-related piping would have been included in scope per 10 CFR 54.4(a)(1).
- A flexible connection in the NS piping segment such as an expansion joint, flexible hose, or other component that effectively decouples the piping system.
- In the case of an NS piping segment that has transitioned below-ground, a point where the buried NS piping segment exits the ground.
- The NS piping run transitions to small diameter branch piping, where the area moment of inertia ratio of the larger diameter piping to the smaller diameter piping is ≥10.
- The end of the NS piping run, such as a drain pipe that ends at an open floor drain.

These conservative criteria provide assurance that the first equivalent anchor is included within the license renewal boundary. In some cases, this bounding approach resulted in an overly conservative license renewal boundary determination. In cases where it was deemed appropriate to limit the additional scope for a specific piping system, specific piping anchors (or equivalent anchors) were identified via the review of isometric piping drawings. In a limited number of instances, when isometric drawings were not available, plant walkdowns were performed to determine the location of the piping anchors (or equivalent anchors).

This methodology provides for the determination of license renewal boundary endpoints that are at or beyond the location of the first equivalent anchor point for NS piping that is attached to SR piping. The associated piping supports and plant equipment, up to and including the license renewal boundary endpoints, are included in the scope of license renewal. The results of the application of this methodology are included in the Supplemental Information section provided later in this response.

B. As described in LRA Section 2.1.3.6, non-safety-related (NS) fluid-containing components that are spatially oriented such that their failure could prevent the satisfactory accomplishment of a safety-related (SR) function of a SR system, structure, or component (SSC), are included in the scope of license renewal. The identification of these NS components was based on knowledge-based reviews of the facility configuration. These reviews were conducted by experienced plant personnel and were supplemented by facility walkdowns, as needed. Further discussion of the original methodology used to determine the NS components that are in the scope of license renewal due to their "spatial orientation" is provided in LRA section 2.1.3.6.

Non-safety-related fluid-containing components in low-energy systems that could affect the function of SR SSCs due to their spatial orientation were determined based on the judgment of the evaluator. Considerations included collapse envelop, fluid leakage, spray, and flood potential. Based on discussions with the NRC staff, Dominion has developed more comprehensive guidelines to limit the use of judgment in the determination of these in-scope NS components. The following revised criteria were used to re-evaluate NS fluid-containing components in low-energy systems that are spatially-oriented such that their failure could prevent the satisfactory accomplishment of a safety-related function of a SR SSC:

NS components containing or potentially containing fluids <200°F and <275 psig (low-energy) are included in the scope of license renewal unless both (a) and (b) below apply:

(a) The NS component cannot directly leak, spray or fall on SR components in the immediate area because one of the following conditions exist:

- The NS component is located in a room, cubicle, tunnel, enclosure, or enclosed corridor, which does not contain any SR mechanical or electrical components.

- The NS component is located in an open space, but is separated from SR mechanical or electrical components by solid physical barriers such as walls, floors, and ceilings.

- The NS component is located in an open space, is maintained at atmospheric pressure, and there are no SR mechanical or electrical components located within the collapse envelope of the NS component.

(b) The fluid contents of the NS components cannot flow from the area through doorways, grating, or floor penetrations, and then drain or drip on SR components in an adjacent area(s). Credit may be taken for curbing, dikes, and floor drains. These mitigating features are also being included in license renewal scope.

These revised criteria provide comprehensive guidance for the determination of the NS components in low-energy systems that could affect SR SSC functions due to their spatial orientation. The results of the application of these revised criteria are included in the following Supplemental Information section.

Supplemental Information:

Dominion has implemented the methodology changes discussed in Subparts A and B above. This implementation has resulted in the addition of systems and components to the scope of license renewal. The extent of the additional scope and the aging management review for added components are discussed in this section.

Systems and Components

No new Unit 2 or Unit 3 systems were added to the scope of license renewal due to the NS attached to SR piping methodology for either unit. The following Unit 2 systems have been added to the scope of license renewal as a result of the implementation of the spatial methodology changes discussed above:

- Aerated Liquid Radwaste
- Solid Waste Processing
- Turbine Building Closed Cooling Water
- Water Box Priming
- Auxiliary Steam Reboiler and Deaerating Feedwater
- Exciter Air Cooler
- Stator Liquid Cooler
- Turbine Lube Oil

No new Unit 3 systems were added to the scope of license renewal as a result of the implementation of the enhanced spatial orientation methodology.

The implementation of the spatial and/or NS attached to SR piping methodologies caused many systems, previously in the scope of license renewal, to have expanded license renewal boundaries. Aging management reviews have been performed for the components within these expanded boundaries and for the new systems added to the scope of license renewal. With the exception of the new Millstone Unit 3 NS component type "Groundwater Underdrains Storage Tank", the aging management reviews have verified that the material, environment, aging effect, aging management program (MEAP) combinations for the added component types are bounded by the MEAP combinations previously submitted for review in the LRA as supplemented by letters to the NRC dated July 7, 2004 (S/N: 04-320 and 04-327).

The Millstone Unit 3 groundwater underdrains storage tank was added to the scope of license renewal and an aging management review was performed. This review identified one new MEAP combination associated with the tank internal environment. The aging management review results are as follows:

Component Type	Intended Functions	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Groundwater Underdrains Storage Tank	PB, LSI	Stainless Steel	Raw Water	Loss of Material	Tank Inspection Program	VII.C1.1-a	3.3.1-17	E

The MEAP combination associated with the internal environment of the groundwater underdrains storage tank is stainless steel, raw water, loss of material and the Tank Inspection Program Aging Management Program (AMP). The combination of stainless steel material, raw water environment, and loss of material aging effect was previously addressed many times in the LRA; but the aging effect was managed by either the Work Control Process, Fire Protection Program, or Inservice Inspection Program: Containment Inspections AMPs.

The aging management review results for the newly added systems are included in Tables 1 through 8 of this response.

Structures

One Millstone Unit 2 structure has been added to the scope of license renewal as a result of the NS attached to SR piping methodology. The foundation of the primary water storage tank (previously listed in LRA Table 2.2-4 as not in scope) has been added. An aging management review has verified that the MEAP combination for the tank foundation is bounded by the MEAP combinations previously submitted for review in the LRA as supplemented by letters to the NRC dated July 7, 2004 (S/N: 04-320 and 04-327).

No Millstone Unit 3 structures have been added to the scope of license renewal. The groundwater underdrains storage tank shares the foundation of the refueling water storage tank, which is in the scope of license renewal. Note that LRA Table 2.2-4 inadvertently listed a structure "Unit 3 Groundwater Underdrains Storage Tank Foundation" although there is no such structure at Millstone Power Station.

Table 1: Auxiliary Systems – Aerated Liquid Radwaste – Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Conductivity Element	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.1-a	3.3.1-17	E
Flow Elements	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.1-a	3.3.1-17	E
Flow Indicators	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.1-a	3.3.1-17	E
Pipe	LSI;PB	Carbon Steel	(E) Air	None	None			I;6
			(E) Borated Water Leakage	Loss of Material	Boric Acid Corrosion	VII.I.1-a	3.3.1-14	A;1
					General Condition Monitoring	VII.I.1-a	3.3.1-14	A;1
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.1-a	3.3.1-17	E
Pipe	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.1-a	3.3.1-17	E
Pumps	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.2-a	3.3.1-17	E
Tubing	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.1-a	3.3.1-17	E
Valves	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.2-a	3.3.1-17	E
Valves	LSI;PB	Carbon Steel	(E) Air	None	None			I;6
			(E) Borated Water Leakage	Loss of Material	Boric Acid Corrosion	VII.I.1-a	3.3.1-14	A;1
					General Condition Monitoring	VII.I.1-a	3.3.1-14	A;1
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.2-a	3.3.1-17	E

[1] Notes correspond to the notes in Millstone Unit 2 LRA Section 3.3 tables.

Table 2: Auxiliary Systems – Solid Waste Processing – Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Flow Indicators	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.1-a	3.3.1-17	E
Pipe	LSI;PB	Carbon Steel	(E) Air	None	None			I;6
			(E) Borated Water Leakage	Loss of Material	Boric Acid Corrosion	VII.I.1-a	3.3.1-14	A;1
					General Condition Monitoring	VII.I.1-a	3.3.1-14	A;1
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.1-a	3.3.1-17	E
Pipe	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.1-a	3.3.1-17	E
Pumps	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.2-a	3.3.1-17	E
Spent Resin Fill Head Tank	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Air	Loss of Material	Work Control Process			G;2
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.2-a	3.3.1-17	E
Tubing	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.1-a	3.3.1-17	E
Valves	LSI;PB	Stainless Steel	(E) Air	None	None			G
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.2-a	3.3.1-17	E
Valves	LSI;PB	Carbon Steel	(E) Air	None	None			I;6
			(E) Borated Water Leakage	Loss of Material	Boric Acid Corrosion	VII.I.1-a	3.3.1-14	A;1
					General Condition Monitoring	VII.I.1-a	3.3.1-14	A;1
			(I) Raw Water	Loss of Material	Work Control Process	VII.C1.2-a	3.3.1-17	E

[1] Notes correspond to the notes in Millstone Unit 2 LRA Section 3.3 tables.

Table 3: Auxiliary Systems – Turbine Building Closed Cooling Water – Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Chemical Addition Tank	LSI;PB	Stainless Steel	(E) Air	Loss of Material	General Condition Monitoring			G;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.2-a	3.3.1-15	E
Chiller Condensers (Tubes)	LSI;PB	Copper alloys	(E) Gas	None	None			G
			(I) Treated Water	Loss of Material	Work Control Process	VII.C1.3-a	3.3.1-17	E
					Work Control Process	VII.C1.3-a	3.3.1-29	E
Exciter Air Coolers (Tubes)	LSI;PB	Copper alloys	(E) Air	Loss of Material	Work Control Process	VII.F2.2-a	3.3.1-05	C
			(I) Treated Water	Loss of Material	Work Control Process	VII.C1.3-a	3.3.1-29	E
					Work Control Process	VII.C1.3-a	3.3.1-17	E
Flexible Hoses	LSI;PB	Stainless Steel	(E) Air	Loss of Material	General Condition Monitoring			G;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.2-a	3.3.1-15	E
Flow Elements	LSI;PB	Stainless Steel	(E) Air	Loss of Material	General Condition Monitoring			G;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.2-a	3.3.1-15	E
Flow Indicators	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
Flow Orifices	LSI;PB	Stainless Steel	(E) Air	Loss of Material	General Condition Monitoring			G;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.2-a	3.3.1-15	E
Pipe	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
Pumps (TBCCW)	LSI;PB	Cast Iron	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C1.3-a	3.3.1-29	E
					Work Control Process	VII.C2.3-a	3.3.1-15	E

Table 3: Auxiliary Systems – Turbine Building Closed Cooling Water – Aging Management Evaluation (cont.)

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Spent Fuel Pool Area Supplemental Cooling Heat Exchangers (Tubes)	LSI;PB	Copper alloys	(E) Air	Loss of Material	Work Control Process	VII.F2.2-a	3.3.1-05	C
			(I) Treated Water	Loss of Material	Work Control Process	VII.C1.3-a	3.3.1-29	E
					Work Control Process	VII.C1.3-a	3.3.1-17	E
TBCCW Heat Exchangers (Channel Head)	LSI;PB	Cast Iron	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Sea Water	Loss of Material	Work Control Process	VII.C1.3-a	3.3.1-29	E
					Work Control Process	VII.C1.3-a	3.3.1-17	E
TBCCW Heat Exchangers (Shell)	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
TBCCW Heat Exchangers (Tubes)	LSI;PB	Copper alloys	(E) Treated Water	Loss of Material	Work Control Process			H
					Work Control Process	VII.C1.3-a	3.3.1-29	E
					Work Control Process	VII.C1.3-a	3.3.1-17	E
			(I) Sea Water	Buildup of Deposit	Work Control Process	VII.C1.3-b	3.3.1-17	E
				Loss of Material	Work Control Process	VII.C1.3-a	3.3.1-29	E
					Work Control Process	VII.C1.3-a	3.3.1-17	E

Table 3: Auxiliary Systems – Turbine Building Closed Cooling Water – Aging Management Evaluation (cont.)

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
TBCCW Heat Exchangers (Tubesheet)	LSI;PB	Copper alloys	(E) Sea Water	Buildup of Deposit	Work Control Process	VII.C1.3-b	3.3.1-17	E
				Loss of Material	Work Control Process	VII.C1.3-a	3.3.1-29	E
					Work Control Process	VII.C1.3-a	3.3.1-17	E
			(I) Treated Water	Loss of Material	Work Control Process	VII.C1.3-a	3.3.1-17	E
					Work Control Process	VII.C1.3-a	3.3.1-29	E
Tubing	LSI;PB	Stainless Steel	(E) Air	Loss of Material	General Condition Monitoring			G;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.2-a	3.3.1-15	E
Valves	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.2-a	3.3.1-15	E

[1] Notes correspond to the notes in Millstone Unit 2 LRA Section 3.3 tables.

Table 4: Auxiliary Systems – Water Box Priming – Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Filter/strainers	LSI;PB	Copper alloys	(E) Air	None	None			I;10
			(I) Air	Loss of Material	Work Control Process	VII.F2.2-a	3.3.1-05	C
Flow Orifices	LSI;PB	Stainless Steel	(E) Air	None	None			I;11
			(I) Air	Loss of Material	Work Control Process	VII.F2.4-a	3.3.1-05	C
Flow Switches	LSI;PB	Stainless Steel	(E) Air	None	None			I;11
			(I) Air	Loss of Material	Work Control Process	VII.F2.4-a	3.3.1-05	C
Pipe	LSI;PB	Copper alloys	(E) Air	None	None			I;10
			(I) Air	Loss of Material	Work Control Process	VII.F2.2-a	3.3.1-05	C
Valves	LSI;PB	Copper alloys	(E) Air	None	None			I;10
			(I) Air	Loss of Material	Work Control Process	VII.F2.2-a	3.3.1-05	C

[1] Notes correspond to the notes in Millstone Unit 2 LRA Section 3.3 tables.

Table 5: Steam and Power Conversion System – Auxiliary Steam Reboiler and Deaerating Feedwater – Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Auxiliary Steam Feedwater Surge Tank	LSI	Carbon Steel	(E) Air	None	None			I;4
			(I) Treated Water and Steam	Loss of Material	Chemistry Control for Secondary Systems Program	VIII.B1.1-a	3.4.1-07	D
Pipe	LSI	Carbon Steel and Low-alloy Steel	(E) Air	None	None			I;4
			(I) Treated Water and Steam	Loss of Material	Chemistry Control for Secondary Systems Program	VIII.B1.1-a	3.4.1-07	D
Sample Coolers (Shell)	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VIII.H.1-b	3.4.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VIII.F.4-e	3.4.1-10	E
Valves	LSI	Carbon Steel and Low-alloy Steel	(E) Air	None	None			I;4
			(I) Treated Water and Steam	Loss of Material	Chemistry Control for Secondary Systems Program	VIII.B1.2-a	3.4.1-07	D

[1] Notes correspond to the notes in Millstone Unit 2 LRA Section 3.4 tables.

Table 6: Steam and Power Conversion System – Exciter Air Cooler – Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Main Transformer & Generator Isophase Bus Duct Cooling Exchangers (Coils)	LSI;PB	Copper alloys	(E) Air	Loss of Material	Work Control Process			F
			(I) Treated Water	Loss of Material	Work Control Process			F

[1] Notes correspond to the notes in Millstone Unit 2 LRA Section 3.4 tables.

Table 7: Steam and Power Conversion System – Stator Liquid Cooler – Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Deionizer	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
Filter/strainers	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
Flow Indicators	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
Flow Orifices	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.5-a	3.3.1-15	E
Level Indicators	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
Pipe	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
Pumps	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.3-a	3.3.1-15	E
Stator Liquid Coolers (Channel Head)	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
Stator Liquid Coolers (Shell)	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E

Table 7: Steam and Power Conversion System – Stator Liquid Cooler – Aging Management Evaluation (cont.)

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Stator Liquid Coolers (Tube sheet)	LSI;PB	Carbon Steel	(E) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.1-a	3.3.1-15	E
Stator Liquid Cooling Water Storage Tank	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.4-a	3.3.1-15	E
Tubing	LSI;PB	Stainless Steel	(E) Air	Loss of Material	General Condition Monitoring			G;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.2-a	3.3.1-15	E
Valves	LSI;PB	Stainless Steel	(E) Air	Loss of Material	General Condition Monitoring			G;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.2-a	3.3.1-15	E
Valves	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VII.I.1-b	3.3.1-05	A;2
			(I) Treated Water	Loss of Material	Work Control Process	VII.C2.2-a	3.3.1-15	E

[1] Notes correspond to the notes in Millstone Unit 2 LRA Section 3.4 tables.

Table 8: Steam and Power Conversion System – Turbine Lube Oil – Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Filter/strainers	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VIII.H.1-b	3.4.1-05	A;2
			(I) Oil	Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C
Flow Indicators	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VIII.H.1-b	3.4.1-05	A;2
			(I) Oil	Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C
Flow Orifices	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VIII.H.1-b	3.4.1-05	A;2
			(I) Oil	Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C
Level Indicators	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VIII.H.1-b	3.4.1-05	A;2
			(I) Oil	Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C
Pipe	LSI;PB	Stainless Steel	(E) Air	Loss of Material	General Condition Monitoring			G
			(I) Oil	Cracking	Work Control Process			H;3
				Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C
Pipe	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VIII.H.1-b	3.4.1-05	A;2
			(I) Oil	Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C
SGFP Lube Oil Cooler (Shell)	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VIII.H.1-b	3.4.1-05	A;2
			(I) Oil	Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C
SGFP Turbine Lube Oil Reservoir	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VIII.H.1-b	3.4.1-05	A;2
			(I) Oil	Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C

Table 8: Steam and Power Conversion System – Turbine Lube Oil – Aging Management Evaluation (cont.)

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes[1]
Tubing	LSI;PB	Stainless Steel	(E) Air	Loss of Material	General Condition Monitoring			G
			(I) Oil	Cracking	Work Control Process			H;3
				Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C
Valves	LSI;PB	Carbon Steel	(E) Air	Loss of Material	General Condition Monitoring	VIII.H.1-b	3.4.1-05	A;2
			(I) Oil	Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C
Valves	LSI;PB	Stainless Steel	(E) Air	Loss of Material	General Condition Monitoring			G
			(I) Oil	Cracking	Work Control Process			H;3
				Loss of Material	Work Control Process	VIII.G.5-d	3.4.1-04	C

[1] Notes correspond to the notes in Millstone Unit 2 LRA Section 3.4 tables.

RAI 2.3.1.1-1

For Unit 2 Only

On page 2-46 of the Millstone Unit 2 LRA it states that the vessel support pads located below the primary nozzles provide for support of the reactor vessel. The weight of the reactor vessel is transmitted through the reactor vessel support pads to the concrete biological shield wall that surrounds the reactor vessel. Since the vessel support pads provide structural support for the reactor vessel and were not identified in LRA Table 2.3.1-1, the staff requests the applicant to verify whether the components have been included in scope of license renewal and are subject to an aging management review (AMR), or provide an explanation for the exclusion.

For Unit 3 Only

On page 2-48 of the Millstone Unit 3 LRA it states that the nozzle support pads, which are integral with and located below four of the primary nozzles, provide support of the reactor vessel. The weight of the reactor vessel is transmitted through the nozzle support pads to the neutron shield tank that surrounds the reactor vessel. Since the nozzle support pads provide structural support for the reactor vessel and were not identified in LRA Table 2.3.1-1, the staff requests the applicant to verify whether the components have been included in scope of license renewal and are subject to an AMR, or provide an explanation for the exclusion.

Dominion Response:

Unit 2

The reactor vessel support pads are welded to three of the six primary nozzles and are in the scope of license renewal. The vessel support pads are included in the "Primary Nozzle and Safe End" subcomponent in LRA Table 2.3.1-1.

Unit 3

The reactor nozzle support pads are integral with four of the eight primary nozzles and are in the scope of license renewal and subject to aging management review. The nozzle support pads are included in the "Primary Nozzles" subcomponent in LRA Table 2.3.1-1.

RAI 2.3.1.1-2

Page 2-45 of the Millstone Unit 2 LRA and page 2-47 of the Millstone Unit 3 LRA states two self-energizing O-ring gaskets prevent leakage of reactor coolant between the mating surfaces of the reactor closure head flange and the reactor vessel flange. Furthermore, it was stated in the Unit 2 and Unit 3 FSARs that the space between the double O-ring seal is monitored to detect an increase in pressure, which indicates a leak past the inner O-ring. A leak indicator in containment indicates pressure. Upon high temperature a control room alarm is sounded. Later in the both LRAs (page 3-18, Unit 2; page 3-19, Unit 3), the applicant explains the leak detection components are not within the scope of license renewal because the O-ring leak monitoring tubing and valves are not spatially oriented in a fashion that would impact the safety function of any safety-related components. While the component may not be within scope with respect to spatial interaction, based on the staff's experience with license renewal, the staff has determined that these leakoff lines should, in general, be within scope requiring aging management on the basis of maintaining a pressure boundary. Please provide further justification for the exclusion of O-ring leak monitor tubes or submit an AMR for the stated component.

Dominion Response:

As stated on Page 3-18 in the Unit 2 LRA and Page 3-19 in the Unit 3 LRA, leakage flow past the inner O-ring is limited in the event of seal failure by a small diameter hole (3/16" for Unit 2 and 1/8" for Unit 3) in the reactor vessel flange that is smaller than the inside diameter of the leak detection line. Additionally, the potential flowrate through the small diameter hole in the flange is within the normal make-up capability of the Chemical and Volume Control System such that the leak detection system does not constitute the RCS pressure boundary. Therefore, the reactor vessel flange seal leak detection system does not meet the criteria of 10CFR54.4(a) and is not within the scope of license renewal.

RAI 2.3.1.1-3

Page 2-47 of the Millstone Unit 3 LRA states the hemispherical, welded bottom head has penetrations (instrumentation tube) for movable in-core thimble tubes, which extend into the reactor vessel interior and mate with the lower internals assembly. The core support ledge, located inside the reactor vessel just below the vessel flange, supports the entire weight of the reactor vessel internals and the fuel. The lower internals assembly hangs from the core's support ledge and is provided with lateral support by core support pads. Since the lower internals assembly provides structural support for in-scope components and was not identified in LRA Table 2.3.1-1, the staff requests the applicant to verify whether the component has been included in scope of license renewal and is subject to an AMR, or provide an explanation for the exclusion.

Dominion Response:

The reactor vessel lower internals assembly is included in the scope of license renewal and subject to aging management review. The components of the lower internals assembly are included in LRA Table 2.3.1-2, "Reactor Vessel Internals". An assembly drawing is provided in FSAR Figure 3.9N-8.

RAI 2.3.1.2-1

The Millstone Unit 2 FSAR states that in-core instrumentation (ICI) assemblies are inserted into the core through instrumentation nozzles in the top closure head of the reactor vessel. Each assembly is guided into position in the center of the fuel assembly via a fixed guide tube and instrument thimble assembly. A flange-type seal forms a pressure boundary for each assembly at the instrument nozzle. Instrument nozzles and instrument thimble assemblies; however, do not appear to have been included within the scope of license renewal requiring an AMR. The staff requests the applicant to explain why these components, which provide a pressure boundary and structural support for in-scope equipment, are not in scope requiring an AMR.

Dominion Response:

Instrument nozzles are in the scope of license renewal and are included in the subcomponent "Instrument Tubes" and "Instrument Tube Flange and Studs/Nuts/Washers" in LRA Table 2.3.1-1.

The instrument thimble assemblies are in the scope of license renewal and are included in the subcomponent "ICI Support Plate and Guide Tubes" in LRA Table 2.3.1-2.

RAI 2.3.1.2-2

Page 2-49 of the Millstone Unit 3 LRA states the lower core support assembly consists of the core barrel, the core baffle, the lower core plate and support columns, the neutron shield pads, and the core support which is welded to the core barrel. The lower core support assembly can be removed, if desired, following a complete core offload. It appears that the core support which is welded to the core barrel is not listed in LRA Table 2.3.1-2 and is not within scope requiring an AMR. Since the core support provides structural support for in-scope equipment, the staff requests the applicant to verify whether the component has been included in scope of license renewal and is subject to an AMR, or provide an explanation for the exclusion.

Dominion Response:

The core support is in the scope of license renewal and identified as the "Lower support forging" in LRA Table 2.3.1-2.

RAI 2.3.1.3-1

Page 2-49 of both the Unit 2 and Unit 3 LRAs states the pressurizer is a vertically oriented cylindrical vessel connected to the reactor coolant system hot-leg via the surge line piping and to the cold-leg via the spray line. The pressurizer consists of a shell section and an upper and lower head. Pressurizer nozzles are provided for various connections (e.g., relief valves, safety valves, spray line, and surge line). The pressurizer is supported by seismic support lugs and a support skirt that is welded to the lower head. The following components associated with the pressurizer, however, were not listed in LRA Table 2.3.1-3 and do not appear to have been included within the scope of license renewal requiring an AMR. The staff requests the applicant to justify why these components have not been included within the scope of license renewal requiring an AMR or submit an AMR for the necessary components.

Subcomponent	**Intended Function**
Pressurizer - Nozzles (Surge, Spray, Safety, Relief, Instrument)	Pressure Boundary
Pressurizer - Nozzle Safe Ends	Pressure Boundary
Pressurizer - Heater Sheath	Pressure Boundary
Pressurizer - Manway and Cover	Pressure Boundary
Pressurizer - Surge Line	Pressure Boundary
Pressurizer - Spray Head Assembly	Spray Pattern
Pressurizer - Support Lugs	Structural Support
Pressurizer - Support Skirt and Flange	Structural Support

Dominion Response:

The pressurizer, including all subcomponents that perform intended functions, is included in the scope of license renewal and subject to aging management review. The pressurizer was evaluated as part of the Reactor Coolant System and is not considered a major component as described in LRA Section 2.1.5.2. Therefore, pressurizer subcomponents are not listed in LRA Table 2.3.1-3. The pressurizer subcomponents listed in the subject RAI are included in the component types "Pressurizer" and "Pressurizer Heaters" in Unit 2 and Unit 3 LRA Tables 2.3.1-3. Subcomponents of the pressurizer are indicated in Unit 2 and Unit 3 LRA Tables 3.1.2-3.

RAI 2.3.1.3-2

For Unit 2 Only

Page 2-49 of the Millstone Unit 2 LRA states the reactor coolant pumps are vertical single-stage centrifugal pumps. The reactor coolant pump casing, cover (including the thermal barrier), inner tubes of the seal cooler, closure bolting, and driver mount are considered part of the reactor coolant system pressure boundary. The upper and lower reactor coolant pump motor lube oil coolers and the outer tubes of the seal cooler provide a reactor building closed cooling water system pressure boundary. The pump casing and driver mount, however, were not listed in Millstone Unit 2 LRA Table 2.3.1-3 and do not appear to have been included within the scope of license renewal requiring an AMR. The staff requests the applicant to explain why these components, which are considered part of the reactor coolant system pressure boundary, are not in scope requiring an AMR or submit an AMR for the stated components.

For Unit 3 Only

Page 2-50 of the Millstone Unit 3 LRA states the reactor coolant pumps are vertical single-stage centrifugal pumps. The reactor coolant pump casing, cover (main flange), thermal barrier (including integral heat exchanger) and closure bolting are considered part of the reactor coolant system pressure boundary. The upper and lower reactor coolant pump motor lube oil coolers provide a reactor plant closed cooling system pressure boundary. The pump casing and main flange, however, were not listed in Millstone Unit 3 LRA Table 2.3.1-3 and do not appear to have been included within the scope of license renewal requiring an AMR. The staff requests the applicant to explain why these components, which are considered part of the reactor coolant system pressure boundary, are not in scope requiring an AMR or submit an AMR for the stated components.

Dominion Response:

The Unit 2 reactor coolant pumps casing and driver mount are in the scope of license renewal and subject to aging management review. These items are considered subcomponents of the reactor coolant pump and are included in the component type "Reactor Coolant Pump" in Table 2.3.1-3. These subcomponents are identified uniquely in Table 3.1.2-3 as "Reactor Coolant Pumps (Casing)" and "Reactor Coolant Pumps (Driver Mount Assembly)", respectively.

The Unit 3 reactor coolant pumps casing and main flange are in the scope of license renewal and subject to aging management review. These items are considered subcomponents of the reactor coolant pump and are included in the component type "Reactor Coolant Pump" in Table 2.3.1-3. The pump casing is identified in Table 3.1.2-3 as "Reactor Coolant Pumps (Casing)". The reactor coolant pump cover (main flange) and thermal barrier are an integral part and are identified as "RCP Thermal Barriers" in Table 3.1.2-3.

RAI 2.3.1.3-3

Page 2-49 of the Millstone Unit 2 LRA and page 2-51 of the Millstone Unit 3 LRA state that the evaluation boundary for the reactor coolant system includes welds. It appears that the subject component was not discussed in the LRA (Table 2.3.1-3) and therefore, the staff requests the applicant to verify whether the component is within scope and require an AMR, or provide justification for the exclusion.

Dominion Response:

The Reactor Coolant System welds are in the scope of license renewal and require aging management review. Welds are considered a part of the host component (i.e., pipe, nozzle, etc.) and are not uniquely identified in Table 2.3.1-3. Refer to Dominion letter dated July 26, 2004, Serial No. 04-405, Response to RAI 2.3.3.2-2B, for additional clarification.

RAI 2.3.1.4-1

The FSAR states the steam generators are vertically mounted on bearing plates which allow lateral motion due to thermal expansion of the reactor coolant piping. Bearing plates, however, were not listed in Millstone Unit 2 LRA Table 2.3.1-4 and do not appear to have been included within the scope of license renewal requiring an AMR. The staff requests the applicant to explain why this component, which provides structural support for in-scope equipment, is not in scope requiring an AMR.

Dominion Response:

Structural supports for major reactor coolant system components are evaluated separately from the component and its integral parts as NSSS Equipment Supports as described in LRA Section 2.1.5.3, Structural Screening. The steam generator support structure, including the bearing plates, is included in the scope of license renewal and described in LRA Section 2.4.3, NSSS Equipment Supports.

RAI 2.3.2.3-1

The FSAR states the containment sump is protected from clogging by the sump screen. Sump screens are normally used in the containment sump which provides water for the RWST recirculation phase and one of the intended functions is to protect the pumps from debris and cavitation due to harmful vortex following a LOCA. The subject component was not identified as within scope in LRA Table 2.3.2-3, which listed component groups for the RWST and Containment Sump requiring an AMR. Please explain why sump screens are not in scope or submit an AMR for the stated component.

Dominion Response:

The Containment Sump Screen is in the scope of license renewal and subject to aging management review as indicated in LRA Table 2.4.1-1.

RAI 2.3.3.32-2

The following water-based fire suppression systems are not included in the scope for license renewal for fire protection according to the applicable piping and instrumentation diagram:

1. Unit 2, Warehouse #9 wet pipe sprinkler system
2. Unit 2, Craft Assembly Building auto sprinkler system
3. Unit 2, Maintenance Shop auto sprinkler system

Provide the bases for not including these systems.

Dominion Response:

The scoping for fire protection systems was based on the Millstone Unit 2 fire protection licensing basis (10CFR50, Appendix R). The sprinkler systems identified in RAI 2.3.3.32-2 are not part of the fire protection licensing basis since protection of the associated structure is not credited. Therefore, only the portions of these sprinkler systems from the main fire loop, up to and including components necessary to isolate the system, are in the scope of license renewal.

RAI 2.3.3.32-3

Drawing 25203-LR26011, Sh. 1 of 6 shows the diesel generator room pre-action sprinkler systems' supervisory air supply to be in scope for license renewal. This same drawing shows a pre-action sprinkler system for the STG governor housing and oil lines, but a supervisory air line is not shown on the drawing. Section 2.1.3.7.1 does not list pre-action system supervisory air as being in scope for license renewal. Confirm that pre-action system supervisory air piping and valves for the STG system are in scope - from the connection to the water piping back through the check valve (as shown for the diesel generator room systems).

Dominion Response:

The pre-action sprinkler system for the steam turbine generator governor housing and oil lines is not an air-supervised system. Therefore, supervisory air lines are not identified for this sprinkler system on license renewal drawing 25203-LR26011, Sh. 1.

RAI 2.3.3.32-4

Please describe the program for both Unit 2 and Unit 3 that ensures continued access to an adequate supply of Halon for the extended life of the plant and/or plans to convert or replace the systems when a supply is no longer available.

Dominion Response:

There is no established program credited for license renewal to ensure the continued access to an adequate supply of Halon for the gaseous fire suppression system. In the event that the supply of Halon becomes inadequate during the period of extended operation, appropriate actions would be initiated to maintain compliance with the fire protection licensing basis.

RAI 2.3.3.33-1

The Unit 3, Wall Hydrant at Elev 24'-6" of Control Building is not included in the scope for license renewal for fire protection according to P&ID No. 25212-LR26946, Sheet 4. Provide the basis for not including this hydrant.

Dominion Response:

The wall hydrant at elevation 24'-6" in the Control Building was inadvertently omitted from scope. The wall hydrant consists of a section of carbon steel piping that penetrates the Control Building wall with copper alloy valves inside the building and a copper alloy cap on the outside. The wall hydrant components are included within the component types "Pipe" and "Valves" in the Unit 3 LRA Table 2.3.3-37. The environment external to the portion of the wall hydrant inside the Control Building and the interior of the pipe is a dry air environment. Therefore, there are no aging effects and aging management is not required. The capped portion of the wall hydrant outside the Control Building is exposed to an atmosphere/weather environment. The associated aging effect in this environment is the loss of material due to general corrosion and will be managed by the General Condition Monitoring Program.

RAI 2.4-3

The staff requires additional information concerning the possibility that some thermal insulation may serve an intended function, in accordance with 10 CFR 54.4(a)(2), to control the maximum temperature of safety-related structures and structural components that meet 10 CFR 54.4(a)(1). Thermal insulation is typically passive and long-lived. If it also serves an intended function in accordance with 10 CFR 54.4(a)(2), then it meets the criteria for inclusion within the scope of license renewal.

Possible examples are (1) maintaining the maximum temperature of NSSS support members below the maximum temperature assumed in the design basis of the supports; and (2) maintaining the maximum temperature of structural concrete below the threshold levels of 150°F for general areas and 200°F for local areas around hot penetrations.

Part 1 – Millstone 2

Millstone 2 FSAR Section 5.2.7.2.2 "Design of High Temperature Penetrations" states:

> High temperature piping penetrations consist of two for feedwater, two for main steam, and two for steam generator blowdown. These have a maximum operating temperature range between 435°F and 550°F. Thermal insulation is provided in the air gap between the pipe and penetration liner sleeve. The combination of insulation and penetration cooling is designed to restrict maximum temperature in the concrete to 150°F.
>
> For the condition created by loss of penetration cooling, the maximum steady state temperature in the concrete is 300°F at the penetration surface and decreases to 120°F at a maximum radial depth of 48 inches in the containment wall (Section 9.9.4.4.1).

Millstone 2 FSAR Section 9.9.4 "Containment Penetration Cooling System" states in subsection 9.9.4.4.1:

> The containment penetration cooling system is provided with two full capacity fans. Each fan has the capability of maintaining the concrete temperature around the sleeve below 150°F. Following the unlikely loss of penetration cooling, a maximum temperature of 390°F may be tolerated for 120 days without appreciable loss of strength of the concrete (Subsection 5.1.3).

Millstone 2 LRA Section 2.3.3.18 "Containment Penetration Cooling System" states:

> The Containment Penetration Cooling System functions to limit the temperature of Containment structure concrete to 150°F in the vicinity of hot piping penetrations. The system consists of two vane axial fans and the associated system ductwork and dampers. The system contains fire dampers to prevent the spread of a fire.
>
> The Containment Penetration Cooling System is in the scope of license renewal because the system meets 10CFR54.4(a)(2) by providing cooling air to the concrete area surrounding the containment piping penetrations. The Containment Penetration Cooling System also meets 10CFR54.4(a)(3) because the system supports fire protection.

From the information in FSAR Section 5.2.7.2.2, thermal insulation works in combination with the Containment Penetration Cooling System to limit the temperature of concrete at high-temperature penetrations. LRA Section 2.3.3.18 indicates that the Containment Penetration Cooling System is in the scope of license renewal because the system meets10CFR54.4(a)(2).On this basis, it appears to the staff that the thermal insulation also meets 10CFR54.4(a)(2).

Therefore, the applicant is requested to (1) identify whether any thermal insulation at Millstone 2 serves an intended function in accordance with 10 CFR 54.4(a)(2); (2) describe plant-specific operating experience related to degradation of (a) thermal insulation in general, and (b) thermal insulation that serves an intended function in accordance with 10 CFR 54.4(a)(2); and (3) describe the scoping and screening evaluation for thermal insulation that serves an intended function in accordance with 10 CFR 54.4(a)(2), including the technical basis for either inclusion within or exclusion from the scope of license renewal.

<u>Part 2 - Millstone 3</u>

Millstone 3 FSAR Section 3.8.1.1.4 (D)(1) describes "Sleeved Piping Penetration" as follows:

> These penetrations have a sleeve around the outside of forged piping with integral flued head. Sleeved penetrations are used for multiple small pipes passing through one penetration and for thermally hot piping systems. Thermally hot piping is insulated to prevent the operating temperature of the concrete adjacent to the sleeve, during normal operation or any other long term period, from exceeding 150°F except at local areas around the penetrations which are allowed to have increased temperatures not exceeding 200°F; for accident or other short term periods, the temperatures are not to exceed 350°F for the interior surface. However, local areas are allowed to reach 650°F from steam or water jets in the event of pipe failure. Penetrations in which the insulation would

be insufficient to maintain the concrete within the allowable temperature limit are equipped with a cooling jacket located inside the sleeve. The cooling water for the cooling jacket is supplied by the component cooling water subsystem. Each penetration sleeve carrying thermally hot piping is designed with adequate space between the sleeve and the piping to allow for the required pipe insulation and for the cooling jacket.

Millstone 3 LRA Table 2.3.3-4 identifies "Penetration Coolers" as a component type requiring aging management for the Reactor Plant Component Cooling System.

From the information in FSAR Section 3.8.1.1.4 (D)(1), thermal insulation works alone or in combination with the cooling jacket to limit the temperature of concrete at high-temperature penetrations. LRA Table 2.3.3-4 indicates that penetration coolers are included in the scope of license renewal. On this basis, it appears to the staff that the thermal insulation serves an intended function in accordance with 10 CFR 54.4(a)(2) and meets the criteria for inclusion within the scope of license renewal.

Therefore, the applicant is requested to (1) identify whether any thermal insulation at Millstone 3 serves an intended function in accordance with 10 CFR 54.4(a)(2); (2) describe plant-specific operating experience related to degradation of (a) thermal insulation in general, and (b) thermal insulation that serves an intended function in accordance with 10 CFR 54.4(a)(2); and (3) describe the scoping and screening evaluation for thermal insulation that serves an intended function in accordance with 10 CFR 54.4(a)(2), including the technical basis for either inclusion within or exclusion from the scope of license renewal.

Dominion Response:

There is no discussion of insulation functioning to limit the maximum temperature of NSSS equipment supports included in the FSAR. There are no insulated NSSS equipment supports.

Cooling systems and the application of thermal insulation for high temperature piping containment penetrations are designed to maintain containment structure concrete temperatures within limits to ensure that long-term degradation of the concrete does not occur that could degrade the integrity of the structure, as identified in the FSAR references cited in RAI 2.4-3. Although failure of the penetration cooling systems would not immediately result in the inability of the containment structure to perform its intended function, the penetration cooling systems were conservatively included in the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

There is currently no thermal insulation included in the scope of license renewal for Millstone Unit 2 or Unit 3. Since the thermal insulation associated with containment piping penetrations functions to limit the heat transferred to the surrounding concrete, similar to the piping penetration cooling systems that are in the scope of license renewal, Dominion will conservatively also include the thermal insulation in the scope of license renewal. The intended function applied to the insulation is to prevent excessive heat transmission to the containment concrete surrounding the piping penetrations. Based on the aging management review performed for the fiberglass, asbestos, and calcium silicate piping penetration thermal insulation, there are no applicable aging effects in the indoor air environment and no aging management program is required.

RAI 2.4-4

In both the Millstone 2 and Millstone 3 LRAs, Table 2.4.1-1 “Unit x Containment” lists “pipe” and “valve bodies” under the ”Structural Member” column. In both LRAs, Section 2.4.1 “Containment” does not specifically describe these items. The applicant is requested to describe the pipe and valve bodies that are included as part of the Millstone 2 and 3 containments.

Dominion Response:

LRA Section 2.4.1, Containment, describes the personnel lock, which allows for access into and out of the Containment. The personnel lock includes an equalizing system to equalize pressure inside and outside the lock. This function is accomplished through the use of piping and valves. In LRA Table 3.5.2-1, a Note is assigned to the Structural Members "Pipe" and "Valve Bodies" which states that these components are related to the personnel lock equalizing system.

RAI 2.4-5

Section 2.4.1, Containment In both the Millstone 2 and Millstone 3 LRAs, Section 2.4.1 "Containment" describes containment electrical penetrations as follows: The electrical penetrations consist of an electrical penetration module installed into a penetration sleeve that is welded to the liner plate. The evaluation boundary consists of the sleeve and attachment weld to the electrical penetration module. Spare electrical penetrations are also part of the evaluation boundary. The electrical penetration module is evaluated as described in Section 2.5.2, Electrical Penetrations. LRA Section 2.5.2 "Electrical Penetrations" states: Electrical penetrations permit the conduction of electrical power or signals through the Containment wall while maintaining the integrity of the Containment pressure boundary. The electrical penetration feed-through modules consist of one or more electrical conductors in a tubular metallic cylinder. The cylinder passes through a header plate which is manufactured with an adapter ring that is field-welded to the Containment penetration sleeve to provide the Containment pressure boundary. The header plate may contain one or more modules that make up the total electrical penetration assembly. The modules contain conductor extensions, conductor supports, and seals which are either epoxy, O-ring, or mechanical compression seals. Nitrogen is used for monitoring of seal pressure integrity. From the information provided in the LRAs, it appears that the AMR for the Containment pressure boundary function of the electrical penetration feed-through modules is evaluated as part of the electrical scope, instead of as part of the structures scope. The staff considers the Containment pressure boundary function of the electrical penetration feed-through modules to be part of the structures scope. The applicant is requested to submit an AMR for the Containment pressure boundary function of electrical penetration feed-through modules as part of the structures scope.

Dominion Response:

The evaluation boundaries for the containment electrical penetrations are described in LRA Sections 2.4.1 and 2.5.2 and the aging management review results are provided in LRA Tables 3.5.2-1 and 3.6.2-2. The information provided in these sections meets the requirements of 10 CFR 54.21(a). Therefore, no changes to the LRA are deemed necessary.

RAI 2.4-6

LRA Section 2.4.2.17 for Millstone 2 discusses the scoping and screening results for the Unit 2 Intake Structure. In order to complete the review of this section of the LRA, the staff requests the following additional information:

a. The LRA states that the trash racks for the Unit 2 Intake Structure are within the scope of license renewal and references FSAR Section 5.6 for further details. The staff has reviewed this FSAR section and cannot identify the trash racks on FSAR Figure 5.6-1. This figure does identify a course screen guide and a fine screen guide. Please clarify whether these two guides are the same as the trash racks referred to in the LRA. If not, please identify the location of the trash racks on FSAR Figure 5.6-1 and clarify whether the course screen and fine screen guides are within the scope of license renewal. If not, please explain why not.

b. The LRA states that the traveling screens for the Unit 2 Intake Structure are not in the scope of license renewal because they do not perform an intended function. FSAR Section 9.7.2.2.1 states that the service water pumps take suction downstream from the traveling screens in the intake structure. This configuration is also illustrated in FSAR Figure 5.6-1. Please provide the technical basis for the conclusion that the traveling screens are not within the scope of license renewal.

c. FSAR Figure 5.6-1 identifies four sluice gates located on the north face of the Intake Structure. These sluice gates appear to be located in the Recirculation Distribution Box on the Intake Structure Wall as shown on FSAR Figure 5.6-2 and apparently are associated with the operation of the Unit 2 Bypass Line discussed in LRA Section 2.4.2.20. Please clarify whether these sluice gates are within the scope of license renewal. If they are, please identify where they are included in LRA Table 2.4.2-17. If they are not, please explain why not.

Dominion Response:

a. FSAR Figure 5.6-1 identifies a course screen guide and a fine screen guide. The course screen guide is installed for the trash racks. The course screen guide is within the scope of license renewal and inspected as part of the trash rack assembly. The fine screen and guide are not within the scope of licensee renewal because the fine screen is not utilized.

b. The traveling screens are part of the non-safety related circulating water system that supports normal plant operation. During normal plant operation, the circulating water pumps draw a significant flow of cooling water through the bays of the Intake Structure to support the main condenser cooling requirements. The flow velocity during normal plant operation is approximately 1.0 ft/sec. This flow rate creates the potential for debris and sediment to enter the bays. During emergency operation when the circulating water pumps are not in operation, the service water pumps draw a small amount of cooling water through the bays with a low flow velocity (approximately 0.09 ft/sec). The low flow velocity will create an insignificant amount of debris and sediment and the traveling water screens will be able to pass sufficient amount of cooling water to the service water pumps to allow for safe shutdown. The service water pumps also have their own discharge strainers to filter out small debris and vegetation. Therefore, the traveling screens do not provide a license renewal intended function as defined in 10CFR 54.4(a)(1), (2) or (3) and are not in scope for license renewal.

c. The sluice gates consist of a frame, guides, and sliding gate installed in the concrete chamber walls. These component parts are the equivalent of valve internals and have been determined to be active components. However, the sluice gate is not configured with a housing in a manner similar to a valve body. Therefore, although the sluice gates are in the scope of license renewal, they are active components that do not require aging management review, and are not included in LRA Table 2.4.2-26.

RAI 2.4-7

LRA Section 2.4.2.18 for Millstone 2 discusses the scoping and screening results for the sea walls. The LRA states that the walls are post-tensioned reinforced concrete sea walls. FSAR Section 2.5.4.2.1 states that the anchorage system for the walls consists of five to eleven strands, consisting of seven wires per strand, which are anchored into bedrock by drilling and grouting. It also states that the anchorages are encased in concrete. A typical anchorage is shown in FSAR Figure 2.5-15. LRA Table 2.4.2-18 states that the sea wall structural members that require aging management review are "structural reinforced concrete (footing, walls)." Please clarify whether the wall anchorage system shown in FSAR Figure 2.5-15 is also within the scope of license renewal and is included as part of the item listed in LRA Table 2.4.2-18. If not, please explain why not.

Dominion Response:

The sea wall anchorage functions to maintain the integrity of the sea wall and is in the scope of license renewal. The sea wall anchorage was inadvertently omitted from LRA Table 2.4.2-18 and Table 3.5.2-19. The sea wall anchorage system, consisting of the anchorage strands, has been evaluated for the effects of aging. The carbon steel anchor strands are anchored in rock by drilling and grouting. The unbonded length of the steel strands is located within a polyvinyl chloride (PVC) pipe that is completely grouted following the post-tensioning operation. The anchorage system is located in the center of the 4-foot thick reinforced concrete sea wall. The concrete, in addition to the grout and PVC pipe, provides ample protection such that the anchorage system is not exposed to an aggressive environment. Therefore, the aging management review concluded that there are no aging effects requiring management of the anchorage system.

RAI 2.4-8

LRA Section 2.4.1 for Millstone 3 discusses the scoping and screening results for the Containment. The LRA states that a seismic Category 1 reinforced concrete ring girder encircles the Containment structure to prevent postulated sliding of rock wedges toward the Containment wall during a seismic event. LRA Table 2.4.1-1 identifies the ring girder as requiring an aging management review and LRA Table 3.5.2-1 presents the aging management review results for the concrete structural members of the ring girder. FSAR Section 3.8.1.1.5 states that the ring girder is isolated from the containment wall by a compressible material. FSAR Figures 3.8-1, 3.8-23 and 3.8-24 identify the following components between the ring girder and the containment wall: compressible material, waterproofing membrane, protection board, ribbed fiberglass and waterstop. Some applicable components such as moisture barrier and expansion joint/seismic gap material (between adjacent buildings/structures) are generally identified in LRA Tables 2.4.1-1 and 2.4.2-36 as requiring an aging management review. Please clarify whether all the components between the ring girder and the containment wall that are identified in FSAR Figures 3.8-1, 3.8-23 and 3.8-24 are within the scope of license renewal. If so, please identify where they are included in LRA Tables 2.4.1-1 and 2.4.2-36.

Dominion Response:

The components listed in RAI 2.4-8, that are located between the ring girder and the containment wall, are identified in FSAR Figures 3.8-1, 3.8-23, and 3.8-24. They include: compressible material, waterproofing membrane, protection board, ribbed fiberglass, and waterstop. Of these, only the ribbed fiberglass material and the waterstops are within the scope of license renewal and subject to aging management review as described below.

The compressible material was installed during construction to maintain a separation gap between the ring girder and the Containment structure. The gap material also functioned as a gap filler to prevent debris from entering this gap until the adjacent building floors were constructed. With these floors in place, there is no possibility of debris entering the gap between the ring girder and the Containment structure, and the gap filler material no longer serves a function. Therefore, the compressible material is not in the scope of license renewal.

The waterproofing membrane is installed to minimize the effects of groundwater on the containment walls and foundation. However, the membrane is known to be breached and, when groundwater penetrates or otherwise circumvents the membrane, the water drains to an underdrains removal system that includes a layer of porous concrete beneath the Containment and Engineered Safety Features (ESF) Building foundations. As such, failure of the waterproof membrane does not affect the structural integrity of the Containment structure or liner. Therefore, the waterproof membrane does not perform a license renewal intended function and is not in the scope of license renewal.

The protection board was placed during construction of the containment and ring girder structures to protect the waterproofing membrane. This component no longer serves a function and is not in the scope of license renewal.

The ribbed fiberglass was placed in sheets against the outside wall of the Containment structure during construction to provide an intentional space for flow of any groundwater leaking through the waterproofing membrane down to the underdrains removal system. Although it is considered unlikely that this flowpath would not be maintained even in the event of failure of the ribbed fiberglass sheets, these components have been included in the scope of license renewal and subjected to an aging management review. As a result, the fiberglass material has been evaluated for the effects of aging in an air and a water environment. There are no applicable aging effects in these environments and there is no requirement to apply an aging management program for these components.

Waterstops are included in the scope of license renewal and are subject to aging management review as part of the concrete structural member with which they are associated as described in LRA Appendix C, Section C2.4.

RAI 2.4-9

LRA Section 2.4.2.26 for Millstone 3 discusses the scoping and screening results for the Unit 3 Circulating and Service Water Pumphouse and references FSAR Section 3.8.4 for further details. FSAR Figure 3.8-69 (Sheet 4 of 4) indicates that sluice gates are located in the concrete chamber located in the front of the pumphouse. It appears that these sluice gates are associated with the operation of the Unit 3 Recirculation Tempering Line discussed in LRA Section 2.4.2.30. Please clarify whether these sluice gates are within the scope of license renewal. If they are, please identify where they are included in LRA Table 2.4.2-26. If they are not, please explain why not.

Dominion Response:

The sluice gates consist of a frame, guides, and sliding gate installed in the concrete chamber walls. These component parts are the equivalent of valve internals and have been determined to be active components. However, the sluice gate is not configured with a pressure boundary housing. Therefore, although the sluice gates are in the scope of license renewal, they are active components that do not require aging management review, and are not included in LRA Table 2.4.2-26.

RAI 2.4-10

LRA Section 2.4.2.27 for Millstone 3 discusses the scoping and screening results for the Unit 3 West Retaining Wall. The LRA states that the Unit 3 retaining wall is in the scope of license renewal and meets 10CFR54.4(a)(1) because it is a Seismic Category I structure that provides protection for safety-related service water piping. FSAR Section 3.8.4.1 states that the function of the west retaining wall is to protect the Category 1 service water and electrical lines located behind the wall and to be part of the shoreline protection. FSAR Section 2.5.5.1.1 further states that the west retaining wall is to protect the circulating and service water lines from being undermined due to wave action on the adjoining slope. This slope is referred to in FSAR Section 2.5.5.1.1 as the "shoreline slope" and the FSAR states that a multilayer stone armor zone was placed on the slope for protection against wave action during the probable maximum hurricane. There is considerable discussion in FSAR Section 2.5.5 concerning the analysis of the stability of this slope under static, dynamic and post-earthquake conditions. Please explain whether the shoreline slope serves an intended function in accordance with 10CFR54.4(a)(2). If so, please identify the components of the slope that are subject to an aging management review and the results of that review.

Dominion Response:

The shoreline slope configuration and multilayer stone armor zone described in FSAR Section 2.5.5.1.1 is not required to protect the nearby West Retaining Wall and Circulating and Service Water Pumphouse Category I structures or the service water lines and electrical cabling. However, failure of the shoreline slope stone armor, which was placed to protect the slope from wave action based on the probable maximum hurricane, could result in erosion or a slope failure of the shoreline slope and displacement of material to near the intake bays, possibly resulting in a restriction of the service water pump suction. Therefore, the multilayer stone armor zone should have been included in the scope of license renewal and subject to aging management review.

The stone armor was sized to remain in place during the probable maximum hurricane. The stone is hard crystalline rock that is not expected to experience significant degradation over the period of extended operation. Additionally, operating experience has indicated no degradation of this multilayer stone armor zone since it was constructed. Therefore, the aging management review concluded that there are no aging effects requiring management for the multilayer stone armor zone.

RAI 2.4-11

LRA Section 2.4.2.28 for Millstone 3 discusses the scoping and screening results for the sea walls. The LRA states that the walls are reinforced concrete with post-tensioned rock anchors consisting of steel tendons. FSAR Section 2.5.5.1.1 provides similar information. A typical anchorage is not shown in the Millstone 3 FSAR; however, from the written description, it appears that the details are similar to those shown in Figure 2.5-15 of the Millstone 2 FSAR. LRA Table 2.4.2-28 lists the sea wall structural members requiring aging management review as "structural reinforced concrete (footing, walls)." Please clarify whether the Millstone 3 sea wall anchorage system is the same as that shown in the Millstone 2 FSAR Figure 2.5-15. Indicate whether the anchorage system is within the scope of license renewal and included as part of the item listed in LRA Table 2.4.2-28. If the anchorage system is not included in the scope of license renewal, please explain why not.

Dominion Response:

The Unit 3 sea wall anchorage design is the same as the Unit 2 design except that the unbonded length of the anchor strands is protected with a corrosion protection material instead of grout.

The sea wall anchorage functions to maintain integrity of the sea wall and is in the scope of license renewal. The sea wall anchorage was inadvertently omitted from LRA Table 2.4.2-28 and Table 3.5.2-29. The sea wall anchorage system, consisting of the anchorage strands, has been evaluated for the effects of aging. The carbon steel anchor strands are anchored in rock by drilling and grouting. The unbonded length of the steel strands is located in a polyvinyl chloride (PVC) pipe that is filled with a corrosion protection material. The anchorage system is located in the center of the 4-foot thick reinforced concrete sea wall. The concrete, in addition to the corrosion protection material and the PVC pipe, provides ample protection such that the anchorage system is not exposed to an aggressive environment. Therefore, the aging management review concluded that there are no aging effects requiring management for the anchorage system.

RAI 2.4-12

Millstone 2 LRA Section 2.4.1 "Containment" references Unit 2 FSAR Section 5.9.3.3 for additional details about the containment post-tensioning system. Unit 2 FSAR Section 5.9.3.3.4 "Corrosion Protection" states "As a result of the Millstone Unit No. 2 tendon surveillance program, sixteen horizontal tendons have been identified as subject to ground water intrusion. To prevent ground water intrusion, the corrosion protection material is continuously supplied to the subject tendons at a pressure slightly above hydrostatic pressure of the ground water. The tendons so pressurized are horizontal tendons 12H01 through 12H06, 12H08 through 12H10, 31H01 through 31H04, 31H01, 32H02, and 32H03." In accordance with 10CFR54.4(a)(2), the system that continuously supplies corrosion protection material to the sixteen (16) horizontal tendons appears to serve an intended function. The applicant is requested to submit a scoping and screening evaluation and AMR for this system. If applicable, provide the technical basis for excluding this system from the scope of license renewal.

(Note: this was RAI 2.4-14 (M3) in Revision 0, 05/03/04)

Dominion Response:

The safety-related containment post-tensioning system is in the scope of license renewal because it provides containment structural integrity. The post-tensioning system is composed of horizontal and vertical tendon wires and associated tendon anchorages that are used to prestress the cylindrical portion of the concrete Containment. Corrosion protection material (grease) is continuously applied as a preventative measure to prevent the intrusion of water into 16 horizontal hoop tendons that have been identified as subject to ground water intrusion. Failure to supply the corrosion protection material to the tendons may allow ground water intrusion, but would not affect the tension on the containment tendons or the structural integrity of the Containment. Additionally, no credit is taken for corrosion protection of the containment tendons in the determination of aging effects. Loss of material was identified for the containment tendons and is managed with the Inservice Inspection Program: Containment Inspections AMP as indicated in LRA Table 3.5.2-1.

Therefore, since the pressurized application of corrosion protection material to the tendons is not required for containment structural integrity or to maintain proper tension of the tendons, and is not credited in the aging management review, it does not meet the criteria of 10CFR54.4(a)(2) for being included in the scope of license renewal.

RAI 2.4-13

LRA Sections 2.4.1 and 2.4.2.7 identify the presence of a porous concrete subfoundation that is founded on bedrock, under the Containment Structure and part of the Engineered Safety Features Building. LRA Tables 2.4-1and 2.4.2-7-list "subfoundation" as a component type subject to aging management review. LRA Section 2.3.3.51 "Reactor Plant Aerated Drains System" states:

> In addition, the Reactor Plant Aerated Drains System includes the Engineered Safety Features Building porous concrete groundwater sump that collects groundwater and prevents it from adversely affecting the Containment or imparting hydrostatic pressure on the containment liner. The sump pump discharges the collected groundwater to the groundwater underdrains storage tank located in the yard.
>
> The Reactor Plant Aerated Drains System is in the scope of license renewal because it meets 10CFR54.4(a)(1) by providing Containment pressure boundary integrity, collection and removal of groundwater from the ESF building underdrains and porous concrete, ...
>
> The evaluation boundary of the Reactor Plant Aerated Drains System includes piping and components that provide for collection and removal of groundwater from the ESF Building underdrains and porous concrete, and those components that provide an isolation boundary for the service water pump cubicles and the Supplemental Leak Collection and Release System. The evaluation boundary also includes components that are spatially oriented near safety related equipment in the Auxiliary Building, ESF Building, Control Building, and Containment structure.

LRA Table 2.3.3-48 lists the "groundwater sump" as a component type subject to aging management review for the Reactor Plant Aerated Drains System.

The staff reviewed referenced Millstone 3 FSAR Sections 1.2.3, 3.8.1, 3.8.1.1, 3.8.3, 9.3.3 and Table 3.2-1. The staff also reviewed other applicable FSAR Sections 1.8, 2.5.4.6.1, 3.4.1.2, 3.8.1.6.4, 3.8.5.1, 3.8.5.6, 9.3.3.1, 9.3.3.2.4, 9.3.3.2.4.1, 9.3.3.3, and 9.3.3.4, in order to better understand the porous concrete subfoundation and its intended function, and the components of the Reactor Plant Aerated Drains System that are essential to accomplish this intended function. The staff identified a number of other structural and mechanical components, in addition to the porous concrete subfoundation and the porous concrete groundwater sump, that appear to be essential to accomplish this intended function. Examples are the groundwater underdrains storage tank and its foundation; flow path between the groundwater sump and the groundwater underdrains storage tank; the outflow components from the groundwater underdrains storage tank; sump pump; standpipe assembly; sump water level and pump operability monitoring instrumentation. Therefore, the applicant is requested to

(1) provide a clear and concise description of the safety-related groundwater collection and removal intended function; (2) identify all the structural and mechanical components that are essential to accomplishing this intended function; (3) list the components identified in (2) above that are within the scope of license renewal, and indicate where they are covered in LRA Sections 2.3 or 2.4; and (4) list the components identified in (2) above that are not within the scope of license renewal, and provide the technical basis for this determination.

(Note: this was RAI 2.4-15 (M3) in Revision 0, 05/03/04)

Dominion Response:

As stated in Millstone Unit 3 LRA Section 2.3.3.51, an intended function of the Reactor Plant Aerated Drains System is the collection and removal of groundwater from the ESF building underdrains and porous concrete. As further stated in Section 2.3.3.51, the evaluation boundary of the system includes the piping and components that provide for collection and removal of groundwater from the ESF Building underdrains and porous concrete. Specifically, the evaluation boundary, as identified on license renewal drawing 25212-LR26906, Sh. 4, includes the piping from the porous concrete subfoundation underdrains to the collection sump, the sump pump, the pump discharge piping, and the sump casing and expansion joint to a point outside the ESF Building. The applicable components are included in the component types "Expansion Joints", "Groundwater Sump", "Pipe", and "Pumps" in LRA Table 2.3.3-48. (Note: The groundwater sump, 3SRW*SUMP6, was inadvertently not highlighted on license renewal drawing 25212-LR26906, Sh. 4). The evaluation boundary shown on license renewal drawing 25212-LR26906, Sh. 4, stops where the sump discharge reaches the yard area outside the ESF Building since this is sufficient to accomplish the intended function to collect and remove drainage from the porous concrete subfoundation. The groundwater underdrains storage tank and associated foundation, and components in the flowpath outside the ESF Building, are not required to support the identified intended function.

However, in response to RAI 2.1-1, the groundwater underdrains storage tank and associated piping have been added to the scope of license renewal as a non-safety-related component that is spatially oriented such that its failure could prevent the function of safety-related SSCs. The groundwater underdrains storage tank shares the foundation of the Unit 3 refueling water storage tank which is in the scope of license renewal as indicated in LRA Table 2.4.2-32.

Sump level monitoring and pump operability instrumentation, although in scope, are active components and not subject to aging management review.

RAI 2.4-14

FSAR Sections 2.5.4.12 and 3.8.4.1 state that rock dowels were installed around the periphery of the auxiliary building to provide stability during seismic loading. FSAR Section 2.5.4.12 also states that rock anchors were installed (1) in the turbine building to provide resistance to overturning due to tornado loading, and (2) in the service building to provide resistance to uplift due to buoyant forces and seismic forces. LRA Sections 2.4.2.2 Unit 3 Auxiliary Building, 2.4.2.12 Unit 3 Service Building and 2.4.2.13 Unit 3 Turbine Building do not discuss the use of rock dowels and/or rock anchors for these structures, and rock dowels/rock anchors are not specifically identified as component types requiring an aging management review in LRA Tables 2.4.2 2, 2.4.2 12, and 2.4.2 13. Please clarify whether these rock dowels/anchors are within the scope of license renewal. If they are, please identify where they are included in LRA Tables 2.4.2 2, 2.4.2 12 and 2.4.2 13. If not within the scope of license renewal, provide the technical basis for this determination.

Dominion Response:

Rock dowels are installed around the periphery of the Auxiliary Building foundation and rock anchors are installed in the Service Building and Turbine Building foundation. These rock dowels and rock anchors are considered part of the concrete foundation and are included in the structural member "Structural Reinforced Concrete" in LRA Tables 2.4.2-2, 2.4.2-12, and 2.4.2-13 and subject to aging management.

RAI 2.5-1

Table 2.5.1 of the LRA lists electrical cables and connectors not subject to EQ requirements to be subjected to an aging management review (AMR). It does not include splices, and fuse holder (non-metallic portions). Provide a technical justification of why splices, and fuse holders are excluded from the AMR.

Dominion Response:

Splices are considered an integral part of the cable and non-EQ splices are included in the commodity groups "Conductors" and "Insulation" in LRA Table 2.5.1-1 and the aging management review results are included in LRA Table 3.6.2-1. Fuse holders (including non-metallic portions) that are not part of a larger assembly, but support safety-related and non-safety-related functions in which a failure of a fuse precludes a safety function from being accomplished, are subject to aging management review and will be evaluated prior to the period of extended operation as described in LRA Section 2.1.6.5. This commitment is identified as Commitment 6 in LRA Appendix A, Table A6.0-1.

RAI 2.5-2

When cables are included in AMR, are there any non-safety-related cables (not in scope of license renewal) excluded from the AMR. If they are, how these cables are treated if they run in the same conduits or raceways with other cables.

Dominion Response:

The only non-safety-related cables that are not subject to aging management review are the Unit 2 control element drive mechanism and Unit 3 control rod drive mechanism cables. In some instances, these cables may be routed in the same raceways as in-scope non-EQ cables. However, since an areas-based approach is used to manage the effects of aging for non-EQ cables, as described in LRA Section B2.1.8, "Electrical Cables and Connectors not Subject to 10 CFR 50.49 Environmental Qualification Requirements", all cables within a raceway are subject to the aging management program.

RAI 2.5-3

Explain why grounding systems are not within the scope of license renewal.

Dominion Response:

The station grounding system bonds metal raceways, building structural steel, and plant equipment to earth ground through an installed grounding grid. The station grounding system is non-safety-related and is provided for personnel and equipment protection. In the event of a fault in an electrical circuit or component, the grounding system includes the capability to detect and/or isolate the fault to minimize equipment damage. The grounding system does not prevent faults and is not required for equipment operation. Failure of the system cannot affect the accomplishment of any safety functions. Therefore, the system does not perform an intended function that meets the criteria of 10 CFR 54.4(a) and is not within the scope of license renewal.

RAI 2.5-4

Section 2.5, Table 2.5.1 of the LRA does not include the transmission connections to be included in the AMR. Transmission connections are within the scope of license renewal, are considered long-lived, passive components and should be included in the AMR. Explain why transmission connections are excluded from the AMR.

Dominion Response:

Transmission connections are within the scope of license renewal and subject to aging management review. Transmission connections are included in the commodity group "Conductors" in LRA Table 2.5.1-1.

RAI 3.2-1

LRA Tables 3.2.2-1 for the containment recirculation components identify loss of material as an aging affect applicable to nickel based alloys and copper alloys exposed to internal and external air environments. The LRA does not identify the alloy zinc content for these materials. The LRA credits the work control process for managing loss of material of the nickel based alloy containment recirculation cooler tubesheets and copper alloy tubes in an external air environment and the AMP "Service Water System" for managing loss of material on the interior of copper alloy channel heads and tubes and nickel based alloy tubesheets. Industry documents such as EPRI report 1003056 identify various corrosion mechanisms causing loss of material in an air environment subject to moisture. Aging mechanisms such as selective leaching, crevice corrosion and galvanic corrosion are material and location dependent. Identify the alloy zinc content and clarify if selective leaching is an applicable aging mechanism. If selective leaching is an applicable aging mechanism, clarify if hardness testing and one-time inspection required by GALL AMP XI.M33 will be used. Also clarify how visual inspections required by the aging management programs are effective in managing loss of material by providing for inspections at locations that are susceptible to the aging mechanism such as tbe [the] tubesheet and channel head interiors which may be inaccessible for visual inspection. The applicant is requested to provide the following additional information (a) frequency of the inspections including the bases. (b) Inspection methods which verify the loss of material in the recirculation cooler channel heads, tube sheets and tubes (c) Identify any operating experience to demonstrate the effectiveness of the work control process and the service water program to manage loss of material in nickel based alloys and copper alloys exposed to an external air environment.

Dominion Response:

The containment recirculation cooler tubes and channel head lining are copper-nickel material and the tubesheet is nickel-copper (Monel) material. Zinc is not an alloying element for any of these materials. Therefore, selective leaching is not an applicable aging mechanism for these components.

The containment recirculation coolers are maintained in a dry lay-up condition and loss of material due to corrosion is not expected. However, since the coolers are flushed and flow tested on a periodic basis, the aging management review conservatively considered the environment for the coolers to be intermittently wetted. As a result, loss of material due to corrosion was determined to be an applicable aging effect for the containment recirculation coolers. The coolers are accessed and the tubesheets and channel head interiors are inspected as part of the Service Water System (Open-Cycle Cooling) AMP described in LRA Appendix B, Section B2.1.21. In addition, components that are opened or disassembled for maintenance activities are visually inspected as part of the Work Control Process aging management program as described in Appendix B, Section B2.1.25. For containment recirculation cooler locations that are not readily accessible for visual inspection, the Work Control Process AMP remains effective in that other work activities which are associated with components representative of the specific materials and environments of the coolers provide an indication of the condition of the cooler components.

The containment recirculation coolers are inspected every other refueling outage in accordance with the Service Water System (Open-Cycle Cooling) AMP. The containment recirculation cooler inlet ends are accessed and a visual inspection is performed.

Demonstration of the effectiveness of the Service Water System (Open-Cycle Cooling) AMP is addressed in the discussion of operating experience provided in the LRA Section B2.1.21. Operating experience related to the Work Control Process AMP is addressed in LRA Section B2.1.25.

RAI 3.2-2

The applicant states in the LRA "The Millstone Unit 3 containment recirculation coolers and service water supply piping to these heat exchangers are infrequently used loops but are not flushed in accordance with GL 89-13. The containment recirculation coolers are maintained in a dry lay up condition. Thus, no mechanism exists for tube side fouling and the ability of the coolers to perform their intended function is maintained. The service water supply piping to these heat exchangers is flushed on a semi-annual basis to displace any mussel or hydroid colonies onto screens installed on the tubesheets of these heat exchangers. The accumulated debris on the screens is then removed after the flushing evolution." The applicant is requested to provide information based on inspections and applicant's self-assessment programs which assure that with the present state of fouling the recirculation coolers in Unit 3 will be able to perform to perform their intended function during the period of extended operation. For example are visual inspections performed and correlated to an acceptable degree of fouling to determine the effectiveness of the dry lay up program?

Dominion Response:

Review of the last three years of inspection data for the Unit 3 A, B, C and D containment recirculation coolers and discussion with the system engineer indicate that the degree of fouling is minor and did not affect the operability of the heat exchangers. The semi-annual service water inlet piping flush and inspection did not identify foreign debris in most cases. Some inspections did identify small amounts of mussel shell pieces and evaluations in accordance with plant procedures were performed to determine if the heat exchanger operation could have been impacted; however, no concerns were identified. Based on the results of the current flushing and inspection frequency, the dry lay up program is effective in maintaining the degree of fouling at a level that supports plant operation. Any substantial change in the effectiveness of the flush and inspection surveillance results would be addressed through the corrective action program.

RAI 3.3-A-2

The LRA identifies cracking in ductwork joint seals using Dux Seal material for various ventilation system components in the auxiliary systems. The general condition monitoring program is credited with managing this aging effect through the use of visual inspections of external surfaces and the LRA tables do not identify aging effects for ductwork seals exposed to the internal environment. In some cases, drying and cracking of seals from the internal environment with continuous air flow could potentially be more severe than the external environment. The general condition monitoring AMP described in LRA Section B2.1.13 does not identify specific criteria, including the inspection frequency and its technical basis, unique to managing ductwork joint seals and it is not clear how external visual inspections will manage internal degradation. Clarify how visual inspection of the external surfaces of ductwork joint seals is adequate to detect internal cracking prior to loss of the component pressure boundary function. In addition, the condition monitoring program is limited to accessible plant areas. Clarify how ductwork joint seals in inaccessible areas are inspected and/or tested for cracking. Also provide the inspection frequency, including its technical basis, and the operational history to demonstrate the effectiveness of the general condition monitoring program to manage cracking in ductwork joint seals.

Dominion Response:

Dux Seal is an adhesive/sealant-saturated fabric cloth that is applied to the external surface of ductwork at the crimped and riveted joints in order to provide a leak-tight seal. The material (also termed Hardcast) cures hard and rigid, and is not similar to duct tape. Since it is applied to the outside surface of the duct, the primary exposure environment is ambient air. No aging effects are expected to originate from the inside of the ductwork due to the limited exposure to the ductwork internal environment. Therefore, the cracking aging effect has been determined to require management due to the external environment.

Ductwork is generally not routed through inaccessible areas of the plant, and no inaccessible ductwork joint seals were identified as part of the aging management review.

The cracking aging effect for the ductwork joint seals is visually observable during the inspections performed as part of the General Condition Monitoring Aging Management Program as described in LRA Appendix B, Section B2.1.13. Inspections are performed by the system engineers as part of comprehensive system evaluations performed quarterly, and by the plant equipment operators during daily rounds of plant areas to verify proper component and system operation. Significant degradation of the ductwork joint seals has not been identified, however, the effectiveness of the General Condition Monitoring AMP is demonstrated by operating experience associated with other plant components as cited in Appendix B, Section B2.1.13.

RAI 3.3-A-3

LRA Tables 3.3.2-34 and 3.3.2-36 for the diesel generator and station blackout diesel generator respectively identify loss of material as an aging effect applicable to nickel based alloys and copper alloys exposed to a moisture-laden air and/or intermittently wetted environment. The LRA does not identify the alloy zinc content for these materials. The LRA credits the work control process for managing loss of material in the interior of nickel based alloy valves and the general condition monitoring program for managing loss of material on the exterior of copper alloy radiators. These AMPs primarily rely on visual inspections. Industry documents such as EPRI report 1003056, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Rev. 3 identify various corrosion mechanisms, including selective leaching, causing loss of material in copper alloys with greater than 15% zinc content in an air environment subject to moisture. Loss of material from selective leaching is specifically addressed in GALL AMP XI.M33, but page B-7 of the LRA states that the aging management reviews did not identify the need for this aging management program. Identify the alloy zinc content for these materials and clarify if selective leaching is an applicable aging mechanism. If selective leaching is an applicable aging mechanism, clarify if hardness measurement and one-time inspection required by GALL AMP XI.M33 will be used to manage the aging effect.

Dominion Response:

Dominion conservatively assumed that all copper alloys were of a material composition that could be susceptible to selective leaching. Accordingly, the zinc content for copper alloys was not identified in the LRA since it was not used as an input to the evaluation of aging mechanisms. Selective leaching was not considered an applicable aging mechanism for nickel-based alloys.

Selective leaching of copper alloys was not considered to be significant in a moisture-laden air and/or an intermittently wetted environment unless conditions were conducive to water collection or pooling which would cause wetting for a significant period of time. If water collection or pooling was present for a component, the component was evaluated with a raw water environment as defined in LRA Table 3.0-1.

The copper alloy components in the diesel generator system associated with moisture-laden air are the pipes and tubes of the turbocharger and intercooler air systems. Wetting is possible during the operation of these components which normally occurs only during monthly Technical Specification surveillance testing. Wetted conditions would dissipate after use due to the elevated temperatures of operation. Therefore, wetting for a significant time period would not occur.

The copper alloy component in the diesel generator system associated with intermittent wetting is the level indicator (sight glass) on the jacket cooling water expansion tanks. Portions of this component are normally dry but may occasionally become wetted. Wetting for a significant time period is not expected.

The copper alloy component in the station blackout diesel generator system associated with intermittent wetting is the radiator that is exposed to an atmosphere/weather environment. Atmosphere/weather environments and selective leaching are discussed in the response to RAI 3.3-B-2.

Based on the above, loss of material due to selective leaching was not identified for the diesel generator and station blackout diesel generator copper alloy components exposed to a moisture-laden air and/or intermittently wetted environment. However, loss of material due to general corrosion was conservatively identified as an aging effect for these components and the Work Control Process and the General Condition Monitoring AMPs provide management of this aging effect.

RAI 3.3-B-2

LRA Tables 3.3.2-2, 3.3.2-12, 3.3.2-15 and 3.3.2-41 for the service water, instrument air, CVCS and station blackout diesel generator systems respectively identify loss of material as an aging effect applicable to nickel-based and copper alloys exposed to an atmosphere/weather and treated water environments. The LRA does not identify the alloy zinc content for these materials. The LRA credits the general condition monitoring program for managing loss of material on the exterior of various nickel based or copper alloy materials and the work control process for managing loss of material in the interior of copper alloy tubes and tubesheets. These AMPs primarily rely on visual inspections. Industry documents such as EPRI report 1003056, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Rev. 3 identify various corrosion mechanisms, including selective leaching, causing loss of material in copper alloys with greater than 15% zinc content in a treated water environment or an air environment subject to moisture. Loss of material from selective leaching is specifically addressed in GALL AMP XI.M33, but page B-7 of the LRA states that the aging management reviews did not identify the need for this aging management program. Identify the alloy zinc content for these materials and clarify if selective leaching is an applicable aging mechanism. If selective leaching is an applicable aging mechanism, clarify if hardness measurement and one-time inspection required by GALL AMP XI.M33 will be used to manage the aging effect.

Dominion Response:

Dominion conservatively assumed that all copper alloys were of a material composition that could be susceptible to selective leaching. Accordingly, the zinc content for copper alloys was not identified in the LRA since it was not used as an input to the evaluation of aging mechanisms. Selective leaching was not considered an applicable aging mechanism for nickel-based alloys.

Selective leaching of copper alloy components in the instrument air and station blackout diesel generator systems was not considered to be significant in an atmosphere/weather environment since this environment only involves periodic wetting of surfaces due to precipitation. Generally, surfaces would dry out and remain dry the majority of the time. If water collection or pooling from precipitation was present for a component, the component material was evaluated with a raw water environment as defined in LRA Table 3.0-1. However, loss of material due to general corrosion was conservatively identified as an aging effect for these components and the General Condition Monitoring AMP provides overall management of this aging effect.

Selective leaching of copper alloy components in the instrument air, station blackout diesel generator, and CVCS systems that are subjected to a treated water environment has been re-evaluated and considered to be an applicable aging mechanism. Although the treated water is adjusted to specifically control corrosion by the reduction of oxygen and/or the addition of corrosion inhibitor compounds, there is potential for selective leaching of susceptible materials in this environment. Management of loss of material due to selective leaching of copper alloy components in a treated water environment is performed by the Work Control Process AMP. Specific inspections for selective leaching by the Work Control Process are addressed in Audit Item #85 in the Dominion letter to the NRC staff dated July 7, 2004 (Serial No. 04-320).

No copper alloy components in the service water system are associated with a treated water or atmosphere/weather environment.

RAI 3.3.35-A-1

LRA Table 3.3.2-34 identifies copper alloy tubesheets in the lube oil heat exchangers as susceptible to buildup of deposit in an oil environment. The LRA identifies heat transfer as an intended function for the tube sheet and credits the work control process AMP for managing this aging effect. This AMP identifies the use of lubricating oil analysis to detect contaminants and visual inspections to detect buildup of deposits. In heat exchangers, buildup of deposit (commonly known as fouling) can adversely affect the heat transfer function. The diesel generators are normally only operated for short operational periods and the lubricating oil may not have a chance to reach steady state or worse case conditions during testing. Clarify if heat exchanger performance tests to recognized industry practices are used to detect fouling in the lube oil heat exchangers or are frequent visual inspections and cleaning required. In the absence of heat exchanger performance testing, submit the technical justification that unacceptable buildup of deposit on the tube sheet exposed to lubricating oil would be detected prior to loss of the required heat transfer function.

Dominion Response:

The performance of the lube oil heat exchangers is confirmed during emergency diesel generator (EDG) periodic surveillance testing. In accordance with plant Technical Specifications, the EDGs are operated at design load for a minimum of 60 minutes each 31 days. This test loading and duration ensures that the diesel engine and its auxiliary systems, including lubricating oil, reach steady state temperature conditions. The lube oil heat exchanger operates at steady state conditions for the majority of this testing period, thereby providing sufficient data to evaluate the heat transfer performance of the lube oil heat exchanger.

Buildup of deposit due to fouling in an oil environment is not expected to be significant, but is conservatively assumed in the aging management review for these heat exchangers because of the potential for water contamination of the oil. Buildup of deposit is managed by the Work Control Process AMP, which includes the periodic testing of the EDGs. Lube oil temperature is recorded during EDG testing and abnormal readings would initiate an evaluation through the corrective action process to determine the cause of the elevated temperatures. The frequency of the EDG performance tests ensures that fouling would not prevent the intended function of the lube oil heat exchanger. In addition, a review of Millstone operating experience indicates that there has been no instances of fouling of the EDG lube oil heat exchangers affecting the heat transfer intended function.

RAI 3.4-1

The LRA identifies a borated water leakage environment for various components in the steam and power conversion and ESF systems and both the boric acid corrosion program and general condition monitoring program are credited with managing loss of material from external surfaces. The boric acid corrosion program described in LRA Section B2.1.3 appears to be limited to components located inside containment, as addressed in NUREG-1801, Section XI.M10. Clarify why the boric acid corrosion program is credited for managing boric acid corrosion in systems that are located outside containment. Also, in regard to the effectiveness of the general condition monitoring program, clarify:

i) How the program manages loss of material for components not normally accessible.
ii) The basis of the inspection frequency (once per refueling outage) considering the potential rate for material loss.
iii) What acceptance criteria and corrective actions are applied to the visual indication of boric acid crystals without material degradation.
iv) How the program provides for promptly identifying the specific cause and location of the borated water leakage.

Dominion Response:

The Boric Acid Corrosion Program provides requirements to adequately manage boric acid related degradation of the reactor coolant system, ASME Class 1, 2 and 3 components, and associated or neighboring systems, structures, and components that are in the scope of License Renewal. The requirements of the Millstone Boric Acid Corrosion Program surpass the requirements listed in NUREG-1801, Section XI.M10, in that it is additionally applied to an identified boric acid system leak anywhere in the plant. As part of the Aging Management Review process, the Boric Acid Corrosion Program, along with the General Condition Monitoring Program, is credited for managing aging for the external surface of equipment located in a building that contains a boric acid liquid system (such as the Steam and Power Conversion system, the ESF system, and the Radwaste Ventilation system).

The General Condition Monitoring Program and the Boric Acid Corrosion Program are both listed for various components in the steam and power conversion, ESF, and radwaste ventilation systems because collectively they manage the loss of material for the external surfaces of these components. The General Condition Monitoring Program provides supplemental inspections to the Boric Acid Corrosion Program for managing loss of material due to boric acid corrosion in systems that are located outside containment, such as steam and power conversion, ESF, and radwaste ventilation systems. Any instances of boric acid leakage identified during general condition monitoring activities are entered into the corrective action program and evaluated using the guidance of the Boric Acid Corrosion Program.

The effectiveness questions identified are addressed by the Boric Acid Corrosion Program, not the General Condition Monitoring Program, since the Boric Acid Corrosion Program provides the evaluation and corrective actions when any evidence of boric acid leakage is identified. A more detailed answer is as follows:

i) Non-insulated components are examined by inspecting the accessible external surfaces for direct and indirect evidence of leakage. For components whose external surfaces are inaccessible for direct visual examination, the surrounding areas (including equipment surfaces located underneath the components) are examined for signs of leakage and other areas are considered where leakage may be channeled.

The Boric Acid Corrosion Program recognizes that boric acid leaks can travel down sloped pipes or under insulation. Evidence of leakage can also be determined for components with vertical surfaces of insulation by examining the lowest elevation where the leakage may be detectable. Horizontal surfaces of insulation can be examined at insulation joints. When there is doubt as to a leak's origin, the evidence (i.e., accumulation of boric acid crystals) needs to be preserved until an evaluation has been performed to estimate the source, pathway, target and amount that may be affected. This includes the removal of insulation to determine the leak location.

For those areas identified as infrequently accessed areas, for the purposes of detecting boric acid leakage, entry into the area is performed often enough (at least once per refueling interval) to credit the inspections in the General Condition Monitoring AMP and the Boric Acid Corrosion AMP. The one exception is the Unit 3 demineralizer cubicles area. However, for this area, a video inspection is performed at least once per ten years to verify the integrity of the equipment. Based on operating experience, there is reasonable assurance that this inspection interval will detect borated water leakage prior to the loss of intended function of the affected equipment.

ii) The Millstone Boric Acid Corrosion Program examines locations susceptible to boric acid leakage inside Containment during each refueling outage. It is not practical to perform these examinations while the reactor plant is operating. Any boric acid leakage identified by plant personnel is either corrected prior to the end of the outage or is evaluated to ensure the intended function is maintained until a repair can be performed. Dominion is aware of the issues associated with boric acid corrosion, and the plant operating conditions that could be indicative of boric acid leakage. For potential boric acid corrosion leakage, which may develop between refueling cycles, changes in plant parameters would provide indication that a potential leak may exist. Both identified and unidentified leakage is strictly monitored and trended for changes in sump level, flow rates, and frequency of pump operation. Changes in ambient conditions inside containment also provide indication of potential boric acid leakage. Abnormal ambient conditions inside containment are documented through the corrective action process, which may require a shutdown of the reactor plant in order to repair a leak inside containment. Plant operating experience indicates that boric acid inspections performed once per refueling cycle are adequate to maintain the intended function of the equipment in containment. Plant and industry operating experience indicates that a boric acid leak that starts during the operating cycle does not damage the equipment to the point where it cannot perform its intended function.

iii) In accordance with the Boric Acid Corrosion Program, any boric acid leakage identified by plant personnel (including boric acid crystals without material degradation) is documented through the corrective action process (10 CFR 50, Appendix B). Minor leakage may be just cleaned or, if leakage is more severe, a Boric Acid Corrosion Program assessment of the boric acid build-up is performed prior to clean-up. The leakage source, path, and target areas are located, and corrective actions are implemented as determined by the Boric Acid Corrosion Program. Corrective actions include timely repair of the leakage after detection to prevent or mitigate the extent of boric acid corrosion. Where evaluations are performed without repair or replacement, engineering analysis reasonably assures that the intended function is maintained consistent with the current licensing basis.

iv) The Boric Acid Corrosion Program provides for prompt identification of the specific cause and location of borated water leakage.

See response in item iii above.

Accessible areas are traversed on a daily basis by plant personnel who have been informed of expectations related to boric acid identification and corrective action. Personnel are expected to attempt to identify the leakage source as well as the extent of condition on secondary plant equipment. The Corrective Action Process triggers an investigation by the Boric Acid Corrosion Program. Minor boric acid may be just cleaned, more substantial leakage requires equipment to be repaired to stop the leak or an engineering evaluation be performed to ensure the intended function of the equipment is maintained until such a time that the leak can be repaired.

RAI 3.4-2

Section 3.4, Steam and Power Conversion Systems - Unit 3 The LRA Table 3.4.2-3 credits the AMP B2.124 "Tank Inspection Program" for managing the loss of material of the aluminum condensate storage tank in a damp soil environment. The applicant is requested to provide the following additional information regarding the aging management of this tank. (a) The alloy content of the aluminum and the welded joints or connections. (b) Type of coatings and/or linings, if any. (c) Support configuration of the tank in the moist soil environment. (d) The NDE methods which are employed to determine degradation of the tank walls and bottom (e) The frequency of the wall thickness measurements, their locations and acceptance criteria (f) The operating history of the tank relating to degradation and remedial actions taken in the past.

Dominion Response:

(a) The aging management review for the condensate storage tank did not credit any specific alloy content in the determination of applicable aging mechanisms/effects for the aluminum tank or welds.

(b) The condensate storage tank is not coated or lined. Additionally, as stated in LRA Appendix C, Section C2.4, coatings and linings were not credited in the determination of applicable aging effects for in-scope components, including tanks.

(c) The support configuration for the condensate storage tank consists of a reinforced concrete foundation with an oiled sand cushion as described in LRA Section 2.4.2.32. The oiled sand tank bottom supporting material was conservatively assumed to be equivalent to moist soil for the purposes of the aging management review.

(d) The aging management review for the condensate storage tank concluded that the tank bottom could be subject to loss of material. As discussed in LRA Appendix B, Section B2.1.24 "Tank Inspection Program", thickness measurement of the tank bottom will be performed using volumetric non-destructive examination methods.

(e) Per LRA Appendix A, Table A6.0-1, commitment 24, a baseline inspection of the condensate storage tank bottom will be performed prior to the period of extended operation. After that, as a minimum (depending upon baseline inspection results), inspections will occur every ten years. As noted in (d) above, the tank bottom thickness will be measured using volumetric non-destructive examination methods prior to the period of extended operation. Subsequent inspections will be performed on a frequency consistent with scheduled tank internals inspection activities.

(f) The operating history associated with the condensate storage tank is described in LRA Appendix B, Section B2.1.24. During a past inspection of the tank, water was found to be slowly leaking from the tank. Previous inspections of the tank had detected only occasional wetness. Internal operating experience had identified that the bottom of a similarly designed tank (the condensate surge tank) had already been replaced. The condensate surge tank did not have a barrier installed between the aluminum tank bottom and the sand that forms part of the base mat. An alkaline solution resulting from groundwater intrusion to the concrete foundation ring caused pitting of the aluminum and eventual through-wall leakage. An engineering evaluation concluded that the condensate storage tank and condensate surge tank were both built at the same time using a similar design. As a result of the investigation and previous operating experience, a design change was implemented to replace the condensate storage tank bottom. The new tank bottom was essentially a one for one replacement. In addition, the existing oil and sand mixture under the tank bottom was replaced with washed, clean, neutral, dry, low chloride and compacted sand, and asphalt impregnated fiber board was installed as a barrier between the aluminum tank and concrete foundation ring.

RAI 3.4-3

The LRA Table 3.4.2-4 credits the AMP B2.1.25 'Work Control Process' to manage the change in material properties and cracking of rubber in various expansion joints in a treated water environment. The applicant has identified no aging effect for these expansion joints in an external air environment. The work control process AMP described in LRA Section B2.1.25 does not identify specific criteria unique to managing rubber expansion joints and it is not clear how external visual inspections will manage internal degradation. Clarify how visual inspection of the external surfaces of the expansion joints is adequate to detect internal cracking prior to loss of the component pressure boundary function. In addition to visual inspections, clarify if other testing methods will be used, such as hardness testing to determine change of material properties. Identify any operating experience pertaining to rubber expansion joint inspections to demonstrate the effectiveness of the work control process program to manage cracking and change in material properties in rubber expansion joints exposed to treated water and external air.

Dominion Response:

There are no external aging effects applicable to these expansion joints. In addition, there are no external visual inspections credited for management of internal aging effects of the expansion joints. The Work Control Process aging management program referenced in LRA Table 3.4.2-4 for these expansion joints uses internal inspections to detect signs of aging as described in LRA Appendix B Section B2.1.25. Maintenance activities performed in accordance with the Work Control Process provide opportunities to visually inspect the internal surfaces of these components.

Internal cracking and change of material properties for these elastomer components are visually observable by such conditions as evidence of cracking and crazing, discoloration, distortion, evidence of swelling, tackiness, evaluation of resiliency and indentation recovery, etc.

Millstone Unit 2 commitment item 25 (and commitment item 26 for Millstone Unit 3) identified in LRA Appendix A, Table A6.0-1, provides for changes to maintenance and work control procedures to ensure inspections are appropriately and consistently performed.

A review of operating experience associated with these expansion joints indicates that degradation is observable through the Work Control Process activities. Conditions such as cracking and swelling have been noted resulting in replacement of the affected expansion joints.

Therefore, the Work Control Process manages the internal aging effects of the expansion joints to provide reasonable assurance that the intended function will be maintained.

RAI 3.5-1:

For item numbers 3.5.1-03 to 3.5.1-06 (Table 3.5.1) of the LRA, the applicant cites Containment ISI and Containment leak rate test as the aging management programs. A review of AMP B2.1.6 indicates that the Appendix J leak rate testing is part the ISI Program: Containment Inspections. In Appendix J program, the applicant takes credit for only Type A tests to measure the overall primary containment leakage rates. This is a major deviation from NUREG-1801, Section XI.S4 program. Also, the review indicates that the applicant is taking credit for the 1998 Edition of Subsections IWE of Section XI of the ASME Code, without citing compliance with the limitations and modifications associated with this Edition of the Code in 10 CFR 50.55a (67 FR 60520). This is a major deviation from NUREG-1801 Section XI.S1 program and requirements of the regulation. In view of these deviations, and the fact that the Type A leak rate testing may occur every 10 to 15 years, the applicant is requested to provide information as to how it plans to monitor the aging and leak-tightness of the components covered by item numbers 3.5.1-03 to 3.5.1-06. The applicant is requested to address seals and gaskets associated with equipment hatches, air locks, and, electrical and mechanical penetrations.

Dominion Response:

This item was identified as Audit Item 47 during the AMP/AMR Audit conducted the week of May 3, 2004. Dominion provided a supplemental response to Audit Item 47 as documented in the Dominion letter (Serial Number 04-320) dated July 7, 2004. In this letter, it was stated that the Millstone LRA has been supplemented to additionally credit Type B Local Leak Rate Tests (in accordance with 10CFR50, Appendix J) as part of the Containment ISI Aging Management Program. Type B Local Leak Rate Testing will ensure that the Containment pressure boundary function associated with the seals and gaskets for equipment hatches, air-locks, and, electrical and mechanical penetrations will be maintained during the period of extended operation.

The typical frequency for performing Type B Local Leak Rate tests is every four refueling outages (approximately every six years). Twenty-five percent of Type B electrical penetrations are performed on-line just prior to or following each refueling outage (approximately every 1 ½ years).

RAI 3.5-4

In addressing item 3.5.1-27, for the reinforced concrete structures subjected to elevated temperatures (e.g., primary shield walls, pressurizer and steam generator enclosures, reactor vessel supports, and the containment concrete around high energy penetrations) the applicant states: "NUREG-1801 is not applicable." Items IIA1.1-h and III.A4-1c of NUREG-1801 are directly applicable to Group 4 structural concrete. For these structures, the applicant is requested to provide the following information:

1. The method(s) of monitoring the concrete temperatures in these structures.

2. If the primary shield wall concrete, the containment concrete, or any other structural components within Millstone 2 and 3 containments are kept below the threshold temperature (i.e. 150°F) by means of air cooling, provide the operating experience related to the performance of the cooling system.

3. The results of the latest inspection of these structures, in terms of cracking, spalling, and condition of reactor vessel support structures, etc.

Dominion Response:

1. For Millstone Unit 2, the temperature of the primary shield wall concrete in the area of the reactor vessel supports is monitored and an alarm is provided in the control room if the temperature exceeds 150°F. Embedded cooling coils are provided at these locations to remove heat from the concrete. Although not directly measured, the temperature of the concrete in other areas of the Unit 2 containment, and in the Unit 3 containment, is maintained below threshold values by the design of ventilation systems. The containment ventilation systems maintain average containment internal air temperature below 120°F in accordance with Technical Specification requirements. Local ambient air temperatures in areas such as the steam generator cubicles and the pressurizer cubicle are maintained well below 150°F. The localized concrete temperature in the vicinity of high energy piping containment penetrations is maintained below the threshold value by the containment penetration cooling system, which consists of a ventilation system in Unit 2 (the Containment Penetration Cooling System described in LRA Section 2.3.3.18) and a water cooling system in Unit 3 (as part of the Reactor Plant Component Cooling System described in LRA Section 2.3.3.6).

2. The containment ventilation systems operate consistently in order to provide compliance with Technical Specification containment average temperature limit of 120°F. Failures of these systems to provide adequate cooling requires plant shutdown and, therefore, the threshold values for concrete temperature would not be exceeded. The containment concrete in the area of the Unit 2 high energy piping penetrations is cooled by the containment penetration cooling system. A review of plant operating experience has indicated that this system also operates consistently

and there are no identified failures that would have resulted in local concrete temperatures exceeding threshold values.

3. The latest inspections of the containment structure were performed in March 2001 and October 2003 for Unit 2 and in September 2002 for Unit 3. These inspections did not identify instances of significant cracking or spalling in the primary shield wall, pressurizer and steam generator enclosures, reactor vessel support concrete, or the containment concrete around high-energy penetrations. These inspection results provide further assurance that elevated temperature of containment concrete is not a significant concern for Millstone Unit 2 and Unit 3 containments.

RAI 3.5-5

Under column "Structural Member" in Table 3.5.2-x, Structures and Component Supports, Structures Monitoring Program is listed as an AMP for many structural members, such as doors, sliding bearings, metal siding sealants, roofing, siding, scuppers, miscellaneous steel, expansion joint/seismic gap material, and flood door/gate gasket. Item 18 in Table A6.0-1, License Renewal Commitments, states, "The Structures Monitoring Program and implementing procedures will be modified to include all in-scope structures." The staff assumes that the words "in-scope structures" include all structural members listed in Table 3.5.2-x that use the Structures Monitoring Program as an AMP. Please confirm whether the staff's assumption is correct or not.

Dominion Response:

This assumption is correct. Any in scope structural members that are not currently in the Structures Monitoring Program, such as those listed above, but are required to be inspected, will be added to the program prior to the period of extended operation.

RAI 3.5-6

The Work Control Process is listed as an AMP for many structural members, such as the rubber seal of the spent fuel pool gate, the carbon steel sump liner, and the neoprene gaskets in junction, terminal, and pull boxes. The staff did not find that these structural members were included in the scope of program of the B2.1.25 Work Control Process or that Table A6.0-1 lists these structural members in the Work Control Process as a license renewal commitment. Please explain how the Work Control Process includes and tracks the structural members listed in Table 3.5.2-x that use the Work Control Process as an AMP.

Dominion Response:

The Work Control Process inspects materials and environments in lieu of specific component types. Inspections are performed as part of preventive maintenance, corrective maintenance, predictive analysis, periodic surveillances, etc. A review of the Work Control Process inspection opportunities for each material and environment group that is in scope of License Renewal was performed for Millstone Units 2 and 3. It demonstrated adequate inspection opportunities for the vast majority of material and environment combinations.

A review of the Work Control Process inspection opportunities for each material and environment group supplemental to the initial review conducted during the development of the LRA will be performed. Baseline inspections will be performed for the material and environment combinations that have not been inspected as part of the Work control Process. This commitment is identified in Appendix A, Table A6.0-1 License Renewal Commitments, Item 30 (Unit 2) and 31 (Unit 3). These inspections will address the above item if no opportunity for inspection has been provided, prior to the period of extended operation. Unacceptable inspection results will be identified in the Corrective Action process. Corrective actions will consider the extent of condition of all component types included in that material and environment combination.

RAI 3.5-7

Structures Monitoring Program and Infrequently Accessed Area Inspection Program were listed as AMPs for Structural Reinforced Concrete (Beams, Columns, Floor slabs, Foundation mat slabs, Roof slabs, Walls) under column "Structural Member" and under column "Notes" H, 20 in Tables 3.5.2-18 for Unit 2 and H, 23 in Table 3.5.2-27 for Unit 3. Please identify the structural components, such as beams and walls that are managed by either program or by both programs and provide basis for the selection of the program.

Dominion Response:

The structural member "Structural Reinforced Concrete" in Unit 2 LRA Table 3.5.2-18 and Unit 3 LRA Table 3.5.2-27 includes Beams, Columns, Floor slabs, Foundation mat slabs, Roof slabs, and Walls. The Structural Reinforced Concrete components associated with the table line item with Note H, 20 (Unit 2) or H, 23 (Unit 3) are only the Floor slabs, Foundation mat slabs, and Walls. As indicated in Note 20 in the Unit 2 LRA table (or Note 23 in the Unit 3 LRA table), the Infrequently Accessed Area Inspection Program manages the effects of aging for structural members/components in the intake structure water bays between the waterline and the bottom of the intake structure operating deck since this area is infrequently accessed as described in LRA Appendix B, Section B2.1.15. The Structures Monitoring Program manages the effects of aging for structural members/components in the water bay below the waterline since this area is inspected by the Structures Monitoring Program AMP. The effects of aging for the Walls are managed by both the Infrequently Accessed Areas Inspection Program (above the waterline) and the Structures Monitoring Program (below the waterline). The Infrequently Accessed Area Inspection Program manages the effects of aging for the Floor slabs (underside of the operating deck) and the Structures Monitoring Program manages the effects of aging for the Foundation mat slabs.

RAI 3.5-8

The polyethylene form used for expansion joint/seismic gap material between adjacent buildings/structures in the atmosphere/weather environment is listed as no aging effect requiring management in Table 3.5.2-37 of Unit 3. Provide technical data to show that the polyethylene form material will not degrade in the atmosphere/weather environment and the plant operating experience to substantiate it.

Dominion Response:

The polyethylene foam material used for seismic gap filler is covered by a flashing and not exposed to rain, wind, or sun. There should not have been an Expansion joint/Seismic gap material line item in LRA Table 3.5.2-37 with an atmosphere/weather environment. As indicated in Table 3.5.2-37, aging effects for the polyethylene foam are managed by the Structures Monitoring Program.

RAI 3.5-9

Table 3.5.2-37 of Unit 3 lists Structures Monitoring Program as the AMP for neoprene used for flood gate gasket, roof hatch seals, and watertight door gasket, but lists Work Control Process as the AMP for neoprene used for gaskets in junction, terminal, and pull boxes. Explain the need for using different AMPs for the same material.

Dominion Response:

The Structures Monitoring Program AMP manages the aging effects for flood gates, roof hatches, and watertight doors, which are considered to be structural members, and includes inspection of the associated flood gate gasket, roof hatch seals, and watertight door gaskets. The Structures Monitoring Program AMP does not include inspection of junction, terminal, and pull boxes since these items are not considered to be structural members. Therefore, the Work Control Process AMP is credited for managing aging effects associated with gaskets in junction, terminal and pull boxes.

RAI 3.5-10

Table 3.5.2-37 lists no aging effect requiring management for carbon steel junction, terminal, and pull boxes in air environment. Provide data to show that the carbon steel will not rust in the air that may contain moisture and the plant operating experience to substantiate it.

Dominion Response:

As described in note 35 for the carbon steel junction, terminal, and pull boxes in LRA Table 3.5.2-37, loss of material is not an applicable aging effect since these components are not exposed to an intermittent wetted environment.

This conclusion is consistent with the North Anna and Surry License Renewal SER concurrence that carbon steel components have not experienced corrosion degradation that would affect the intended function of components due to humidity in the absence of cyclic or intermittent wetting (North Anna Power Station Units 1 and 2, and Surry Power Station, Units 1 and 2, NUGREG-1766, Section 3.8.5.2.1, Page 3-230). Further, this conclusion is supported by a review of Millstone plant-specific operating experience, which identifies no instances of loss of material due to corrosion of the junction, terminal, and pull boxes in an air environment.

RAI 3.5-11

Do you have piping and component supports that are anchored to concrete by using bolts with yield strength greater than 150 ksi? If yes, identify the AMP for those bolts and provide basis for the selection of the AMP if Bolting Integrity program is not selected.

Dominion Response:

No piping or component supports in Millstone Unit 2 or 3 have been identified as being anchored to concrete using anchor bolts with specified yield strengths greater than 150 ksi.

RAI 3.5-12

Table 3.5.2-25 of Unit 2 and Table 3.5.2-36 of Unit 3 list Boric Acid Corrosion as an AMP for galvanized steel electrical conduit and cable trays. The staff did not find that galvanized steel was included in the Boric Acid Corrosion program as described in B2.1.3. Please address this discrepancy.

Dominion Response:

The electrical conduit and cable trays listed in Unit 2 LRA Table 3.5.2-25 and Unit 3 LRA Table 3.5.2-36 are fabricated from carbon steel material that was galvanized for corrosion protection, and has been termed "galvanized steel" in the tables. Since no credit has been taken for the galvanized coating as described in LRA Appendix C, Section C2.4, the electrical conduit and cable trays loss of material aging effect due to boric acid corrosion is managed with the Boric Acid Corrosion program. Accordingly, this material is in the category of materials termed "carbon and low alloy steel" in the Boric Acid Corrosion program as described in B2.1.3.

RAI 3.5-13

Table 3.5.2-21 of Unit 2 and Table 3.5.2-31 of Unit 3 list Infrequently Accessed Area Inspection Program three times as the AMP for concrete pipes. Explain the reason for listing the program three times.

Dominion Response:

Each line item for concrete pipe in Unit 2 LRA Table 3.5.2-21 on page 3-507 and in Unit 3 Table 3.5.2-31 on page 3-613 is a unique line item with a corresponding NUREG-1801 Volume 2 Item and/or a note. As a result, some table data (such as the AMP) is repeated multiple times for these lines.

For example, for the lines in the tables associated with the change of material properties aging effect for the concrete pipe, the first line is associated with NUREG-1801 item III.A6.1-b for the leaching of calcium hydroxide aging mechanism. The second line is associated with NUREG-1801 item III.A6.1-e for the aggressive chemical attack aging mechanism. Finally, the third line is not associated with a NUREG-1801 item since the alkali-aggregate reaction aging mechanism leading to a change of material properties is not included in NUREG-1801, although Dominion has conservatively included this aging mechanism as discussed in LRA Appendix C, Section C3.2.2. For each of these aging mechanisms that result in the change of material properties aging effect for the concrete pipe, the Infrequently Accessed Areas Inspection Program AMP manages the identified aging effect.

RAI 3.5-15

Millstone 2 only: A review of Appendix 5F of the Millstone 2 FSAR indicates that the hoop and vertical tendons located in the below-grade portion of the containment have experienced continuous problem of water leakage through them. The corrective action adopted for the hoop tendons is to keep the sheathing filler in the affected tendons at pressures slightly above hydrostatic pressure. For this sustained condition the applicant is requested to provide the following information:

a. What are the conditions of vertical tendons affected by the water leakage?

b. For the purpose of lift-off testing during tendon surveillance, do you select some tendons from these affected tendons as additional samples?

c. The hydrostatic pressure on the hoop tendons at the bottom of the cylinder could be significant. Such high-sustained pressures could give rise to leakage of corrosion protection medium (CPM) from the sheathing (see Trojan Plant experience in NUREG-1522). Please provide an assessment of the CPM leakage and presence of water for the affected tendons in terms of the acceptance criteria in IWL-3221.2, IWL-3221.3, and IWL-3221.4.

Dominion Response:

a. The Millstone Unit 2 Containment structure is environmentally protected by an Enclosure Building, which eliminates most degradation mechanisms. Operating Experience has been provided in the License Renewal Application Appendix B (Section B2.1.16) regarding the long-term effects of water intrusion. The discussion specifically states that the condition of the tendon gallery has improved and water intrusion has decreased. This section also discusses the 25th year physical surveillance of Millstone Unit 2 containment post-tensioning performed in accordance with ASME Section XI, Subsection IWL requirements, and includes the results of the tendon surveillance examinations and tests. The section identifies that the losses in tendon forces were less than expected for a plant of its age, and concludes that the Containment structure has experienced no abnormal degradation of the post tensioning system. The section identifies that a regression analysis of the tendon forces was performed, which predicts that the values will remain above minimum design requirements well beyond the next surveillance interval.

   The 25th year physical surveillance for Millstone Unit 2 included the inspection of anchorage components. Grease caps were selected and removed in accordance with Subsection IWL requirements, and a complete grease coating was found for all tendon ends inspected including those vertical tendons selected. All wire samples were acceptable for diameter, corrosion condition, and physical properties. All tendons were resealed and regreased, with no more than 10% duct volume added.

The presence of water was found in one surveillance tendon (vertical tendon 31V24). The amount of free water present was 16 ounces (Note: The total grease net duct volume for this tendon is 191.94 gallons). This same vertical tendon had also been selected for lift-off testing with satisfactory results. The grease caps for the adjacent tendons (31V22, 31V23 and 31V25) were removed for examination of the tendon ends. No free water was present, and the CPM was tested with satisfactory results. The anchor head corrosion condition of all four tendons was excellent and no broken wires were found. In addition, the exterior of tendon anchorage grease cans (including all vertical tendons) were inspected for the presence of water and grease leaks and none were found.

b. Millstone Unit 2 does not select any additional tendons from the affected hoop tendons for lift-off testing, and only tests those affected tendons that were selected to comply with ASME Section XI, Subsection IWL requirements. When affected tendons are lift-off tested in accordance with IWL requirements, Millstone Unit 2 lift-off tests the adjacent tendons as additional samples in accordance with Subsection IWL should unsatisfactory lift-off test results be identified for the affected tendons.

c. As a result of the Millstone Unit 2 tendon surveillance program, seventeen hoop tendons were identified as subject to groundwater intrusion. These tendons were modified to ensure that grease is continuously supplied at a pressure that is slightly above the hydrostatic pressure of the groundwater. The number of tendons containing water has significantly reduced from the ten tendons identified during the third and fourth tendon surveillances to only one tendon identified during each of the last two surveillances. For the tendon identified with free water during the last surveillance (12H01), an inspection of head revealed acceptable levels of corrosion with no button heads missing (other than those intentionally removed for corrosion inspection). The CPM for each of the identified seventeen hoop tendons was sampled and replaced during the 25th year physical surveillance. The analysis of the CPM samples taken from each tendon showed acceptable results for all tests (ions, water and neutralization number). These grease replacement tendons were also successfully filled with no more than 10% net duct volume added, as required in accordance with Subsection IWL.

As previously identified, the operating experience for Millstone Unit 2 identifies that the condition of the tendon gallery has improved, the water intrusion has decreased, and the Containment structure has experienced no abnormal degradation of the post tensioning system.

RAI 3.6-1

Section 3.6, Aging Management of Electrical and I&C - Electrical Penetrations The applicant identified a dual function associated with the electrical penetrations, namely maintain the pressure boundary of the containment and conduct electrical current through the containment. 1. In as much as the pressure boundary contains non-metallic components such as Polysulfone and Vitron, please clarify why there is no aging management program required for those materials that maintain containment integrity or identify the AMP that does cover this function. 2. In as much as the electrical conduction function of the electrical penetrations contain electrical connectors, please clarify why there is no aging management program required for those materials that maintain electrical conductivity or identify the AMP that does cover this function.

Dominion Response:

The non-EQ electrical penetration modules for Millstone Units 2 and 3 were qualified to the same requirements as the EQ electrical penetrations. Qualification testing of the penetration modules for a minimum forty-year life included verification of the modules to maintain electrical and pressure boundary integrity under normal and accident conditions. The Viton O-rings used for the seals were identified as the most limiting non-metallic material for qualification life with respect to temperature effects. Review of the EQ analysis for the Viton material indicated that it had a life expectancy exceeding sixty years at a temperature well above the normal operating temperature experienced by the penetrations. In addition, the penetration modules were qualified at a radiation dose in excess of the expected 60-year life dose. Insulation materials used for the conductor, including splices and terminations, that are part of the penetration module were included in the qualification testing. Therefore, it was concluded that the non-metallic pressure boundary and insulating materials of the electrical penetration modules will perform their intended function for the period of extended operation with no aging management program required. The non-EQ electrical penetration modules installed at Millstone were manufactured by Conax and GE. All materials for these penetration modules were qualified by the qualification testing performed for the EQ electrical penetrations described above.

RAI 4.3.1-3

The Westinghouse Owners Group issued Topical Report WCAP-14577, Revision 1-A, "Aging Management for Reactor Internals," to address the aging management of the reactor vessel internals. The staff's review of WCAP-14577, Revision 1-A identified a number of issues that should be addressed on a plant specific basis. Renewal Applicant Action Item 11 specified in WCAP -14577, Revision 1-A indicates that the fatigue TLAA of the reactor vessel internals should be addressed on a plant specific basis. Discuss the design basis for the components listed in Table 3-3 of WCAP-14577, Revision 1-A. Indicate how fatigue of these components is managed.

Dominion Response:

The RPV stress report (CENC-1282) does not address cumulative fatigue usage for the reactor internals. The Millstone Unit 3 reactor pressure vessel was designed to the requirements of the 1971 Edition of ASME Section III with Addenda through Summer 1973, Millstone Unit 3 LRA Section 4, Table 4.3-1. Thus, there is no fatigue TLAA associated with the Millstone Unit 3 reactor pressure vessel internals. WCAP-14577 refers to a TLAA for plants with reactor pressure vessels designed to ASME Section III, Subsection NG (published in 1974).

RAI 4.3.2-1

Section 4.3.2 of the LRA describes the evaluation of non-Class 1 components. The LRA indicates that three piping systems may exceed 7,000 full temperature thermal cycles during the period of extended operation. The LRA also indicates that these systems were evaluated using appropriate stress range reduction factors and found acceptable for the period of extended operation. Describe the criteria used to obtain the stress range reduction factors.

Dominion Response:

ASME Section III, Subsection NC-3600 was used in the Millstone Unit 2 reanalysis of these three (hot leg sample line, pressurizer steam space sample line, and common hot leg/pressurizer steam space sample line) piping systems. The allowable expansion stresses were recalculated to incorporate the increased number of equivalent full-temperature thermal cycles and stress range reduction factors appropriate for the projected number of cycles. The recalculated allowable expansion stresses were then compared to the expected piping system expansion stresses to determine whether the expected exceeded the allowable expansion stresses. These results can be found in Table 1. Expected expansion stresses were found to be acceptable over the period of extended operation.

Table 1
Comparison of Allowable versus Expected
Sample Line Expansion Stresses

Sample Line	Cycles/ Week	Cycles Through 60-Years	Allowable Expansion Stress (ksi)	Expected Expansion Stress (ksi)	Percent Allowable
Hot Leg	3	9,360	24,728	16,603	67
Pressurizer Steam Space	3	9,360	24,728	20,753	84
Common Hot Leg/Pressurizer Steam Space	6	18,720	21.980	14.254	65

RAI 4.5-1

The TLAA description indicates that a number of time-limited assumptions such as corrosion rates, losses of tendon prestress, and changes in material properties have been utilized in performing the analysis. The applicant is requested to provide a quantitative summary of the corrosion rates, factors contributing to tendon prestress loss (e.g., creep, shrinkage, and relaxation of prestressing steel) and a factor(s) related to change in material properties used in performing the analysis.

Dominion Response:

The evaluation of containment tendon examination and surveillance test results involves the use of time-limited assumptions. The Millstone Unit 2 tendon surveillance program consists of periodically inspecting the physical condition of a randomly selected group of tendons identified in accordance with Regulatory Guide 1.35. Visual and quantitative examinations are performed of the tendon sheathing filler material, anchorages, measurements of tendon liftoff forces (plus a visual assessment of stressing washers, shims, bearing plates), tensile testing of wire samples and corrosion assessments. Comparison of liftoff forces from the most recent tendon examinations to original installation lock-off forces provides direct evidence of potential system degradation.

Containment tendon examination and surveillance test results can be found in the responses to RAI 4.5-5 (Figures 1, 2 and 3), RAI 4.5-6 (Tables 1, 2 and 3) and in RAI 4.5-7 (Table 1). These figures and tables include such quantitative tendon examination results as the actual and projected decreases in tendon group lock-off force, the presence or absence of free water, corrosion assessments, tensile testing results, and sheathing filler chemical analysis results. These inspection results reveal that that the Millstone Unit 2 containment post tensioning system has experienced no abnormal degradation. Tendon lock off-force values were found to remain constant with projected lock-off forces (Millstone Unit 2 LRA, Section 4 – Figure 4.5-1) remaining above minimum requirements over the period of extended operation.

RAI 4.5-6

Section 5.9.3.3.4 of Millstone-2 FSAR indicates that sixteen (below grade) horizontal tendons were identified to have ground water intrusion. The FSAR also indicated that the corrosion protection medium is continuously supplied to these tendons at a pressure slightly above the hydrostatic pressure to prevent intrusion of ground water.

Appendix 5F of Millstone-2 indicates that the below grade portions of about 70 vertical tendons have been subjected to ground water intrusion. The Appendix also describes the attempts made to reduce the potential of corrosion of the components of these tendons.

Because of the unusual maintenance conditions of these tendons, they are likely to experience higher age related degradation (corrosion of wires, corrosion of anchorage components, etc.). The applicant is requested to provide the following information related to these tendons:

a. During periodic inspections, are the samples from these tendons selected for special inspection and lift-off testing?

b. Which tendons out of these tendons are included in the samples used in Tables 4.5-2 and 4.5-3?

c. For the affected tendons, please provide a summary of the results of inspections performed in accordance with IWL-2523.

Dominion Response:

a. All testing is performed in accordance with the Millstone Unit 2 ASME Section XI *Inservice Inspection Program*. No tendons are selected for special inspection and lift-off testing. All tendons identified for examination, including those that have previously experienced water intrusion, are subject to the same tests and inspections.

b. The horizontal tendons that experienced groundwater intrusion, included in Millstone Unit 2 LRA Section 4 - Table 4.5-2, are tendons 12H01, 12H05 and 12H08. Vertical tendon 23V26, which also experienced water intrusion, is included in Millstone Unit 2 LRA Section 4 - Table 4.5-3.

c. Inspection results for these tendons (in addition to those examinations required by IWL-2523) are contained in the response to RAI 4.5-4 (Table 3) and in the following Tables 1, 2 and 3.

Table 1
Millstone Unit 2
Summary of Tendon Inspection Results

Inspection Year	Tendon Number	Free Water	Button Heads	Anchor Heads	Shims	Bearing Plate
25	12H01	22 oz.	1	2/3, NC	2, NC	2, NC
25	12H06	None	-	-	-	-
25	31H04	None	-	-	-	-
20	12H01	62 oz	1	2/3, NC	2, NC	2, NC
20	12H02	None	-	-	-	-
20	12H03	None	-	-	-	-
20	12H04	None	-	-	-	-
20	12H05	None	1	2/3, NC	2/1, NC	2/1, NC
20	12H06	None	-	-	-	-
20	12H08	None	-	-	-	-
20	12H09	None	-	-	-	-
20	12H10	None	-	-	-	-
20	31H01	None	-	-	-	-
20	31H02	None	-	-	-	-
20	31H03	None	-	-	-	-
20	31H04	None	-	-	-	-
20	32H01	None	-	-	-	-
20	32H02	None	-	-	-	-
20	32H03	None	-	-	-	-
15	12H01	≤ 4 oz.	1	2/3, NC	2, NC	2, NC
15	12H08	≤ 1 oz.	1	2, NC	2/1, NC	2, NC

Corrosion Level key:

1 - bright metal, no visible corrosion.
2 - visible oxide, no pitting.
3 - inactive pitting (≤ 0.003 inches).
NC – no cracks.

Table 2
Millstone Unit 2
Summary of Wire Testing Results

Inspection Year	Tendon Number	Sample No.	Corrosion Level[1]	Sample Location (ft)[2]	Wire Diameter (in)[3]	Yield Strength (psi)[4]	Ultimate Strength (psi)[5]	Elongation @ Failure[6]
20	12H01	1	2	20-29	0.250	228,889	266,674	4.6%
		2	2	150-159	0.250	237,491	265,445	4.9%
		3	2	270-279	0.250	237,491	266,674	5.4%
20	12H05	1	1	20-29	0.250	235,955	265,445	4.9%
		2	1	150-159	0.250	241,177	265,752	4.8%
		3	1	270-279	0.250	241,791	264,216	4.5%
15	12H01	1	1	30-39	0.250	235,778	266,344	4.70%
		2	2	150-159	0.250	239,917	266,026	4.55%
		3	1	260-269	0.250	243,738	266,981	4.55%
15	12H08	A1[7]	1	30-39	0.250	232,594	266,026	5.45%
		A2[7]	1	150-159	0.250	232,594	263,479	5.15%
		A3[7]	1	291-300	0.250	228,137	263,797	4.75%
		B1[7]	1	30-39	0.250	231,321	259,021	5.20%
		B2[7]	1	150-159	0.250	234,505	260,931	4.95%
		B3[7]	1	291-300	0.250	228,455	259,658	5.10%
		C1[7]	1	30-39	0.250	232,276	261,887	4.80%
		C2[7]	1	150-159	0.250	234,505	262,523	4.90%
		C3[7]	1	291-300	0.250	230,047	261,250	5.15%

1. Corrosion Level:
   Level 1 - bright metal, no visible corrosion.
   Level 2 - visible oxide, no pitting.
2. Nominal wire length 300 ft.
3. Wire diameter 0.250 ±0.002 inches.
4. Acceptable yield strength ≥ 204,000 psi.
5. Acceptable ultimate strength ≥ 240,000 psi.
6. Acceptable elongation at failure ≥ 4%.
7. 3 broken wires (designated A, B and C) identified during 15-year inspection. Wires considered broken during original installation.

Table 3
Millstone Unit 2
Summary of Sheathing Filler Results

Inspection Year	Tendon Number	Chloride (ppm)[1]	Nitrate (ppm)[1]	Sulfide (ppm)[1]	% Water Content[2]	Neutral mgKOH/g[3]
25	12H01	<0.50	<0.50	<0.50	0.21-6.60	54.5-38.5
25	12H02	<0.50	<0.50	<0.50	1.00	43.9
25	12H03	<0.50	<0.50	<0.50	2.00	42.0
25	12H04	<0.50	<0.50	<0.50	0.84	45.9
25	12H05	<0.50	<0.50	<0.50	0.41	45.5
25	12H06	<0.50	<0.50	<0.50	0.53	45.2
25	12H08	<0.50	<0.50	<0.50	0.63	41.2
25	12H09	<0.50	<0.50	<0.50	0.92	38.8
25	12H10	<0.50	<0.50	<0.50	0.58	43.2
25	31H01	<0.50	<0.50	<0.50	1.20	31.6
25	31H02	<0.50	<0.50	<0.50	0.63	45.0
25	31H03	<0.50	<0.50	<0.50	0.34	43.8
25	31H04	<0.50	<0.50	<0.50	0.41	43.8
25	32H01	<0.50	<0.50	<0.50	2.50	37.2
25	32H02	<0.50	<0.50	<0.50	0.30	45.3
25	32H03	<0.50	<0.50	<0.50	0.69	44.4
20	12H01	<0.50	<0.50	<0.50	0.72-4.92	76.3-22.4
20	12H02	<0.50	<0.50	<0.50	1.80	11.4
20	12H03	<0.50	<0.50	<0.50	1.50	44.2
20	12H04	<0.50	<0.50	<0.50	0.90	48.1
20	12H05	<0.50	<0.50	<0.50	0.20-0.72	57.1-13.0
20	12H06	<0.50	<0.50	<0.50	0.77	42.9
20	12H08	<0.50	1.32	<0.50	1.00	44.9
20	12H09	<0.50	1.26	<0.50	1.30	28.9
20	12H10	<0.50	0.66	<0.50	0.80	46.8
20	31H01	<0.50	<0.50	<0.50	0.32	68.3
20	31H02	<0.50	0.80	<0.50	1.00	42.5
20	31H03	<0.50	1.45	<0.50	0.70	18.0
20	31H04	<0.50	1.72	<0.50	0.20	42.9
20	32H01	<0.50	1.26	<0.50	2.00	36.3
20	32H02	<0.50	1.32	<0.50	0.21	41.6
20	32H03	<0.50	<0.50	<0.50	0.70	49.3
15	12H01	<0.50	<0.50	<0.20	≤0.3	39.8-31.4
15	12H08	<0.50	<0.50	<0.20	≤0.1	53.2-33.6

1. Acceptable limit <10.0 ppm
2. Acceptable limit <10% dry weight
3. Acceptable limit >0 mg KOH/g

RAI 4.5-7

Section A3.4 of the Millstone 2 FSAR Supplement provides a summary of the TLAA in a generic term. Table 4.5-1 of NUREG-1800 recommends a discussion of trend lines and predicted lower limit (PLL) in the FSAR supplement. In order for the summary to be meaningful, as a minimum, the applicant should provide a Table showing the minimum required prestressing forces and the projected (to 60 years) prestressing forces for each group of tendons which would verify the validity of the analysis results based on the inspections conducted during the period of extended operation. The applicant is requested to supplement the information in Section A.3.4 of the FSAR Supplement.

Dominion Response:

The following information will be incorporated into Section A3.4 of the Millstone Unit 2 FSAR Supplement.

Projected and actual prestressing forces are identified in the following Table 1 through the 25-year inspection period. These results were used to project acceptable dome, vertical and horizontal forces through the current and extended period of operation. Since containment tendon examinations are performed on a 5-year interval, force projections will be refined and updated as necessary following each examination.

Table 1
Millstone Unit 2
Containment Tendon Prestress

Inspection Year	Dome Tendon Projected (kips)	Dome Tendon Actual(1) (kips)	Vertical Tendon Projected (kips)	Vertical Tendon Actual(1) (kips)	Horizontal Tendon Projected (kips)	Horizontal Tendon Actual(1) (kips)
1	1615	1563.7	1630	1596	1623	1578.5
3	1566	(2)	1598	(2)	1576	(2)
5	1544	(2)	1583	(2)	1555	(2)
10	1514	(2)	1562	(2)	1525	(2)
15	1496	1487.7	1550	1563.8	1508	1485.5
20	1483	1468.7	1542	1531.7	1496	1508
25	1474	1474.8	1535	1510.7	1486	1481.4
40	1453	-	1521	-	1467	-
60	1435	-	1509	-	1449	-

1. Average of all values.
2. Regulatory Guide 1.35 requires the testing of the same tendons, including those that have been detensioned and then retensioned. With this variability, average value not calculated.

RAI 4.7.1-1

The applicant states in the LRA Section 4.7.1 that the Millstone Unit 2 polar crane was originally designed to the requirements of the Electric Overhead Crane Institute Specification No 61. This design was subsequently reconciled to the guidance contained in NUREG-0612. The applicant is requested to identify and discuss any items in the reconciliation process, which affected the TLAA for the crane. Also provide the allowable stress range for the weldments for this crane and the maximum stress range at rated load.

Dominion Response:

There were no reconciliation items that affected the polar crane TLAA (NRC to W. G. Council, *Control of Heavy Loads (Phase 1) for Millstone Unit 2* dated September 14, 1984). Table 1 provides the design stress ranges for the Unit 2 polar crane in accordance with Crane Manufacturers Association of America (CMAA) Specification No. 70.

In accordance with NUREG-0612, the load carrying parts of the polar crane, except for structural members and hoisting ropes, were designed such that the calculated static stress in the material, based on rated load, will not exceed 20% of the assumed average ultimate strength of the material. The Millstone Unit 2 polar crane was designed for a load of 578 tons (NRC to Northeast Nuclear Energy Company, *Summary of Meeting of March 20, 1991 With Representatives of Northeast Utilities Concerning the Construction Aspects of the Millstone Unit 2 Steam Generator Replacement Project*, Letter A09459 dated April 4, 1991), but the largest typical load, the pressure vessel head (including the associated weight of the lifting rig, CEDMs and CEDM coolers), is nominally 140 tons.

The Millstone Unit 2 polar crane is used primarily during refueling outages. Assuming four load cycles per year (pressure vessel head removal and replacement plus other miscellaneous uses such as RCP motor movement) for a 60-year period of time, the polar crane would only experience a nominal 240 load cycles through the current and extended periods of operation. This number is significantly less than the 100,000 design load cycles (Millstone Unit 2 LRA Section 4.7.1).

Table 1
Design Stress
Ranges

Condition	General Description	Stress Types(1)	Design Stress (ksi)	Maximum (ksi)
Built-up Members	Base metal and weld metal in members	T C Rev S	≤ 33 ≤ 33 ≤ 33 -	≤ 33 ≤ 33 ≤ 33 -
Groove Welds	Base metal and weld metal at full penetration groove welded splices	T C Rev S	≤ 40 - ≤ 40 -	≤ 40 - ≤ 40 -
Fillet Welded Connections	Base metal at intermittent fillet welds	T C Rev S	≤ 17 ≤ 17 ≤ 17 ≤ 17	≤ 17 ≤ 17 ≤ 17 ≤ 17
Miscellaneous	Base metal adjacent to short welded attachment	T C Rev S	≤ 28 ≤ 28 ≤ 28 -	≤ 28 ≤ 28 ≤ 28 -
	Base metal adjacent to long fillet weld attachment	T C Rev S	≤ 17 ≤ 17 ≤ 17 -	≤ 17 ≤ 17 ≤ 17 -
	Base metal at plug or slot welds	T C Rev S	≤ 17 ≤ 17 ≤ 17 -	≤ 17 ≤ 17 ≤ 17 -
	Shear Stress on normal area shear connectors	T C Rev S	- - - ≤ 15	- - - ≤ 15
	Shear on plug or slot welds	T C Rev S	- - - ≤ 15	- - - ≤ 15

(1): T - Tensile Stress.
C - Compressive Stress.
Rev - Reversal of Tensile or Compressive Stresses.
S - Shear including Shear Stress reversal.

RAI DSSA/SPSB-1

For Millstone unit 2 Control Room Air Conditioning System, described on LRA drawing 25203-LR26027 sheet 3 at C-4 and D-4, items X-42A and X-42B include cooling coils but no heating coils. Neither cooling nor heating coils are included in table 2.3.3-19. Clarify whether these heating and cooling coils and the associated housings are in the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to aging management review in accordance with 10 CFR 54.21(a)(1). If they are, they should be included in table 2.3.3-19. If they are excluded from the scope of license renewal and not subject to an AMR, provide justification for the exclusion.

Dominion Response:

Items X-42A and X-42B on license renewal drawing 25203-LR26027 Sh. 3 at C-4 and D-4 are the Control Room Air Conditioning System air-handling units cooling coils. The air-handling units are not equipped with heating coils. The cooling coil performs a pressure boundary intended function and is included in the component type "Control Room Air Handling Units" in LRA Table 2.3.3-19. The housing and coil are evaluated separately in LRA Table 3.3.2-19 as "Control Room Air Handling Units (Housing)" and "Control Room Air Handling Units (Coils)".

RAI DSSA/SPSB-2

For Millstone unit 2 Enclosure Building Filtration System, described on LRA drawing 25203-LR26028 sheet 5 at J-10 and F-10, items X-61A and X-61B include heating and cooling coils that are not listed in LRA table 2.3.3-23. Clarify whether these heating and cooling coils and the associated housings are in the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to aging management review in accordance with 10 CFR 54.21(a)(1). If they are, they should be included in LRA table 2.3.3-23. If they are excluded from the scope of license renewal and not subject to an AMR, provide justification for the exclusion.

Dominion Response:

Items X-61A and X-61B shown on license renewal drawing 25203-LR26028, Sh. 5 at J-10 and F-10 are the Enclosure Building Filtration System filter bank dehumidifier heaters. There are no cooling coils associated with these filter banks. The electric dehumidifier heaters are designed to maintain the relative humidity of the air stream entering the charcoal filters at less than 90 percent. As stated in Unit 2 FSAR, Section 6.7.2.1, an analysis has been performed that shows the relative humidity of the entering air stream will remain less than 90 percent regardless of heater operation. Therefore, the dehumidifier electric heaters are not in the scope of license renewal. The housings associated with the filter banks are in the scope of license renewal and identified as "Enclosure Building Filtration Filter Bank Housings" in LRA Table 2.3.3-23.

RAI DSSA/SPSB-3

None of the Filtration Systems nor Heating Ventilation and Air Conditioning (HVAC) Systems in the Millstone 3 LRA include duct sealants or wall sealants in the applicable tables, nor are sealants indicated on LRA drawings. Clarify whether sealants are in the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to aging management review in accordance with 10 CFR 54.21(a)(1). If sealants are in the scope of license renewal, update the LRA by providing the applicable information in the appropriate LRA tables. If sealants are excluded from the scope of license renewal and not subject to an AMR, provide justification for the exclusion.

Dominion Response:

Duct sealants should have been included in the scope of license renewal for the Unit 3 Auxiliary Building Ventilation System, Control Building Ventilation System, and Supplementary Leak Collection and Release System and shown in LRA Tables 2.3.3-18, 2.3.3-24, and 2.3.3-33, respectively. Wall sealants were evaluated as part of buildings and structures in LRA Section 2.4.2 as Metal Siding-Caulking and are included in LRA Table 2.4.2-1. Sealants are not specifically identified on plant drawings.

The aforementioned ductwork joint seals perform a pressure boundary function and are subject to aging management review. The sealant is an elastomeric material and is subject to cracking and change of material properties in an air environment. The aging effects will be managed with the General Condition Monitoring aging management program.

RAI DSSA/SPSB-4

For Millstone units 2 and 3 LRA, none of the air intake or exhaust structures include screens within the scope of license renewal. Clarify whether screens for air intake and exhaust structures are in the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to aging management review in accordance with 10 CFR 54.21(a)(1). If screens for intake and exhaust structures are in the scope of license renewal, update the LRA by providing the applicable information in the appropriate tables. If screens for intake and exhaust structures are excluded from the scope of license renewal and not subject to an AMR, provide justification for the exclusion.

Dominion Response:

Screens are installed over wall openings in plant structures that serve as ventilation intake or exhaust points. These screens are installed for maintenance purposes to aid in maintaining the associated ductwork free from nesting materials and debris from birds and other wildlife. Although the build-up of debris in the ventilation intakes and exhausts is not expected to affect the function of the plant ventilation systems regardless of the condition of the screens, the screens are not conservatively included in the scope of license renewal. The screens will be included with the structural member "Miscellaneous Steel" in the LRA screening results tables for the Unit 2 Auxiliary Building and Turbine Building and the Unit 3 Auxiliary Building, Control Building, Hydrogen Recombiner Building, Engineered Safety Features Building, Main Steam Valve Building, Emergency Generator Enclosure and Fuel Oil Tank Vault, and Circulating and Service Water Pumphouse. The carbon steel screens are exposed to an atmosphere/weather environment. The aging effect of loss of material will be managed by the Structures Monitoring Program.

RAI DSSA/SPSB-5

For Millstone Unit 3, LRA Section 2.3.2.2 Quench Spray System, described on LRA drawing 25212-LR26915 sheet 1, refueling water recirculating pumps are included within the scope of license renewal but refueling water coolers 3-QSS-E1A and EIB are not shown included within the scope of license renewal subject to aging management review (AMR). If they are excluded from the scope of license renewal, provide justification for the exclusion.

Dominion Response:

The non-safety-related RWST coolers shown on LR drawing 25212-LR26915, Sh. 1, were not originally included in the scope of license renewal because the RWST temperature is maintained within limits in accordance with Technical Specification requirements. However, in response to RAI 2.1-1, these coolers, and associated piping and valves, have been added to scope as non-safety-related components that are spatially oriented such that their failure could prevent the function of safety-related SSCs. The stainless steel RWST cooler channel heads, piping, and valves are subject to loss of material in a treated water internal environment and in an atmosphere/weather external environment. This aging effect is managed by the Chemistry Control for Primary Systems Program internally and the General Condition Monitoring AMP externally. The cooler shell, and cooling water piping and valves, are carbon steel and are subject to loss of material in the treated water internal environment and in the atmosphere/weather external environment. The loss of material of internal surfaces is managed by the Closed-Cycle Cooling Water System AMP and external aging is managed by the General Condition Monitoring AMP.

Attachment 2

Supplemental Request for Additional Information Response

Millstone Power Station Units 2 & 3
Dominion Nuclear Connecticut, Inc.

RAI 2.3.3.35-2A

License renewal drawing 25203-LR26018, Sheets 2 and 3, at locations H5 and E7 show level glasses and sight glasses as being subject to an AMR. However, these components are not listed in LRA Table 2.3.3-34. These components provide a pressure boundary intended function. Clarify whether these components are included with another component type. If not, justify their exclusion from the scope of license renewal and from being subject to an AMR or update the corresponding tables to include these components.

Dominion Response:

The subject level glasses and sight glasses shown at locations H-5 and E-7 on license renewal drawing 25203-LR26018, Sh. 2 and Sh. 3, are in the scope of license renewal and included in the component type "Level Indicators" in LRA Table 2.3.3-34.

Supplemental Information:

On an August 19, 2004 telephone conversation, the staff requested clarification of the materials associated with the diesel generator level indicators discussed in the above RAI response. LRA Table 3.3.2-34 indicates that the Level Indicators are constructed of copper alloy material. The staff asked whether or not there is glass material associated with these level indicators. If this was, the staff asked Dominion to identify where the glass is evaluated in the LRA.

In response to this request, Dominion stated that the level glasses and sight glasses in the Diesel Generator System that are included in the component type "Level Indicators" do consist of glass material mounted in a copper alloy housing.

As part of the aging management review process, glass material was evaluated and found to have no aging effects requiring management in any expected plant environment. Therefore, as a result, glass material is not included in the LRA aging management review results tables in Section 3.

Attachment 3

Additional Information in Support of
Applications for Renewed Operating Licenses

Millstone Power Station Units 2 & 3
Dominion Nuclear Connecticut, Inc.

The following additional information, in support of the Millstone Power Station, Units 2 and 3 License Renewal Applications (LRAs), is provided as a result of audits of the Aging Management Programs (AMP) and Aging Management Reviews (AMR),

Audit Item 183

The applicant proposes to manage loss of material aging effect by using chemistry control for secondary systems for the following stainless steel material with Vol.2 items VIII.G.5.-c /E.4-e & Vol. 1 item 3.4.1-10 for the following items (LRA Unit 2):

- P. 3-367: Flow elements, Orifices
- P. 3-369: Tubing, Valves
- P. 3-371: Flow elements,
- P. 3-371, 3-373, 3-375: Tubing (VIII.E.4-e)
- P. 3-376: Tubing
- P: 3-377: Flow elements, Flow orifices, Tubing
- P. 3-379: Expansion joints, Flow elements
- P. 3-380: Flow orifices
- P. 3-381: Restricting orifices
- P. 3-382: Tubing, Valves
- P. 3-387: Tubing
- P. 3-389: Tubing (proposes work control process to manage loss of material)

The applicant proposed GALL Vol. 1 item recommends closed-cycle cooling water system with no further evaluation. The applicant's AMR proposed water chemistry program for secondary systems. The environments for the applicant proposed GALL Vol. 1 item is closed-cycle cooling water instead of PWR secondary water. The GALL recommends to manage loss of material for stainless steel components exposed internally to secondary water environment using PWR secondary water program and the AMP to be augmented by verifying the effectiveness of water chemistry control and detection of aging effects is to be further evaluated. Please justify the difference (further evaluation, AMP program, environment, vol 1 & 2 items listed in LRA)

The above question applies to Unit 3 S&PC systems also.

Dominion Response:

The items cited in the question were matched to the NUREG-1801 item on the basis of similar material, environment, and aging effect. The selected aging management program was not similar to the AMP referenced in NUREG-1801 as indicated by the associated Note E.

NUREG-1801 item VIII.E.4-a, which references the Chapter XI.M2 "Water Chemistry" AMP, should have been chosen for these items, along with a Note D to indicate that the component is different than the component described in the NUREG-1801 item. The further evaluation recommendation associated with item VIII.E.4-a in LRA Table 3.4.1, Item 3.4.1-02, is addressed in LRA Section 3.4.2.2.2. The effectiveness of the Millstone Chemistry Control for Secondary Systems Program is confirmed by the Work Control Process as described in LRA Appendix B, Section B2.1.6. The Work Control Process provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities on an ongoing basis.

The Work Control Process provides input to the corrective action program if aging effects are identified. The corrective action program evaluates the cause and extent of the condition and, if required, recommends enhancements to ensure continued effectiveness of the Chemistry Control for Secondary Systems Program.

Audit Item 186

In MPS 3 LRA Table 3.3.2-27, Page 3-310, the applicant credits the work control process program to manage loss of material of carbon steel condensers (shell) and copper alloy condenser (tubes) in an internal environment of gas (Note G).

However, also in LRA Table 3.3.2-27, the project team identified several other carbon steel and copper alloy component types that have no aging effect in the same environment (Note G).

The project team asked the applicant to justify the difference in aging effects and aging management programs between the two material, environment, aging effect, and aging management program combinations.

Dominion Response:

It was conservatively assumed that a small amount of moisture may be present in the refrigerant gas environment. This moisture could condense in the condenser shell-side due to exposure to cooling water (cold seawater) on the tube-side of the condenser. Therefore, the loss of material aging effect was applied to the condenser subcomponents, including the shell and tubes, exposed to a gas environment. The applicable LRA Table 3.3.2-27 line items should have included Note 2 indicating that the component could be subject to an intermittently wetted environment.

Other carbon steel and copper alloy components in a gas environment are not exposed to potential condensation and, therefore, would not experience the loss of material aging effect.

Audit Item 187

In MPS 3 LRA Table 3.3.2-27, the applicant credits the work control process program to manage loss of material of copper alloy condensers (tubes) in an external environment of gas (Note A). This AMR line item references the GALL Report Item VII.F.2.2-a, which is an environment of warm, moist air. The project team asked the applicant to clarify the environment, aging effect, and aging management program combination.

Dominion Response:

It was conservatively assumed that a small amount of moisture may be present in the refrigerant gas environment. This moisture could condense in the condenser shell-side due to exposure to cooling water (cold seawater) on the tube-side of the condenser. The potential for moisture in the refrigerant gas was incorrectly compared to the warm, moist air environment described in NUREG-1801 Item VII.F2.2-a. No matching item from NUREG-1801 should have been listed in LRA Table 3.3.2-27 for the condenser tube-side subcomponents, and Note G should have been listed instead of Note A. Additionally, since these components could be subject to an intermittent wetting environment, Note 2 should have been applied for the subject items.