From: <john.hufnagel@exeloncorp.com>
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Date: 12/02/2005 7:47:54 PM
Subject: Batch 3 - AMP Program Basis Documents

Donnie/Greg,

In the spirit of not waiting to deliver Audit products that are ready for your review, here are six of nine of the PBDs that we had indicated we would provide by Monday, 12/5.(Batch 3). This brings to sixteen the number of upgraded program basis documents that we have provided for the Auditors review. The other three from Batch 3 will be provided on Monday.

Attached please find the following PBDs in Word format: B.1.34 (Electrical - E-1), B.1.15 (Boraflex Rack Management), B.1.35 (Electrical E-2), B.1.20 (Fire Water System), B.1.24 (One Time Inspections) and B.1.29 (Appendix J).

Note that these Word files have been "write" protected to prevent inadvertent revisions to the files. This should not preclude viewing, copying, pasting, etc. Let us know if there are any problems.

When we transmit the final three documents of Batch 3, I will update the answer to Audit question AMP-147, indicating the additional program basis documents that have been provided up through Batch 3.

Please let me know if there are any questions/problems.

- John.

<<Final PBD-AMP-B.1.34 Rev 0.doc>> <<PBD B.1.15 Boraflex Rack Management Rev 0.doc>> <<Final PBD E-2 B.1.35 Rev 0.doc>> <<PBD 1.20 Fire Water Rev 0.doc>> <<Final PBD B.1.29 Appendix J Rev. 0.doc>> <<FINAL PBD B.1.24 Rev 0.doc>>

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CC: <fred.polaski@exeloncorp.com>

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Final PBD E-2 B.1.35 Rev 0.doc		152064
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PROGRAM BASIS DOCUMENT

PBD-AMP-B.1.34

Revision 0

ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

GALL PROGRAM XI.E1 - ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Prepared By: ______________________

Reviewed By: ______________________

Program Owner Review: ______________________

Technical Lead Approval: ______________________

Revision History:

Revision	*Prepared by:*	*Reviewed by:*	*Program Owner:*	*Approved by:*
0	*Deb Spamer*	*Ahmed Ouaou*	*Raj Pruthi*	*Don Warfel*
Date				

Summary of Revisions:

Rev. Number	Reason for the Revision(s)
0	Initial Issue

TABLE OF CONTENTS

1.0 PURPOSE AND METHODOLOGY

1.1 Purpose

The purpose of this Program Basis Document is to document and evaluate those activities of the Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program that are credited for managing cable and connection age related insulation degradation, due to adverse environmental conditions, as part of Oyster Creek License Renewal to meet the requirements of the License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

This includes the following:

- The identification of the scope of the program;
- The evaluation of program elements against NUREG-1801;
- The review of Operating Experience to demonstrate program effectiveness;
- The identification of required program enhancements; and
- The identification of Oyster Creek documents required to implement the program.

1.2 Methodology

The nuclear power plant License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," describes the License Renewal process and provides requirements for the contents of License Renewal Applications. 10 CFR 54.21(a)(3) states:

"For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the Current Licensing Basis (CLB) for the period of extended operation."

The NRC and the industry identified 10 program elements that are useful in describing an aging management program and then demonstrating its effectiveness. These program elements are described in Appendix A.1, Section A.1.2.3 of the Standard Review

Plan. NUREG-1801 uses these program elements in Section XI to describe acceptable aging management programs.

This Program Basis Document provides a comparison of the credited Oyster Creek program with the elements of the corresponding NUREG-1801 Chapter XI program XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements. Project Level Instruction PLI-8 "Program Basis Documents" prescribes the methodology for evaluating Aging Management Programs. An evaluation of Oyster Creeks aging management program criteria or activities to those of the NUREG-1801 program elements is performed and a conclusion is reached concerning consistency for each individual program element. A demonstration of overall program effectiveness is made after all program elements are evaluated. Required program enhancements are documented. An overall determination is made as to consistency with the program description in NUREG-1801.

2.0 PROGRAM DESCRIPTION

2.1 Program Description

<u>NUREG-1801:</u>

In most areas within a nuclear power plant, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment for those areas. Conductor insulation materials used in cables and connections may degrade more rapidly than expected in these adverse localized environments. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

a) *The purpose of the aging management program described herein is to provide reasonable assurance that the intended functions of electrical cables and connections that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized* *environments caused by heat, radiation, or moisture will be maintained consistent with the current licensing basis through the period of extended operation. This program considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR-109619.*

b) *The program described herein is written specifically to address cables and connections at plants whose configuration is such that most (if not all) cables and connections installed in adverse localized environments are accessible. This program, as described, can be thought of as a sampling program. Selected cables and connections from accessible areas (the inspection sample) are inspected and represent, with reasonable assurance, all cables and connections in the adverse localized environments. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections. As such, this program does not apply to plants in which most cables are inaccessible. As stated in NUREG/CR-5643, "The major concern with cables is the performance of aged cable when it is exposed to accident conditions." The statement of considerations for the final license renewal rule (60 Fed. Reg. 22477) states, "The major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions."*

c) *Since they are not subject to the environmental qualification requirements of 10 CFR 50.49, the electrical cables and connections covered by this aging management program are either not exposed to harsh accident conditions or are not required to remain functional during or following an accident to which they are exposed.*

<u>Oyster Creek:</u>

In most areas of the Oyster Creek Generating Station, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment for those areas. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

Conductor insulation materials used in cables and connections may degrade more rapidly than expected in these adverse localized environments. For Oyster Creek, adverse localized environments would be the areas that have temperature, radiation and/or moisture significantly higher than the plant design ambient conditions, and could appreciably increase the rate of aging of the cables or connections or have an immediate adverse effect on operability.

In some areas of the Oyster Creek Generating Station, the plant design environment exceeds the 60-year service-limiting environments (temperature and radiation dose) for some insulation materials installed at Oyster Creek. Per the EPRI TR-1003057, License Renewal Electrical Handbook, a 60-year service-limiting environment is the environment to which the materials could be exposed for 60 years and still perform their design function. In lieu of an analysis to determine which plant areas exceed the 60-year service limiting environments for the materials that are located within those areas, Oyster Creek has elected to include these adverse environments, in addition to the adverse localized environments, in the scope of this aging management program.

a) The Oyster Creek aging management program will provide reasonable assurance that the intended functions of the non-EQ electrical cables and connections within the scope of 10 CFR 54 exposed to adverse localized environments caused by heat, radiation or moisture will be maintained through the extended period of operation. The Oyster Creek aging management program will also provide reasonable assurance that the intended functions of the non-EQ electrical cables and connections within the scope of 10 CFR 54 exposed to ambient conditions in excess of 60-year service-limiting environments caused by heat, radiation or moisture will be maintained through the extended period of operation. This program considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI-109619.

b) It is estimated that most of the cables and connections exposed to adverse environments are accessible. A representative sample of accessible electrical cables and connections installed in adverse localized environments and ambient conditions in excess of 60-year service-limiting environments will be visually inspected. They will be inspected for signs of accelerated age-related degradation. If an unacceptable condition or situation is identified for a cable or connection, a determination will be made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections. Additional inspections, repair or replacement will be initiated as appropriate.

c) This new aging management program (AMP) applies to the Oyster Creek non-EQ cables and connections within the scope of license renewal. By definition, non-EQ cables and connections are either not exposed to harsh accident conditions or are not required to remain functional during or following an accident to which they are exposed. However, because EQ and non-EQ cables are not distinguishable by field inspection, no effort is necessary to separate EQ and non-EQ cables, in an area inspected, making the scope of cables inspected conservatively large. Therefore, by definition and the inspection scoping process, this program adequately incorporates the concern that deteriorated cable system failures might be induced during accident conditions.

2.2 Overall NUREG-1801 Consistency

The Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that is consistent with NUREG-1801 aging management program XI. E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

2.3 Summary of Exceptions to NUREG-1801

None. The new Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is found to be adequate to support the extended period of operation with no exceptions.

2.4 Summary of Enhancements to NUREG-1801

None. The new Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification

Requirements aging management program is found to be adequate to support the extended period of operation with no enhancements.

3.0 EVALUATIONS AND TECHNICAL BASIS

Note

This section is organized by quoting the relevant NUREG-1801 Chapter XI program element (September 2005 version) followed by the related Oyster Creek program attributes and a conclusion of the comparison. Where applicable, the NUREG-1801 program element was separated into logical sub-elements and addressed accordingly.

Implementing procedure references are included in **( )** for information purposes. This information from the source procedure has been either directly extracted from the procedure or summarized for inclusion into this PBD.

3.0 Scope of Program

NUREG-1801:

This inspection program applies to accessible electrical cables and connections within the scope of license renewal that are installed in adverse localized environments caused by heat or radiation in the presence of oxygen.

Oyster Creek:

This aging management program applies to non-EQ electrical cables and connections within the scope of license renewal that are installed in adverse localized environments or ambient conditions in excess of 60-year service-limiting environments caused by heat or radiation or moisture in the presence of oxygen. **(Reference: MA-AA-723-500 paragraph 1.1)** Connections included in the scope of this program are splices, terminal blocks, connectors and fuse blocks. **(Reference: MA-AA-723-500, Attachment 5, Guidelines for Engineering Evaluation; and MA-AA-723-500, Attachment 6, Terms and Definitions)**

(Note: The referenced implementing procedure, MA-AA-723-500, is an existing issued Exelon corporate procedure for implementation of NUREG-1801, XI.E1 aging management programs at Dresden, Peach Bottom and Quad Cities. Some of the aging management program elements, as applicable to Oyster Creek, are already included in MA-AA-723-500 and are so referenced through out this program basis document. The remainder of the aging management program elements, as applicable to Oyster Creek, require Oyster Creek specific revisions to MA-AA-723-500. These future procedure revisions are being tracked via commitment tracking A/R 330592, Assignment 35.)

The Oyster Creek Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program manages cable and connection age related insulation degradation, due to adverse environmental conditions, for the electrical commodities listed in Table 5.2. The implementing documents for this aging management program are listed in Table 5.1 and are described throughout the individual program element discussions. The commitment numbers under which these implementing documents are being revised are contained within the listings in Table 5.1.

<u>Exceptions to NUREG-1801, Element 1:</u>

None.

<u>Enhancements to NUREG-1801, Element 1:</u>

None.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 1, Scope of Program.

3.1 Preventive Actions

<u>NUREG-1801:</u>

This is an inspection program and no actions are taken as part of this program to prevent or mitigate aging degradation.

<u>Oyster Creek:</u>

No actions are taken as part of this program to prevent or mitigate aging degradation.

<u>Exceptions to NUREG-1801, Element 2:</u>

None.

Enhancements to NUREG-1801, Element 2:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 2, Preventive Actions.

3.2 Parameters Monitored or Inspected

NUREG-1801:

A representative sample of accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies. Technical basis for the sample selected is to be provided.

Oyster Creek:

The Oyster Creek B.1.34 program will inspect accessible cables and connections in identified adverse localized environments and in areas with ambient conditions in excess of insulation 60-year service-limiting environments. The only exclusions would be per engineering evaluation; for example, inspections may be evaluated by engineering for possible elimination in locations where actual general and/or localized environmental conditions do not exceed cable and connection 60-year service-limiting environments. Future revision to MA-AA-723-500 for implementation of Oyster Creek license renewal commitments will incorporate Oyster Creek specific criteria for the Parameters Monitored or Inspected element of this program. **(Reference: MA-AA-723-500, Attachment 5, Guidelines for Engineering Evaluation)**

Localized adverse environments are identified considering Oyster Creek specific environmental considerations. This is implemented by design engineering listing known adverse localized temperature and radiation environments. Sources for this list include plant operating history, corrective action work requests, previous walkdown data and radiation protection surveys. Engineering will document what areas are to be walked down by maintenance for identification of localized adverse environments. Electrical maintenance then performs walkdowns for areas selected by engineering. The walkdowns include consideration for areas containing cables and connections in close proximity to hot process pipe and equipment. Typical areas for adverse environmental conditions include areas with high temperature process fluid piping and vessels, and areas with equipment that operate at high temperature, which will include areas near main steam isolation valves, main steam pipe tunnels, and areas adjacent to uninsulated process piping. **(Reference: MA-AA-723-500, Paragraph 4., Main Body; and MA-AA-723-500, Attachment 5, Guidelines for Engineering Evaluation)**

It is important to note that general area inspections will be performed in addition to inspections in adverse localized environments, since Oyster Creek ambient conditions are in excess of insulation 60-year service-limiting environments. Oyster Creek ambient conditions are documented in Oyster Creek's Engineering Standard ES-027, Environmental Parameters – Oyster Creek NGS, Revision 4. Oyster Creek's insulation materials are documented in various design documents including PIMS, vendor manuals, and engineering specifications. 60-year service-limiting environments, by insulation material are tabulated in EPRI TR-1003057, License Renewal Electrical Handbook, December 2001, Table 9-1, All Commonly Used Age-Degradable Materials, Applications and 60-Year Service-Limiting Environments. A review of this information identified the general areas for inspection at Oyster Creek.

This program is for a representative sample of accessible cables and connections where the sample is not based on a sampling specification or percentage but rather on a focus to include the key areas of concern. Key areas of concern include general areas where ambient conditions are in excess of 112 degrees F and a cumulative 60-year radiation dose of 30E06 rads as well as adverse localized environments. Inspections are to be performed on accessible cables and connections in the identified general areas and adverse localized environments, where accessible is defined at cables and connections that can be reviewed and approached easily. Inspections may be evaluated by engineering for possible elimination in locations where general and localized environmental conditions do not exceed cable and connections design limits.

Oyster Creek specific environmental criteria identifies general areas for walkdown and inspection. These general areas for walkdown are taken from the Oyster Creek Engineering Standard ES-027 for Environmental Parameters. Oyster Creek 60-year maximum temperature is 256 degrees F. Oyster Creek's 60-year maximum radiation dose is 30E06 rads. For Oyster Creek cables, the 60-year service-limiting temperature is 112 degrees F for PVC insulation. For Oyster Creek cables, the 60-year service-limiting radiation dose is below the 30E06 rads for insulations made of fluorinated ethylene propylene, silicon, and neoprene.

Because the Oyster Creek environmental parameters exceed the 60-year service-limiting environments of cable insulations, accessible cables and connections in rooms and plant areas exceeding 112 degrees F and a 60-year dose of 30E06 rads will be inspected. These areas include: all elevations of the Drywell (drywell Zones I, II, III, IV, V, VI, and VII); Reactor Building Zone 35, the steam tunnel; and Turbine Building elevation 0' to 3'6"(Zone D) and elevation 23'6" (Zone L). In addition to these general area inspections, inspections will be done for accessible cables and connections in adverse localized environments where the threshold for adverse is defined as in excess of 112 degrees F or with a 60-year dose of 30E06 rad or greater.

Therefore, general area inspections are included in this program along with adverse localized environment inspections for accessible cables and connections.

<u>Exceptions to NUREG-1801, Element 3:</u>

None.

<u>Enhancements to NUREG-1801, Element 3:</u>

None.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 3, Parameters Monitored or Inspected.

3.3 Detection of Aging Effects

NUREG-1801:

Conductor insulation aging degradation from heat, radiation, or moisture in the presence of oxygen causes cable and connection jacket surface anomalies. A representative sample of accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, or surface contamination. Accessible electrical cables and connections installed in adverse localized environments are visually inspected at least once every 10 years. This is an adequate period to preclude failures of the conductor insulation since experience has shown that aging degradation is a slow process. A 10-year inspection interval will provide two data points during a 20-year period, which can be used to characterize the degradation rate. The first inspection for license renewal is to be completed before the period of extended operation.

Oyster Creek:

A representative sample of accessible electrical cables and connections installed in adverse environments will be visually inspected for connection and cable jacket surface anomalies, such as embrittlement, discoloration, cracking, or surface contamination.

Surface anomalies are precursors to insulation aging degradation from temperature, radiation or moisture. The inspection frequency will be at least once every 10 years, with the first inspection to be conducted prior to the extended period of operation. This is an adequate period to preclude failures of the conductor insulation since experience has shown that aging degradation is a slow process. Future revision to MA-AA-723-500 for implementation of Oyster Creek license renewal commitments will incorporate Oyster Creek specific criteria for the Detection of Aging Effects element of this program. **(Reference MA-AA-723-500, Paragraph 4.3.5)**

Exceptions to NUREG-1801, Element 4:

None.

Enhancements to NUREG-1801, Element 4:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 4, Detection of Aging Effects.

3.4 Monitoring and Trending

NUREG-1801:

Trending actions are not included as part of this program because the ability to trend inspection results is limited. However, trending would provide additional information on the rate of degradation.

Oyster Creek:

Trending actions are not included as part of this program.

Exceptions to NUREG-1801, Element 5:

None.

Enhancements to NUREG-1801, Element 5:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 5, Monitoring and Trending.

3.5 Acceptance Criteria

NUREG-1801:

The accessible cables and connections are to be free from unacceptable, visual indications of surface anomalies, which suggest that conductor insulation or connection degradation exists. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function.

Oyster Creek:

The acceptance criteria for this program is that the inspected accessible cables and connections are to be free from visual indications of surface anomalies, such as discoloration, embrittlement, cracking, softening, deformation, swelling or surface contamination such as moisture, chemicals or oil. Inspections will also look for evidence of moisture accumulation or water damage on cable raceways. Anomalies will be documented and provided to engineering for further evaluation and subsequent corrective action(s). An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. Future revision to MA-AA-723-500 for implementation of Oyster Creek license renewal commitments will incorporate Oyster Creek specific criteria for the Acceptance Criteria element of this program. **(Reference: MA-AA-723-500, Paragraph 4.3.5)**

Exceptions to NUREG-1801, Element 6:

None.

Enhancements to NUREG-1801, Element 6:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria.

3.6 Corrective Actions

NUREG-1801:

All unacceptable visual indications of cable and connection jacket surface anomalies are subject to an engineering evaluation. Such an evaluation is to consider the age and operating environment of the component, as well as the severity of the anomaly and whether such an anomaly has previously been correlated to degradation of conductor insulation or connections. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, or relocation or replacement of the affected cable or connection. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50,

Appendix B, acceptable to address the corrective actions.

Oyster Creek:

Unacceptable visual indications of connection and cable jacket surface anomalies will be subject to an engineering evaluation under the corrective action process. **(Reference: MA-AA-723-500 Paragraphs 4.3.7, 4.3.8 and 4.3.9)** Such an evaluation will consider the age and operating environment of the component, as well as the severity of the anomaly and whether such an anomaly has previously been correlated to the degradation of conductor insulation or connections. Corrective actions may include testing, shielding or otherwise changing the environment, or replacement or the affected cable or connection. When an unacceptable condition or situation is identified, a determination will be made as to whether the same condition or situation is applicable to the other accessible or inaccessible cables or connections.

Oyster Creek's corrective action process is governed by 10 CFR 50, Appendix B and is implemented by corporate administrative procedures. The corrective action process generically applies to Oyster Creek activities, even when not specifically invoked by a procedure line item. **(Reference: LS-AA-125)**

Exceptions to NUREG-1801, Element 7:

None.

Enhancements to NUREG-1801, Element 7:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 7, Corrective Actions.

3.7 Confirmation Process

NUREG-1801:

As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

Oyster Creek:

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.

Exceptions to NUREG-1801, Element 8:

None.

Enhancements to NUREG-1801, Element 8:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 8, Confirmation Process.

3.8 Administrative Controls

NUREG-1801:

As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

Oyster Creek:

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.

Exceptions to NUREG-1801, Element 9:

None.

Enhancements to NUREG-1801, Element 9

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 9, Administrative Controls.

3.9 Operating Experience

NUREG-1801:

Operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above (within three feet of) steam generators, pressurizers or hot process pipes, such as feedwater lines. These adverse localized environments have been found to cause degradation of the insulating materials on electrical cables and connections that is visually observable, such as color changes or surface cracking. These visual indications can be used as indicators of degradation.

Oyster Creek:

As noted in NUREG-1801, industry operating experience has shown that adverse localized environments have been shown to exist and have been found to produce visibly observable degradation of insulating materials for electrical cables and connections. A review of plant operating experience at Oyster Creek shows degradation of insulating material for electrical cables and connections occurred in several systems. The problems encountered and evaluated did not cause significant safety or risk impact to the plant.

Operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek Operating Experience process. The Operating Experience process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The second way is through the process for managing programs. This process requires the review of program related operating experience by the program owner.

Both of these processes review operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

Demonstration that the effects of aging are effectively managed will be achieved through objective evidence that shows that cable and connector insulation degradation due to adverse environmental conditions is being adequately managed. The following examples of operating experience provide objective evidence that the Electrical Cable and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirement aging management program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation.

1. Several instances of degradation of cables in adverse localized environments have been identified at Oyster Creek during the conduct of routine maintenance activities.

    a. CAP O2001-0483 evaluated cable routed in conduits that were either touching or in close proximity to the Iso Condenser Vent (hot process) Pipe, located in the area of the Control Rod Drive Hydraulic Control Units in the Reactor Building. It was noted that this pipe was only partially insulated, probably removed to accommodate fire protection piping and that the observed configuration was most likely original design (proximate causes). The evaluation determined that the cable was designed for this environment (i.e., the cable service-limiting design criteria were not exceeded in the localized environment of the hot pipe) and the cable's associated component, per satisfactory quarterly testing, was operable. An existing specification, SP-9000-41-005, effective since 1986, for cable and raceway system installations would preclude future installations that might jeopardize cable insulation integrity. A work request was completed to re-insulate the vent pipe.

    b. CAPs O1998-0734 and O2000-1604 evaluated condenser conductivity monitor cables routed and terminated in the turbine building basement electrical panel. Proximate cause of cable embrittlment is environmental conditions. The CAPs determined that failures of these circuits and their associated components were non-consequential in that the 1998 identified cables would be repaired if and as they failed and the 2000 identified cables would be abandoned in place if and as they failed.

c. CAP O2002-0813 evaluated a diesel generator control circuit cable with cracked insulation. It was determined that the minor nature of insulation cracking and physically arrangement of adjacent wires precluded this issue from causing a diesel generator operability concern. Proximate cause of the insulation cracking was environmental conditions. The wire was wrapped with electrical tape and scheduled for replacement during future scheduled inspection.

d. CAPs O2000-0609 and O2004-2153 evaluated leaking/dripping cable insulations. The 2000 identified issue involved PVC cable, was evaluated by a laboratory, and determined to be the result of a phenomenon called "bleeding." The cables were demonstrated to be operationally sound and it was recommendations that the installation be monitored. A similar occurrence is evaluated in the 2004 CAP.

The evaluations and subsequent actions associated with these CAPs provide objective evidence that Oyster Creek's operating experience does not show an adverse trend with respect to cable insulation performance. The problems encountered and evaluated would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to address the identified concern. There is confidence that the implementation of this new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will effectively manage age related degradation of cable and connection insulation due to adverse environmental conditions. Oyster Creek's operating experience supports implementation of this aging management program in alignment with NUREG-1801.

2. Since this is a new aging management program, there is no

plant specific operating experience with this aging management program, beyond the above demonstrated use of the corrective action process.

3. Industry operating experience has demonstrated that adverse localized environments can degrade the insulation of cables and connectors potentially impacting electrical continuity. The SAND96-0344 report provides extensive documentation of industry experience and analysis which is further reflected in subsequent IEEE (e.g., Std. P1205-2000) and EPRI (e.g., TR-1003057) documents. The phenomena is reflected in the program elements as described in NUREG-1801, Chapter XI program XI.E1.

Oyster Creek has a history of age-related cable failures involving inaccessible medium voltage cables in a wetted environment. Operating experience and associated aging management for these cables is addressed in PBD-AMP- B.1.36, Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

3.10 Conclusion

The Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is credited for managing cable and connection age related insulation degradation, due to adverse environmental conditions, for the electrical commodity groups listed in Table 5.2. The Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program's elements have been evaluated against NUREG-1801 in Section 3.0. Program exceptions have been identified in Section 2.3. Program enhancements have been identified in Section 2.4. The implementing documents and commitment numbers for this aging management program are listed in Table 5.1. The relevant operating experience has been reviewed and a demonstration of program effectiveness is provided in Section 3.10.

Based on the above, the new implementation of the Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program provides reasonable assurance that cable and connection age related insulation degradation, due to adverse environmental conditions, will be adequately managed so that the intended functions of the electrical commodities within the scope of license renewal will be maintained during the period of extended operation.

4.0 REFERENCES

4.1 Generic to Aging Management Programs

4.1.1 10 CFR 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants*

4.1.2 10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*

4.1.3 NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants*, Revision 1, dated September 2005

4.1.4 NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, Revision 1, dated September 2005

4.1.5 10 CFR 50.49, *Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants*

4.1.6 NUREG/CR-5643, *Insights Gained From Aging Research*, U. S. Nuclear Regulatory Commission, March 1992

4.2 Industry Standards

4.2.1 EPRI TR-109619, *Guideline for the Management of Adverse Localized Equipment Environments*, Electric Power Research Institute, Palo Alto, CA, June 1999

4.2.2 IEEE Std. P1205-2000, *IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations*

4.2.3 SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations*, prepared by Sandia National Laboratories for the U.S. Department of Energy, September 1996

4.2.4 EPRI TR-1003057, *License Renewal Handbook,* December

2001

4.3 Oyster Creek Program References

4.3.1 Exelon Procedure MA-AA-723-500, *Inspection of Non-EQ Cables and Connections for Managing Adverse Localized Environments*

4.3.2 Oyster Creek Engineering Standard ES-027, *Environmental Parameters – Oyster Creek NGS*

4.3.3 Oyster Creek Specification, SP-9000-41-005, *Installation Specification for Cables and Raceways at Oyster Creek*

4.3.4 Passport AR 330592, Assignment 35, Subassignments 01 and 02

4.3.5 Oyster Creek AMP Audit Questions

1. AMP-101
2. AMP-102
3. AMP-131
4. AMP-136

5.0 TABLES

5.1 Aging Management Program Implementing Documents

Procedure Number	Procedure Title	Commitment No.	Status
MA-AA-723-500	Inspection of Non EQ Cables and Connections for Managing Adverse Localized Environments (revised to address Oyster Creek applicability, radiation, sample selection basis)	AR # 00330592.34.01	ACC/ASG
New Routine Task RXXXXXXX	Perform Cable Inspections per MA-AA-723-500	AR # 00330592.34.02	ACC/ASG

5.3 Aging Management Review Results

SSC Name	Structure and/or Component	Material	Environment	Aging Effect
Electrical Commodity Groups	Electrical penetrations	Various organic polymers (e.g., EPR, XLPE, PVC, ETFE)	Adverse Localized Environment (External)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure/ degradation of organics (Thermal/ thermoxidative), radiolysis and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation, and moisture intrusion
Electrical Commodity Groups	Insulated cables and connections	Various organic polymers (e.g., EPR, XLPE, PVC, ETFE)	Adverse Localized Environment (External)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure/ degradation of organics (Thermal/ thermoxidative), radiolysis and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation, and moisture intrusion

6.0 ATTACHMENTS

6.1 LRA Appendix A

6.2 LRA Appendix B

PROGRAM BASIS DOCUMENT

PBD-AMP-B.1.15

Revision 0

BORAFLEX RACK MANAGEMENT PROGRAM

GALL PROGRAM XI.M22 - BORAFLEX RACK MANAGEMENT PROGRAM

Prepared By: ______________________

Reviewed By: ______________________

Program Owner Review: ______________________

Technical Lead Approval: ______________________

Revision History:

Revision	*Prepared by:*	*Reviewed by:*	*Program Owner:*	*Approved by:*
0	*A. Ouaou*	*G. Beck*	*H. Sharma*	*F. Polaski*
Date				

Summary of Revisions:

Rev. Number	Reason for the Revision(s)
0	Initial Issue

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1.0 PURPOSE

1.1 Purpose

The purpose of this Program Basis Document is to document and evaluate those activities of the Oyster Creek Boraflex Rack Management aging management program that are credited for managing reduction of neutron-absorbing capacity of Boraflex panels as part of Oyster Creek License Renewal to meet the requirements of the License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

This includes the following:

- The identification of the scope of the program;
- The evaluation of program elements against NUREG-1801;
- The review of Operating Experience to demonstrate program effectiveness;
- The identification of required program enhancements;
- The identification of Oyster Creek documents required implementing the program.

1.2 Methodology

The nuclear power plant License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," describes the License Renewal process and provides requirements for the contents of License Renewal Applications. 10 CFR 54.21(a)(3) states:

"For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the Current Licensing Basis (CLB) for the period of extended operation."

The NRC and the industry identified 10 program elements that are useful in describing an aging management program and then demonstrating its effectiveness. These program elements are described in Appendix A.1, Section A.1.2.3 of the Standard Review Plan. NUREG-1801 uses these program elements in Section XI to describe acceptable aging management programs.

This Program Basis Document also provides a comparison of the credited Oyster Creek program with the elements of the corresponding NUREG-1801 Chapter XI program XI.M22, Boraflex Monitoring. Project Level Instruction PLI-8 "Program Basis Documents" prescribes the methodology for evaluating Aging Management Programs. An evaluation of Oyster Creek's aging management program criteria or activities to those of the NUREG-1801 program elements is performed and a conclusion is reached concerning consistency for each individual program element. A demonstration of overall program effectiveness is made after all program elements are evaluated. Required program enhancements are documented. An overall determination is made as to consistency with the program description in NUREG-1801.

2.0 PROGRAM DESCRIPTION

2.1 Program Description

NUREG-1801:

a) *A Boraflex monitoring program for the actual Boraflex panels is implemented in the spent fuel racks to assure that no unexpected degradation of the Boraflex material would compromise the criticality analysis in support of the design of spent fuel storage racks.*

b) *The applicable aging management program (AMP), based on manufacturer's recommendations, relies on periodic inspection, testing, monitoring, and analysis of the criticality design to assure that the required 5% subcriticality margin is maintained.*

c) *The frequency of the inspection and testing depends on the condition of the Boraflex, with a maximum of five years. Certain accelerated samples are tested every two years. Results based on test coupons have been found to be unreliable in determining the degree to which the actual Boraflex panels have been degraded.*

d) *This AMP includes: (1) performing neutron attenuation testing, called blackness testing, to determine gap formation in Boraflex panels; (2) completing sampling and analysis for silica levels in the spent fuel pool water and trending the results by using the EPRI RACKLIFE predictive code or its equivalent on a monthly, quarterly, or annual basis (depending on Boraflex panel condition); and (3) measuring boron areal density by techniques such as the BADGER device. Corrective actions are initiated if the test results find that the 5% subcriticality margin cannot be maintained because of current or projected future Boraflex* *degradation.*

Oyster Creek:

a) The Oyster Creek Boraflex Rack Management Program implements monitoring activities for the actual Boraflex panels in the spent fuel storage pool. The program employs a defense in depth strategy to detect, trend, and take appropriate actions as required to ensure that criticality analysis in support of the design of spent fuel racks is not compromised (**Reference: NF-AA-610 paragraph 1.0, 4.6, 1002.6 paragraph 1.0**).

b) The program was developed based on Boraflex manufacturer's recommendations, industry guidelines developed in response to NRC Generic Letter (GL) 96-04 (**Reference: 1002.6 paragraph 2.4**), and plant specific operating experience. It relies on periodic inspection of Boraflex sample coupons, in-situ testing of the racks using the BADGER device, monitoring of dissolved silica in the spent fuel storage pool and trending the results using EPRI RACKLIFE predictive code, and analysis of the criticality design to assure that the required 5% subcriticality margin is maintained (**Reference: 1002.6 Appendix A**).

c) The program implementing procedures require inspection and testing of Boraflex sample coupons located in the spent fuel pool. Certain accelerated sample coupons are inspected and tested every 2 years (**Reference: 1002.6 paragraph 3.2**). Long-term sample coupons are inspected and tested on a frequency of 5 years (**Reference: 1002.6 paragraph 3.1**). The results of these tests are used only to assess the condition of the actual Boraflex panels in the spent fuel racks. The results are not relied upon to determine the degree of degradation of the actual Boraflex panels. The In-situ testing using the BADGER device, which is done every 3 years, is relied upon to establish the condition of the actual Boraflex panels, and the basis for the required corrective actions (**Reference: 1002.6 Appendix A, paragraph 5**).

d) The program includes sampling and analysis for silica levels in the spent fuel storage pool water on a weekly basis and trending the results using RACKLIFE is on a frequency of two years or less. Areal density tests are performed on a frequency of 3 years using the BADGER device (**Reference: 1002.6 Appendix A**). Blackness test is not performed and thus constitutes an exception to NUREG-1801 XI.M22 program. The test has been replaced with areal density test using the

BADGER device as explained in section 2.2 below

If an adverse trend is identified in the peak % boron loss that would conservatively cause k_{eff} for the spent fuel in the storage racks to become equal to or rise above .95 (5% subcritical), then corrective actions are initiated. These actions may include further BADGER testing, application of administrative controls on fuel placement, and modification of storage racks **(Reference: 1002.6 paragraph 3.0, Appendix A paragraph 6.0)**.

Overall NUREG-1801 Consistency

The Oyster Creek Boraflex Rack Management aging management program is an existing program that is consistent with NUREG-1801 aging management program XI.M22, Boraflex Monitoring with the following exception.

2.2 Summary of Exceptions to NUREG-1801

Blackness test is not performed. This test is performed only on Boraflex sample coupons not on the actual Boraflex panels in the spent fuel racks. The test provides information regarding gaps or missing sections in the Boraflex sample coupon being tested which could be used to represent the condition of Boraflex panels in the spent fuel racks. However these results have be found to be unreliable with regard to predicating the degree of degradations of the actual Boraflex panels in the spent fuel racks. The areal density test using the BADGER device provides more reliable data on the condition of Boraflex panels in the spent fuel racks as explained below.

The areal density testing using BADGER provides a direct measurement of in-rack performance of Boraflex panels. This test measures gaps, erosion and general thinning of the scanned Boraflex panel. The areal density test is used to benchmark the RACKLIFE Boraflex performance model. The detail provided by areal density testing provides a compelling and comprehensive basis to determine spent fuel storage rack operability and margin to criticality.

In summary blackness testing gives only an indication whether neutron absorber is present or not in a Boraflex panel whereas BADGER test provides a quantitative measurement of Boron-10 areal density of neutron absorber in the rack **(Reference: 4.3.12)**

2.3 Summary of Enhancements to NUREG-1801

None. The existing Oyster Creek Boraflex Rack Monitoring aging management program is found to be adequate to support the extended period of operation with no enhancements.

3.0 EVALUATIONS AND TECHNICAL BASIS

<u>**Note**</u>

This section is organized by quoting the relevant NUREG-1801 Chapter XI program element (September 2005 version) followed by the related Oyster Creek program attributes and a conclusion of the comparison. Where applicable, the NUREG-1801 program element was separated into logical sub-elements and addressed accordingly.

Implementing procedure references are included in **( )** for information purposes. This information from the source procedure has been either directly extracted from the procedure or summarized for inclusion into this PBD.

3.0 Scope of Program

<u>NUREG-1801:</u>

The AMP manages the effects of aging on sheets of neutron-absorbing materials affixed to spent fuel racks. For Boraflex panels, gamma irradiation and long-term exposure to the wet pool environment cause shrinkage resulting in gap formation, gradual degradation of the polymer matrix, and the release of silica to the spent fuel storage pool water. This results in the loss of boron carbide in the neutron absorber sheets.

<u>Oyster Creek:</u>

The Boraflex Rack Management Program applies to the neutron-absorbing Boraflex sheets affixed to spent fuel racks. The Boraflex AMP includes sampling of dissolved reactive silica in the spent fuel storage pool, monitors Boraflex's aging effects through the RACKLIFE Computer model and in-situ testing using the BADGER device. RACKLIFE provides calculated peak and average % of loss of boron carbide in the neutron absorber sheets.
Boraflex coupon surveillance test has been in effect since 1986 when the density poison racks were installed. The surveillance coupons are approximately 2"x4"x0.045" Boraflex sheets encased

in stainless steel and placed on sample holder. There are two sample holders containing coupons for long term and accelerated exposure testing. The accelerated coupons are positioned to receive exposure at a faster rate than the spent fuel racks and are tested biennially to serve as an early indication of Boraflex degradation (**Reference: NF-AA-610 paragraph 4.6.1, CY-AB-120-300 paragraph 4.3.1, 1002.6 Appendix A**).

The Oyster Creek Boraflex Rack Management Program aging management program manages the aging effects of reduction of neutron-absorbing capacity for Boraflex panels for the system, components, and environment listed in Table 5.2. The implementing documents for this aging management program are listed in Table 5.1 and are described throughout the individual program element discussions.

Exceptions to NUREG-1801, Element 1:

None.

Enhancements to NUREG-1801, Element 1:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 1, Scope of Program.

3.1 Preventive Actions

NUREG-1801:

For Boraflex panels, monitoring silica levels in the storage pool water, measuring gap formation by blackness testing, periodically measuring boron areal density, and applying predictive codes, are performed. These actions ensure that degradation of the neutron-absorbing material is identified and corrected so the spent fuel storage racks will be capable of performing their intended functions during the period of extended operation, consistent with current licensing basis (CLB) design conditions.

Oyster Creek:

The Boraflex Rack Management Program monitors the condition of

Boraflex to ensure that its degradation is detected and corrected before a loss of intended function. No preventive or mitigating actions are associated with the program. Monitoring activities include sampling and trending of silica levels in the storage pool water, periodically measuring boron areal density and Gap formation using the BADGER device. RACKLIFE code is used to trend Boraflex degradation (**Reference: 1002.6 Appendix A, paragraph 9 and 5, CY-AB-120-300 paragraph 4.3.1**).

Exceptions to NUREG-1801, Element 2:

None.

Enhancements to NUREG-1801, Element 2:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 2, Preventive Actions.

3.2 Parameters Monitored or Inspected

NUREG-1801:

a) *The parameters monitored include physical conditions of the Boraflex panels, such as gap formation and decreased boron areal density, and the concentration of the silica in the spent fuel pool.*

b) *These are conditions directly related to degradation of the Boraflex material. When Boraflex is subjected to gamma radiation and long-term exposure to the spent fuel pool environment, the silicon polymer matrix becomes degraded and silica filler and boron carbide are released into the spent fuel pool water. As indicated in the Nuclear Regulatory Commission (NRC) Information Notice (IN) 95-38 and NRC Generic Letter (GL) 96-04, the loss of boron carbide (washout) from Boraflex is characterized by slow dissolution of silica from the surface of the Boraflex and a gradual thinning of the material. Because Boraflex contains about 25% silica, 25% polydimethyl siloxane polymer, and 50% boron carbide, sampling and analysis of the presence of silica in the spent fuel pool provide an indication of depletion of boron carbide from Boraflex; however, the degree to which Boraflex has degraded is ascertained through measurement of the boron areal density.*

<u>Oyster Creek:</u>

Parameters monitored include physical conditions of the Boraflex panels, such as gap formation and decreased boron areal density, and the concentration of the silica in the spent fuel storage pool. The In-situ testing using the BADGER device provides for monitoring physical condition of Boraflex panels, such as gap formation and decreased boron areal density. Sampling and testing of spent fuel storage pool water for silica levels and trending the results using RACKLIFE program provide an indication of physical condition of Boraflex. An increase in silica level is directly related to degradation of Boraflex material. RACKLIFE program is used to calculate the amount of degradation that has occurred to the Boraflex. Boron areal density testing using the BADGER device are conducted periodical to validate the RACKLIFE model. The BADGER device test includes measurement of gaps and cracks **(Reference: 1002.6 Appendix A, CY-AB-120-300 paragraph 4.3.1)**.

Test samples are visually inspected for evidence of gross changes or deterioration including surface texture, discoloration, cracking, tearing, voids, craters, and loss of material. The samples are also tested for hardness, dimensional measurements, and weight measurement. Hardness tests are made using a Shore Durometer Type A-2. Dimensional measurements include length, width, and thickness **(Reference: 1002.6 paragraph 3.4)**.

Industry and plant-specific operating experience have shown that Boraflex material degrades when subjected to gamma radiation and long-term exposure to the spent fuel storage pool environment. The Boraflex silicon polymer matrix becomes degraded and silica filler and boron carbide are released into the spent fuel storage pool water. As indicated in the Nuclear Regulatory Commission (NRC) Information Notice (IN) 95-38 and NRC Generic Letter (GL) 96-04, the loss of boron carbide (washout) from Boraflex is characterized by slow dissolution of silica from the surface of the Boraflex and a gradual thinning of *the material. Sampling and analysis of the spent fuel storage pool water for the presence of silica provide an indication of depletion of boron carbide from Boraflex. However areal density measurements conducted periodically using the BADGER device provide a reliable means for assessing the extent of Boraflex degradation* ***(Reference: 1002.6 Appendix A paragraph 5 and 9, CY-AB-120-300 paragraph 4.3.1).***

Exceptions to NUREG-1801, Element 3:

None.

Enhancements to NUREG-1801, Element 3:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 3, Parameters Monitored or Inspected.

3.3 Detection of Aging Effects

NUREG-1801:

a) The amount of boron carbide released from the Boraflex panel is determined through direct measurement of boron areal density and correlated with the levels of silica present with a predictive code.

b) This is supplemented with detection of gaps through blackness testing and periodic verification of boron loss through areal density measurement techniques such as the BADGER device.

Oyster Creek:

a) The amount of boron carbide released from the Boraflex panels is determined through direct measurement of boron areal density and correlated with the levels of silica present through the use of predictive code (RACKLIFE).

b) Detection of gaps through blackness testing is replaced by periodic verification of boron loss through areal density measurements using the BADGER device (**Reference: 1002.6 Appendix A paragraph 1, 5**). Boraflex sample coupons are inspected periodically to provide early warnings of any Boraflex material degradation. The result of visual examination, hardness test, dimensional measurements, and weight measurement for each test sample coupon are compared to the results of its pre-irradiated condition or initial characterization (**Reference: 1002.6 paragraph 3.0**). The comparison provides an indication of Boraflex degradation in the spent fuel pool. However since sample or coupon test results have been found to be unreliable in determining the degree to which the actual Boraflex panels have been degraded, areal density tests using the BADGER device are conducted periodically to ensure degradation of Boraflex panels is effectively managed.

Exceptions to NUREG-1801, Element 4:

Blackness test is not performed. This test only provides information regarding the presence of neutron absorber material. It will provide information regarding gaps or missing sections in the Boraflex panel. However this test alone is not a good indicator of the condition of Boraflex panels in the spent fuel racks. The results of the blackness test along with surveillance sample coupons are required to indirectly estimate the performance of spent fuel storage rack absorber material.

The areal density testing using BADGER provides a direct measurement of in-rack performance of Boraflex panels. This test measures gaps, erosion and general thinning of the scanned Boraflex panel. The areal density test is used to benchmark the RACKLIFE Boraflex performance model. The detail provided by areal density testing provides a compelling and comprehensive basis to determine spent fuel storage rack operability and margin to criticality.

In summary blackness testing gives only an indication whether neutron absorber is present or not in a Boraflex panel whereas BADGER test provides a quantitative measurement of Boron-10 areal density of neutron absorber in the rack (**Reference: 4.3.12**).

Enhancements to NUREG-1801, Element 4:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 4, Detection of Aging Effects with exceptions as described above.

3.4 Monitoring and Trending

NUREG-1801:

The periodic inspection measurements and analysis are to be compared to values of previous measurements and analysis to provide a continuing level of data for trend analysis.

Oyster Creek:

Periodic inspection measurements and analysis of boron areal density and sampling of silica level in the spent fuel storage pool provide data used to trend and predicting performance of Boraflex.

The program includes sampling and analysis for silica levels in the spent fuel pool water on a weekly basis and trending the results using RACKLIFE is on a frequency of two years or less. Areal density tests are performed on a frequency of 3 years using the BADGER device (**Reference: 1002.6 Appendix A paragraph 1, 5, 9**)

Boraflex sample coupons are inspected periodically to provide early warnings of any Boraflex material degradation. The result of visual examination, hardness test, dimensional measurements, and weight measurement for each test sample coupon is compared to the results of its pre-irradiated condition or initial characterization The comparison results are trended to provide an early indication of Boraflex condition (**Reference: 1002.6 paragraph 3.0**).

Exceptions to NUREG-1801, Element 5:

None.

Enhancements to NUREG-1801, Element 5:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 5, Monitoring and Trending.

3.5 Acceptance Criteria

NUREG-1801:

The 5% subcriticality margin of the spent fuel racks is to be maintained for the period of extended operation.

Oyster Creek:

The objective of the program is to maintain the 5% subcriticality margin of the spent fuel racks in accordance with Oyster Creek Technical Specifications and UFSAR. **(Reference NF-AA-610 paragraph 4.6.4.2, 1002.6 paragraph 3.0)**. Criticality analysis is performed if **(Reference: 1002.6 Appendix A paragraph 4)**

- RACKLIFE calculates a peak panel Boron loss of greater than 10% B_4C.
- BADGER testing indicating Boraflex sample coupons have greater the 4.1% shrinkage or an areal density of less than 0.01003 gm/cm^2.
- BADGER testing indicating total gaps greater than 5.89 inches, panel width of less the 5.33 inches

The Boraflex sample coupons provide early warning of degradations that could impact subcriticality margin. Acceptance criteria for the sample coupons is,

- Visual – No cracking, separation, tears or significant loss of material as evidenced by craters, voids, and edge deterioration.

- Hardness – Increase from base value to 95-100 on Shore A scale and then stay relatively constant throughout the exposure period. No decrease in hardness greater than 2 units between successive tests.
- Weight – No more than 2% loss in weight from pre-irradiated value.
- Length and Width – Up to 4.1% change (shrinkage)
- Thickness – Less than 3 mils change in thickness
- If the sample coupons do not meet the above criteria, actions are taken to evaluate the impact on subcriticality margin (**Reference: 1002.6 paragraph 7.0**).

Exceptions to NUREG-1801, Element 6:

None.

Enhancements to NUREG-1801, Element 6:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria.

3.6 Corrective Actions

NUREG-1801:

Corrective actions are initiated if the test results find that the 5% subcriticality margin cannot be maintained because of the current or projected future degradation. Corrective actions consist of providing additional neutron-absorbing capacity by Boral or boron steel inserts, or other options, which are available to maintain a subcriticality margin of 5%. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

Oyster Creek:

Corrective actions are initiated in accordance with the corrective action process (**Reference: LS-AA-125**) if an adverse trend is identified in the peak % boron loss that would conservatively cause k_{eff} for the spent fuel in the storage racks to become equal to or rise above .95 (5% subcritical). Boraflex panels that show excessive boron loss, which could significantly impact criticality margins such that the updated criticality analysis would not yield acceptable results, either the cell is permanently vacated of fuel and is blocked or a supplementary neutron absorber panel is inserted as additional neutron-absorber material.

Procedure LS-AA-125, "Corrective Action Program (CAP) Procedure" and supporting documents implement Exelon Quality Assurance Topical Report (QATR), which is based on the 18 criteria set forth in 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.

The procedure provides direction for using the CAP to address undesirable conditions and opportunities for improvement. The CAP process encompasses condition identification, condition documentation in a Condition Report (CR or CAP), assignment of significance level and investigation class, investigation, corrective action determination, root cause analysis, investigation report review and approval, action tracking, and trend analysis.

For Boraflex Rack Management Program, the CAP process is initiated if an adverse trend is identified in the peak % boron loss that would conservatively cause keff for the spent fuel in the storage racks to become equal to or rise above .95 (5% subcritical).

Exceptions to NUREG-1801, Element 7:

None.

Enhancements to NUREG-1801, Element 7:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 7, Corrective Actions.

3.7 Confirmation Process

NUREG-1801:

Site quality assurance (QA) procedures, site review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

Oyster Creek:

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.

Exceptions to NUREG-1801, Element 8:

None.

Enhancements to NUREG-1801, Element 8:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 8, Confirmation Process.

3.8 Administrative Controls

NUREG-1801:

See Item 8, above.

Oyster Creek:

See Item 8, above.

Exceptions to NUREG-1801, Element 9:

None.

Enhancements to NUREG-1801, Element 9

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 9, Administrative Controls.

3.9 Operating Experience

NUREG-1801:

The NRC IN 87-43 addresses the problems of development of tears and gaps (average 1-2 in., with the largest 4 in.) in Boraflex sheets due to gamma radiation-induced shrinkage of the material. NRC INs 93-70 and 95-38 and NRC GL 96-04 address several cases of significant degradation of Boraflex test coupons due to accelerated dissolution of Boraflex caused by pool water flow through panel enclosures and high accumulated gamma dose. Two spent fuel rack cells with about 12 years of service have only 40% of the Boraflex remaining. In such cases, the Boraflex may be replaced by boron steel inserts or by a completely new rack system using Boral. Experience with boron steel is limited; however, the application of Boral for use in the spent fuel storage racks predates the manufacturing and use of Boraflex. The experience with Boraflex panels indicates that coupon surveillance programs are not reliable. Therefore, during the period of extended operation, the measurement of boron areal density correlated, through a predictive code, with silica levels in the pool water is verified. These monitoring programs provide assurance that degradation of Boraflex sheets is monitored, so that appropriate actions can be taken in a timely manner if significant loss of neutron-absorbing capability is occurring. These monitoring programs ensure that the Boraflex sheets will maintain their integrity and will be effective in performing its intended function.

Oyster Creek:

The Oyster Creek spent fuel pool was refitted with high-density spent fuel storage racks in 1985. These racks utilize neutron absorber material Boraflex for reactivity control. Boraflex has been observed to be subject to in-service degradation from the combined effects of gamma radiation from spent fuel and long-term exposure to the aqueous pool environment.

Operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek Operating Experience process. The Operating Experience process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The second way is through the process for managing programs. This process requires the review of program related operating experience by the program owner.

Both of these processes review operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that reduction of neutron-absorbing capacity in Boraflex panels is being adequately managed. The following examples of operating experience provide objective evidence that the Boraflex Rack Management aging management program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

To date two boron areal density tests, using the BADGER device, have been completed.

1. The initial test was conducted in 1997 **(Reference 4.3.4)** wherein 42 panels of Boraflex were subject to quantitative assay of boron-10 areal density with BADGER. The results show that the average areal density of 41 of the panels exceeded the minimum areal density (0.0090 grams B-10/ cm^2) as certified by the manufacturer of the Boraflex. The areal density of the other panel (0.0089grams B-10/cm^2) was slightly below the minimum certified areal density when the measurement uncertainty is considered. The average areal density of all panels tested is .0120 +/- 0.0013 grams B-10/cm^2 compared with a manufactured batch areal density of

0.01114 grams B-10/cm². Of the 42 panels tested, eight showed local anomalies, other than gaps, which were expected. The type of non-gap anomalies include local cracks or thin spots and excessive pull back of the top edge of the panel. In general, the greatest pull back was in panels, which did not develop a gap(s). In addition 3 panels had what either could be interpreted as a small crack or a local thin spot near the top of the panels. In either case, the anomaly is very local and would have a negligible reactivity effect. This example provides objective evidence that degradation of Boraflex sheets would be detected prior to loss of intended function and, adequate corrective action would be taken.

2. The second BADGER in-situ test, conducted in 2001, involved inspection of 40 panels, including several panels inspected in 1997. The test results indicate that some of the Boraflex panels have sustained some in-service degradation and few higher dose panels showed moderate loss of boron carbide. The degradations observed include some areas of local dissolution, and the formation of shrinkage-induced gaps. The average areal density of all panels is 0.0122 +/- 0.0013 grams B-10/cm². This compares with an as-fabricated batch average of 0.01123 +/- 0.0004 grams B-10/cm² and a minimum as-fabricated certified value of 0.009 grams B-10/cm². It is therefore concluded that the average areal density of the Oyster Creek Boraflex is well in excess of the minimum certified areal density (**Reference: 4.3.5**). This example provides objective evidence that degradation of Boraflex sheets would be detected prior to loss of intended function and, adequate corrective action would be taken.

The results of the two BADGER test campaigns at Oyster Creek were used to characterize the state of Oyster Creek spent fuel racks Boraflex panels at the time of testing. Test results show that the Boraflex has undergone degradation experienced in the industry. However criticality analysis and projections using the updated RACKLIFE model, concluded that 5% subcriticality margin the spent fuel racks will be maintained (**Reference: 4.3.6**).

As a result of the two tests, the frequency for conducting the BADGER test was changed from every 4 years to 3 years. These examples provide objective evidence that degradation of Boraflex sheets would be detected prior to loss of intended function and, adequate corrective action would be taken to prevent recurrence.

3.10 Conclusion

The Oyster Creek Boraflex Rack Management aging management program is credited for managing reduction of neutron-absorbing capacity of Boraflex panels for the systems, components, and environments listed in Table 5.2. The Oyster Creek Boraflex Rack Management program's elements have been evaluated against NUREG-1801 in Section 3.0. Program exceptions have been identified in Section 2.3. Program enhancements have been identified in Section 2.4. The implementing documents for this aging management program are listed in Table 5.1. The relevant operating experience has been reviewed and a demonstration of program effectiveness is provided in Section 3.10.

Based on the above, the continued implementation of the Oyster Creek Boraflex Rack Management aging management program provides reasonable assurance that reduction of neutron-absorbing capacity of Boraflex panels will be adequately managed so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

4.0 REFERENCES

4.1 Generic to Aging Management Programs

4.1.1 10 CFR 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants*

4.1.2 10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*

4.1.3 NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,* Revision 1, dated September 2005

4.1.4 NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, Revision 1, dated September 2005

4.2 Industry Standards

4.2.1 USNRC Generic Letter (GL) 96-03

4.2.2 EPRI Report NP-6159, December 1988, "An Assessment of Boraflex Performance in Spent Nuclear Fuel Storage Racks".

4.3 Oyster Creek Program References

4.3.1 NF-AA-610, "On-Site Wet Storage of Spent Nuclear Fuel"

4.3.2 CY-AB-120-300, "Spent Fuel Pool"

4.3.3 Procedure 1002.6, " Oyster Creek Spent Fuel Rack In-Service Surveillance and Management Program for Boraflex Racks"

4.3.4 NET-092-06 Rev. 0, "Zinc Demonstration Program: BADGER Test Campaign at Oyster Creek Nuclear Station", Northeast Technology Corp. for Electric Power Research Institute; March 1998.

4.3.5 NET-187-01, "BADGER TEST Campaign at Oyster Creek", Northeast Technology Corp, Kingston, NY March 29, 2002.

4.3.6 NET-200-01 Rev. 2, "Criticality Analysis of the Oyster Creek Spent Fuel Rack for GE-11 Fuel with Boraflex Panel Degradation Projected Through 2009", Northeast

Technology Corp, Kingston, NY June 2004.

4.3.7 TR-117 Rev. 2, "Criticality Analysis for the Oyster Creek High Density Spent Fuel Rack with Boraflex Degradation", June 2001.

4.3.8 "Blackness Testing of Boraflex In selected Cells of the Spent Fuel Storage Racks In The Oyster Creek Nuclear Plant", HOLTEC International, October 1993.

4.3.9 TDR-1131 Rev. 2, "Boraflex Gap Evaluation for the Oyster Creek Spent Fuel Pool Racks", October 1994.

4.3.10 Calculation C-1302-254-E620 Rev. 0, "Criticality Analysis of Oyster Creek Spent Fuel Storage Racks with Boraflex degradation", March 2000

4.3.11 6730-96-2300, Letter from GPU Nuclear to US NRC, "Oyster Creek Nuclear Generating Station Docket No. 50-219 Response to Generic Letter 96-04", October 15, 1996.

4.3.12 EPRI TR-107335, "BADGER, a probe for nondestructive Testing of Residual Boron-10 Absorber Density in Spent –Fuel Racks; Development and Demonstration".

5.0 TABLES

5.1 Aging Management Program Implementing Documents

Procedure Number	Procedure Title	Commitment No.	Status
1002.6	Oyster Creek Spent Fuel Rack In-Service Surveillance and Management of Boraflex Racks	0330592.15.03	ACC/ASG
CY-AB-120-300	Spent Fuel Pool	0330592.15.01	ACC/ASG
NF-AA-610	On-Site Wet Storage of Spent Nuclear Fuel	0330592.15.02	ACC/ASG

5.2 Aging Management Review Results

SSC Name	Structure and/or Component	Material	Environment	Aging Effect
Fuel Storage and Handling Equipment	Spent Fuel Storage Racks	Boraflex	Treated Water < 140F	Reduction of Neutron-Absorbing Capacity

6.0 ATTACHMENTS

6.1 LRA Appendix A

6.2 LRA Appendix B

PROGRAM BASIS DOCUMENT

PBD-AMP-B.1.35

Revision 0

ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS

GALL PROGRAM XI.E2 - ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS

Prepared By: ______________________

Reviewed By: ______________________

Program Owner Review: ______________________

Technical Lead Approval: ______________________

Revision History:

Revision	*Prepared by:*	*Reviewed by:*	*Program Owner:*	*Approved by:*
0	*Deb Spamer*	*Ahmed Ouaou*	*Everett Johnson*	*Don Warfel*
Date				

Summary of Revisions:

Rev. Number	Reason for the Revision(s)
0	Initial Issue

TABLE OF CONTENTS

1.0 PURPOSE AND METHODOLOGY

1.1 Purpose

The purpose of this Program Basis Document is to document and evaluate those activities of the Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program that are credited for managing cable and connection age related insulation degradation, due to adverse environmental conditions, as part of Oyster Creek License Renewal to meet the requirements of the License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

This includes the following:

- The identification of the scope of the program;
- The evaluation of program elements against NUREG-1801;
- The review of Operating Experience to demonstrate program effectiveness;
- The identification of required program enhancements; and
- The identification of Oyster Creek documents required to implement the program.

1.2 Methodology

The nuclear power plant License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," describes the License Renewal process and provides requirements for the contents of License Renewal Applications. 10 CFR 54.21(a)(3) states:

"For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the Current Licensing Basis (CLB) for the period of extended operation."

The NRC and the industry identified 10 program elements that are useful in describing an aging management program and then demonstrating its effectiveness. These program elements are described in Appendix A.1, Section A.1.2.3 of the Standard Review Plan. NUREG-1801 uses these program elements in Section XI to describe acceptable aging management programs.

This Program Basis Document provides a comparison of the credited Oyster Creek program with the elements of the corresponding NUREG-1801 Chapter XI program XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits. Project Level Instruction PLI-8 "Program Basis Documents" prescribes the methodology for evaluating Aging Management Programs. An evaluation of Oyster Creek's aging management program criteria or activities to those of the NUREG-1801 program elements is performed and a conclusion is reached concerning consistency for each individual program element. A demonstration of overall program effectiveness is made after all program elements are evaluated. Required program enhancements are documented. An overall determination is made as to consistency with the program description in NUREG-1801.

2.0 PROGRAM DESCRIPTION

2.1 Program Description

<u>NUREG-1801:</u>

In most areas within a nuclear power plant, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the design environment. Conductor insulation materials used in electrical cables may degrade more rapidly in adverse localized environments. An adverse localized environment is significantly more severe than the specified service environment for the cable. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

Exposure of electrical cables to adverse localized environments caused by heat, radiation, or moisture can result in reduced *insulation resistance (IR). Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, high voltage, low-level signals such as radiation monitoring and nuclear instrumentation circuits because a reduced IR may contribute to signal inaccuracies.*

a) *The purpose of the aging management program described herein is to provide reasonable assurance that the intended functions of electrical cables that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are used in instrumentation circuits with sensitive, high voltage, low-level signals exposed to adverse localized environments caused by heat, radiation or moisture will be maintained consistent with the current licensing basis through the period of extended operation. This program considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR-109619.*

   In this aging management program, either of two methods can be used to identify the existence of aging degradation. In the first method, calibration results or findings of surveillance testing programs are evaluated to identify the existence of cable aging degradation. In the second method, direct testing of the cable system is performed.

b) *This program applies to high-range-radiation and neutron flux monitoring instrumentation cables in addition to other cables used in high voltage, low-level signal applications that are sensitive to reduction in IR. For these cables, GALL XI.E1 does not apply.*

   As stated in NUREG/CR-5643, "The major concern with cables is the performance of aged cable when it is exposed to accident conditions." The statement of considerations for the final license renewal rule (60 Fed. Reg. 22477) states, "The major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions."

c) *Since they are not subject to the environmental qualification requirements of 10 CFR 50.49, the electrical cables covered by this aging management program are either not exposed to harsh accident conditions or are not required to remain* *functional during or following an accident to which they are exposed.*

Oyster Creek:

In most areas of the Oyster Creek Generating Station, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment for those areas. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

Conductor insulation materials used in cables and connections may degrade more rapidly than expected in these adverse localized environments. For Oyster Creek, adverse localized environments would be the areas that have temperature, radiation and/or moisture significantly higher than the plant design ambient conditions, and could appreciably increase the rate of aging of the cables or connections or have an immediate adverse effect on operability.

Exposure of electrical cables to adverse localized environments can result in reduced insulation resistance. A reduction in insulation resistance is a concern for Oyster Creek sensitive, high voltage, low level signals for Intermediate Range Power Monitoring (IRM), Local Power Range Monitoring/Average Power Range Monitoring (LPRM/APRM), Reactor Building High Radiation Monitoring, and Air Ejector Offgas Radiation Monitoring because a reduced insulation resistance may contribute to signal inaccuracies.

a) The Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environment Qualification Requirements Used in Instrumentation Circuits aging management program will provide reasonable assurance that the intended functions of the non-EQ electrical cables not subject to the environmental qualification requirements of 10 CFR 50.49 and used in circuits with sensitive, high voltage, low-level signals exposed to adverse localized environments caused by heat, radiation or moisture will be maintained consistent with the current licensing basis through the period of extended operation. This program considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI-109619.

This aging management program will use two different methods for identifying the potential existence of aging degradation. Routine calibration tests performed as part of the plant surveillance test program are used to identify the potential existence of aging degradation in the Reactor Building High Radiation Monitoring and Air Ejector Offgas Radiation Monitoring systems. When an instrumentation loop is found to be out of calibration during routine surveillance testing, troubleshooting is performed on the loop, including the instrumentation cable. Direct cable testing is used to identify the potential existence of aging related insulation degradation in the LPRM/APRM and IRM systems. Potential degradation of insulation will be evaluated in accordance with the corrective action process, including the implementation of subsequent corrective action for the LPRM/APRM and IRM cables that fail to meet the acceptance criteria of the cable tests.

b) For Oyster Creek, the cables within the scope of this program are the cables used in sensitive, high voltage, instrumentation circuits with low level signals for in-scope neutron and radiation monitoring systems: Intermediate Range Monitoring (IRM), Local Power Range Monitoring/Average Power Range Monitoring (LPRM/APRM), Reactor Building High Radiation Monitoring, and Air Ejector Offgas Radiation Monitoring. These are cable applications that are sensitive to reduction in insulation resistance.

c) For Oyster Creek, the radiation monitoring cable systems covered by this aging management program are not part of the EQ program. By definition, non-EQ cables and connections are either not exposed to harsh accident conditions or are not required to remain functional during or following an accident to which they are exposed. Therefore, by definition and the inspection scoping process, this program adequately incorporates the concern that deteriorated cable system failures might be induced during accident conditions.

2.2 Overall NUREG-1801 Consistency

The Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits is an existing program that is consistent with NUREG-1801 aging management program XI. E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits, with enhancements as described in 2.4 below.

2.3 Summary of Exceptions to NUREG-1801

None. The existing Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits is found to be adequate to support the period of extended operation with no exceptions.

2.4 Summary of Enhancements to NUREG-1801

The Oyster Creek Electrical Cables and Connections Not Subject to 10 CR 50.49 Environmental Qualification Requirement Used in Instrumentation Circuits aging management program will be enhanced to include the following:

- Calibration results are currently not trended and reviewed. This existing program will be enhanced such that the calibration test results for the Reactor Building High Radiation Monitoring and Air Ejector Offgas Radiation Monitoring systems will be trended and reviewed. This review will be performed prior to the period of extended operation and every 10 years thereafter.
- Cable test results are currently not trended and reviewed. This existing program will be enhanced such that the cable test results for the IRM and LPRM/APRM systems will be trended and reviewed. This review will be performed prior to the period of extended operation and every 10 years thereafter.

3.0 EVALUATIONS AND TECHNICAL BASIS

Note

This section is organized by quoting the relevant NUREG-1801 Chapter XI program element (September 2005 version) followed by the related Oyster Creek program attributes and a conclusion of the comparison. Where applicable, the NUREG-1801 program element was separated into logical sub-elements and addressed accordingly.

Implementing procedure references are included in ( ) for information purposes. This information from the source procedure has been either directly extracted from the procedure or summarized for inclusion into this PBD.

3.0 Scope of Program

NUREG-1801:

This program applies to electrical cables and connections (cable system) used in circuits with sensitive, high voltage, low-level signals such as radiation monitoring and nuclear instrumentation that are subject to aging management review.

Oyster Creek:

For Oyster Creek, the cables and connections within the scope of this program are the cables and connections used in instrumentation circuits with sensitive, high voltage, low level signals that are part of Oyster Creek's license renewal, in-scope neutron and radiation monitoring systems: Intermediate Range Monitoring (IRM), Local Power Range Monitoring/Average Power Range Monitoring (LPRM/APRM), Reactor Building High Radiation Monitoring, and Air Ejector Offgas Radiation Monitoring.

The Oyster Creek Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program manages cable and connection age related insulation degradation, in sensitive, high voltage, low-level signal circuits, due to adverse environmental conditions, for the electrical commodities listed in Table 5.2. The implementing documents for this aging management program are listed in Table 5.1 and are described throughout the individual program element discussions. The commitment numbers under which these implementing documents are being revised are contained within the listings in Table 5.1.

Exceptions to NUREG-1801, Element 1:

None.

Enhancements to NUREG-1801, Element 1:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 1, Scope of Program.

3.1 Preventive Actions

NUREG-1801:

No actions are taken as part of this program to prevent or mitigate aging degradation.

Oyster Creek:

This program consists of surveillance tests and cable tests. No actions are taken as part of this program to prevent or mitigate aging degradation.

Exceptions to NUREG-1801, Element 2:

None.

Enhancements to NUREG-1801, Element 2:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 2, Preventive Actions.

3.2 Parameters Monitored or Inspected

NUREG-1801:

The parameters monitored are determined from the specific calibration, surveillances or testing performed and are based on the specific instrumentation circuit under surveillance or being calibrated, as documented in plant procedures.

Oyster Creek:

Intermediate Range Monitoring: (IRM)

For the IRM system, the cables from the detectors to the control room panels are subject to Current/Voltage (I/V) and Time Domain Reflectometry (TDR) testing. **(Reference: 2400-SMI-3623.03, paragraph 6.6; and 2400-SMI-3623.08, paragraph 6.3)** The I/V and TDR test data is used to calculate the cable insulation resistance and will indicate if insulation resistance is reduced. These tests verify the insulation resistance of the cables, along with the operability of the detectors and connectors. Cable testing is being credited for the IRM system. The existing program will be enhanced such that the test results will be reviewed once every 10 years for cable aging degradation. The first review will be performed prior to the period of extended operation.

Local Power Range Monitoring/Average Power Range Monitoring (LPRM/APRM):

For the LPRM/APRM system, the cables from the detectors to the control room panels are subject to Current/Voltage (I/V) and Time Domain Reflectometry (TDR) testing. **(Reference: 2400-SMI-3623.03, paragraph 6.6; and 2400-SMI-3623.09, paragraph 6.3)**The I/V and TDR test data is used to calculate the cable insulation resistance and will indicate if insulation resistance is reduced. These tests verify the insulation resistance of the cables, along with the operability of the detectors and connectors. Cable testing is being credited for the LPRM/APRM system. The existing program will be enhanced such that the test results will be reviewed once every 10 years. The first review will be performed prior to the period of extended operation.

Reactor Building High Radiation Monitoring:

In accordance with NUREG 1801, calibration surveillance testing is credited for Reactor Building High Radiation Monitoring system. The calibration required by technical specifications utilizes a source capable of producing photon energy in the range expected during normal and abnormal conditions. **(Reference: 621.3.005, paragraphs, 6.4, 6.5, 6.6, and 6.7)** This check is performed with the entire system, including detectors, cables, and control room chassis, intact. This demonstrates that no detector or connecting cable degradation has occurred that could inhibit the system from performing its intended function. Cable testing is not being credited. The existing program will be enhanced such that the calibration results will be reviewed once every 10 years for cable aging degradation. The first review will be performed prior to the period of extended operation.

Air Ejector Offgas Radiation Monitoring:

In accordance with NUREG 1801, calibration surveillance testing is credited for Air Ejector Offgas Radiation Monitoring system. The calibration required by technical specifications utilizes a source capable of producing photon energy in the range expected during normal and abnormal conditions. **(Reference: 621.3.002, paragraphs 6.5 and 6.6)** This check is performed with the entire system, including detectors, cables, and control room chassis, intact. This demonstrates that no detector or connecting cable degradation has occurred that could inhibit the system from performing its intended function. Cable testing is not being credited. This program will be enhanced such that the calibration results will be reviewed once every 10 years for cable aging degradation. The first review will be performed prior to the period of extended operation.

<u>Exceptions to NUREG-1801, Element 3:</u>

None.

<u>Enhancements to NUREG-1801, Element 3:</u>

The Parameters Monitored/Inspected element of the Oyster Creek Electrical Cables and Connections Not Subject to 10 CR 50.49 Environmental Qualification Requirement Used in Instrumentation Circuits aging management program will be enhanced to include the following:

- This existing program will be enhanced such that the calibration test results for the Reactor Building High Radiation Monitoring and Air Calibration results are currently not trended and reviewed. Ejector Offgas Radiation Monitoring systems will be trended and reviewed. This review will be performed prior to the period of extended operation and every 10 years thereafter.
- Cable test results are currently not trended and reviewed. This existing program will be enhanced such that the cable test results for the IRM and LPRM/APRM systems will be trended and reviewed. This review will be performed prior to the period of

extended operation and every 10 years thereafter.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 3, Parameters Monitored or Inspected, with the enhancements described above.

3.3 Detection of Aging Effects

NUREG-1801:

a) *Review of calibration results or findings of surveillance programs can provide an indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance.*

b) *By reviewing the results obtained during normal calibration or surveillances, an applicant may detect severe aging degradation prior to the loss of the cable and connection intended function. The first reviews will be completed before the period of extended operation and at least every ten years thereafter.*

c) *All calibration or surveillance results that fail to meet acceptance criteria will be reviewed for aging effects when the results are available.*

d) *In cases where a calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results described above, the applicant will perform cable system testing. A proven cable system test for detecting deterioration of the insulation system (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable insulation condition as justified in the application) will be performed.*

e) *The test frequency of these cables shall be determined by the applicant based on engineering evaluation, but the test frequency shall be at least once every ten years.*

f) *The first test shall be completed before the period of extended operation.*

Oyster Creek:

a) Review of calibration and cable test results can provide an indication of the existence of aging effects based on acceptance criteria related to instrument circuit performance and insulation resistance. Routine calibration tests performed as part of the plant surveillance test program are used to identify the potential existence of aging degradation in the Reactor Building High Radiation Monitoring and Air Ejector Offgas Radiation Monitoring systems. Cable testing is performed to identify the potential existence of aging degradation in the IRM and LPRM/APRM systems.

b) By reviewing the results obtained during calibration and cable testing, severe aging degradation will be detected prior to the loss of the cable and/or connection intended function(s).

The normal calibration frequency in the Technical Specifications **(Reference: Technical Specifications, Table 4.1.1)** for the Reactor Building High Radiation Monitoring, once every three months, and Air Ejector Offgas Radiation Monitoring, once every 24 months, systems provides reasonable assurance that aging degradation will be detected prior to loss of cable intended function. These calibrations are currently being performed in accordance with the Technical Specification specified frequency; therefore, these tests have already been performed prior to the period of extended operation. Calibrations will continue to be performed in accordance with the Technical Specification frequency during the period of extended operation. Additionally, this existing program will be enhanced to incorporate periodic trending and review of calibration results. This review will be performed prior to the period of extended operation and every 10 years thereafter.

The IRM and LPRM/APRM cables are tested every 24 months, providing reasonable assurance that aging degradation will be detected prior to the loss of cable intended function. **(Reference: PM02112I, PM02111I, and PM00023I)** These cable tests are currently being performed in accordance with the aging management program frequency (once every 24 months); therefore, these tests have already been performed prior to the period of extended operation. Cable tests will continue to be performed on a once per 24-month frequency during the period of extended operation. Additionally, this existing program will be enhanced to incorporate periodic trending and review of cable testing results. This review will be performed prior to the period of extended operation and every 10 years thereafter.

c) Calibration and cable test results that fail to meet acceptance criteria are reviewed for aging effects. When an Air Ejector Offgas Radiation Monitoring system or a Reactor Building High Radiation Monitoring system instrumentation loop is found to be out of calibration during routine surveillance testing, troubleshooting is performed on the loop, including the instrumentation cable. **(Reference: 621.3.002 and 621.3.005)** Results of IRM and LPRM/APRM system cable testing are reviewed to identify the potential existence of aging degradation. **(Reference: PM02112I, PM02111I, and PM00023I)** Subsequent periodic reviews, being added as a program enhancement, would include data from surveillance or cable tests that failed to meet acceptance criteria. Additionally, these periodic reviews can identify an adverse trend in surveillance or cable test results.

d) The IRM and LPRM/APRM cables are tested for insulation resistances. This test is a direct indication of the condition of the insulation and will detect significant aging degradation prior to the loss of cable intended function. A proven cable system test for detecting deterioration of the insulation system, including both insulation resistance tests and time domain reflectometry tests have been implemented by these existing tests for the IRM and LPRM/APRM systems. **(Reference: 2400-SMI-3523.03, 2400-SMI-3623.08, and 2400-SMI-3623.09)** The Air Ejector Off Gas Radiation Monitoring and Reactor Building High Radiation Monitoring system cables are not IR or TDR tested because the cables are tested during the Technical Specification required calibration (see paragraph b. above).

e) The IRM and LPRM/APRM cables are currently and will continue to be tested every 24 months. **(Reference: PM02112I, PM02111I, and PM00023I)** A subsequent periodic review of test results, being added as an enhancement to this program, will be performed prior to the period of extended operation and every 10 years thereafter. (See b. above for calibration and periodic test review frequencies for Air Ejector Off Gas Radiation Monitoring and Reactor Building High

Radiation Monitoring systems.)

f) The IRM and LPRM/APRM system cable tests are currently being performed on a frequency of every 24 months; therefore, these tests have already been performed prior to the period of extended operation. A subsequent periodic review of test results, being added as an enhancement to this program, will be performed prior to the period of extended operation and every 10 years thereafter. (See b. above for calibration and periodic test review frequencies and identification of already completed tests for Air Ejector Off Gas Radiation Monitoring and Reactor Building High Radiation Monitoring systems.)

Exceptions to NUREG-1801, Element 4:

None.

Enhancements to NUREG-1801, Element 4:

The Detection of Aging Effects element of the Oyster Creek Electrical Cables and Connections Not Subject to 10 CR 50.49 Environmental Qualification Requirement Used in Instrumentation Circuits aging management program will be enhanced to include the following:

- Calibration results are currently not trended and reviewed. This existing program will be enhanced such that the calibration test results for the Reactor Building High Radiation Monitoring and Air Ejector Offgas Radiation Monitoring systems will be trended and reviewed. This review will be performed prior to the period of extended operation and every 10 years thereafter.
- Cable test results are currently not trended and reviewed. This existing program will be enhanced such that the cable test results for the IRM and LPRM/APRM systems will be trended and reviewed. This review will be performed prior to the period of extended operation and every 10 years thereafter.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 4, Detection of Aging Effects, with the enhancements described above.

3.4 Monitoring and Trending

NUREG-1801:

Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. However, test results that are trendable provide additional information on the rate of degradation.

Oyster Creek:

Test results that are trendable provide additional information on the rate of degradation. Although not a part of the existing Electrical Cables and Connections Not Subject to 10 CR 50.49 Environmental Qualification Requirement Used in Instrumentation Circuits aging management program implementing documents, trending actions will be added as an enhancement. Calibration and cable test results will be trended prior to the period of extended operation and every 10 years thereafter.

Exceptions to NUREG-1801, Element 5:

None.

Enhancements to NUREG-1801, Element 5:

The Parameters Monitored/Inspected element of the Oyster Creek Electrical Cables and Connections Not Subject to 10 CR 50.49 Environmental Qualification Requirement Used in Instrumentation Circuits aging management program will be enhanced to include the following:

- Calibration results are currently not trended and reviewed. This existing program will be enhanced such that the calibration test results for the Reactor Building High Radiation Monitoring and Air Ejector Offgas Radiation Monitoring systems will be trended and reviewed. This review will be performed prior to the period of extended operation and every 10 years thereafter.
- Cable test results are currently not trended and reviewed. This existing program will be enhanced

such that the cable test results for the IRM and LPRM/APRM systems will be trended and reviewed. This review will be performed prior to the period of extended operation and every 10 years thereafter.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 5, Monitoring and Trending, with the enhancements described above.

3.5 Acceptance Criteria

NUREG-1801:

Calibration results or findings of surveillance and cable system testing results are to be within the acceptance criteria, as set out in procedures.

Oyster Creek:

Air Ejector Offgas Radiation Monitoring and Reactor Building High Radiation Monitoring, calibration results are to be within the acceptance criteria as set out in the Technical Specification surveillance calibration procedures **(Reference: 621.3.002, paragraph 7.1 and 621.3.005, paragraph 7.1)**. The IRM and LPRM/APRM cable test results are to be within the acceptance criteria as set out in the testing procedures. **(Reference: SMI-2400-3623.03, paragraph 6.8; SMI-2400-3623.08, paragraph 6.11; and SMI-2400-3623.09, paragraph 6.5)** Periodic trending and review of subsequent surveillance and cable test results will be evaluated considering the acceptance criteria provided for existing implementing procedures.

Exceptions to NUREG-1801, Element 6:

None.

Enhancements to NUREG-1801, Element 6:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria.

3.6 Corrective Actions

NUREG-1801:

Corrective actions such as recalibration and circuit trouble-shooting are implemented when calibration or surveillance results or findings of surveillances do not meet the acceptance criteria. An engineering evaluation is performed when the test acceptance criteria are not met in order to ensure that the intended functions of the electrical cable system can be maintained consistent with the current licensing basis. Such an evaluation is to consider the significance of the test results, the operability of the component, the reportability of the event, the extent of the concern, the potential root causes for not meeting the test acceptance criteria, the corrective actions required, and likelihood of recurrence. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

Oyster Creek:

An issue report under the Corrective Action Program will be written and corrective action taken for the IRM and LPRM/APRM cables that fail to meet the acceptance criteria of the cable tests.

For Air Ejector Offgas Monitoring and Reactor Building High Radiation Monitoring, corrective actions such as recalibration and circuit trouble-shooting are implemented when calibration results do not meet the acceptance criteria. When the instrument loop cannot be recalibrated to meet the technical specifications surveillance calibration acceptance requirements, a condition report under the Corrective Action Program will be written and corrective action taken. **(Reference: 621.3.002, paragraph 7.2; and 621.3.005, paragraph 7.2)**

The Oyster Creek corrective action process considers significance of the surveillance/test results, operability of the associated components and systems, reportability, extent of condition, root causes and likelihood or recurrence. The associated engineering evaluation is to ensure that there is consistency with current licensing basis **(Reference: LS-AA-125)**.

Oyster Creek's corrective action process is governed by 10 CFR 50, Appendix B and is implemented by corporate administrative procedures. The corrective action process generically applies to Oyster Creek activities, even when not specifically invoked by a procedure line item. **(Reference: LS-AA-125)**

Exceptions to NUREG-1801, Element 7:

None.

Enhancements to NUREG-1801, Element 7:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 7, Corrective Actions.

3.7 Confirmation Process

NUREG-1801:

As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address confirmation process.

Oyster Creek:

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.

Exceptions to NUREG-1801, Element 8:

None.

Enhancements to NUREG-1801, Element 8:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 8, Confirmation Process.

3.8 Administrative Controls

NUREG-1801:

As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

Oyster Creek:

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.

Exceptions to NUREG-1801, Element 9:

None.

Enhancements to NUREG-1801, Element 9

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 9, Administrative Controls.

3.9 Operating Experience

NUREG-1801:

Operating experience has identified a case where a change in temperature across a high range radiation monitor cable in containment resulted in substantial change in the reading of the monitor. Changes in instrument calibration can be caused by degradation of the circuit cable and are a possible indication of electrical cable degradation.

The vast majority of site specific and industry wide operating experience regarding neutron flux instrumentation circuits is related to cable/connector issues inside of containment near the reactor vessel.

Oyster Creek:

In a review of industry operating experience, as noted in NUREG-1801, adverse localized environments have been shown to produce degradation of radiation monitoring system cables and connectors. Oyster Creek has experienced degradation of radiation monitoring system cables and connectors that were identified during the conduct of routine calibration and cable testing. However, the Oyster Creek operating experience review results do not display an adverse trend with respect to cable and connection insulation performance in sensitive, high voltage, low-level instrumentation circuits.

Operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek Operating Experience process. The Operating Experience process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The second way is through the process for managing programs. This process requires the review of program related operating experience by the program owner.

Both of these processes review operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that in instrumentation circuits with sensitive, high voltage, low-level signals, cable and connector insulation degradation due to adverse environmental conditions is being adequately managed. The following examples of operating experience provide objective evidence that the Electrical Cable and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program, that includes an enhancement to trend and review test results prior to the period of extended operation and every 10-years thereafter, is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation.

1. A few instances of degradation of cable insulation in adverse localized environments have been identified at Oyster Creek during the conduct of routine maintenance, calibration and testing activities. Just as importantly, some of the CAPs for these systems and components identify other causes for system and component issues, not related to age degradation of the insulation in these detector/monitor circuits.

    a) CAPs O2003-1308 and O2004-1644 evaluated issues with the "A" and "B" Air Ejector Offgas Radiation Monitoring channels, respectively. In the 2003 CAP, there was a slow and steady downward trend of the "A" channel output. In the 2004 CAP there was a 29% step change in the "B" channel output. Both occurrences were observed by operations. In both instances, cables were determined to be degraded by comparison of cable test results of the degraded cables and other properly functioning instrumentation channel. It is believed that the proximate cause is cable insulation degradation due to exposure to adverse environments. In both cases, normal outputs were restored by replacement of detector cables. The radiation monitoring channel was determined to be operable providing objective evidence that insulation degradation will be detected prior to loss of intended function, and adequate corrective actions are taken to prevent recurrence.

    b) CAP O2002-1937 evaluates a spike on LPRM 28-33C. It was determined based on follow-up IV cable testing, that the spike was most likely caused by detector "whiskers," which are not related to insulation degradation. It should be noted that this CAP documents General Electric's, the vendor for this system, recommendation to use IV testing for burn off of "whiskers" and restoration of channel monitoring functions, further supporting the use IV testing as part of the condition monitoring of this aging management program.

c) CAP O1999-0235 evaluates two LPRMs that failed upscale resulting in an APRM going "high" and a subsequent half scram. A definitive root cause was not identified in the CAP, although General Electric did not believe that the upscale failures were a result of cable issues.

2. CAP O2003-1097 was initiated to determine if there was an adverse trend in the performance of IRMs (and SRMs) during Oyster Creek plant shutdowns, outage periods and startups. CAPs dealing with IRM (and SRM) issues since 1998 were reviewed and binned by causes, including spiking, which is the primary symptom of insulation degradation. The data did not indicate that spiking had become a more prevalent issue as the system aged. Following assertive engineering principles, corrective actions to address spiking causes were implemented. None of these seven actions addressed cable and connection insulation degradation since it had not been determined to be a recurring cause. Subsequently, CAP O2004-1314 was initiated to evaluate a subsequent failure of IRM channels 13, 14, and 18. Under vessel cable connections were identified, via the Char testing implementing this program, as a potential weak link with respect to loop susceptibility to noise (see corrective action 12). Monitoring/testing of circuits is continuing. Other causes to noise susceptibility were identified with associated corrective actions.

3. Industry operating experience has demonstrated that adverse localized environments can degrade the insulation of cables and connectors used in sensitive, high voltage, low signal instrumentation circuits, potentially impacting electrical continuity and associated signal accuracies. As supported by NUREG-1801, radiation monitoring systems have industry operating experience documenting failure of these components to provide accurate indication/monitoring due to cable and connector insulation degradation. The SAND96-0344 report provides additional industry operating experience and analysis for these instrumentation circuits.

3.10 Conclusion

The Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program is credited for managing cable and connection age related insulation degradation, due to adverse environmental conditions, in instrumentation circuits with sensitive, high voltage, low-level signals, for the electrical commodity groups listed in Table 5.2. The Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program's elements have been evaluated against NUREG-1801 in Section 3.0. Program exceptions have been identified in Section 2.3. Program enhancements have been identified in Section 2.4. The implementing documents and commitment numbers for this aging management program are listed in Table 5.1. The relevant operating experience has been reviewed and a demonstration of program effectiveness is provided in Section 3.10.

Based on the above, the enhanced implementation of the Oyster Creek Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program provides reasonable assurance that in instrumentation circuits with sensitive, high voltage, low-level signals, cable and connection age related insulation degradation, due to adverse environmental conditions, will be adequately managed so that the intended functions of these electrical cables and connections within the scope of license renewal will be maintained during the period of extended operation.

4.0 REFERENCES

4.1 Generic to Aging Management Programs

4.1.1 10 CFR 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants*

4.1.2 10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*

4.1.3 NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,* Revision 1, dated September 2005

4.1.4 NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, Revision 1, dated September 2005

4.1.5 10 CFR 50.49, *Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants*

4.1.6 NUREG/CR-5643, *Insights Gained From Aging Research*, U. S. Nuclear Regulatory Commission, March 1992

4.1.7 ISG-15, Proposed Interim Staff Guidance (ISG)-15: Revision of Generic Aging Lessons Learned (GALL) Aging Management Program (AMP) XI.E2, "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits."

4.2 Industry Standards

4.2.1 EPRI TR-109619, *Guideline for the Management of Adverse Localized Equipment Environments*, Electric Power Research Institute, Palo Alto, CA, June 1999

4.2.2 IEEE Std. P1205-2000, *IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations*

4.2.3 SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations*, prepared by Sandia National Laboratories for the U.S. Department of Energy, September 1996

4.2.4 EPRI TR-1003057, License Renewal Electrical Handbook, December 2001

4.3 Oyster Creek Program References

4.3.1 Oyster Creek Procedure 2400-SMI-3623.03, IRM, SRM, LPRM Characterization Trending and Diagnostics

4.3.2 Oyster Creek Procedure 2400-SMI-3623.08, IRM Detector Current-Voltage (I.V.) Testing

4.3.3 Oyster Creek Procedure 2400-SMI-3623.0, Calibration and

Operation of the LPRM Diagnostic

4.3.4 Oyster Creek Routine Work Order R0802887 for implementing 2400-SMI-3623.03

4.3.5 Oyster Creek Routine Work Order R0802888 for implementing 2400-SMI-3623.08

4.3.6 Oyster Creek Routine Work Order R2063767 for implementing 2400-SMI-3623.09

4.3.7 Oyster Creek Surveillance Test 621.3.002, Air Ejector Off Gas Radiation Monitor Check Source Functional Test

4.3.8 Oyster Creek Surveillance Test 621.3.005, High Radiation Monitor – Reactor Building Isolation – Calibration

4.3.9 Oyster Creek Routine Work Order R0803575 for implementing ST 621.3.002

4.3.10 Oyster Creek Routine Work Order R0803579 for implementing ST 621.3.005

4.3.11 Passport AR 330592, Assignment 35, Subassignments

01, 02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, and 13 (see Table 5.1)

4.3.12 Oyster Creek AMP Audit Questions

a) AMP-132

4.3.13 Oyster Creek Technical Specification Table 4.1.1

4.3.14 Exelon procedure LS-AA-125, Corrective Action Program (CAP) Procedure, Revision 9

5.0 TABLES

5.1 Aging Management Program Implementing Documents

Procedure Number	Procedure Title	Commitment No.	Status

2400-SMI-3623.03	IRM, SRM, LPRM Characterization Trending and Diagnostics (TDR testing)	AR # 00330592-35-01	ACC/ASG
2400-SMI-3623.08	IRM Detector Current-Voltage (I.V.) Testing	AR # 00330592-35-02	ACC/ASG
2400-SMI-3623.09	Calibration and Operation of the LPRM Diagnostic (I.V. testing)	AR # 00330592-35-11	ACC/ASG
New Routine Task RXXXXXXX	New work order for trending of tests results from 2400-SMI-2400-3623.03, SMI-2400-3623.08, and SMI-2400-3623.09	AR # 00330592-35-13	ACC/ASG
R0802887 PM02111I	WO for implementing SMI-2400-3623.03 for Time Domain Reflectometry Cable Testing for IRMs	AR # 00330592-35-05	ACC/ASG
New Routine Task RXXXXXXX	WO for implementing SMI-2400-3623.03 for Time Domain Reflectometry Cable Testing for LPRM/APRMs	AR # 00330592-35-03	ACC/ASG
R0802888 PM02112I	WO for implementing SMI-2400-3623.08 for Current-Voltage (I.V.) Cable Testing for IRMs	AR # 00330592-35-04	ACC/ASG
R2063767 PM00023I	WO for implementing SMI-2400-3623.09 for Current-Voltage (I.V.) Cable Testing for LPRM/APRMs	AR # 00330592-35-12	ACC/ASG
621.3.002	Air Ejector Off Gas Radiation Monitor Check Source Functional Test	AR # 00330592-35-06	ACC/ASG
621.3.005	High Radiation Monitor – Reactor Building Isolation - Calibration	AR # 00330592-35-07	ACC/ASG
New Routine Task RXXXXXXX	New work order for trending of tests results from 621.3.002 and 621.3.005	AR # 00330592-35-08	ACC/ASG
R0803575 ST21302A	WO for implementing 621.3.002	AR # 00330592-35-09	ACC/ASG
R0803579 ST21305A	WO for implementing 621.3.005	AR # 00330592-35-10	ACC/ASG

5.2 Aging Management Review Results

SSC Name	Structure and/or Component	Material	Environment	Aging Effect
Electrical Commodity Groups	Insulated cables and connections in instrumentation circuits	Various organic polymers (e.g., EPR, XLPE, PVC, ETFE)	Adverse Localized Environment (External)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure/ degradation of organics (Thermal/ thermoxidative), radiolysis and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation, and moisture intrusion

6.0 ATTACHMENTS

6.1 LRA Appendix A

6.2 LRA Appendix B

PROGRAM BASIS DOCUMENT

PBD-AMP-B.1.20

Revision 0

FIRE WATER SYSTEM

GALL PROGRAM XI.M27 - FIRE WATER SYSTEM

Prepared By: ______________________

Reviewed By: ______________________

Program Owner Review: ______________________

Technical Lead Approval: ______________________

Revision History:

Revision	*Prepared by:*	*Reviewed by:*	*Program Owner:*	*Approved by:*
0	*K. Muggleston*	*S. C. Getz*	*Tim Trettel*	*Don Warfel*
Date				

Summary of Revisions:

Rev. Number	Reason for the Revision(s)
0	Initial Issue

TABLE OF CONTENTS

0.0 PURPOSE AND METHODOLOGY

0.1 Purpose

The purpose of this Program Basis Document is to document and evaluate those activities of the Oyster Creek Fire Water System aging management program that are credited for managing loss of material and reduction of heat transfer aging effects, as part of Oyster Creek License Renewal to meet the requirements of the License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

This includes the following:

- The identification of the scope of the program;
- The evaluation of program elements against NUREG-1801;
- The review of Operating Experience to demonstrate program effectiveness;
- The identification of required program enhancements; and
- The identification of Oyster Creek documents required to implement the program

0.2 Methodology

The nuclear power plant License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," describes the License Renewal process and provides requirements for the contents of License Renewal Applications. 10 CFR 54.21(a)(3) states:

"For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the Current Licensing Basis (CLB) for the period of extended operation."

The NRC and the industry identified 10 program elements that are useful in describing an aging management program and then demonstrating its effectiveness. These program elements are described in Appendix A.1, Section A.1.2.3 of the Standard Review Plan. NUREG-1801 uses these program elements in Section XI to describe acceptable aging management programs.

The purpose of this Program Basis Document is to identify and describe the basis for the Fire Water System aging management program and associated activities credited for managing loss of material and reduction of heat transfer aging effects. This Program Basis Document also provides a comparison of the credited Oyster Creek program with the elements of the corresponding NUREG-1801 Chapter XI program XI.M27 Fire Water System aging management program. Project Level Instruction PLI-8 "Program Basis Documents" prescribes the methodology for evaluating Aging Management Programs. An evaluation of Oyster Creek's aging management program criteria or activities to those of the NUREG-1801 program elements is performed and a conclusion is reached concerning consistency for each individual program element. A demonstration of overall program effectiveness is made after all program elements are evaluated. Required program enhancements are documented. An overall determination is made as to consistency with the program description in NUREG-1801.

1.0 PROGRAM DESCRIPTION

1.1 Program Description

<u>NUREG-1801:</u>

a) *This aging management program (AMP) applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, water storage tanks, and aboveground and underground piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) codes and standards. Such testing assures the minimum functionality of the systems. Also, these systems are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated.*

b) *A sample of sprinkler heads is to be inspected by using the guidance of NFPA 25 "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (1998 Edition), Section 2-3.1.1, or NFPA 25 (2002 Edition), Section 5.3.1.1.1. This NFPA section states "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." It also contains guidance to perform this sampling every 10 years after the initial field service testing.*

c) *The fire protection system piping is to be subjected to required flow testing in accordance with guidance in NFPA 25 to verify design pressure or evaluated for wall thickness (e.g., non-*

intrusive volumetric testing or plant maintenance visual inspections) to ensure that aging effects are managed and that wall thickness is within acceptable limits.

d) These inspections are performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation. The plant-specific inspection intervals are to be determined by engineering evaluation of the fire protection piping to ensure that degradation will be detected before the loss of intended function.

e) The purpose of the full flow testing and wall thickness evaluations is to ensure that corrosion, MIC, or biofouling is managed such that the system function is maintained.

Oyster Creek:

a) The Oyster Creek Fire Water System (B.1.20) aging management program applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, water storage tanks, and aboveground and underground piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) codes and standards or approved Fire Protection Program commitments. The Oyster Creek Fire Protection system is normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated. A low pressure condition is alarmed in the main control room by auto start of a diesel engine driven fire pump.

b) The Oyster Creek Fire Water System aging management program will be enhanced to include 50-year sprinkler head inspections using the guidance of NFPA 25 "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (1998 Edition), Section 2-3.1.1. This NFPA section states "Where sprinklers have been in service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing." This NFPA section also contains guidance to perform this sampling every 10 years after the initial field service testing. The initial 50-year inspections will be determined based on the date of the sprinkler system installation. Subsequent inspections will be performed every 10 years after the initial 50-year inspections.

c) The Oyster Creek fire protection system service main piping is subject to flow testing in accordance with NFPA guidance. The Oyster Creek Fire Water System aging management program will be enhanced to inspect selected portions of the fire protection system piping located aboveground and exposed to water, by non-intrusive volumetric examinations, to ensure that aging effects are managed and that wall thickness is within acceptable limits.

d) The initial wall thickness inspections will be performed before the end of the current operating term and thereafter at a frequency of at least once every 10 years during the period of extended operation. This inspection interval is based on the historical good operating experience with the fire protection system piping, as described in the Operating Experience section of this Program Basis Document. Based on the system design and inspection standards, and the good operating experience with respect to fire protection system piping internal conditions, initial NDE inspections prior to the period of extended operation, with additional periodic inspections at 10-year intervals thereafter, will assure detection of aging effects prior to loss of system intended functions.

e) The Oyster Creek Fire Water System aging management program will be enhanced to perform water sampling for the presence of microbiological influenced corrosion (MIC) every 5 years. The fire protection system service main piping flow testing in accordance with NFPA guidance, and the program enhancements to perform wall thickness evaluations and water sampling for the presence of MIC, will ensure that corrosion, MIC, or biofouling is managed such that the system function is maintained.

1.2 Overall NUREG-1801 Consistency

The Oyster Creek Fire Water System aging management program is an existing program that is consistent with NUREG-1801 aging management program XI, with the program enhancements described in below in Section 2.4.

1.3 Summary of Exceptions to NUREG-1801

None. The existing Oyster Creek Fire Water System aging management program is found to be adequate to support the extended period of operation with no exceptions.

1.4 Summary of Enhancements to NUREG-1801

The existing Oyster Creek Fire Water System aging management program is found to be adequate to support the extended period of operation with the following enhancements:

- The Oyster Creek Fire Water System aging management program will be enhanced to include 50-year sprinkler head inspections using the guidance of NFPA 25 "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (1998 Edition), Section 2-3.1.1.
- The Oyster Creek Fire Water System aging management program will be enhanced to inspect selected portions of the fire protection system piping located aboveground and exposed to water, by non-intrusive volumetric examinations.
- The Oyster Creek Fire Water System aging management program will be enhanced to perform water sampling for the presence of microbiological influenced corrosion (MIC) every 5 years.
- The Oyster Creek Fire Water System aging management program will be enhanced to include visual inspection of the water storage tank heater pressure boundary components during the periodic tank internal inspection.

2.0 EVALUATIONS AND TECHNICAL BASIS

Note

This section is organized by quoting the relevant NUREG-1801 Chapter XI program element (September 2005 version) followed by the related Oyster Creek program attributes and a conclusion of the comparison. Where applicable, the NUREG-1801 program element was separated into logical sub-elements and addressed accordingly.

Implementing procedure references are included in **( )** for information purposes. This information from the source procedure has been either directly extracted from the procedure or summarized for inclusion into this Program Basis Document.

2.0 Scope of Program

NUREG-1801:

a) The AMP focuses on managing loss of material due to corrosion, MIC, or biofouling of carbon steel and cast-iron components in fire protection systems exposed to water.

b) Hose stations and standpipes are considered as piping in the AMP.

Oyster Creek:

a) The Fire Water System AMP focuses on managing loss of material due to corrosion, MIC, or biofouling of carbon steel and cast-iron components in fire protection systems exposed to water. The program also manages loss of material for copper alloy, aluminum and stainless steel components exposed to water, and also carbon steel, cast iron and copper alloy components exposed to indoor or outdoor air.

The Aboveground Outdoor Tanks (B.1.21) aging management program addresses aging management of the water storage tank external surfaces and tank bottom. External surfaces of buried fire main piping will be evaluated as part of the Buried Piping Inspection program (B.1.26).

b) This aging management program for fire water systems manages the aging effects of fire water system piping and piping elements, tanks, heat exchangers, hydrants, and sprinkler heads through system monitoring, periodic tests and inspection activities. Hose stations and standpipes are considered as piping in the aging management program.

Exceptions to NUREG-1801, Element 1:

None.

Enhancements to NUREG-1801, Element 1:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 1, Scope of Program.

2.1 Preventive Actions

NUREG-1801:

To ensure no significant corrosion, MIC, or biofouling has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections may be conducted.

Oyster Creek:

This program includes preventive actions to preclude buildup of significant corrosion, MIC or biofouling by providing for periodic flushing, system performance testing, and inspections to identify these degraded conditions prior to loss of system intended functions.

Fire system main header flow tests are conducted at least once every three years. The flow test procedure is designed to establish maximum flow conditions in the fire system main header, such that flow characteristics can be measured and evaluated for indication of internal piping degradation or fouling. This procedure measures system hydraulic resistance as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of internal piping degradation from significant corrosion or fouling would be detected in a timely manner. **(Reference: 101.2, Attachment 101.2-3, Section 2.C.1.f., 645.6.023 Section 1.0)**

Hydrant flow tests are conducted at least once every twelve months. The test procedure requires each fire hydrant to be fully opened and flushed until water has sufficiently cleared. **(Reference: 101.2, Attachment 101.2-3, Section 8.B.1.c., 645.6.007 Section 1.0)**

Flow tests and hydrant flushing minimize the accumulation of contaminants inside the fire system piping, and detect signs of internal pipe fouling or buildup of corrosion.

The condition of the fire pumps is confirmed once every 18 months by performance of a pump functional test that confirms adequate discharge flow and pressure. **(Reference: 645.6.012, Section 1.0)**

The program will be enhanced to perform water sampling for the presence of MIC every 5 years. **(Reference: R0804258, PM81101M)**

The program will be enhanced to include requirements for periodic non-intrusive fire protection piping wall thickness measurements. These non-intrusive inspections will be conducted prior to the end of the current term and repeated on a frequency not exceeding every 10 years. These inspections will be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the flow requirements of the fire protection system.

<u>Exceptions to NUREG-1801, Element 2:</u>

None.

Enhancements to NUREG-1801, Element 2:

- The Oyster Creek Fire Water System aging management program will be enhanced to inspect selected portions of the fire protection system piping located aboveground and exposed to water, by non-intrusive volumetric examinations.
- The Oyster Creek Fire Water System aging management program will be enhanced to perform water sampling for the presence of MIC every 5 years.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 2, Preventive Actions, with the above enhancements.

2.2 Parameters Monitored or Inspected

NUREG-1801:

Loss of material due to corrosion and biofouling could reduce wall thickness of the fire protection piping system and result in system failure. Therefore, the parameters monitored are the system's ability to maintain pressure and internal system corrosion conditions. Periodic flow testing of the fire water system is performed using the guidelines of NFPA 25, or wall thickness evaluations may be performed to ensure that the system maintains its intended function.

Oyster Creek:

During normal standby conditions, an electric motor driven pump maintains fire header pressure. Significant leakage (exceeding the capacity of this pump) would be identified by decreased system pressure resulting in automatic start of the diesel driven fire pumps. An automatic start of a diesel driven fire pump is alarmed in the main control room. Therefore, the system's ability to maintain pressure is monitored.

Flow testing is conducted at 3-year intervals to determine the condition of the underground fire protection piping. This procedure measures system hydraulic resistance as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of internal piping degradation from significant corrosion or fouling would be detected in a timely manner. The test is performed at maximum available flow through a yard hydrant, and is considered a full flow test in accordance with NFPA standards (Reference 4.2.2, Section 3-3.1.1). Annual fire hydrant flushing confirms flow through each hydrant. **(Reference: 101.2, Attachment 101.2-3, Sections 2.C.1.f, 8A, 8B, 645.6.023 Section 1.0, 645.6.007 Section 1.0)**

New activities will be initiated to include requirements for periodic non-intrusive fire protection piping wall thickness measurements. These non-intrusive inspections will be conducted prior to the end of the current term and repeated on a frequency not exceeding every 10 years.

Exceptions to NUREG-1801, Element 3:

None.

Enhancements to NUREG-1801, Element 3:

The Oyster Creek Fire Water System aging management program will be enhanced to inspect selected portions of the fire protection system piping located aboveground and exposed to water, by non-intrusive volumetric examinations.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 3, Parameters Monitored or Inspected, with the above enhancement.

2.3 Detection of Aging Effects

NUREG-1801:

a) *Fire protection system testing is performed to assure that the system functions by maintaining required operating pressures.*

b) *Wall thickness evaluations of fire protection piping are performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion.*

c) *These inspections are performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation. As an alternative to non-intrusive testing, the plant maintenance process may include a visual inspection of the internal surface of the fire protection piping upon each entry to the system for routine or corrective maintenance, as long as it can be demonstrated that* *inspections are performed (based on past maintenance history) on a representative number of locations on a reasonable basis.*

d) *These inspections must be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the design flow of the fire protection system.*

e) *If the environmental and material conditions that exist on the interior surface of the below grade fire protection piping are similar to the conditions that exist within the above grade fire protection piping, the results of the inspections of the above grade fire protection piping can be extrapolated to evaluate the condition of below grade fire protection piping. If not, additional inspection activities are needed to ensure that the intended function of below grade fire protection piping will be maintained consistent with the current licensing basis for the period of extended operation. Continuous system pressure monitoring, system flow testing, and wall thickness evaluations of piping are effective means to ensure that corrosion and biofouling are not occurring and the system's intended function is maintained.*

f) *General requirements of existing fire protection programs include testing and maintenance of fire detection and protection systems and surveillance procedures to ensure that fire detectors, as well as fire protection systems and components are operable.*

g) *Visual inspection of yard fire hydrants performed annually in accordance with NFPA 25 ensures timely detection of signs of degradation, such as corrosion. Fire hydrant hose hydrostatic tests, gasket inspections, and fire hydrant flow tests, performed annually, ensure that fire hydrants can perform their intended function and provide opportunities for degradation to be detected before a loss of intended function can occur.*

h) *Sprinkler heads are inspected before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.*

<u>Oyster Creek:</u>

a) During normal standby conditions, an electric motor driven pump maintains fire header pressure. Significant leakage (exceeding the capacity of this pump) would be identified by decreased system pressure resulting in automatic start of the diesel driven fire pumps. An automatic start of a diesel driven fire pump is alarmed in the main control room (Reference 4.3.1, 4.3.2). Fire protection system functions are assured by maintaining required system operating pressures.

b) New activities will be initiated to include requirements for periodic wall thickness measurements of fire protection piping to identify evidence of loss of material due to corrosion, using non-intrusive (e.g., volumetric) testing techniques.

c) These non-intrusive inspections will be conducted prior to the end of the current term and repeated on a frequency not exceeding every 10 years during the period of extended operation. Although maintenance process may include a visual inspection of the internal surface of the fire protection piping upon each entry to the system for routine or corrective maintenance, Oyster Creek does not credit these inspections as an alternative to non-intrusive testing. The non-intrusive inspections are performed on a representative number of locations. The selected locations will be from stagnant no-flow portions of the sprinkler systems that contain water. To assure the locations are varied and provide a good representation of system internal conditions, locations will be selected as follows:

- A minimum of 10 locations will be selected
- A minimum of 4 locations will be selected from fire water system piping in the reactor building
- A minimum of 4 locations will be selected from fire water system piping in the turbine building
- Selected locations will include a minimum of 2 sprinkler systems in the reactor building and 2 sprinkler systems in the turbine building, in the small bore piping downstream of the sprinkler isolation valve and flow alarm valve
- Selected locations will include a minimum of 2 locations in the large bore (>4") branch piping that supplies the various sprinkler systems and hose stations
- A minimum of one location on a large bore fire pump discharge line at the fire pumphouse will be included

d) These non-intrusive inspections will be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the flow requirements of the fire protection system.

e) Above grade piping is representative of below grade piping for purposes of internal inspections, as the materials and internal environments are similar. The piping material is the same. The buried piping is a heavier wall pipe. (Reference 4.3.4) The internal fluid is the same.

f) General requirements of the Oyster Creek fire protection program include testing and maintenance of fire detection and protection systems and surveillance procedures to ensure that fire detectors, as well as fire protection systems and components are operable. Testing and surveillance requirements are identified as technical requirements in the fire protection program, and confirm the operating status of the fire detection and suppression systems. When operability requirements cannot be demonstrated, compensatory measures are implemented until appropriate maintenance or other corrective actions are taken to restore operability. **(Reference: 101.2, Section 4.10.4, 4.10.5, Attachment 101.2-3, CC-AA-211, Section 1.1)**

Sprinkler system inspections are performed at least once every refueling outage to ensure that signs of external surface degradation, including corrosion, would be detected in a timely manner. **(Reference 645.6.011, Section 6.2, 6.3)**

g) Visual inspection of yard fire hydrants performed annually in accordance with NFPA guidance ensures timely detection of signs of degradation, such as corrosion. Fire hydrant hose hydrostatic tests, gasket inspections, and fire hydrant flow tests, performed annually, ensure that fire hydrants can perform their intended function and provide opportunities for degradation to be detected before a loss of intended function can occur. **(Reference: 645.6.007 Section 1.0, 645.6.003 Section 6.4 645.6.006 Section 6.0, Procedure 101.2, Attachment 101.2-3, Sections 2.C.1.f, 8A, 8B)**

h) The Oyster Creek Fire Water System program will be enhanced to perform sprinkler head sampling in accordance with NFPA 25, Section 2-3.1. Representative samples will be submitted to a testing laboratory prior to being in service 50 years. Thereafter, this testing will be repeated on a frequency of once every 10 years during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

Initial inspections will be performed prior to the sprinkler heads being in service for 50 years. As stated in NRC ISG-04, fire protection piping is typically designed for a 50-year life. The initial plant construction period was approximately 4 years, so the earliest date for sprinkler installations would have been early to mid 1965. Many sprinkler systems were not installed until the 1979 to 1981 timeframe, and as such will not reach a 50-year life until well after the end of the current operating term and also well beyond the first 10-year inspection.

Exceptions to NUREG-1801, Element 4:

None.

Enhancements to NUREG-1801, Element 4:

- The Oyster Creek Fire Water System aging management program will be enhanced to inspect selected portions of the fire protection system piping located aboveground and exposed to water, by non-intrusive volumetric examinations.
- The Oyster Creek Fire Water System aging management program will be enhanced to include 50-year sprinkler head inspections using the guidance of NFPA 25 "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (1998 Edition), Section 2-3.1.1.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 4, Detection of Aging Effects, with the above enhancements.

2.4 Monitoring and Trending

NUREG-1801:

a) *System discharge pressure is monitored continuously.*
b) *Results of system performance testing are monitored and trended as specified by the associated plant commitments pertaining to NFPA codes and standards.*
c) *Degradation identified by non-intrusive or internal inspection is evaluated.*

Oyster Creek:

a) The water based fire protection system is a normally pressurized system. Pressure is continuously maintained with an electric motor driven pump, and a diesel driven fire pump will start automatically on low system pressure. The automatic start of a diesel fire pump is alarmed in the main control room (Reference 4.3.1, 4.3.2), and in this manner, system pressure is continuously maintained and monitored.

b) The fire protection program ensures that testing and inspection activities have been performed and the results have been documented and reviewed by the Fire System Engineer for analysis and trending. **(Reference CC-AA-211, Section 3.1.6)**

c) New activities will be initiated to include requirements for periodic wall thickness measurements of fire protection piping to identify evidence of loss of material due to corrosion, using non-intrusive (e.g., volumetric) testing techniques. These new activities will include an evaluation of identified degradation for impact on the system or component intended functions.

Exceptions to NUREG-1801, Element 5:

None.

Enhancements to NUREG-1801, Element 5:

The Oyster Creek Fire Water System aging management program will be enhanced to inspect selected portions of the fire protection system piping located aboveground and exposed to water, by non-intrusive volumetric examinations.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 5, Monitoring and Trending with the above enhancement.

2.5 Acceptance Criteria

NUREG-1801:

The acceptance criteria are

a) the ability of a fire protection system to maintain required pressure,

b) no unacceptable signs of degradation observed during non-intrusive or visual assessment of internal system conditions, and

c) that no biofouling exists in the sprinkler systems that could cause corrosion in the sprinkler heads.

Oyster Creek:

a) The water based fire protection system is a normally pressurized system. Pressure is continuously maintained with an electric motor driven pump, and a diesel driven fire pump will start automatically on low system pressure. The automatic start of a diesel fire pump is alarmed in the main control room, and in this manner, system pressure is continuously maintained and monitored. If the electric motor driven pump is not able to maintain the required pressure, appropriate corrective actions will be taken to restore the system pressure boundary integrity.

b) New activities will be initiated to include requirements for periodic wall thickness measurements of fire protection piping to identify evidence of loss of material due to corrosion, using non-intrusive (e.g., volumetric) testing techniques. These new activities will include an evaluation of identified degradation for impact on the system or component intended functions. Wall thickness will be evaluated against the applicable design standards and system requirements for minimum wall thickness. Indications of fouling of the inner diameter of the piping will be evaluated as it applies to the flow requirements of the fire protection system.

c) If the NDE inspections detect significant wall thinning or fouling due to internal corrosion, the inspection results will be evaluated by engineering for acceptability. Engineering will determine the rate at which the corrosion is progressing. Unacceptable results will be documented in the corrective action program. An extent of condition review, which is an integral part of the corrective action program, addresses the need to expand the inspection sample population or adjust the inspection frequency if appropriate.

   The new inspection activities will include an evaluation of identified fouling. Acceptance criteria will be established to preclude fouling in the sprinkler systems that could cause corrosion in the sprinkler heads.

<u>Exceptions to NUREG-1801, Element 6:</u>

None.

<u>Enhancements to NUREG-1801, Element 6:</u>

The Oyster Creek Fire Water System aging management program will be enhanced to inspect selected portions of the fire protection system piping located aboveground and exposed to water, by non-intrusive volumetric examinations.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria with the above enhancement.

2.6 Corrective Actions

NUREG-1801:

Repair and replacement actions are initiated as necessary. For fire water systems and components identified within scope that are subject to an AMR for license renewal, the applicant's 10 CFR Part 50, Appendix B, program is used for corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

Oyster Creek:

Evaluations are performed for test or inspection results that do not satisfy established criteria and an Issue Report (IR) is initiated to document the concern in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program **(Reference: CC-AA-211, Section 4.19)**. The corrective action process ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined and an action plan is developed to preclude recurrence.

Exceptions to NUREG-1801, Element 7:

None.

Enhancements to NUREG-1801, Element 7:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 7, Corrective Actions.

2.7 Confirmation Process

NUREG-1801:

See Item 7, above.

Oyster Creek:

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.

Exceptions to NUREG-1801, Element 8:

None.

Enhancements to NUREG-1801, Element 8:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 8, Confirmation Process.

2.8 Administrative Controls

NUREG-1801:

See Item 7, above.

Oyster Creek:

See Item 8, above.

Exceptions to NUREG-1801, Element 9:

None.

Enhancements to NUREG-1801, Element 9

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 9, Administrative Controls.

2.9 Operating Experience

NUREG-1801:

Water-based fire protection systems designed, inspected, tested and maintained in accordance with the NFPA minimum standards have demonstrated reliable performance.

Oyster Creek:

The Oyster Creek water-based fire protection system is designed, inspected, tested and maintained in accordance with the applicable NFPA minimum standards and has demonstrated reliable performance. Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that loss of material or reduction of heat transfer is being adequately managed in piping, piping components, sprinklers, nozzles, valves, hydrants, tanks and other components in the Fire Water System. The operating experience described below provides objective evidence that the Fire Water System aging management program as implemented at Oyster Creek has been effective in managing age related degradation. With the enhancements described in this Program Basis Document, the Fire Water System aging management program will continue to be effective in managing age related degradation for the period of extended operation.

Operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek Operating Experience process. The Operating Experience process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The second way is through the process for managing programs. This process requires the review of program related operating experience by the program owner.

Both of these processes review operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), Westinghouse documents (e.g., TBs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

A review of Oyster Creek operating experience has identified a single case of through-wall piping failure, and this failure was associated with a 1 ½" cooling water line on one of the diesel driven fire pump diesel engines. This line is exposed to water flow conditions when the associated diesel driven pump is operated, and drains back to the pump bay when the diesel pump is not operating. A failure analysis was performed on a sample of the failed piping. The failure analysis determined that turbulent flow downstream of a 90° elbow tended to remove corrosion product buildup, and that constant removal of corrosion product buildup would expose fresh metal leading to accelerated attack. The preferential attack identified on the bottom of the pipe suggests the attack might have been influenced by incomplete drainage following pump operation. The resulting stagnant lay-up of fresh water provides a favorable condition for MIC attack. The condition created pin-hole leaks which have been repaired. As a result of this failure, NDE inspections were performed at piping locations subject to similar conditions. Some additional small bore wall thinning has been identified, and is being tracked for repair and replacement. This example provides objective evidence that detected degradation is entered into the corrective action process for evaluation and repair. It also demonstrates that the corrective action process effectively determines the cause of the degradation, identifies similarly susceptible locations, and evaluates those locations through performance of NDE examinations to identify additional areas to be tracked for repair prior to loss of intended function. (CAP O2003-2586)

The Fire Protection system manager has performed visual inspections of piping internal conditions when exposed during maintenance activities. The piping internals have been observed to be in very good condition with no significant internal fouling or corrosion buildup. System flow tests have not indicated increasing system pressure drop. This provides objective evidence that system testing as directed by the program is effective in confirming the absence of fouling or corrosion products buildup.

The operating experience of the Fire Water System aging management program did not show any adverse trend in Fire Water System performance. Problems identified did not cause in loss of the system intended function, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Fire Water System aging management program will effectively detect age related degradation in piping and other components prior to loss of system or component intended functions. Periodic self-assessments of the Fire Water System aging management program are performed to identify the areas that need improvement to maintain the quality performance of the program.

2.10 Conclusion

The Oyster Creek Fire Water System aging management program is credited for managing loss of material and reduction of heat transfer aging effects for the systems, components, and environments listed in Table 5.2. The Oyster Creek Fire Water System aging management program elements have been evaluated against NUREG-1801 in Section 3.0. There are no Program exceptions identified in Section 2.3. Program enhancements have been identified in Section 2.4. The implementing documents and commitment numbers for this aging management program are listed in Table 5.1. The relevant operating experience has been reviewed and a demonstration of program effectiveness is provided in Section 3.10.

Based on the above, the continued implementation of the Oyster Creek Fire Water System aging management program provides reasonable assurance that loss of material and reduction of heat transfer aging effects will be adequately managed so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

3.0 REFERENCES

3.1 Generic to Aging Management Programs

3.1.1 10 CFR 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants*

3.1.2 10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*

3.1.3 NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,* Revision 1, dated September 2005

3.1.4 NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, Revision 1, dated September 2005

3.2 Industry Standards

3.2.1 EPRI TR 114882, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools," Appendix B, "Raw Water"

3.2.2 NFPA-25, Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems, 1998 Edition

3.3 Oyster Creek Program References

3.3.1 BR 3021, Sheet 4, Revision 3, Diesel Fire Pump Electrical Elementary Drawing

3.3.2 DJP 3E-811-17-1001, Revision 1, Fire Protection Water System Electrical Elementary Diagram

3.3.3 SP-1302-52-108, Revision 3, Specification for Inspection of Tanks

3.3.4 SYS-LL-OC-1, Revision 4, Oyster Creek Nuclear Generating Station Line List and Specifications

4.0 TABLES

4.1 Aging Management Program Implementing Documents

Procedure Number	Procedure Title	Commitment No.	Status

101.2	Oyster Creek Fire Protection Program	330592.20.10	ACC/ASG
645.6.023	Fire Suppression Water System Underground Flow Test	330592.20.02	ACC/ASG
R0803914, ST45623A	Fire Suppression Water System Underground Flow Test.	330592.20.06	ACC/ASG
645.6.007	Fire Protection System Flush	330592.20.11	ACC/ASG
R0803893, ST45607A	Fire Protection System Flush.	330592.20.14	ACC/ASG
645.6.012	Fire Pump Functional Test	330592.20.13	ACC/ASG
R0803901, ST45612A	Fire Pump Functional Test	330592.20.16	ACC/ASG
R0801029, PM00337F	Perform Internal Inspection to meet Fire Insurance Requirements.	330592.20.17	ACC/ASG
R0804258, PM81101M	MIC Testing of Fire Protection Water.	330592.20.03	ACC/ASG
CC-AA-211	Fire Protection Program	330592.20.01	ACC/ASG
645.6.003	Fire Hose Station, Hose House and Fire Hydrant Inspection	330592.20.04	ACC/ASG
R0803888, ST45603B	Fire Hose Station, Hose House and Fire Hydrant Inspection	330592.20.07	ACC/ASG
645.6.006	Fire Hose Hydrostatic Testing	330592.20.05	ACC/ASG
R0803891, ST45606A	Fire Hose Hydrostatic Test	330592.20.08	ACC/ASG
R0803892, ST45606B	Fire Hose Hydrostatic Test	330592.20.08	ACC/ASG
645.6.011	Deluge and Sprinkler System Inspection	330592.20.12	ACC/ASG
R0803889, ST45611A	Deluge and Sprinkler System Inspection	330592.20.15	ACC/ASG
R0803900, ST45611B	Deluge and Sprinkler System Inspection	330592.20.15	ACC/ASG

4.2 Aging Management Review Results

SSC Name	Structure and/or Component	Material	Environment	Aging Effect
Fire Protection System	Fire hydrant	Cast Iron	Outdoor Air (External)	Loss of Material
Fire Protection System	Fire hydrant	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Flexible Hose	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Flexible Hose	Copper	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Flow Element (Annubar)	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Fire Protection System	Flow Element (Annubar)	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Flow Element (Annubar)	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Gauge Snubber	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Gear Box	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Fire Protection System	Heat Exchangers	Copper Alloy (Tubes)	Raw Water – Fresh Water (External)	Loss of Material
Fire Protection System	Heat Exchangers	Copper Alloy (Tubes)	Raw Water – Fresh Water (External)	Reduction of Heat Transfer
Fire Protection System	Heat Exchangers	Copper Alloy (Shell)	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Hose Manifold	Carbon and low alloy steel	Outdoor Air (External)	Loss of Material
Fire Protection System	Hose Manifold	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Piping and fittings	Carbon and low alloy steel	Outdoor Air (External)	Loss of Material
Fire Protection System	Piping and fittings	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Fire Protection System	Piping and fittings	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Fire Protection System	Piping and fittings	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Piping and fittings	Brass	Raw Water – Fresh Water (Internal)	Loss of Material

Fire Protection System	Piping and fittings	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Pump Casing (Redundant Fire Pump)	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Fire Protection System	Pump Casing (Redundant Fire Pump)	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Pump Casing (Vertical Turbine)	Cast Iron (discharge head)	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Pump Casing (Vertical Turbine)	Cast Iron (discharge head)	Indoor Air (External)	Loss of Material
Fire Protection System	Pump Casing (Vertical Turbine)	Carbon and low alloy steel (column pipe)	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Pump Casing (Vertical Turbine)	Carbon and low alloy steel (column pipe)	Outdoor Air (External)	Loss of Material
Fire Protection System	Pump Casing (Vertical Turbine)	Carbon and low alloy steel (column pipe)	Raw Water – Fresh Water (External)	Loss of Material
Fire Protection System	Pump Casing (Vertical Turbine)	Bronze (bowls)	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Pump Casing (Vertical Turbine)	Bronze (bowls)	Raw Water – Fresh Water (External)	Loss of Material
Fire Protection System	Restricting Orifice	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Restricting Orifice	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Fire Protection System	Restricting Orifice	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Fire Protection System	Restricting Orifice	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Sprinkler Heads	Brass	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Sprinkler Heads	Brass	Outdoor Air (External)	Loss of Material
Fire Protection System	Sprinkler Heads	Brass	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Sprinkler Heads	Brass	Outdoor Air (External)	Loss of Material
Fire Protection System	Strainer	Stainless Steel	Raw Water – Fresh Water (External)	Loss of Material
Fire Protection System	Strainer Body	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Strainer Body	Carbon and low alloy steel	Indoor Air (External)	Loss of Material

Fire Protection System	Strainer Body	Cast Iron	Indoor Air (External)	Loss of Material
Fire Protection System	Strainer Body	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Tank Heater	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Tanks (Retarding Chamber)	Cast Iron	Indoor Air (External)	Loss of Material
Fire Protection System	Tanks (Retarding Chamber)	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Tanks (Water Storage)	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Thermowell	Carbon and low alloy steel	Outdoor Air (External)	Loss of Material
Fire Protection System	Thermowell	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Valve Body	Bronze	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Valve Body	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Valve Body	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Fire Protection System	Valve Body	Bronze	Outdoor Air (External)	Loss of Material
Fire Protection System	Valve Body	Brass	Outdoor Air (External)	Loss of Material
Fire Protection System	Valve Body	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Valve Body	Cast Iron	Outdoor Air (External)	Loss of Material
Fire Protection System	Valve Body	Carbon and low alloy steel	Outdoor Air (External)	Loss of Material
Fire Protection System	Valve Body	Brass	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Valve Body	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Valve Body	Cast Iron	Indoor Air (External)	Loss of Material
Fire Protection System	Water Motor Alarm	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Water Motor Alarm	Aluminum	Raw Water – Fresh Water (Internal)	Loss of Material
Fire Protection System	Water Motor Alarm	Cast Iron	Indoor Air (External)	Loss of Material

5.0 ATTACHMENTS

5.1 LRA Appendix A

5.2 LRA Appendix B

PROGRAM BASIS DOCUMENT

PBD-AMP-B.1.29

Revision 0

10 CFR PART 50, APPENDIX J

GALL PROGRAM XI.S4 - 10 CFR PART 50, APPENDIX J

Prepared By: ______________________

Reviewed By: ______________________

Program Owner Review: ______________________

Technical Lead Approval: ______________________

Revision History:

Revision	*Prepared by:*	*Reviewed by:*	*Program Owner:*	*Approved by:*
0	*S. C. Getz*	*G. J. Beck*	*R. M. Francis*	*Don Warfel*
Date				

Summary of Revisions:

Rev. Number	Reason for the Revision(s)
0	Initial Issue

TABLE OF CONTENTS

1.0 PURPOSE AND METHODOLOGY

1.1 Purpose

The purpose of this Program Basis Document is to document and evaluate those activities of the Oyster Creek 10 CFR 50 Appendix J aging management program that are credited for managing loss of material, loss of preload, loss of sealing, loss of leak tightness, and cracking as part of Oyster Creek License Renewal to meet the requirements of the License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

This includes the following:

- The identification of the scope of the program;
- The evaluation of program elements against NUREG-1801;
- The review of Operating Experience to demonstrate program effectiveness;
- The identification of required program enhancements;
- The identification of Oyster Creek documents required to implement the program.

1.2 Methodology

The nuclear power plant License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," describes the License Renewal process and provides requirements for the contents of License Renewal Applications. 10 CFR 54.21(a)(3) states:

"For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the Current Licensing Basis (CLB) for the period of extended operation."

The NRC and the industry identified 10 program elements that are useful in describing an aging management program and then demonstrating its effectiveness. These program elements are described in Appendix A.1, Section A.1.2.3 of the Standard Review Plan. NUREG-1801 uses these program elements in Section XI to describe acceptable aging management programs.

The Program Basis Document provides a comparison of the credited Oyster Creek program with the elements of the corresponding NUREG-1801 Chapter XI program XI.S4, 10 CFR 50 Appendix J. Project Level Instruction PLI-8 "Program Basis Documents" prescribes the methodology for evaluating Aging Management Programs. An evaluation of Oyster Creek's aging management program criteria or activities to those of the NUREG-1801 program elements is performed and a conclusion is reached concerning consistency for each individual program element. A demonstration of overall program effectiveness is made after all program elements are evaluated. Required program enhancements are documented. An overall determination is made as to consistency with the program description in NUREG-1801.

2.0 PROGRAM DESCRIPTION

2.1 Program Description

NUREG-1801:

a) *As described in 10 CFR Part 50, Appendix J, containment leak rate tests are required "to assure that (a) leakage through the primary reactor containment and systems and components penetrating primary containment shall not exceed allowable leakage rate values as specified in the technical specifications or associated bases and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of the containment, and systems and components penetrating primary containment."*

b) *Appendix J provides two options, A and B, either of which can be chosen to meet the requirements of a containment LRT program. Under Option A, all of the testing must be performed on a periodic interval. Option B is a performance-based approach. Some of the differences between these options are discussed below, and more detailed information for Option B is provided in the Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.163 and NEI 94-01, Rev. 0.*

Oyster Creek:

a) The 10CFR50 Appendix J program conducts tests to assure that (a) leakage through the primary reactor containment and systems and components penetrating primary containment shall not exceed allowable leakage rate values as specified in the technical specifications or associated bases and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of the containment, and systems and components penetrating primary containment. The Primary Containment Leakage Rate Testing Program (LRT) provides for aging management of pressure boundary degradation and loss of leak tightness due to aging effects such as loss of material, cracking, or loss of preload in various systems penetrating primary containment. The program also detects age related loss of sealing and degradation in material properties of gaskets, o-rings, and packing materials for the containment boundary access points. This program is being credited for aging management of containment isolation barrier piping and valves that constitute a potential primary containment atmospheric pathway during or following a design basis accident (DBA). Test connection vents and drains one inch or less in diameter, which consist of a double barrier and are administratively secured closed, are not required to be tested.

The Oyster Creek LRT program is performed in accordance with approved corporate and plant procedures which establish the requirements for development, implementation, and administration of a leak rate test program. The plant specific program documents and procedures provide instructions for actual performance of the LRT. **(Reference ER-AA-380; ER-OC-380)**

b) The Oyster Creek LRT program is performed in accordance with the regulations and guidance provided in 10CFR50 Appendix J Option B, Regulatory Guide 1.163, NEI 94-01, ANSI/ANS 56.8, and approved plant program documents and procedures. LRTs are performed to assure that leakage through the systems and components penetrating primary containment does not exceed allowable leakage limits specified in the technical specifications. LRTs are performed on isolation valves and containment pressure boundary barriers at frequencies that comply with the requirements of 10CFR50 Appendix J Option B.

2.2 Overall NUREG-1801 Consistency

The Oyster Creek 10 CFR 50 Appendix J is an existing program that is consistent with NUREG-1801 aging management program XI.S4, 10CFR 50 Appendix J.

2.3 Summary of Exceptions to NUREG-1801

None. The existing Oyster Creek 10 CFR 50 Appendix J is found to be adequate to support the extended period of operation with no exceptions.

2.4 Summary of Enhancements to NUREG-1801

None. The existing Oyster Creek 10 CFR 50 Appendix J aging management program is found to be adequate to support the extended period of operation with no enhancements.

3.0 EVALUATIONS AND TECHNICAL BASIS

Note

This section is organized by quoting the relevant NUREG-1801 Chapter XI program element (September 2005 version) followed by the related Oyster Creek program attributes and a conclusion of the comparison. Where applicable, the NUREG-1801 program element was separated into logical sub-elements and addressed accordingly.

Implementing procedure references are included in **( )** for information purposes. This information from the source procedure has been either directly extracted from the procedure or summarized for inclusion into this PBD.

3.0 Scope of Program

NUREG-1801:

a) *The scope of the containment LRT program includes all pressure-retaining components. Two types of tests are implemented. Type A tests are performed to measure the overall primary containment integrated leakage rate, which is obtained by summing leakage through all potential leakage paths, including containment welds, valves, fittings, and components that penetrate containment. Type B tests are performed to measure local leakage rates across each pressure-containing or leakage-limiting boundary for containment penetrations.*

b) *Type A and B tests described in 10 CFR Part 50, Appendix J, are acceptable methods for performing these LRTs.*

c) *Leakage testing for containment isolation valves (normally performed under Type C tests), if not included under this program, is included under LRT programs for systems containing the isolation valves.*

Oyster Creek:

a) The LRT program is credited with managing the aging degradation of pressure retaining boundaries of piping and components of the various systems penetrating the containment. Type A, or Integrated Leak Rate Tests (ILRTs), measure overall primary containment leakage as a whole. Type B, or Local Leak Rate Tests (LLRTs), are performed to measure local leakage rates across each pressure-containing or leakage-limiting boundary for the primary containment isolation system containment penetrations. The method, extent and schedule of these tests will detect minor leakage prior to loss of intended function. **(Reference: Oyster Creek Technical Specifications, Section 4.5; ER-AA-380, paragraph 1; ER-OC-380, paragraph 1.0)**

b) The 10CFR50 Appendix J requirements for Type 'A', 'B', and 'C' leakage tests are used for the containment isolation barrier piping and valves leak testing. The result of the Type 'A' ILRT demonstrates that to allow for plant startup, containment leakage as a whole does not exceed the 0.75 La acceptance criteria, where La is the maximum allowable Type 'A' test leakage rate at Pa (the calculated peak containment internal pressure related to the DBA). The leakage rate acceptance criteria for the Primary Containment Leakage Rate Testing Program for Type 'B' and Type 'C' tests is 0.60 La at Pa. **(Reference: Oyster Creek Technical Specifications, Section 4.5; ER-AA-380, paragraph 1; ER-OC-380, paragraph 1.0)**

c) Leakage testing for containment isolation valves is performed under Type C tests as part of this program. **(Reference: Oyster Creek Technical Specifications, Section 4.5; ER-AA-380, paragraph 1; ER-OC-380, paragraph 1.0)**

The Oyster Creek 10 CFR 50 Appendix J aging management program manages the aging effect of loss of material, loss of preload, loss of sealing, loss of leak tightness, and cracking for the systems, components, and environments listed in Table 5.2. The implementing documents for this aging management program are listed in Table 5.1 and are described throughout the individual program element discussions. The commitment numbers under which these implementing documents are being revised are contained within the listings in Table 5.1.

Exceptions to NUREG-1801, Element 1:

None.

Enhancements to NUREG-1801, Element 1:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 1, Scope of Program.

3.1 Preventive Actions

NUREG-1801:

No preventive actions are specified; the containment LRT program is a monitoring program.

Oyster Creek:

The primary containment leakage testing program does not prevent or mitigate degradation due to aging effects but provides measures for condition monitoring to detect the degradation prior to loss of intended function. **(Reference: ER-AA-380, paragraph 1.2)**

Exceptions to NUREG-1801, Element 2:

None.

Enhancements to NUREG-1801, Element 2:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 2, Preventive Actions.

3.2 Parameters Monitored or Inspected

NUREG-1801:

The parameters to be monitored are leakage rates through containment shells; containment liners; and associated welds, penetrations, fittings, and other access openings.

Oyster Creek:

The parameters monitored are leakage rates of the containment as a whole and leakage rates through airlocks, penetrations, piping, welds, valves, and fittings. The ILRT measures overall containment leakage and the LLRTs measure the pressure retaining integrity and leakage rates of individual containment penetrations. **(Reference: ER-AA-380, paragraph 1)**

Exceptions to NUREG-1801, Element 3:

None.

Enhancements to NUREG-1801, Element 3:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 3, Parameters Monitored or Inspected.

3.3 Detection of Aging Effects

NUREG-1801:

a) *A containment LRT program is effective in detecting degradation of containment shells, liners, and components that compromise the containment pressure boundary, including seals and gaskets.*

b) *While the calculation of leakage rates demonstrates the leak-tightness and structural integrity of the containment, it does not by itself provide information that would indicate that aging degradation has initiated or that the capacity of the containment may have been reduced for other types of loads, such as seismic loading. This would be achieved with the additional implementation of an acceptable containment inservice inspection program as described in XI.S1 and XI.S2.*

Oyster Creek:

a) The primary containment LRT program detects degradation of the containment, piping, and components, including seals and gaskets, that compromise the containment pressure boundary through the use of pressure tests to verify the pressure retaining integrity of the containment. The LRTs demonstrate the leak-tightness of containment isolation barriers. **(Reference: ER-AA-380; ER-OC-380)**

b) Calculation of leakage rates demonstrates the leak-tightness and structural integrity of the containment. Refer to XI.S1, ASME Section XI, Subsection IWE for descriptions and compliance with the ISI and concrete structures inspection programs. XI.S2, ASME Section XI, Subsection IWL applies to Class CC containments only, and is not applicable to Oyster Creek.

Exceptions to NUREG-1801, Element 4:

None.

Enhancements to NUREG-1801, Element 4:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 4, Detection of Aging Effects.

3.4 Monitoring and Trending

NUREG-1801:

Because the LRT program is repeated throughout the operating license period, the entire pressure boundary is monitored over time. The frequency of these tests depends on which option (A or B) is selected.

a) With Option A, testing is performed on a regular fixed time interval as defined in 10 CFR Part 50, Appendix J

b) In the case of Option B, the interval for testing may be increased on the basis of acceptable performance in meeting leakage limits in prior tests. Additional details for implementing Option B are provided in NRC Regulatory Guide 1.163 and NEI 94-01, Rev.0

Oyster Creek:

Since the primary containment leakage testing program must be repeated throughout the operating license period, the entire primary containment pressure boundary is being monitored and trended over time.

a) Oyster Creek has elected to perform the containment leak rate test program in accordance with Option B, as presented in

10CFR50, Appendix J. **(Reference: ER-AA-380, paragraph 1.3; ER-OC-380, paragraph 1.0)** The fixed time intervals of Option A do not apply, however the monitoring and trending requirements contained within 10CFR50 Appendix J are the same for both Option A and Option B.

b) Oyster Creek has elected to perform the containment leak rate test program in accordance with Option B, as presented in 10CFR50, Appendix J, including guidance provided in R.G. 1.163 and NEI 94-01, Rev. 0. **(Reference: ER-AA-380, paragraph 1.3; ER-OC-380, paragraph 1.0)** This option allows for limited flexibility in developing a performance based leak rate test program. The monitoring and trending requirements contained within 10CFR50 Appendix J are the same for both Option A and Option B.

Exceptions to NUREG-1801, Element 5:

None.

Enhancements to NUREG-1801, Element 5:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 5, Monitoring and Trending.

3.5 Acceptance Criteria

NUREG-1801:

a) Acceptance criteria for leakage rates are defined in plant technical specifications.

b) These acceptance criteria meet the requirements in 10 CFR Part 50, Appendix J, and are part of each plant's current licensing basis. The current licensing basis carries forward to the period of extended operation.

Oyster Creek:

a) The cumulative acceptance criteria for leakage rates are defined in the plant technical specifications. The maximum allowable leakage limits for the LRT program are established to provide assurance that the limits of 10CFR100 will not be exceeded. **(Reference: Oyster Creek Technical**

Specifications, Section 4.5)

b) These acceptance criteria meet the requirements of 10CFR50, Appendix J, and are part of the current licensing basis (CLB). The CLB carries forward to the period of extended operation. **(Reference: ER-AA-380, paragraph 1; ER-OC-380, paragraph 1.0)**

Exceptions to NUREG-1801, Element 6:

None.

Enhancements to NUREG-1801, Element 6:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria.

3.6 Corrective Actions

NUREG-1801:

a) Corrective actions are taken in accordance with 10 CFR Part 50, Appendix J, and NEI 94-01. When leakage rates do not meet the acceptance criteria, an evaluation is performed to identify the cause of the unacceptable performance, and appropriate corrective actions must be taken.

b) As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

Oyster Creek:

a) Corrective actions are performed in accordance with procedures that meet the requirements of 10CFR50 Appendix J and NEI 94-01. Evaluations are performed for test or inspection results that do not satisfy established criteria and an issue report is initiated to document the concern in accordance with plant administrative procedures. **(Reference: ER-AA-380, paragraphs 1.3, 1.4, 4.1.9, 4.10; ER-OC-380, paragraphs 1.0, 5.5.6)**

b) The 10 CFR 50 Appendix B corrective actions program (CAP) ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined and an action plan is developed to preclude repetition. **(Reference: ER-AA-380, paragraphs 1, 4.1.9, 4.10; ER-OC-380, paragraphs 1.0, 5.5.6)**

Exceptions to NUREG-1801, Element 7:

None.

Enhancements to NUREG-1801, Element 7:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 7, Corrective Actions.

3.7 Confirmation Process

NUREG-1801:

a) *When corrective actions are implemented to repair a condition that causes excessive leakage, confirmation by additional leak rate testing is performed to confirm that the deficiency has been corrected.*

b) *As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.*

Oyster Creek:

a) Repairs are leak rate tested to confirm that the deficiency has been corrected. Confirmation by additional leak rate retesting is conducted in accordance with approved procedures. **(Reference: ER-AA-380, paragraph 4.2.8; ER-OC-380, paragraph 5.5.6)**

b) Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.

Exceptions to NUREG-1801, Element 8:

None.

Enhancements to NUREG-1801, Element 8:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 8, Confirmation Process.

3.8 Administrative Controls

NUREG-1801:

a) *Results of the LRT program are documented as described in 10 CFR Part 50, Appendix J, to demonstrate that the acceptance criteria for leakage have been satisfied. The test results that exceed the performance criteria must be assessed under 10 CFR 50.72 and 10 CFR 50.73.*

b) *As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.*

Oyster Creek:

a) The LRT program documents and trends test results in accordance with the requirements and guidance provided in 10CFR50 Appendix J. The LRT program demonstrates that the test results meet the requirements contained in the acceptance criteria. Tests results that fail to meet the acceptance criteria defined in the plant technical specifications are reported in accordance with approved procedures that meet the requirements of 10CFR50.72 and 10CFR50.73. **(Reference ER-AA-380, paragraph 1; ER-OC-380, paragraph 1.1)**

b) See Item 8, above for a discussion regarding meeting the requirements of 10CFR50 Appendix B.

Exceptions to NUREG-1801, Element 9:

None.

Enhancements to NUREG-1801, Element 9

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 9, Administrative Controls.

3.9 Operating Experience

NUREG-1801:

To date, the 10 CFR Part 50, Appendix J, LRT program has been effective in preventing unacceptable leakage through the containment pressure boundary. Implementation of Option B for testing frequency must be consistent with plant-specific operating experience.

Oyster Creek:

Industry experience indicates that the primary containment leakage testing program activities have been effective in maintaining the pressure integrity of the containment boundaries, including identification of leakage within the various systems pressure boundaries. The Oyster Creek facility demonstrates a good operating experience in maintaining the integrity of the containment boundaries as evidenced by the selection of Option B of 10 CFR 50 Appendix J leakage testing requirements. Oyster Creek has experienced 'as found' LLRT results that were in excess of the administrative limits for the individual containment penetration. Evaluations were performed and corrective actions were taken to restore the individual containment penetration leakage rates to within the established administrative leakage limits. The experience at Oyster Creek with the 10 CFR 50 Appendix J aging management program shows that the program is effective in managing loss of material, loss of preload, loss of sealing, loss of leak tightness, and cracking in the containment, associated welds, penetrations, and other access openings.

Operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek Operating Experience process. The Operating Experience process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The second way is through the process for managing programs. This process requires the review of program related operating experience by the program owner.

Both of these processes review operating experience from both external and internal (also referred to as in-house) sources.

External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that loss of material, loss of preload, loss of sealing, loss of leak tightness, and cracking in the containment, associated welds, penetrations, and other access openings are being adequately managed. The following examples of operating experience provide objective evidence that the Appendix J LRT program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

The LLRT of V-26-8 determined that the leakage rate was above the alert limit for that valve. The rate was evaluated to be acceptable as-found. The valve was subsequently rebuilt and retested satisfactorily the next refueling outage. This example provides objective evidence that leak rates above administrative limits are identified for engineering evaluation, and that corrective actions are taken prior to component loss of intended function. (CAP O2000-1355)

The LLRT of V-19-20 determined that the leakage rate exceeded the action limit. The valve was repaired and the post-maintenance test LLRT was acceptable. This example provides objective evidence that components determined to exceed the allowable leakrates are entered into the corrective actions process, identified for repair, and subsequently retested in accordance with the program. (CAP O2002-1564)

The LLRT of MSIV NS04A determined that the leakage rate failed to meet acceptance criteria. The main seating surface was lapped and a successful LLRT was performed. As a result of this occurrence, the MSIV overhaul procedure was revised to include a documented management review prior to eliminating seat lapping after poppet replacement even if a successful blue check has been obtained. This example provides objective evidence that a component exceeding the allowable leakrate was entered into the corrective actions process, repaired, and subsequently retested per the program. (CAP O2004-3442)

Oyster Creek CAP O2005-1350 describes two issues regarding 10 CFR 50 Appendix J testing of components: 1.) Feedwater piping expansion bellows (considered to be untestable) are not local leak rated tested. The bellows are pressurized during Integrated Leakage Rate Testing. Two main steam bellows and these two feedwater bellows were the subject of a relief request from local leak rate testing due to their design. The main steam bellows were specifically identified in the exemption; the feedwater bellows were not. Clarification of the feedwater bellows exemption status is currently in process. 2.) Shutdown Cooling isolation valves are not leak rate tested due to a system configuration that lacks inboard test boundary valves. Although a previous NRC conclusion determined that these valves did not require an exemption, an error existed in the original exemption submittal. Documentation is not available to indicate these valves have ever been leak rate tested. Clarification of this issue status is in process. These examples provide objective evidence that deficiencies in the Appendix J program are entered into the corrective action process. (CAP O2005-1350)

The operating experience of the Appendix J LRT program did not show any adverse trends in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the LRT program will effectively maintain the integrity of containment, penetrations, and other access openings. Periodic self-assessments of the LRT program are performed to identify the areas that need improvement to maintain the quality performance of the program.

3.10 Conclusion

The Oyster Creek 10 CFR 50 Appendix J aging management program is credited for managing loss of material, loss of preload, loss of sealing, loss of leak tightness, and cracking for the systems, components, and environments listed in Table 5.2. The Oyster Creek 10 CFR 50 Appendix J program's elements have been evaluated against NUREG-1801 in Section 3.0. There are no program exceptions identified in Section 2.3. There are no program enhancements identified in Section 2.4. The implementing documents and commitment numbers for this aging management program are listed in Table 5.1. The relevant operating experience has been reviewed and a demonstration of program effectiveness is provided in Section 3.10.

Based on the above, the continued implementation of the Oyster Creek 10CFR 50 Appendix J aging management program provides reasonable assurance that loss of material, loss of preload, loss of sealing, loss of leak tightness, and cracking will continue to be adequately managed so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

4.0 REFERENCES

4.1 Generic to Aging Management Programs

4.1.1 10 CFR 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants*

4.1.2 10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*

4.1.3 NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,* Revision 1, dated September 2005

4.1.4 NUREG-1801, *Generic Aging Lessons Learned (GALL) Report,* Revision 1, dated September 2005

4.2 Industry Standards

4.2.1 10CFR50 Appendix J, Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors

4.2.2 NEI 94-01, Industry Guideline for Implementing Performance-Based Option of 10CFR50 Appendix J

4.3 Oyster Creek Program References

4.3.1 Oyster Creek Nuclear Generating Station Technical Specifications

5.0 TABLES

5.1 Aging Management Program Implementing Documents

Procedure Number	Procedure Title	Commitment No.	Status
ER-AA-380	Primary Containment leakage Rate Testing Program	00330592.29.01	ACC/ASG
ER-OC-380	Oyster Creek Primary Containment Leakage Rate Testing Program	00330592.29.02	ACC/ASG

5.2 Aging Management Review Results

SSC Name	Structure and/or Component	Material	Environment	Aging Effect
Containment Vacuum Breakers	Expansion Joint	Stainless Steel	Containment Atmosphere (Internal)	Cracking Initiation and Growth
Containment Vacuum Breakers	Expansion Joint	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Containment Vacuum Breakers	Expansion Joint	Stainless Steel	Indoor Air (External)	Cracking Initiation and Growth
Containment Vacuum Breakers	Expansion Joint	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Containment Vacuum Breakers	Piping and fittings	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Containment Vacuum Breakers	Piping and fittings	Stainless Steel	Containment Atmosphere (Internal)	Cracking Initiation and Growth
Containment Vacuum Breakers	Piping and fittings	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Containment Vacuum Breakers	Valve Body	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Containment Vacuum Breakers	Valve Body	Stainless Steel	Containment Atmosphere (Internal)	Cracking Initiation and Growth
Containment Vacuum Breakers	Valve Body (Vacuum Breakers)	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Access Hatch Covers	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Access Hatch Covers	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Class MC Pressure Retaining Bolting	Carbon and low alloy steel	Containment Atmosphere (External)	Loss Of Preload
Primary Containment	Class MC Pressure Retaining Bolting	Carbon and low alloy steel	Indoor Air	Loss Of Preload
Primary Containment	Downcomers	Carbon and low alloy steel	Treated Water < 140F	Loss of Material
Primary Containment	Downcomers	Carbon and low alloy steel	Containment Atmosphere	Loss of Material
Primary Containment	Drywell Head	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Head	Carbon and low alloy steel	Indoor Air (External)	Loss of Material

Primary Containment	Drywell Head	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Head	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Penetration Bellows	Stainless Steel, Dissimilar Metal Welds	Indoor Air (External)	Cracking
Primary Containment	Drywell Penetration Bellows	Stainless Steel, Dissimilar Metal Welds	Containment Atmosphere (Internal)	Cracking
Primary Containment	Drywell Penetration Sleeves	Carbon and low alloy steel, Dissimilar Metal Welds	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Penetration Sleeves	Carbon and low alloy steel, Dissimilar Metal Welds	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Penetration Sleeves	Carbon and low alloy steel, Dissimilar Metal Welds	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Penetration Sleeves	Carbon and low alloy steel, Dissimilar Metal Welds	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Penetration Sleeves	Stainless Steel	Containment Atmosphere (Internal)	Cracking
Primary Containment	Drywell Penetration Sleeves	Stainless Steel	Containment Atmosphere (Internal)	Cracking
Primary Containment	Drywell Penetration Sleeves	Stainless Steel	Indoor Air (External)	Cracking
Primary Containment	Drywell Penetration Sleeves	Stainless Steel	Indoor Air (External)	Cracking
Primary Containment	Drywell Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Locks, Hinges, and Closure Mechanisms	Carbon and low alloy steel	Indoor Air (External)	Loss of Leak Tightness
Primary Containment	Locks, Hinges, and Closure Mechanisms	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Leak Tightness
Primary Containment	Locks, Hinges, and Closure Mechanisms	Bronze	Indoor Air (External)	Loss of Leak Tightness
Primary Containment	Locks, Hinges, and Closure Mechanisms	Bronze	Containment Atmosphere (Internal)	Loss of Leak Tightness
Primary Containment	Penetration Closure Plates and Caps (spare penetrations)	Carbon and low alloy steel	Indoor Air (External)	Loss of Material

Primary Containment	Penetration Closure Plates and Caps (spare penetrations)	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Personnel Airlock/Equipment Hatch	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Personnel Airlock/Equipment Hatch	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Seals, Gaskets, and O-rings	Elastomer	Containment Atmosphere (External)	Loss of Sealing
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Shell Hoop Straps	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Vent line bellows	Stainless Steel (Dissimilar Metal Welds)	Containment Atmosphere (Internal)	Cracking
Primary Containment	Vent line bellows	Stainless Steel (Dissimilar Metal Welds)	Indoor Air (External)	Cracking
Primary Containment	Vent line, and Vent Header	Carbon and low alloy steel	Indoor Air (External)	Loss of Material

Primary Containment	Vent line, and Vent Header	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Reactor Building Ventilation System	Piping and fittings (Primary Containment Isolation Valves)	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Reactor Water Cleanup System	Piping and fittings	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Reactor Water Cleanup System	Valve Body	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material

6.0 ATTACHMENTS

6.1 LRA Appendix A

6.2 LRA Appendix B

PROGRAM BASIS DOCUMENT

PBD-AMP-B.1.24

Revision 0

ONE-TIME INSPECTION

GALL PROGRAM XI.M32 - ONE-TIME INSPECTION

Prepared By: ______________________

Reviewed By: ______________________

Program Owner Review: ______________________

Technical Lead Approval: ______________________

Revision History:

Revision	*Prepared by:*	*Reviewed by:*	*Program Owner:*	*Approved by:*
0	*Mark Miller*	*Stu Getz*	*Tom Quintenz*	*Don Warfel*
Date				

Summary of Revisions:

Rev. Number	Reason for the Revision(s)
0	Initial Issue

TABLE OF CONTENTS

1.0 PURPOSE AND METHODOLOGY

1.1 Purpose

The purpose of this Program Basis Document is to document and evaluate those activities of the Oyster Creek One-Time Inspection aging management program that are credited for managing aging effects as part of Oyster Creek License Renewal to meet the requirements of the License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

This includes the following:

- The identification of the scope of the program;
- The evaluation of program elements against NUREG-1801;
- The review of Operating Experience to demonstrate program effectiveness;
- The identification of required program enhancements;
- The identification of Oyster Creek documents required to implement the program.

1.2 Methodology

The nuclear power plant License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," describes the License Renewal process and provides requirements for the contents of License Renewal Applications. 10 CFR 54.21(a)(3) states:

"For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the Current Licensing Basis (CLB) for the period of extended operation."

The NRC and the industry identified 10 program elements that are useful in describing an aging management program and then demonstrating its effectiveness. These program elements are described in Appendix A.1, Section A.1.2.3 of the Standard Review Plan. NUREG-1801 uses these program elements in Section XI to describe acceptable aging management programs.

This Program Basis Document provides a comparison of the credited Oyster Creek program with the elements of the corresponding NUREG-1801 Chapter XI program XI.M32, One-Time Inspection. Project Level Instruction PLI-8 "Program Basis Documents" prescribes the methodology for evaluating Aging Management Programs. An evaluation of Oyster Creeks aging management program criteria or activities to those of the NUREG-1801 program elements is performed and a conclusion is reached concerning consistency for each individual program element. A demonstration of overall program effectiveness is made after all program elements are evaluated. Required program enhancements are documented. An overall determination is made as to consistency with the program description in NUREG-1801.

2.0 PROGRAM DESCRIPTION

2.1 Program Description

NUREG-1801:

a) *The program includes measures to verify the effectiveness of an aging management program (AMP) and confirm the insignificance of an aging effect. Situations in which additional confirmation is appropriate include (a) an aging effect is not expected to occur but the data is insufficient to rule it out with reasonable confidence; (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected; or (c) the characteristics of the aging effect include a long incubation period. For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation.*

b) *A one-time inspection may also be used to provide additional assurance that aging that has not yet manifested itself is not occurring, or that the evidence of aging shows that the aging is so insignificant that an aging management program is not warranted. (Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35, One Time Inspection of ASME Code Class 1 Small Bore-Piping).*

c) *One-time inspections may also be used to verify the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of* *intended function during the period of extended operation. For example, effective control of water chemistry can prevent some aging effects and minimize others. However, there may be locations that are isolated from the flow stream for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. This program provides inspections that either verifies that unacceptable degradation is not occurring or trigger additional actions that will assure the intended function of affected components will be maintained during the period of extended operation.*

d) The elements of the program include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation. When evidence of an aging effect is revealed by a one-time inspection, the routine evaluation of the inspection results would identify appropriate corrective actions.

e) As set forth below, an acceptable verification program may consist of a one-time inspection of selected components and susceptible locations in the system. An alternative acceptable program may include routine maintenance or a review of repair or inspection records to confirm that these components have been inspected for aging degradation and significant aging degradation has not occurred. One-time inspection, or any other action or program, created to verify the effectiveness of an AMP and confirm the absence of an aging effect, is to be reviewed by the staff on a plant-specific basis.

<u>Oyster Creek:</u>

a) The Oyster Creek One-Time Inspection aging management program includes measures to verify the effectiveness of an aging management program and confirm the insignificance of an aging effect. The program provides additional confirmation that (a) an aging effect is not expected to occur but the data is insufficient to rule it out with reasonable confidence; (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected; or (c) the characteristics of the aging effect include a long incubation period. The One-Time Inspection aging management program confirms that either the aging effect is not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation.

b) The One-Time Inspection aging management program will be used to provide additional assurance that aging that has not yet manifested itself is not occurring, or that the evidence of aging shows that the aging is so insignificant that an aging management program is not warranted.

The One-Time Inspection aging management program will be used for the following:

- To confirm that loss of material in stainless steel piping, piping components, and piping elements is insignificant in an intermittent condensation (internal) environment.
- To confirm that loss of material in steel piping, piping components, and piping elements is insignificant in an indoor air (internal) environment.
- To confirm that loss of material is insignificant for non-safety related (NSR) piping and components of vents and drains, floor and equipment drains, and other systems and components that could contain a fluid, and, are in scope for 10CFR54.4(a)(2) for spatial interaction. The scope of the program consists of only those systems not covered by other aging management activities.
- NUREG-1801 states in XI.M32 that one-time inspection of Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping. This is a new requirement based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

  NUREG-1801 aging management program XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping* will not be used at Oyster Creek. The new Oyster Creek One-Time Inspection aging management program will use volumetric examinations to provide additional assurance that aging that has not yet manifested itself is not occurring, or that the evidence of aging shows that the aging is so insignificant that an aging management program is not warranted for Class 1 piping less than or equal to NPS 4 (which does not receive volumetric examination during inservice inspection).

c) The One-Time Inspection aging management program will be used to verify the system-wide effectiveness of aging management programs that are designed to prevent or minimize aging to the extent that it will not cause a loss of intended function during the period of extended operation. The program provides inspections that either verifies that unacceptable degradation is not occurring or that triggers additional actions that will assure the intended function of affected components will be maintained during the period of extended operation.

The One-Time Inspection aging management program will be used for the following:

- To confirm the effectiveness of the Water Chemistry program to manage the loss of material and crack initiation and growth aging effects. Control of water chemistry may not preclude aging effects in low flow or stagnant flow areas. To confirm the effectiveness of the Water Chemistry program, the One-Time Inspection aging management program will perform one-time inspections on selected components in low flow or stagnant flow areas.
- To confirm the effectiveness of the Closed Cycle Cooling Water System program to manage the loss of material aging effect. Control of closed cycle cooling water chemistry may not preclude aging effects in low flow or stagnant flow areas. The One-Time Inspection aging management program will be used to confirm the absence of aging effects in low flow or stagnant flow areas in closed cycle cooling water systems.
- To confirm the effectiveness of the Fuel Oil Chemistry program and Lubricating Oil Monitoring Activities program to manage the loss of material aging effect. Control of fuel oil and lubricating oil chemistry may not preclude aging effects in low flow or stagnant flow

areas. The One-Time Inspection aging management program will be used to confirm the absence of aging effects in low flow or stagnant flow areas in fuel oil and lubricating oil systems.

d) The elements of the One-Time Inspection aging management program include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation. When evidence of an aging effect is revealed by a one-time inspection, the routine evaluation of the inspection results would identify appropriate corrective actions.

e) The One-Time Inspection aging management program consists of a one-time inspection of selected components and susceptible locations in a system. The program elements include (a) determination of appropriate inspection sample size, (b) identification of inspection locations, (c) selection of examination technique, with acceptance criteria, and (d) evaluation of results to determine the need for additional inspections or other corrective actions. The inspections will be scheduled as close to the end of the current operating license as practical with margin provided to ensure completion prior to commencing the period of extended operation. The inspection requirements may be satisfied by a review of maintenance records, repair or other inspection records to confirm that the component has been inspected for aging degradation and no significant degradation has occurred.

2.2 Overall NUREG-1801 Consistency

The Oyster Creek One-Time Inspection aging management program is a new program that is consistent with NUREG-1801 aging management program XI.M32, One-Time Inspection with exceptions as described in 2.3 below.

2.3 Summary of Exceptions to NUREG-1801

NUREG-1801 states in XI.M32 that one-time inspection of Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping.* NUREG-1801 aging management program XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping* will not be used at Oyster Creek. The new Oyster Creek One-Time Inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

NUREG-1801 references in XI.M32 and XI.M35 the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda for Subsections IWB, IWC, and IWD. The current Oyster Creek ISI Program Plan for the fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

NUREG-1801 states in XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping,* that the guidelines of EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001 should be used for identifying piping susceptible to potential effects of thermal fatigue. EPRI Report 1000701 recommends specific locations for assessment and/or inspection where cracking and leakage has been identified in nominally stagnant non-isolable piping attached to reactor coolant systems in domestic and similar foreign PWRs. As Oyster Creek is a BWR, these inspection guidelines are not applicable. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

2.4 Summary of Enhancements to NUREG-1801

None. The new Oyster Creek One-Time Inspection aging management program is adequate to support the extended period of operation with no enhancements.

3.0 EVALUATIONS AND TECHNICAL BASIS

Note

This section is organized by quoting the relevant NUREG-1801 Chapter XI program element (September 2005 version) followed by the related Oyster Creek program attributes and a conclusion of the comparison. Where applicable, the NUREG-1801 program element was separated into logical sub-elements and addressed accordingly.

Implementing procedure references are included in **( )** for information purposes. This information from the source procedure has been either directly extracted from the procedure or summarized for inclusion into this PBD.

3.0 Scope of Program

NUREG-1801:

a) *The program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation.*

b) *The structures and components for which one-time inspection is specified to verify the effectiveness of the AMPs (e.g., water chemistry control, etc.) have been identified in the Generic Aging Lessons Learned (GALL) Report. Examples include the feedwater system components in boiling water reactors (BWRs) and pressurized water reactors (PWRs).*

Oyster Creek:

a) The One-Time Inspection aging management program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing aging management programs or confirming that there is no need to manage aging-related degradation for the period of extended operation.

The One-Time Inspection aging management program will be used for the following:

- To confirm the effectiveness of the Water Chemistry program to manage the loss of material and crack initiation and growth aging effects. Control of water chemistry may not preclude aging effects in low flow or stagnant flow areas. To confirm the effectiveness of the Water Chemistry program, the One-Time Inspection aging management program will perform one-time inspections on selected components in low flow or stagnant flow areas **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.02, 03, 04, 05, 06, 07, 08, 09, 10, 11).**

- To confirm the effectiveness of the Closed Cycle Cooling Water System program to manage the loss of material aging effect. Control of closed cycle cooling water chemistry may not preclude aging effects in low flow or stagnant flow areas. The One-Time Inspection aging management program will be used to confirm the absence of aging effects in low flow or stagnant flow areas in closed cycle cooling water systems **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.12, 13, 14, 15).**
- To confirm the effectiveness of the Fuel Oil Chemistry program and Lubricating Oil Monitoring Activities program to manage the loss of material aging effect. Control of fuel oil and lubricating oil chemistry may not preclude aging effects in low flow or stagnant flow areas. The One-Time Inspection aging management program will be used to confirm the absence of aging effects in low flow or stagnant flow areas in fuel oil and lubricating oil systems **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.16, 17, 18, 19).**
- To confirm that loss of material in stainless steel piping, piping components, and piping elements is insignificant in an intermittent condensation (internal) environment **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.20).**
- To confirm that loss of material in steel piping, piping components, and piping elements is insignificant in an indoor air (internal) environment **(Reference: Oyster Creek License Renewal Project document**

"Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.21).

- To confirm that loss of material is insignificant for non-safety related (NSR) piping and components of vents and drains, floor and equipment drains, and other systems and components that could contain a fluid, and, are in scope for 10CFR54.4(a)(2) for spatial interaction. The scope of the program consists of only those systems not covered by other aging management activities **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.22).**
- To confirm that cracking initiation and growth due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or thermal and mechanical loading is not occurring in Class 1 piping less than four-inch NPS **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.01).** NUREG-1801 states in XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping,* that the guidelines of EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001 should be used for identifying piping susceptible to the potential effects of thermal fatigue. *This is a new requirement (from XI.M35) based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

  EPRI Report 1000701 recommends specific locations for assessment and/or inspection where cracking and leakage has been identified in nominally stagnant non-isolable piping attached to reactor coolant systems in domestic and similar foreign PWRs. These inspection recommendations do not apply to Oyster Creek which is a BWR.

  Oyster Creek has evaluated the potential for cracking in nominally stagnant non-isolable piping attached to reactor coolant systems and it was concluded that there are no systems with unisolable sections that could be subjected to thermal stratification or oscillations. This evaluation is summarized as follows: Information Notice (IN) 97-46 discusses a situation that occurred at Oconee Unit 2 where cracks developed in an unisolable section of a combined makeup (MU) and high-pressure injection (HPI) line. The Information Notice goes on to reference NRC Bulletin 88-08 and its supplements. Bulletin 88-08 describes the circumstances that occurred at Farley 2 where a crack developed in an unisolable section of ECCS piping. The crack resulted from high cycle thermal fatigue caused by relatively cold water leaking through a closed globe valve. Oyster Creek performed a review of systems connected to the Reactor Coolant System in response to NRC Bulletin 88-08 and its Supplements to determine whether unisolable sections of piping connected to the Reactor Coolant System could be subjected to stresses from temperature stratification or temperature oscillations **(Reference: Letter E. E. Fitzpatrick to USNRC, "Response to NRC Bulletin 88-08 and Supplement 1," dated August 19, 1988)**. It was concluded that there are no systems with unisolable sections which could be subjected to thermal stratification or oscillations. The piping system evaluations encompassed both the weldments (as required by Bulletin 88-08) and the base metal (as required by Supplement 1 to Bulletin 88-08).

b) Systems in the scope of the One-Time Inspection aging management program as identified in the Generic Aging Lessons Learned (GALL) Report and the Oyster Creek Aging Management Reviews include:

AMP/Component	System	Aging Effect

Water Chemistry	• Condensate System • Condensate Transfer System • Containment Spray System • Containment Vacuum Breakers • Control Rod Drive System • Core Spray System • Emergency Service Water System • Feedwater System • Fuel Storage and Handling Equipment • Heating & Process Steam • Isolation Condenser • Main Generator and Auxiliary System • Main Steam System • Main Turbine and Auxiliary System • Noble Metals Monitoring System • Nuclear Boiler Instrumentation • Post-Accident Sampling System • Primary Containment • Process Sampling System • Reactor Building • Reactor Building Closed Cooling Water System • Reactor Head Cooling System • Reactor Recirculation System • Reactor Water Cleanup System • Shutdown Cooling System • Spent Fuel Pool Cooling System • Standby Liquid Control System (Liquid Poison System) • Water Treatment &	Loss of Material Crack Initiation and Growth

Closed Cycle Cooling Water System	• Emergency Diesel Generator and Auxiliary System • Process Sampling System • Reactor Building Closed Cooling Water System • Turbine Building Closed Cooling Water System	Loss of Material
Fuel Oil Chemistry	• Emergency Diesel Generator and Auxiliary System • Fire Protection System • Main Fuel Oil Storage & Transfer System	Loss of Material
Lubricating Oil Monitoring Program	• Control Rod Drive System • Emergency Diesel Generator and Auxiliary System • Feedwater System • Fire Protection System • Main Generator and Auxiliary System • Main Turbine and Auxiliary System • Miscellaneous Floor and Equipment Drain System • Reactor Building Closed Cooling Water System • Reactor Recirculation System • Reactor Water Cleanup System • Service Water System	Loss of Material

N/A (SS/Condensation internal environment)	• Hydrogen & Oxygen Monitoring System • Nitrogen Supply System	Loss of Material
N/A (steel/indoor air internal environment)	• Hardened Vent System • Isolation Condenser System • Reactor Building Ventilation System • Reactor Water Cleanup System • Spent Fuel Pool Cooling System • Water Treatment & Distribution System	Loss of Material
NSR Piping, Pumps, Valves, and Tanks (not covered by other programs) in scope for 10CFR54.4(a)(2) for spatial interaction (e.g., items with a raw water-fresh water environment)	• Drywell Floor and Equipment Drains • Miscellaneous Floor and Equipment Drain System • Reactor Building Floor and Equipment Drains • Roof Drains and Overboard Discharge • Sanitary Waste System	Loss of Material

Class 1 Piping Less than 4 inch in diameter NPS	• Control Rod Drive System • Core Spray System • Feedwater System • Isolation Condenser System • Main Steam System • Nuclear Boiler Instrumentation • Post-Accident Sampling System • Reactor Head Cooling System • Reactor Recirculation System • Reactor Water Cleanup System • Shutdown Cooling System • Standby Liquid Control System (Liquid Poison System)	Crack Initiation and Growth

The Oyster Creek One-Time Inspection aging management program manages the aging effects for the systems, components, materials, and environments listed in Table 5.2. The implementing documents for this aging management program are listed in Table 5.1 and are described throughout the individual program element discussions. The commitment numbers under which these implementing documents are being revised are contained within the listings in Table 5.1.

<u>Exceptions to NUREG-1801, Element 1:</u>

NUREG-1801 states in XI.M32 that one-time inspection of Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping.* NUREG-1801 aging management program XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping* will not be used at Oyster Creek. The new Oyster Creek One-Time Inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4. *This is a new* *exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

NUREG-1801 references in XI.M32 and XI.M35 the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda for Subsections IWB, IWC, and IWD. The current Oyster Creek ISI Program Plan for the fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

NUREG-1801 states in XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping,* that the guidelines of EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001 should be used for identifying piping susceptible to potential effects of thermal fatigue. EPRI Report 1000701 recommends specific locations for assessment and/or inspection where cracking and leakage has been identified in nominally stagnant non-isolable piping attached to reactor coolant systems in domestic and similar foreign PWRs. As Oyster Creek is a BWR, these inspection guidelines are not applicable. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

Enhancements to NUREG-1801, Element 1:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 1, Scope of Program with exceptions as described above.

3.1 Preventive Actions

NUREG-1801:

One-time inspection is an inspection activity independent of methods to mitigate or prevent degradation.

Oyster Creek:

The one-time inspections do not provide for preventive or mitigative actions. One-time inspections verify the effectiveness of chemistry control at managing aging effects. For the Water Chemistry, Closed Cycle Cooling Water System, Fuel Oil, and Lubricating Oil programs, the one-time inspections confirm the absence of aging effects in stagnant or low flow areas **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19)**. Other one-time inspections are used to provide additional assurance that aging that has not yet manifested itself is not occurring, that the evidence of aging shows that the aging is so insignificant that an aging management program is not warranted through the extended period of operation areas **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.01, 20, 21, 22)**. A one-time inspection, through the 10 CFR Part 50, Appendix B corrective action program, may also trigger development of a program necessary to assure component intended functions through the period of extended operation.

Exceptions to NUREG-1801, Element 2:

NUREG-1801 states in XI.M32 that one-time inspection of Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping.* NUREG-1801 aging management program XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping* will not be used at Oyster Creek. The new Oyster Creek One-Time Inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

Enhancements to NUREG-1801, Element 2:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 2, Preventive Actions with exception as described above.

3.2 Parameters Monitored or Inspected

NUREG-1801:

a) *The program monitors parameters directly related to the degradation of a component.*

b) *Inspection is to be performed by qualified personnel following procedures consistent with the requirements of the American Society of Mechanical Engineers (ASME) Code and 10 CFR 50, Appendix B, using a variety of nondestructive examination (NDE) methods, including visual, volumetric, and surface techniques.*

Oyster Creek:

a) The program provides for inspection of loss of material and crack initiation and growth as described below.

Confirmation of chemistry control effectiveness (e.g., water chemistry, closed-cycle cooling water chemistry, fuel oil chemistry, and lubricating oil chemistry) is by inspection of "worse case" one-time inspection of more susceptible materials in potentially more aggressive environments (e.g., low flow or stagnant flow areas) to manage the effects of aging. Inspection for loss of material will consist of thickness measurements using volumetric examination or visual examination (VT-1 or VT-3) of disassembled components. Crack initiation and growth in stainless steel will be by volumetric examination **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19).**

The verification that aging effects are insignificant for piping, piping components, and piping elements not covered by chemistry programs, or, within the scope of 10CFR54.4 (a)(2) for spatial interaction, will be by thickness measurements using volumetric examination or visual examination (VT-1 or VT-3) of disassembled components. Crack initiation and growth in stainless steel will be by volumetric examination **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.20, 21, 22).**

To confirm crack initiation and growth is not occurring in Class 1 piping with a diameter less than four inch NPS (which does not receive volumetric examination during inservice inspection), the program will utilize volumetric examination to inspect areas susceptible to stress corrosion cracking, intergranular stress corrosion cracking, or thermal and mechanical loading **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.01).**

b) Inspections will be performed by qualified personnel following station procedures that are based on applicable codes and standards, including ASME, and 10 CFR 50, Appendix B. Examination methods will include visual examination, VT-1 or VT-3 of disassembled components or volumetric examination measurements, as appropriate for the detection of the specific aging effect **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.01, 02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22).**

<u>Exceptions to NUREG-1801, Element 3:</u>

NUREG-1801 states in XI.M32 that one-time inspection of Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping.* NUREG-1801 aging management program XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping* will not be used at Oyster Creek. The new Oyster Creek One-Time Inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

NUREG-1801 references in XI.M32 and XI.M35 the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda for Subsections IWB, IWC, and IWD. The current Oyster Creek ISI Program Plan for the fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

Enhancements to NUREG-1801, Element 3:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 3, Parameters Monitored or Inspected with exceptions as described above.

3.3 Detection of Aging Effects

NUREG-1801:

a) The inspection includes a representative sample of the system population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin.

b) The program will rely on established NDE techniques, including visual, ultrasonic, and surface techniques that are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR Part 50, Appendix B.

c) The inspection and test techniques will have a demonstrated history of effectiveness in detecting the aging effect of concern. Typically, the one time inspections should be performed as indicated in the following table.

Examples of Parameters Monitored or Inspected And Aging Effect for Specific Structure or Component (1)			
Aging Effect	Aging Mechanism	Parameter Monitored	Inspection Method (2)

(1) The examples provided in the table may not be appropriate for all relevant situations. If the applicant chooses to use an alternative to the recommendations in this table, a technical justification should be provided as an exception to this AMP. This exception should list the AMR line item component, examination technique, acceptance criteria, evaluation standard and a description of the justification.

(2) Visual inspection may be used only when the inspection methodology examines the surface potentially experiencing the aging effect.

Loss of Material	Crevice Corrosion	Wall Thickness	Visual (VT-1 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	Galvanic Corrosion	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	General Corrosion	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	MIC	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	Pitting Corrosion	Wall Thickness	Visual (VT-1 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	Erosion	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Heat Transfer	Fouling	Tube Fouling	Visual (VT-3 or equivalent) or Enhanced VT-1 for CASS
Cracking	SCC or Cyclic Loading	Cracks	Enhanced Visual (VT-1 or equivalent) and/or Volumetric (RT or UT)
Loss of Preload	Thermal Effects, Gasket Creep and Self-loosening	Loosening of Components	Visual (VT-3 or equivalent)

d) *With respect to inspection timing, the population of components inspected before the end of the current operating term needs to be sufficient to provide reasonable assurance that the aging effect will not compromise any intended function at any time during the period of extended operation.*

e) *Specifically, inspections need to be completed early enough to ensure that the aging effects that may affect intended functions early in the period of extended operation are appropriately managed.*

f) *Inspections need to be timed to allow the inspected components to attain sufficient age to ensure that the aging effects with long incubation periods (i.e., those that may affect intended functions near the end of the period of extended operation) are identified.*

g) *Within these constraints, the applicant should schedule the inspection no earlier than 10 years prior to the period of extended operation, and in such a way as to minimize the* *impact on plant operations. As a plant will have accumulated at least 30 years of use before inspections under this program begin, sufficient times will have elapsed for aging effects, if any, to be manifest.*

Oyster Creek:

a) Oyster Creek will perform a one-time inspection of a representative sample of systems and components to confirm that unacceptable degradation is not occurring and the intended function of components will be maintained during the extended period of operation. The program elements include (a) determination of appropriate inspection sample size, (b) identification of inspection locations, (c) selection of examination technique, with acceptance criteria, and (d) evaluation of results to determine the need for additional inspections or other corrective actions. The sample population will focus on the bounding or lead components most susceptible to aging and will be based on considerations such as time in service, severity of operating conditions, and lowest design margin **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005).**

Confirmation of chemistry program (e.g., water chemistry, closed-cycle cooling water chemistry, fuel oil chemistry, and lubricating oil chemistry) effectiveness is by inspection of "worse case" one-time inspection of more susceptible materials in potentially more aggressive environments (e.g., low flow or stagnant flow areas) to manage the effects of aging. Inspection for loss of material will consist of thickness measurements using volumetric examination or visual examination (VT-1 or VT-3) of disassembled components. Crack initiation and growth in stainless steel will be by volumetric examination **(Reference: PassPort AR 00330592.24.02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19).**

The verification that aging effects are insignificant for piping, piping components, and piping elements not covered by chemistry programs, or, within the scope of 10CFR54.4 (a)(2) for spatial interaction, will be by thickness measurements using volumetric examination or visual examination (VT-1 or VT-3) of disassembled components. Crack initiation and growth in stainless steel will be by volumetric examination **(Reference: PassPort AR 00330592.24. 20, 21, 22).**

To confirm crack initiation and growth is not occurring in Class 1 piping with a diameter less than four inch NPS (which does not receive volumetric examination during inservice inspection), the program will inspect areas susceptible to stress corrosion cracking, intergranular stress corrosion cracking, or thermal and mechanical loading **(Reference: PassPort AR 00330592.24.01)**.

b) Inspections will be performed by qualified personnel following station procedures that are based on applicable codes and standards, including ASME, and 10 CFR 50, Appendix B. Examination methods will include established NDE techniques such as visual examination (VT-1 or VT-3 of disassembled components), or volumetric examination as appropriate for the detection of the specific aging effect **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.01, 02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22)**.

c) Inspection techniques used have a demonstrated history of effectiveness in detecting aging effects. The inspection for wall thickness will include visual examination (VT-1 or VT-3 of disassembled components) or volumetric examination. The inspection for cracking will include volumetric examination **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.01, 02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22)**.

The One-Time Inspection program will not be used to manage the aging effects of loss of heat transfer or loss of preload. These aging effects will be managed by other aging management programs (e.g., Closed-Cycle Cooling Water System aging management program, Bolting Integrity aging management program, etc.).

d) Oyster Creek will perform a one-time inspection of a representative sample of systems and components to confirm that unacceptable degradation is not occurring and the intended function of components will be maintained during the extended period of operation. The program elements include (a) determination of appropriate inspection sample size, (b) identification of inspection locations, (c) selection of examination technique, with acceptance criteria, and (d) evaluation of results to determine the need for additional inspections or other corrective actions. The sample population will focus on the bounding or lead components most susceptible to aging and will be based on considerations such as time in service, severity of operating conditions, and lowest design margin. The inspections will be scheduled as close to the end of the current operating license as practical with margin provided to ensure completion prior to commencing the period of extended operation **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005).**

e) The inspections will be scheduled as close to the end of the current operating license as practical with margin provided to ensure completion prior to commencing the period of extended operation. This ensures that the aging effects that may affect intended functions early in the period of extended operation are appropriately identified and managed **(PassPort AR 00330592.24.01, 02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22).**

f) The inspections will be scheduled as close to the end of the current operating license as practical with margin provided to ensure completion prior to commencing the period of extended operation. This ensures that the inspected components have attained sufficient age to ensure that the aging effects with long incubation periods (i.e., those that may affect intended functions near the end of the period of extended operation) are identified **(Reference: PassPort AR 00330592.24.01, 02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22).**

g) The inspections will be scheduled within 10 years prior to the period of extended operation, as close to the end of the current operating license as practical, with margin provided to ensure completion prior to commencing the period of extended operation. The inspection requirements may be satisfied by a review of maintenance records, repair or other inspection records to confirm that the component has been inspected for aging degradation and no significant degradation has occurred. This will only be applied when it has been confirmed that an inspected item has attained sufficient age to ensure that the aging effects with long incubation period can be identified **(Reference: PassPort AR 00330592.24.01, 02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22).**

<u>Exceptions to NUREG-1801, Element 4:</u>

NUREG-1801 states in XI.M32 that one-time inspection of Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping.*

NUREG-1801 aging management program XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping* will not be used at Oyster Creek. The new Oyster Creek One-Time Inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

NUREG-1801 references in XI.M32 and XI.M35 the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda for Subsections IWB, IWC, and IWD. The current Oyster Creek ISI Program Plan for the fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

<u>Enhancements to NUREG-1801, Element 4:</u>

None.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 4, Detection of Aging Effects with exceptions as described above.

3.4 Monitoring and Trending

<u>NUREG-1801:</u>

The program provides for increasing of the inspection sample size and locations in the event that aging effects are detected. Determination of the sample size is based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience. Unacceptable inspection findings are evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections and for monitoring and trending the results.

<u>Oyster Creek:</u>

The One-Time Inspection aging management program provides for the evaluation of the need for follow-up examinations and increased inspection sample size to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation. The determination of the sample size will be based on an assessment of materials of fabrication, environment, plausible aging effects, inspectability, dose considerations, and operating experience. Should aging effects be detected, the corrective action program triggers actions to characterize the nature and extent of the aging effect and determines what subsequent monitoring (including periodic inspection) is needed to ensure intended functions are maintained during the period of extended operation **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.01, 02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22).**

Exceptions to NUREG-1801, Element 5:

NUREG-1801 states in XI.M32 that one-time inspection of Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping.* NUREG-1801 aging management program XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping* will not be used at Oyster Creek. The new Oyster Creek One-Time Inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

NUREG-1801 references in XI.M32 and XI.M35 the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda for Subsections IWB, IWC, and IWD. The current Oyster Creek ISI Program Plan for the fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the* *approved September 2005 GALL.*

NUREG-1801 states in XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping,* that the guidelines of EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001 should be used for identifying piping susceptible to potential effects of thermal fatigue. EPRI Report 1000701 recommends specific locations for assessment and/or inspection where cracking and leakage has been identified in nominally stagnant non-isolable piping attached to reactor coolant systems in domestic and similar foreign PWRs. As Oyster Creek is a BWR, these inspection guidelines are not applicable. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

Enhancements to NUREG-1801, Element 5:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 5, Monitoring and Trending with exceptions as described above.

3.5 Acceptance Criteria

NUREG-1801:

a) *Any indication or relevant conditions of degradation detected are evaluated.*

b) *For example, the ultrasonic thickness measurements are to be compared to predetermined limits, such as the design minimum wall thickness for piping.*

Oyster Creek:

a) Results of the examinations will be evaluated by engineering to determine if loss of material or cracking is occurring. If loss of material or cracking is identified, engineering will determine the rate at which the material is being lost, or, the rate at which the crack is propagating, respectively. Engineering evaluations of the examination results will also a) determine the need for follow-up examinations to monitor the progression of aging degradation, b) identify appropriate corrective actions to mitigate any excessive rates of loss of material or cracking, and c) determine if repair/replacement is required. Corrective actions, if necessary, would expand to include other components **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.01, 02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22).**

b) Ultrasonic thickness measurements will be compared to predetermined limits, such as the design minimum wall thickness for piping **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.02, 03, 04, 05, 06, 07, 08, 09, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22).** For Class 1 piping, the Oyster Creek ISI program directs evaluation of examination results in accordance with the 1995 ASME Section XI Code, 1996 addenda. Examination results are evaluated in accordance with IWB-3131 by comparing the results with the acceptance standards of IWB-3400. Additional examinations are performed in accordance with IWB-2430. **(Reference: Oyster Creek License Renewal Project document "Inspection Sample Basis" dated 08/16/2005; PassPort AR 00330592.24.01, ER-AA-330-002, paragraph 4.10)** *This is a new requirement (from XI.M35) based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

<u>Exceptions to NUREG-1801, Element 6:</u>

NUREG-1801 states in XI.M32 that one-time inspection of Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping.* NUREG-1801 aging management program XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping* will not be used at Oyster Creek. The new Oyster Creek One-Time Inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

NUREG-1801 references in XI.M32 and XI.M35 the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda for Subsections IWB, IWC, and IWD. The current Oyster Creek ISI Program Plan for the fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

Enhancements to NUREG-1801, Element 6:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria with exceptions as described above.

3.6 Corrective Actions

NUREG-1801:

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

Oyster Creek:

Evaluations will be performed for inspection results that do not satisfy established criteria and a Issue Report (IR) will be initiated to document the concern in accordance with the Oyster Creek 10 CFR Part 50, Appendix B corrective action program. The 10 CFR Part 50, Appendix B corrective action program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined and an action plan is developed to preclude repetition.

Exceptions to NUREG-1801, Element 7:

None.

Enhancements to NUREG-1801, Element 7:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 7, Corrective Actions.

3.7 Confirmation Process

NUREG-1801:

See Item 7, above.

Oyster Creek:

See Item 7, above.

Exceptions to NUREG-1801, Element 8:

None.

Enhancements to NUREG-1801, Element 8:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 8, Confirmation Process.

3.8 Administrative Controls

NUREG-1801:

See Item 7, above.

Oyster Creek:

See Item 7, above.

Exceptions to NUREG-1801, Element 9:

None.

Enhancements to NUREG-1801, Element 9

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 9, Administrative Controls.

3.9 Operating Experience

NUREG-1801:

This program applies to potential aging effects for which there are currently no operating experience indicating the need for an aging management program. Nevertheless, the elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice.

Oyster Creek:

Operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek Operating Experience process. The Operating Experience process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The second way is through the process for managing programs. This process requires the review of program related operating experience by the program owner.

Both of these processes review operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

The One-Time Inspection aging management program applies to potential aging effects for which there is currently no operating experience indicating the need for an aging management program. Nevertheless, the elements that comprise these inspections (e.g., inspection techniques) are consistent with industry practice. The program inspections (visual, volumetric) are implemented using industry experience/techniques and the ASME Section XI code.

Specific Operating Experience and objective evidence does exist for attributes in which this program covers, such as the effectiveness of NDE techniques at identifying, confirming, and/or quantifying aging effects. The following examples of operating experience provide objective evidence that NDE is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation. These examples also demonstrate how the corrective action process is used to document and evaluate unacceptable NDE results.

- NDE UT testing of the #1 Fire Diesel Engine cooling water line showed areas that were below manufacturers tolerance for 1-1/2" schedule 80 carbon steel piping (Reference: CAP No. O2004-0161). An engineering evaluation was performed to address the operability of this line and it was concluded that sufficient wall thickness remained and that operability was not impacted. The affected piping was subsequently replaced. This example provides objective evidence that the NDE program identifies aging effects prior to the loss of intended function.
- While performing UT inspections of piping penetrating the Reactor Building wall, it was discovered that the wall thickness of a sump pump discharge line was below code required nominal (Reference: CAP No. O2001-1333). A computation was performed to determine the minimum required wall thickness, using system design pressure. The results show that approximately 85% of nominal wall thickness remained, which equated to a margin of 18 times the minimum required wall thickness. It was concluded that system operability and secondary containment operability was not affected by the condition in the short term, and, because of the large design margin, was not affected in the long term. This example provides objective evidence that deficiencies found during NDE are evaluated for impact on system operability and intended functions.
- An unisolable line from the fuel pool cooling skimmer surge tank was found to be corroded and required examination by UT to determine wall thickness (CAP No. O2000-1128). UT inspection results were

evaluated by engineering and determined to be acceptable. This example provides objective evidence that NDE is effectively utilized to confirm that aging effects will be identified prior to the loss of intended functions.

For objective evidence of the effectiveness of the ASME Section XI program (e.g., scope of the inspections and inspection techniques), see Program Basis Document PBD-AMP-B.1.01, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."

3.10 Conclusion

The new Oyster Creek One-Time Inspection aging management program is credited for managing the aging effects associated with the systems, components, materials, and environments listed in Table 5.2. The Oyster Creek One-Time Inspection aging management program's elements have been evaluated against NUREG-1801 in Section 3.0. Program exceptions have been identified in Section 2.3. There are no program enhancements. The implementing documents and commitment numbers for this aging management program are listed in Table 5.1. The relevant operating experience has been reviewed and a demonstration of program effectiveness is provided in Section 3.10.

Based on the above, the implementation of the Oyster Creek One-Time Inspection aging management program provides reasonable assurance that aging effects will be adequately managed so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

4.0 REFERENCES

4.1 Generic to Aging Management Programs

4.1.1 10 CFR 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants*

4.1.2 10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*

4.1.3 NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,* Revision 1, dated September 2005

4.1.4 NUREG-1801, *Generic Aging Lessons Learned (GALL)*

Report, Revision 1, dated September 2005

4.2 Industry Standards

4.2.1 EPRI Report 1000701, "*Interim Thermal Fatigue Management Guideline (MRP-24),*" January 2001

4.2.2 ASME Boiler and Pressure Vessel Code, Section XI, "Rules for In-service Inspection of Nuclear Plant Components," 1995 Edition through 1996 Addendum

4.3 Oyster Creek Program References

4.3.1 Document Number OC-1, Rev. 1 "ISI Program Plan, Oyster Creek Nuclear Generating Station, Fourth Interval"

4.3.2 Letter E. E. Fitzpatrick to USNRC, "Response to NRC Bulletin 88-08 and Supplement 1," dated August 19, 1988

4.3.3 Letter A. W. Dromerick, Sr. to J. J. Barton, "NRC Bulletin 88-08 Thermal Stresses in Piping Connected to Reactor Coolant Systems," dated September 18, 1991

5.0 TABLES

5.1 Aging Management Program Implementing Documents

Document Number	Description	Commitment Number	Status
N/A	One-Time Inspection: Treated Water/Steam (Class 1 piping less than four – inch nominal pipe size)	00330592.24.01	ACC/ASG
N/A	One-Time Inspection: Treated Water (Condensate System)	00330592.24.02	ACC/ASG
N/A	One-Time Inspection: Treated Water (Spent Fuel Pool Cooling and Cleanup System)	00330592.24.03	ACC/ASG

N/A	One-Time Inspection: Treated Water (Water Treatment & Distribution System)	00330592.24.04	ACC/ASG
N/A	One-Time Inspection: Treated Water/Steam (Main Steam System)	00330592.24.05	ACC/ASG
N/A	One-Time Inspection: Treated Water (Control Rod Drive System)	00330592.24.06	ACC/ASG
N/A	One-Time Inspection: Treated Water (Reactor Water Cleanup System)	00330592.24.07	ACC/ASG
N/A	One-Time Inspection: Treated Water/Steam (Isolation Condenser System)	00330592.24.08	ACC/ASG
N/A	One-Time Inspection: Boiler Treated Water/Aux. Steam (Heating & Process Steam System)	00330592.24.09	ACC/ASG
N/A	One-Time Inspection: Boiler Treated Water/Aux. Steam > 140F (Heating & Process Steam System)	00330592.24.10	ACC/ASG
N/A	One-Time Inspection: Sodium Pentaborate (Standby Liquid Control System)	00330592.24.11	ACC/ASG
N/A	One-Time Inspection: Closed Cooling Water Environment (Process Sampling System)	00330592.24.12	ACC/ASG
N/A	One-Time Inspection: Closed Cooling Water Environment (RBCCW System)	00330592.24.13	ACC/ASG

N/A	One-Time Inspection: Closed Cooling Water Environment (TBCCW System)	00330592.24.14	ACC/ASG
N/A	One-Time Inspection: Closed Cooling Water Environment (Emergency Diesel Generator and Aux System)	00330592.24.15	ACC/ASG
N/A	One-Time Inspection: Fuel Oil (Emergency Diesel Generator and Auxiliary System)	00330592.24.16	ACC/ASG
N/A	One-Time Inspection: Fuel Oil (Fire Protection System)	00330592.24.17	ACC/ASG
N/A	One-Time Inspection: Fuel Oil (Main Fuel Oil System)	00330592.24.18	ACC/ASG
N/A	One-Time Inspection: Lubricating Oil (Various Systems)	00330592.24.19	ACC/ASG
N/A	One-Time Inspection: Condensation (H2O2 System)	00330592.24.20	ACC/ASG
N/A	One-Time Inspection: Indoor Air (Various Systems)	00330592.24.21	ACC/ASG
N/A	One-Time Inspection: Raw Water – Fresh Water (Various Systems)	00330592.24.22	ACC/ASG

5.2 Aging Management Review Results

SSC Name	Structure and/or Component	Material	Environment	Aging Effect
Condensate System	Heat Exchangers	Carbon and low alloy steel - Tube side components	Treated Water (Internal)	Loss of Material
Condensate System	Restricting Orifice	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Condensate System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Condensate System	Valve Body	Cast Iron	Treated Water (Internal)	Loss of Material
Condensate System	Flow Element	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Condensate System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Condensate System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Condensate System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Condensate System	Filter Housing	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Condensate System	Strainer Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Condensate System	Thermowell	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Condensate System	Strainer Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Condensate System	Sensor Element	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Condensate System	Tanks	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Condensate System	Pump Casing	Cast Iron	Treated Water (Internal)	Loss of Material
Condensate System	Tanks	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Tanks	Aluminum	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Restricting Orifice	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Gauge Snubber	Stainless Steel	Treated Water <140F (Internal)	Loss of Material

Condensate Transfer System	Restricting Orifice	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Restricting Orifice	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Piping and fittings	Aluminum	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Piping and fittings	Aluminum	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Valve Body	Aluminum	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Valve Body	Aluminum Bronze	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Pump Casing	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Condensate Transfer System	Valve Body	Aluminum	Treated Water <140F (Internal)	Loss of Material
Containment Spray System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Containment Spray System	Strainer (ECCS Suction)	Stainless Steel	Treated Water < 140F (External)	Loss of Material
Containment Spray System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Containment Spray System	Pump Casing	Carbon and low alloy steel	Treated Water < 140F (External)	Loss of Material
Containment Spray System	Strainer (ECCS Suction)	Stainless Steel	Treated Water < 140F (External)	Loss of Material

Containment Spray System	Strainer (ECCS Suction)	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Containment Spray System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Containment Spray System	Thermowell	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Containment Spray System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Containment Spray System	Strainer (ECCS Suction)	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Containment Spray System	Pump Casing	Cast Iron	Treated Water <140F (Internal)	Loss of Material
Containment Spray System	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Containment Vacuum Breakers	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Containment Vacuum Breakers	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Control Rod Drive System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Control Rod Drive System	Valve Body	Brass	Treated Water (Internal)	Loss of Material
Control Rod Drive System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Control Rod Drive System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Control Rod Drive System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Control Rod Drive System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Control Rod Drive System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Control Rod Drive System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Valve Body	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Control Rod Drive System	Pump Casing	Carbon and low alloy steel (Oil pump)	Lubricating Oil (Internal)	Loss of Material
Control Rod Drive System	Piping and fittings	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material

Control Rod Drive System	Gear Box	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Control Rod Drive System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Accumulator	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Restricting Orifice	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Restricting Orifice	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Strainer Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Control Rod Drive System	Strainer	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Control Rod Drive System	Strainer	Stainless Steel	Treated Water < 140F (External)	Loss of Material
Control Rod Drive System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Control Rod Drive System	Gauge Snubber	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Pump Casing	Stainless Steel (CRD pump)	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Filter Housing	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Filter	Stainless Steel	Treated Water < 140F (External)	Loss of Material
Control Rod Drive System	Filter	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Accumulator	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Control Rod Drive System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Control Rod Drive System	Strainer Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Control Rod Drive System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material

Core Spray System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Core Spray System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Core Spray System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Core Spray System	Sight Glasses	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Restricting Orifice	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Pump Casing (Main and Booster Pumps)	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Valve Body	CASS	Treated Water (Internal)	Loss of Material
Core Spray System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Core Spray System	Thermowell	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Gauge Snubber	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Core Spray System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Core Spray System	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Cyclone Separator	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Pump Casing (Fill Pumps)	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Core Spray System	Restricting Orifice	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Valve Body	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material

Drywell Floor and Equipment Drains	Heat Exchanger (DWEDT)	Carbon and low alloy steel (Covers)	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Valve Body	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Piping and fittings	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Heat Exchanger (DWEDT)	Stainless Steel (Nozzles, Plates)	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Piping and fittings	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Piping and fittings	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Valve Body	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Flow Glass	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Valve Body	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Pump Casing (DWEDT pumps)	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Tanks (DWEDT)	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Flow Element	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Drywell Floor and Equipment Drains	Piping and fittings	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Valve Body	Aluminum	Fuel Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Valve Body	Stainless Steel	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Heat Exchanger (Lube Oil Cooler)	Brass (tubes)	Lubricating Oil (External)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Heat Exchanger (Lube Oil Cooler)	Carbon and low alloy steel (shell side components)	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Pump Casing (Lube Oil)	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Restricting Orifice	Brass	Lubricating Oil (Internal)	Loss of Material

Emergency Diesel Generator and Auxiliary System	Valve Body	Brass	Fuel Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Sensor Element (Lube Oil)	Aluminum	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Piping and fittings	Stainless Steel	Closed Cooling Water (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Sensor Element (Lube Oil)	Stainless Steel	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Strainer Body	Aluminum	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Strainer Body	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Strainer Body	Carbon and low alloy steel	Fuel Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Strainer Body	Aluminum	Fuel Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Restricting Orifice	Brass	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Piping and fittings	Carbon and low alloy steel	Fuel Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Flexible Hose	Carbon and low alloy steel	Fuel Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Tanks (Immersion Heater)	Carbon and low alloy steel	Closed Cooling Water (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Strainer	Stainless Steel	Lubricating Oil (External)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Tanks (Water Tank)	Carbon and low alloy steel	Closed Cooling Water (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Valve Body	Brass	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Valve Body	Carbon and low alloy steel	Fuel Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Filter Housing (Fuel Oil)	Carbon and low alloy steel	Fuel Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Piping and fittings	Carbon and low alloy steel	Closed Cooling Water (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Piping and fittings	Stainless Steel	Lubricating Oil (Internal)	Loss of Material

Emergency Diesel Generator and Auxiliary System	Piping and fittings	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Piping and fittings	Carbon and low alloy steel	Fuel Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Pump Casing (Fuel Oil)	Carbon and low alloy steel	Fuel Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Filter Housing (Lube Oil)	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Sight Glasses	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Temperature Control Manifold (Water Cooling)	Carbon and low alloy steel	Closed Cooling Water (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Valve Body	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Emergency Diesel Generator and Auxiliary System	Valve Body	Carbon and low alloy steel	Fuel Oil (Internal)	Loss of Material
Emergency Service Water System	Heat Exchangers (Containment Spray)	Carbon and low alloy steel (Shell Side Components)	Treated Water (Internal)	Loss of Material
Feedwater System	Strainer Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Feedwater System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Feedwater System	Filter Housing	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Feedwater System	Tanks	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Feedwater System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Feedwater System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Feedwater System	Piping and fittings	Chrome Moly steels	Treated Water (Internal)	Loss of Material
Feedwater System	Piping and fittings	Chrome Moly steels	Treated Water (Internal)	Loss of Material
Feedwater System	Piping and fittings	Chrome Moly steels	Treated Water (Internal)	Cracking Initiation and Growth
Feedwater System	Filter Housing	Stainless Steel	Treated Water (Internal)	Loss of Material
Feedwater System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Feedwater System	Dissolution Column	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Feedwater System	Heat Exchangers	Carbon and low alloy steel - Tube Side Components	Treated Water (Internal)	Loss of Material
Feedwater System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth

Feedwater System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Feedwater System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Feedwater System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Feedwater System	Flow Element	Stainless Steel	Treated Water (Internal)	Loss of Material
Feedwater System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Feedwater System	Pump Casing	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Feedwater System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Feedwater System	Flow Element	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Feedwater System	Expansion Joint	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Feedwater System	Pump Casing	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Feedwater System	Flow Element	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Feedwater System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Feedwater System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Feedwater System	Valve Body	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Feedwater System	Piping and fittings	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Feedwater System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Feedwater System	Thermowell	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Feedwater System	Thermowell	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Feedwater System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Feedwater System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Feedwater System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Feedwater System	Expansion Joint	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Fire Protection System	Gear Box	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Fire Protection System	Heat Exchangers	Copper Alloy (Tubes)	Lubricating Oil (Internal)	Loss of Material
Fire Protection System	Valve Body	Bronze	Fuel Oil (Internal)	Loss of Material

Fuel Storage and Handling Equipment	Fuel Preparation Machine	Aluminum	Treated Water < 140F (External)	Loss of Material
Fuel Storage and Handling Equipment	Fuel Preparation Machine	Stainless Steel	Treated Water < 140F (External)	Loss of Material
Fuel Storage and Handling Equipment	Fuel Grapple/Mast	Stainless Steel	Treated Water < 140F (External)	Loss of Material
Fuel Storage and Handling Equipment	Cask Drop Protection Cylindrical Structure	Stainless Steel	Treated Water < 140F	Loss of Material
Fuel Storage and Handling Equipment	Spent Fuel Storage Racks	Stainless Steel	Treated Water < 140F (External)	Loss of Material
Hardened Vent System	Valve Body	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Hardened Vent System	Piping and fittings	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Heating & Process Steam System	Soot Blowers	Carbon and low alloy steel	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Valve Body	Stainless Steel	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Valve Body	Stainless Steel	Boiler Treated Water (Internal)	Cracking Initiation and Growth
Heating & Process Steam System	Valve Body	Cast Iron	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Valve Body	Copper Alloy	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Valve Body	Copper Alloy	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Strainer Body	Carbon and low alloy steel	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Valve Body	Stainless Steel	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Valve Body	Stainless Steel	Auxiliary Steam (Internal)	Cracking Initiation and Growth
Heating & Process Steam System	Valve Body	Cast Iron	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Strainer Body	Carbon and low alloy steel	Boiler Treated Water (Internal)	Loss of Material

Heating & Process Steam System	Tanks - Deaerator CH-T-2, Condensate Return Unit T-13-1, Heating Boiler Condensate Storage Tank T-13-2, Heating Boiler Flash Tank T-13-3	Carbon and low alloy steel	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Piping and fittings	Stainless Steel	Boiler Treated Water (Internal)	Cracking Initiation and Growth
Heating & Process Steam System	Steam Trap	Copper Alloy	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Piping and fittings	Stainless Steel	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Piping and fittings	Stainless Steel	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Restricting Orifice	Stainless Steel	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Tanks - Deaerator CH-T-2, Condensate Return Unit T-13-1, Heating Boiler Condensate Storage Tank T-13-2, Heating Boiler Flash Tank T-13-3	Carbon and low alloy steel	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Steam Trap	Cast Iron	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Steam Trap	Cast Iron	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Strainer Body	Cast Iron	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Strainer Body	Cast Iron	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Valve Body	Carbon and low alloy steel	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Valve Body	Carbon and low alloy steel	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Steam Trap	Copper Alloy	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Pump Casing - Chemical Addition Pump CH-P-11	Stainless Steel	Boiler Treated Water <140F (Internal)	Loss of Material

Heating & Process Steam System	Pump Casing - Condensate Return Pumps P-13-1A/B, Chemical Feed Addition Pumps CH-P-6A/B, Boiler No. 1 Feed Pumps CH-P-4A/B, Boiler No. 2 Feed Pumps CH-P-3A/B, Deaerator Feed Pumps CH-P-5A/B, Chemical Recirc Pump CH-P-10	Cast Iron	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Flow Element	Stainless Steel	Boiler Treated Water (Internal)	Cracking Initiation and Growth
Heating & Process Steam System	Restricting Orifice	Stainless Steel	Boiler Treated Water (Internal)	Cracking Initiation and Growth
Heating & Process Steam System	Flow Element	Stainless Steel	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Piping and fittings	Stainless Steel	Auxiliary Steam (Internal)	Cracking Initiation and Growth
Heating & Process Steam System	Piping and fittings	Carbon and low alloy steel	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Piping and fittings	Carbon and low alloy steel	Auxiliary Steam (Internal)	Loss of Material
Heating & Process Steam System	Coolers (Sample)	Copper	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Sight Glasses	Carbon and low alloy steel	Boiler Treated Water (Internal)	Loss of Material
Heating & Process Steam System	Heat Exchangers	Copper	Auxiliary Steam (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Valve Body	Stainless Steel	Condensation (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Filter Housing (O2 Analyzers)	Stainless Steel	Condensation (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Drain Trap (O2 Analyzers)	Stainless Steel	Condensation (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Piping and fittings	Stainless Steel	Condensation (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Pump Casing	Stainless Steel	Condensation (Internal)	Loss of Material

Hydrogen & Oxygen Monitoring System	Water Separator (O2 Analyzers)	Stainless Steel	Condensation (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Heat Exchangers (Air Cooled)	Stainless Steel	Condensation (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Flow Element	Stainless Steel	Condensation (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Moisture Separator (H2O2 Analyzers)	Stainless Steel	Condensation (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Piping and fittings	Stainless Steel	Condensation (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Tanks (Volume Chamber)	Stainless Steel	Condensation (Internal)	Loss of Material
Hydrogen & Oxygen Monitoring System	Valve Body	Stainless Steel	Condensation (Internal)	Loss of Material
Isolation Condenser System	Piping and fittings	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Isolation Condenser System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Isolation Condenser System	Valve Body	CASS	Treated Water (Internal)	Loss of Material
Isolation Condenser System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Isolation Condenser System	Piping and fittings	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Isolation Condenser System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Isolation Condenser System	Gauge Snubber	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Isolation Condenser System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Thermowell	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth

Isolation Condenser System	Thermowell	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Isolation Condenser System	Valve Body	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Valve Body	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Piping and fittings	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Heat Exchangers (isolation condensers)	Carbon and low alloy steel (Shell Side Components)	Treated Water <140F (Internal)	Loss of Material
Isolation Condenser System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Isolation Condenser System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Isolation Condenser System	Thermowell	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Isolation Condenser System	Thermowell	Stainless Steel	Treated Water (Internal)	Loss of Material
Isolation Condenser System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Isolation Condenser System	Heat Exchangers (isolation condensers)	Carbon and low alloy steel (Shell Side Components)	Indoor Air (Internal)	Loss of Material
Isolation Condenser System	Valve Body	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Isolation Condenser System	Piping and fittings	Stainless Steel	Steam (Internal)	Loss of Material
Isolation Condenser System	Valve Body	CASS	Steam (Internal)	Loss of Material
Isolation Condenser System	Valve Body	Stainless Steel	Steam (Internal)	Loss of Material
Isolation Condenser System	Piping and fittings	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Main Fuel Oil Storage & Transfer System	Strainer Body	Cast Iron	Fuel Oil (Internal)	Loss of Material
Main Fuel Oil Storage & Transfer System	Valve Body	Carbon and low alloy steel	Fuel Oil (Internal)	Loss of Material

Main Fuel Oil Storage & Transfer System	Pump Casing	Cast Iron	Fuel Oil (Internal)	Loss of Material
Main Fuel Oil Storage & Transfer System	Sight Glasses	Brass	Fuel Oil (Internal)	Loss of Material
Main Fuel Oil Storage & Transfer System	Flow Meter	Cast Iron	Fuel Oil (Internal)	Loss of Material
Main Fuel Oil Storage & Transfer System	Piping and fittings	Carbon and low alloy steel	Fuel Oil (Internal)	Loss of Material
Main Generator and Auxiliary System	Strainer Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Generator and Auxiliary System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Generator and Auxiliary System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Generator and Auxiliary System	Valve Body	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Generator and Auxiliary System	Tanks	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Generator and Auxiliary System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Generator and Auxiliary System	Filter Housing	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Generator and Auxiliary System	Piping and fittings	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Generator and Auxiliary System	Flow Element	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Generator and Auxiliary System	Tanks	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Generator and Auxiliary System	Gauge Snubber	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Generator and Auxiliary System	Heat Exchangers	Carbon and low alloy steel - Shell Side Components	Treated Water (Internal)	Loss of Material
Main Generator and Auxiliary System	Pump Casing	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Generator and Auxiliary System	Pump Casing	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Generator and Auxiliary System	Sensor Element (CE)	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material

Main Generator and Auxiliary System	Restricting Orifice	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Generator and Auxiliary System	Filter Housing	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Steam System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Steam System	Coolers (Sample)	Stainless Steel (Tube Side Components)	Steam (Internal)	Loss of Material
Main Steam System	Piping and fittings	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Eductor	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Steam Trap	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Steam System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Steam System	Strainer Body	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Steam Trap	Chrome Moly steels	Treated Water (Internal)	Loss of Material
Main Steam System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Main Steam System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Steam System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Steam System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Steam System	Sparger (Y-Quencher)	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Steam System	Sparger (Y-Quencher)	Carbon and low alloy steel	Treated Water (External)	Loss of Material
Main Steam System	Valve Body (Bypass Valves)	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Valve Body	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Main Steam System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Steam System	Piping and fittings	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Gauge Snubber	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Main Steam System	Piping and fittings	Carbon and low alloy steel	Treated Water (External)	Loss of Material
Main Steam System	Steam Trap	Chrome Moly steels	Steam (Internal)	Loss of Material
Main Steam System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material

Main Steam System	Valve Body	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Condensing chamber	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Steam System	Condensing chamber	Stainless Steel	Steam (Internal)	Loss of Material
Main Steam System	Condensing chamber	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Steam System	Condensing chamber	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Valve Body (Steam Chest)	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Coolers (Sample)	Stainless Steel (Tube Side Components)	Steam (Internal)	Cracking Initiation and Growth
Main Steam System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Steam System	Piping and fittings	Carbon and low alloy steel	Steam (Internal)	Cracking Initiation and Growth
Main Steam System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Steam System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Steam System	Flow Element (Main Steam Line)	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Condensing chamber	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Steam System	Steam Trap	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Condensing chamber	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Main Steam System	Condensing chamber	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Main Steam System	Flow Element (Main Steam Line)	CASS	Steam	Loss of Material
Main Steam System	Condensing chamber	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Steam System	Flow Element (Main Steam Line)	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Steam System	Valve Body	Carbon and low alloy steel	Steam (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Valve Body	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Pump Casing	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material

Main Turbine and Auxiliary System	Flexible Hose	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Filter Housing	Stainless Steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Piping and fittings	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Pump Casing	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Valve Body	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Thermowell	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Flow Element	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Piping and fittings	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Thermowell	Stainless Steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Restricting Orifice	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Restricting Orifice	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Heat Exchangers	Carbon and low alloy steel - Shell side component	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Heat Exchangers	Carbon and low alloy steel - Shell side component	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Expansion Joint	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Steam Trap	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Tanks	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material

Main Turbine and Auxiliary System	Strainer Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Thermowell	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Flow Element	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Thermowell	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Thermowell	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Filter Housing	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Expansion Joint	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Expansion Joint	Stainless Steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Expansion Joint	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Valve Body	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Piping and fittings	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Flexible Hose	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Pump Casing	Stainless Steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Tanks	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Turbine Casing	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Thermowell	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Piping and fittings	Stainless Steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Valve Body	Carbon and low alloy steel	Steam (Internal)	Loss of Material

Main Turbine and Auxiliary System	Valve Body	Stainless Steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Coolers	Carbon and low alloy steel - Shell side Component	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Strainer Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Piping and fittings	Stainless Steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Accumulator	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Strainer Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Restricting Orifice	Stainless Steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Flow Element	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Main Turbine and Auxiliary System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Tanks	Stainless Steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Valve Body	Stainless Steel	Lubricating Oil (Internal)	Loss of Material
Main Turbine and Auxiliary System	Steam Trap	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Steam Trap	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Restricting Orifice	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Main Turbine and Auxiliary System	Strainer Body	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Strainer Body	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Heat Exchangers	Carbon and low alloy steel - Shell side component	Steam (Internal)	Loss of Material
Main Turbine and Auxiliary System	Piping and fittings	Carbon and low alloy steel	Steam (Internal)	Loss of Material

Main Turbine and Auxiliary System	Tanks	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Valve Body	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Valve Body	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Strainer Body	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Tanks (Regeneration System Waste Tank 1-1 Low and High Conductivity Compartments)	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Pump Casing (Laundry Drain Tank Pump P-22-002)	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Strainer Body	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Pump Casings (Regeneration Waste Transfer Pumps P-22-28A,B and P-22-29A,B)	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Flexible Hose	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Valve Body	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Valve Body	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Piping and fittings	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Tanks (Lab Drain Tank T-22-003)	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Piping and fittings	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Tanks (Laundry Drain Tank T-22-002)	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Tanks (Oil Separator DS-Y-105 and Oil Receiver DS-T-1)	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Piping and fittings	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Miscellaneous Floor and Equipment Drain System	Pump Casing (Lab Drain Tank Pump P-22-003)	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material

Miscellaneous Floor and Equipment Drain System	Piping and fittings	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Nitrogen Supply System	Drip Leg	Stainless Steel	Condensation (Internal)	Loss of Material
Nitrogen Supply System	Piping and fittings	Stainless Steel	Condensation (Internal)	Loss of Material
Nitrogen Supply System	Valve Body	Stainless Steel	Condensation (Internal)	Loss of Material
Noble Metals Monitoring System	Flow Element	Stainless Steel	Treated Water (Internal)	Loss of Material
Noble Metals Monitoring System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Noble Metals Monitoring System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Noble Metals Monitoring System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Noble Metals Monitoring System	Sensor Element	Stainless Steel	Treated Water (Internal)	Loss of Material
Nuclear Boiler Instrumentation	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Nuclear Boiler Instrumentation	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Nuclear Boiler Instrumentation	Condensing chamber	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Nuclear Boiler Instrumentation	Condensing chamber	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Nuclear Boiler Instrumentation	Condensing chamber	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Nuclear Boiler Instrumentation	Piping and fittings	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Nuclear Boiler Instrumentation	Condensing chamber	Stainless Steel	Steam (Internal)	Loss of Material
Nuclear Boiler Instrumentation	Piping and fittings	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Nuclear Boiler Instrumentation	Condensing chamber	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Nuclear Boiler Instrumentation	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Nuclear Boiler Instrumentation	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Nuclear Boiler Instrumentation	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material

Nuclear Boiler Instrumentation	Condensing chamber	Stainless Steel	Treated Water (Internal)	Loss of Material
Nuclear Boiler Instrumentation	Gauge Snubber	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Nuclear Boiler Instrumentation	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Nuclear Boiler Instrumentation	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Nuclear Boiler Instrumentation	Piping and fittings	Stainless Steel	Steam (Internal)	Loss of Material
Nuclear Boiler Instrumentation	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Post-Accident Sampling System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Post-Accident Sampling System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Post-Accident Sampling System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Post-Accident Sampling System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Post-Accident Sampling System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Post-Accident Sampling System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Post-Accident Sampling System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Post-Accident Sampling System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Post-Accident Sampling System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Post-Accident Sampling System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Post-Accident Sampling System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Post-Accident Sampling System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Post-Accident Sampling System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Post-Accident Sampling System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth

Primary Containment	Thermowells	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Thermowells	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Process Sampling System	Piping and fittings	Carbon and low alloy steel	Closed Cooling Water < 140F (Internal)	Loss of Material
Process Sampling System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Process Sampling System	Piping and fittings	Stainless Steel	Closed Cooling Water < 140F (Internal)	Loss of Material
Process Sampling System	Thermowell	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Process Sampling System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Process Sampling System	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Process Sampling System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Process Sampling System	Flexible Hose	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Process Sampling System	Coolers	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Process Sampling System	Sensor Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Building	Fuel Pool Gates	Aluminum	Treated Water < 140F (External)	Loss of Material
Reactor Building	Fuel Pool Skimmer Surge Tank Liner	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Heat Exchangers (Shutdown Cooling)	Stainless Steel (Tube Sheet)	Treated Water <140F	Loss of Material
Reactor Building Closed Cooling Water System	Heat Exchangers (Fuel Pool Cooling)	Carbon Steel (Tubes)	Treated Water (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Heat Exchangers (Shutdown Cooling)	Carbon Steel (Tube Side Components)	Treated Water (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Heat Exchangers (Fuel Pool Cooling)	Carbon Steel (Tube Side Components)	Treated Water (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Piping and fittings	Stainless Steel	Closed Cooling Water < 140F (Internal)	Loss of Material

Reactor Building Closed Cooling Water System	Piping and fittings	Carbon and low alloy steel	Closed Cooling Water (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Coolers (Shutdown Cooling Pumps)	Copper (Seal Cooler Tubes and Tube Side Components)	Treated Water (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Coolers (Shutdown Cooling Pumps)	Cast Iron (Bearing Housing Cooler)	Lubricating Oil (External)	Loss of Material
Reactor Building Closed Cooling Water System	Piping and fittings	Carbon and low alloy steel	Closed Cooling Water (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Heat Exchangers (Augmented Fuel Pool Cooling)	Carbon Steel (Covers, Nozzles)	Treated Water (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Heat Exchangers (Augmented Fuel Pool Cooling)	Stainless Steel (Plates)	Treated Water < 140F (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Piping and fittings	Cast Iron	Closed Cooling Water (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Heat Exchangers (Shutdown Cooling)	Stainless Steel (Tubes)	Treated Water <140F (Internal)	Loss of Material
Reactor Building Closed Cooling Water System	Piping and fittings	Stainless Steel	Closed Cooling Water <140F (Internal)	Loss of Material
Reactor Building Floor and Equipment Drains	Piping and fittings	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Reactor Building Floor and Equipment Drains	Valve Body	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Reactor Building Floor and Equipment Drains	Valve Body	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Reactor Building Floor and Equipment Drains	Valve Body	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Reactor Building Floor and Equipment Drains	Piping and fittings	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Reactor Building Floor and Equipment Drains	Tanks (RBEDT)	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Reactor Building Floor and Equipment Drains	Pump Casing (RBEDT pump)	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Reactor Building Floor and Equipment Drains	Piping and fittings	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Reactor Building Floor and Equipment Drains	Piping and fittings	Stainless Steel	Raw Water – Fresh Water (Internal)	Loss of Material
Reactor Building Floor and Equipment Drains	Piping and fittings	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material

Reactor Building Floor and Equipment Drains	Valve Body	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Reactor Building Ventilation System	Piping and fittings (Primary Containment Isolation Valves)	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Reactor Head Cooling System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Restricting Orifice	Stainless Steel	Steam (Internal)	Loss of Material
Reactor Head Cooling System	Restricting Orifice	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Restricting Orifice	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Restricting Orifice	Stainless Steel	Steam (Internal)	Loss of Material
Reactor Head Cooling System	Restricting Orifice	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Restricting Orifice	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Valve Body	CASS	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Head Cooling System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Reactor Head Cooling System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Piping and fittings	Stainless Steel	Steam (Internal)	Loss of Material
Reactor Head Cooling System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Reactor Head Cooling System	Valve Body	CASS	Treated Water (Internal)	Loss of Material
Reactor Head Cooling System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Reactor Head Cooling System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Reactor Head Cooling System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material

Reactor Head Cooling System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Piping and fittings	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Valve Body	CASS	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Head Cooling System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Head Cooling System	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Head Cooling System	Piping and fittings	Stainless Steel	Steam (Internal)	Cracking Initiation and Growth
Reactor Pressure Vessel	Nozzle (Bottom head drain)	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Reactor Pressure Vessel	Nozzle Safe Ends (Feedwater & Main Steam)	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Reactor Pressure Vessel	Nozzles (Feedwater)	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Reactor Pressure Vessel	Nozzles (Main Steam)	Carbon and low alloy steel	Steam (Internal)	Loss of Material
Reactor Recirculation System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Reactor Recirculation System	Thermowell	Stainless Steel	Treated Water (Internal)	Loss of Material
Reactor Recirculation System	Sight Glasses (oil)	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Reactor Recirculation System	Pump Casing	CASS	Treated Water >482F (Internal)	Loss of Material
Reactor Recirculation System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Reactor Recirculation System	Flow Element	Stainless Steel	Treated Water (Internal)	Loss of Material
Reactor Recirculation System	Thermowell	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Recirculation System	Thermowell	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Recirculation System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Recirculation System	Fluid Drive (M-G Set Coupling) Reservoir	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Reactor Recirculation System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Reactor Recirculation System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth

Reactor Recirculation System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Recirculation System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Recirculation System	Coolers (oil)	Carbon and low alloy steel	Lubricating Oil (Internal) - shell side components	Loss of Material
Reactor Recirculation System	Piping and fittings	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Reactor Recirculation System	Oil Mist Eliminator - Reservoir	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Reactor Recirculation System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Recirculation System	Valve Body	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Reactor Recirculation System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Recirculation System	Valve Body	CASS	Treated Water >482F (Internal)	Loss of Material
Reactor Recirculation System	Filter Housing (oil)	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Reactor Recirculation System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Reactor Water Cleanup System	Heat Exchangers (Cleanup Regenerative)	Stainless Steel (Shell Side Components)	Treated Water (Internal)	Loss of Material
Reactor Water Cleanup System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Valve Body	CASS	Treated Water >482F (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Valve Body	CASS	Treated Water >482F (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Coolers (Cleanup Pre-coat Pump)	Stainless Steel (Tube Side Components)	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Tanks (Cleanup Filter Aid Mix Tank)	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Tanks (Cleanup Recirc. Pump Surge Tank)	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material

Reactor Water Cleanup System	Sight Glasses	Carbon and low alloy steel (Body)	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Sight Glasses	Stainless Steel (Body)	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Strainer Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Strainer Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Filter Housing (Cleanup Filter)	Carbon Steel (with elastomer lining)	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Pump Casing (Cleanup Filter Aid Pumps)	Cast Iron	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Pump Casing (Cleanup Sludge Pump)	Cast Iron	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Pump Casing (Cleanup Filter Precoat Pump)	Cast Iron	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Tanks (Cleanup Backwash Tank)	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Pump Casing (Cleanup Recirc Pumps)	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Demineralizer (Cleanup Demineralizer)	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Heat Exchangers (Cleanup Regenerative)	Stainless Steel (Tube Side Components)	Treated Water (Internal)	Loss of Material
Reactor Water Cleanup System	Heat Exchangers (Cleanup Regenerative)	Stainless Steel (Shell Side Components)	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Reactor Water Cleanup System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Heat Exchangers (Cleanup Regenerative)	Stainless Steel (Tube Side Components)	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material

Reactor Water Cleanup System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Gauge Snubber	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Heat Exchangers (Cleanup Non-Regenerative)	Stainless Steel (Tube Side Components)	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Heat Exchangers (Cleanup Non-Regenerative)	Stainless Steel (Tube Side Components)	Treated Water (Internal)	Loss of Material
Reactor Water Cleanup System	Piping and fittings	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Reactor Water Cleanup System	Pump Casing (Cleanup Auxiliary Pump)	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Reactor Water Cleanup System	Restricting Orifice	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Thermowell	Stainless Steel	Treated Water (Internal)	Loss of Material
Reactor Water Cleanup System	Sensor Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Piping and fittings	Carbon and low alloy steel	Treated Water < 140F (External)	Loss of Material
Reactor Water Cleanup System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Reactor Water Cleanup System	Valve Body	CASS	Treated Water >482F (Internal)	Loss of Material
Reactor Water Cleanup System	Valve Body	CASS	Treated Water >482F (Internal)	Loss of Material
Reactor Water Cleanup System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Valve Body	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Reactor Water Cleanup System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material

Reactor Water Cleanup System	Valve Body	Copper Alloy	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Tanks (Cleanup Recirc. Pumps Lube Oil)	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Reactor Water Cleanup System	Coolers (Cleanup Recirc. Pumps Lube Oil)	Carbon Steel (Shell Side Components)	Lubricating Oil (Internal)	Loss of Material
Reactor Water Cleanup System	Piping and fittings	Copper Alloy	Lubricating Oil (Internal)	Loss of Material
Reactor Water Cleanup System	Valve Body	Cast Iron	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Tanks (Cleanup Filter and Precoat Tank)	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Reactor Water Cleanup System	Tanks (Cleanup Filter Sludge Receiver)	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Roof Drains and Overboard Discharge	Piping and fittings	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Roof Drains and Overboard Discharge	Piping and fittings	Carbon and low alloy steel	Raw Water – Fresh Water (Internal)	Loss of Material
Sanitary Waste System	Piping and fittings	Cast Iron	Raw Water – Fresh Water (Internal)	Loss of Material
Service Water System	Piping and fittings	Copper Alloy	Lubricating Oil (Internal)	Loss of Material
Service Water System	Valve Body	Copper Alloy	Lubricating Oil (Internal)	Loss of Material
Service Water System	Valve Body	Aluminum	Lubricating Oil (Internal)	Loss of Material
Service Water System	Tanks (Service Water Pump Oil Reservoir)	Aluminum	Lubricating Oil (Internal)	Loss of Material
Service Water System	Piping and fittings	Carbon and low alloy steel	Lubricating Oil (Internal)	Loss of Material
Shutdown Cooling System	Flow Element	Stainless Steel	Treated Water (Internal)	Loss of Material
Shutdown Cooling System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Shutdown Cooling System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Shutdown Cooling System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Restricting Orifice	Stainless Steel	Treated Water (Internal)	Loss of Material
Shutdown Cooling System	Thermowell	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material

Shutdown Cooling System	Pump Casing	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Shutdown Cooling System	Flow Element	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Shutdown Cooling System	Flow Element	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Flow Element	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Shutdown Cooling System	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Shutdown Cooling System	Restricting Orifice	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Restricting Orifice	Stainless Steel	Treated Water (Internal)	Loss of Material
Shutdown Cooling System	Restricting Orifice	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Valve Body	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Shutdown Cooling System	Flow Element	Carbon and low alloy steel	Treated Water (Internal)	Cracking Initiation and Growth
Shutdown Cooling System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Diffuser	Aluminum	Treated Water < 140F (External)	Loss of Material
Spent Fuel Pool Cooling System	Piping and fittings	Aluminum	Treated Water < 140F (External)	Loss of Material
Spent Fuel Pool Cooling System	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material

Spent Fuel Pool Cooling System	Piping and fittings	Aluminum	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Valve Body	Aluminum	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Piping and fittings	Aluminum	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Piping and fittings	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Valve Body	Aluminum	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Diffuser	Aluminum	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Thermowells	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Pump Casing (Fuel Pool *Cooling Pumps & Augmented* Fuel Pool Cooling Pumps)	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Spent Fuel Pool Cooling System	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Pump Casing	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Accumulator	Alloy Steel	Treated Water <140F (Internal)	Loss of Material

Standby Liquid Control System (Liquid Poison System)	Valve Body	Stainless Steel	Sodium Pentaborate (Internal)	Cracking Initiation and Growth
Standby Liquid Control System (Liquid Poison System)	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Thermowell	Stainless Steel	Sodium Pentaborate (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Tanks (Liquid Poison Test Tank)	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Tanks (Liquid Poison Tank)	Stainless Steel	Sodium Pentaborate (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Valve Body	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Valve Body	Stainless Steel	Sodium Pentaborate (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Piping and fittings	Stainless Steel	Sodium Pentaborate (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Thermowell	Stainless Steel	Sodium Pentaborate (Internal)	Cracking Initiation and Growth
Standby Liquid Control System (Liquid Poison System)	Tanks (Liquid Poison Tank)	Stainless Steel	Sodium Pentaborate (Internal)	Cracking Initiation and Growth
Standby Liquid Control System (Liquid Poison System)	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Standby Liquid Control System (Liquid Poison System)	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Piping and fittings	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Standby Liquid Control System (Liquid Poison System)	Piping and fittings	Stainless Steel	Sodium Pentaborate (Internal)	Cracking Initiation and Growth
Standby Liquid Control System (Liquid Poison System)	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Standby Liquid Control System (Liquid Poison System)	Valve Body	Stainless Steel	Treated Water (Internal)	Cracking Initiation and Growth
Standby Liquid Control System (Liquid Poison System)	Piping and fittings	Stainless Steel	Treated Water <140F (Internal)	Loss of Material

Standby Liquid Control System (Liquid Poison System)	Flow Element	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Valve Body	Stainless Steel	Treated Water <140F (Internal)	Loss of Material
Standby Liquid Control System (Liquid Poison System)	Piping and fittings	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Turbine Building Closed Cooling Water System	Piping and fittings	Carbon and low alloy steel	Closed Cooling Water (Internal)	Loss of Material
Turbine Building Closed Cooling Water System	Piping and fittings	Galvanized Steel	Closed Cooling Water (Internal)	Loss of Material
Turbine Building Closed Cooling Water System	Piping and fittings	Stainless Steel	Closed Cooling Water < 140F (Internal)	Loss of Material
Water Treatment & Distr. System	Filter Housing (including Purifier M-12-1)	Stainless Steel	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Valve Body	Cast Iron	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Flow Element	Aluminum	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Flexible Hose	Stainless Steel	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Valve Body	Stainless Steel	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Valve Body	Aluminum	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Tanks (including Hot Water Heater H-12-1)	Aluminum	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Restricting Orifice	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Flow Meter	Cast Iron	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Piping and fittings	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Water Treatment & Distr. System	Piping and fittings	Stainless Steel	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Piping and fittings	Carbon and low alloy steel	Treated Water (Internal)	Loss of Material

Water Treatment & Distr. System	Piping and fittings	Aluminum	Treated Water (Internal)	Loss of Material
Water Treatment & Distr. System	Restricting Orifice	Stainless Steel	Treated Water (Internal)	Loss of Material

6.0 ATTACHMENTS

6.1 LRA Appendix A

6.2 LRA Appendix B