UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

May 21, 2001

ORGANIZATION: Nuclear Energy Institute (NEI)

SUBJECT: SUMMARY OF MEETING WITH THE NUCLEAR ENERGY INSTITUTE (NEI) LICENSE RENEWAL TASK FORCE ON DEMONSTRATION PROJECT USING IMPROVED RENEWAL GUIDANCE DOCUMENTS

On May 1, 2001, NEI license renewal task force met with the Nuclear Regulatory Commission (NRC) staff in Rockville, Maryland. The purpose of this meeting was to discuss an industry demonstration project consisting of preparation of sample license renewal application sections following the improved license renewal guidance documents. The improved guidance documents consist of: Generic Aging Lessons learned (GALL) report, Standard Review Plan for License Renewal (SRP-LR), and Regulatory Guide for License Renewal (endorsing NEI document 95-10, Rev. 3). The NEI license renewal task force presented the attached GALL demonstration samples which consisted of three parts: Appendix B, Aging Management Review (the attached reflects a revised Page 16 of this document provided by NEI after the meeting for editorial reasons); GALL References In Body of Text With the Use of Six column Tables; and Use of SRP-LR Table Format (Five Column Tables). A list of meeting attendees and handouts provided by NEI are attached.

During the meeting, NRC staff and NEI Task force agreed that the expectations from the demonstration projects are:

- To identify ways in which GALL can be referenced in renewal applications to achieve the desired effectiveness and efficiency in the review process;
- To minimize the need for requests for additional information (RAI);
- To enhance the transparency of the review process;
- To identify, if any, areas where guidance documents can be enhanced.

The staff requested that the NEI provide additional samples so that the broadest range of experienced staff could participate in the demonstration. The staff indicated to the NEI task force that the demonstration project could be completed by the end of September, if NEI provides the additional samples sections by May 11, 2001.

Sikhindra K. Mitra, Project Manager
License Renewal and Standardization Branch
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Project No. 690

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OFFICE	LA	RLSB	SC:RLSB	BC:RLSB:DRIP
NAME	EGHylton	SKMitra	PTKuo	CGrimes
DATE	5/16/01	5/16/01	5/21/01	5/21/01

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T. Collins
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G. Galletti
B. Thomas
J. Moore
R. Weisman
M. Mayfield
S. Bahadur
A. Murphy
W. McDowell
S. Droggitis
S. Duraiswami
RLSB Staff

A. Thadani
R. Zimmerman
C. Julian
R. Gardner
D. Chyu
M. Modes
J. Vora

NUCLEAR ENERGY INSTITUTE

Project No. 690

cc:

Mr. Joe Bartell
U.S. Department of Energy
NE-42
Washington, D.C. 20585

Mr. Richard P. Sedano, Commissioner
State Liaison Officer
Department of Public Service
112 State Street
Drawer 20
Montipelier, Vermont 05620-2601

Mr. Douglas J. Walters
Nuclear Energy Institute
1776 I Street, N.W., Suite 400
Washington, DC 20006-3708
DJW@NEI.ORG

National Whistleblower Center
3238 P Street, N.W.
Washington, DC 20007-2756

Mr. Stephen T. Hale
Florida Power & Light Company
9760 S.W. 344 Street
Florida City, Florida 33035

Mr. Robert Gill
Duke Energy Corporation
Mail Stop EC-12R
P.O. Box 1006
Charlotte, NC 28201-1006

Mr. Charles R. Pierce
Southern Nuclear Operating Co.
40 Inverness Center Parkway
BIN B064
Birmingham, AL 35242

Mr. David Lochbaum
Union of Concerned Scientists
1707 H Street, NW
Suite 600
Washington, DC 20006-3919

Mr. Garry Young
Entergy Operations, Inc.
Arkansas Nuclear One
1448 SR 333 GSB-2E
Russellville, Arkansas 72802

NRC Meeting Attendance List
May 1, 2001

Name	Organization
1. S K. Mitra	NRC/NRR/DRIP/RLSB
2. P. J. Kang	NRC/NRR/DRIP/RLSB
3. Pei-Ying Chen	NRC/NRR/DE/EMEB
4. Joe Gasper	OPPD
5. Jim Knor	NMC
6. Cary Martin	Southern Co.
7. John Rycyna	CNS
8. Steve Hale	FPL
9. Doug Walters	NEI
10. Donald Ferraro	Winston & Strawn
11. Chris Grimes	NRC/NRR/DRIP/RLSB
12. Duc Nguyen	NRC/NRR/DE/EELB
13. Jit Vora	NRC/RES
14. Raj Anand	NRC/NRR/DRIP/RLSB
15. Sam Lee	NRC/NRR/DRIP/RLSB
16. Steve Hoffman	NRC/NRR/DRIP/RLSB
17. Amar Pal	NRC/NRR/DE/EELB
18. Deann Ralgh	LIS, Scientech
19. Barry Elliot	NRC/NRR/DE/EMCB
20. P. T. Kuo	NRC/NRR/DRIP/RLSB
21. D. C. Jeng	NRC/NRR/DE/EMEB
22. W. C. Liu	NRC/NRR/DRIP/RLSB
23. Kamal Manoly	NRC/NRR/DE/EMEB
24. Bill Bateman	NRC/NRR/DE/EMEB
25. Norman St. Amour	OGC
26. Jerry Dozier	NRC/NRR/DRIP/RLSB
27. Ken Karcher	CP&L

Enclosure 1

GALL Demonstration

Appendix B Program Descriptions And FSAR Sections

Consistent With GALL

FLOW ACCELERATED CORROSION PROGRAM

The Flow Accelerated Corrosion (FAC) Program is credited for aging management of selected piping and components in the following systems:

Main Steam System
Feedwater System
Steam Generator Blowdown System

The Flow Accelerated Corrosion (FAC) Program is consistent with the ten attributes of aging management program XI.M6, Flow Accelerated Corrosion, specified in GALL (August 2000 – DRAFT) Chapter XI.

Operating Experience:

Various sections of the Main Steam, Feedwater, and Blowdown system piping are periodically examined using nondestructive examination to determine the effects of flow accelerated corrosion. Indications of FAC are evaluated and piping may be either repaired or replaced if sufficient wall thinning is identified.

Ultrasonic examinations have identified pipe wall thinning below established screening criteria. On occasion, visual observations have identified through wall erosion on piping components. These deficiencies were documented in accordance with the corrective action program and resulted in repair or replacement of the marginal areas.

A rupture occurred on an auxiliary steam line in 1997 that resulted in significant upgrades to the FAC program to bring it up to current industry standards. Internal audits of the program since the 1997 event show the program has been maintained in accordance with NSAC–202L–R2 .

Based on the program enhancements which have been implemented, the continued implementation of the Flow Accelerated Corrosion (FAC) Program provides reasonable assurance that the aging effects of flow accelerated corrosion will be managed such that Main Steam, Feedwater, and Blowdown system components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision:

The Flow Accelerated Corrosion (FAC) program manages the aging effects of wall loss due to FAC for the Main Steam, Feedwater, and Blowdown Systems. The FAC program relies primarily on monitoring and inspection of piping/components to preclude failure of high and low energy carbon steel piping. The Program Basis Document for FAC clearly defines the actions, procedures and steps required to prevent primary pressure boundary failure of the piping/components in scope. All inspection locations must satisfy specified evaluation criteria in order for a component to remain in service.

The program will be enhanced to address valve body erosion by visual inspections prior to the end of the initial operating license terms for Plant X.

STRUCTURES MONITORING PROGRAM

As identified in Chapter 3, the Structures Monitoring Program is credited for aging management of specific component groups in the following structures:

Auxiliary Building	Containment
Intake Structure	Turbine Building

The Structures Monitoring Program is credited for managing the effects of Loss of Material for selected structures within the scope of license renewal. The program provides for visual inspection and examination of accessible surfaces of specific structures and components, including welds and bolting.

Aging management of structural components that are inaccessible for inspection is accomplished by inspecting accessible structural components with similar materials and environments for aging effects that may be indicative of aging effects for inaccessible structural components.

With identified enhancements, the Structures Monitoring Programs is consistent with the ten attributes identified in the NRC GALL Report (August 2000 DRAFT) for Structures Monitoring Program XI.S6.

Operating Experience

Inspections have been performed in the Auxiliary Building, Containment, Intake Structure, and Turbine Building in 1996/1997 and 1999/2000. No significant deterioration has been identified in the inspections performed.

FSAR Revision

The Structures Monitoring Program manages the aging effect of loss of material. The program provides for periodic visual inspection and examination for degradation of accessible surfaces in designated structures that fall within the scope of license renewal.

PRIMARY CHEMISTRY MONITORING PROGRAM

The Primary Chemistry Monitoring Program is credited for managing the aging affects applicable to the passive component/item groupings exposed to contact with the reactor coolant. The concentration of chemical impurities and chemical additions are controlled through monitoring requirements and compliance with specifications which contain chemistry limits. Section 3 of this LRA provides matrices of the affected components/item groupings and the aging effects mitigated by the monitoring program. The Primary Chemistry Monitoring Program is consistent with the ten criteria of aging management program XI.M11, Water Chemistry, specified in GALL (August 2000 – DRAFT) Chapter XI.

Operating Experience and Demonstation

Operating experience on the primary systems demonstrates the effectiveness of the Primary Water Chemistry Monitoring program. No significant chemistry related degradation for primary components/item groupings has been experienced. Experience has shown that implementation of a primary chemistry program in accordance with accepted industry standards is effective in managing the effects of aging. Based on this experience, the continued implementation of the Primary Chemistry Monitoring program provides reasonable assurance that aging effects will be managed so that primary system components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revison

The Primary Chemistry Monitoring Program maximizes long-term availability of primary systems by minimizing system corrosion, fuel corrosion, and radiation field build-up. The scope of the Primary Chemistry Monitoring Program includes sampling activities and analysis on the following systems: RCS, borated water storage tanks, spent fuel pool system, letdown purification demineralizers, and reactor makeup water. The Primary Chemistry Monitoring Program provides assurance that an elevated level of contaminants and oxygen does not exist in the systems covered by the program. This prevents or minimizes the occurrence of cracking and other aging effects.

OUTER SURFACES OF ABOVE GROUND CARBON STEEL TANKS INSPECTION PROGRAM

GALL (August 2000 – DRAFT) Chapter XI, program XI.M7, Outer Surfaces of Above Ground Carbon Steel Tanks, includes preventative measures to mitigate corrosion by inspecting the external surface of carbon steel tanks with paint or coatings in accordance with standard industry practice. These GALL program recommendations are implemented by the Preventative Maintenance Inspection Program requirements. Section 3 of this LRA provides matrices of the affected components/item groupings and the aging effects mitigated by the monitoring program. The Preventative Maintenance Program is consistent with the ten attributes of an aging management program for XI.M7, Outer Surfaces of Above Ground Carbon Steel Tanks, specified in GALL (August 2000 – DRAFT) Chapter XI.

Operating Experience and Demonstration

Operating experience has shown that protective coatings utilized during the construction and maintenance of are effective barriers to mitigate corrosion. Visual inspections will continue to be performed and corrective actions will be initiated when necessary. No unacceptable indications of cracking, loss of material, and change in material properties is allowed to go uncorrected. Based on this experience, the continued implementation of the Preventative Maintenace Program provides reasonable assurance that aging effects will be managed so that Above Ground Carbon Steel Tanks will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

(not mandatory since the GALL Program description is implemented by the Preventative Maintenance Program)

Outer Surfaces of Above Ground Carbon Steel Tanks Inspection Program

Inspections of Outer Surfaces of Above Ground Carbon Steel Tanks will continue to be performed to ensure that a loss of material due to external surface corrosion of these tanks is adequately managed. The inspection requirements implemented by the Preventative Maintenance Program bound the inspection requirements identified by GALL. XI.M7, Outer Surfaces of Above Ground Carbon Steel Tanks. These inspections will continue for the period of extended operation.

GALL Demonstration

Appendix B Program Descriptions And FSAR Sections

Consistent With GALL With Exceptions

EXTERNAL TANK INSPECTION
SYSTEMS AND STRUCTURES MONITORING PROGRAM

The Plant X System and Structures Monitoring Program includes the GALL Outer Surfaces of Above Ground Carbon Steel Tanks (GALL Chapter XI, Program XI.M7). The Systems and Structures Monitoring Program manages the aging effects of loss of material, cracking, fouling, loss of seal, and change in material properties for selected systems, structures, and components (including above ground carbon steel tanks) within the scope of license renewal. The program provides for visual inspection and examination of accessible surfaces. The Systems and Structures Monitoring Program, except as noted below, is consistent with the ten attributes of an aging management program for GALL XI.M7, Outer Surfaces of Above Ground Carbon Steel Tanks.

Exceptions To Gall Requirements

Carbon steel tanks are coated to minimize corrosion. Coatings minimize corrosion by limiting exposure to the environment. However, no credit has been taken by Plant X for coatings in the determination of aging effects requiring management. Coatings are thus not required to ensure that license renewal intended functions will be maintained for the period of extended operation.

Operating Experience And Demonstration

Material condition inspections have been successfully performed at Plant X since the mid-1980s. The inspection requirements in support of the Maintenance Rule (10 CFR 50.65) have been in effect since 1996 and have proven effective at maintaining systems/structures material condition and detecting unsatisfactory conditions that have resulted in effective corrective actions being taken.

The Systems and Structures Monitoring Program has been an ongoing program at Plant X and has been enhanced over the years to include the best practices recommended by the Institute for Nuclear Power Operations (INPO) and other industry guidance. Additionally, the Systems and Structures Monitoring Program will continue to support implementation of the NRC Maintenance Rule.

The effectiveness of the Systems and Structures Monitoring Program is supported by the improved material conditions, documented by internal as well as external assessments of the last several years. The Systems and

Structures Monitoring Program is the subject of periodic internal and external assessments to insure continued effectiveness and improvement.

Based upon the above, the continued implementation of the Systems and Structures Monitoring Program provides reasonable assurance that the aging effects requiring management will be managed such that systems and structures within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

PRIMARY CHEMISTRY MONITORING PROGRAM

The Primary Chemistry Monitoring Program is credited for managing the aging affects applicable to the passive component/item groupings exposed to contact with the reactor coolant. The concentration of chemical impurities and chemical additions are controlled through monitoring requirements and compliance with specifications which contain chemistry limits. Section 3 of this LRA provides matrices of the affected components/item groupings and the aging effects mitigated by the monitoring program. The Primary Chemistry Monitoring Program is consistent with the ten attributes of aging management program XI.M11, Water Chemistry, specified in GALL (August 2000 – DRAFT) Chapter XI, except as discussed below.

Exception to GALL Requirements

The program description for Water Chemistry, XI.M11, specified in GALL (August 2000 – DRAFT) Chapter XI, requires a one-time inspection for use in conjunction with existing program requirements to be developed and reviewed on a plant specific basis. [p*lant name*] takes exception to the one-time inspection requirement. Operating experience at [p*lant name*] has not identified any problems that would warrant a one-time inspection to confirm the adequacy of the chemistry programs. This experience includes inspections of systems and components during maintenance activities that occur routinely. [*specific examples would be provided here*] These inspections have not identified aging effects other than those identified in the LRA and the adequacy of the chemistry programs has been confirmed by these maintenance-related inspections.

Operating Experience and Demonstration

Operating experience on the primary systems demonstrates the effectiveness of the Primary Water Chemistry Monitoring program. No significant chemistry related degradation for primary components/item groupings has been experienced. Experience has shown that implementation of a primary chemistry program in accordance with accepted industry standards is effective in managing the effects of aging. Based on this experience, the continued implementation of the Primary Chemistry Monitoring program provides reasonable assurance that aging effects will be managed so that primary system components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

The Primary Chemistry Monitoring Program maximizes long-term availability of primary systems by minimizing system corrosion, fuel corrosion, and radiation field build-up. The scope of the Primary Chemistry Monitoring Program includes sampling activities and analysis on the following systems: RCS, borated water storage tanks, spent fuel pool system, letdown purification demineralizers, and reactor makeup water. The Primary Chemistry Monitoring Program provides assurance that an elevated level of contaminants and oxygen does not exist in the systems covered by the program. This prevents or minimizes the occurrence of cracking and other aging effects.

BURIED PIPING MONITORING PROGRAM

The Buried Pipe Monitoring Program, a new program to be initiated prior to expiration of the current license, is credited for managing the aging affects applicable to safety related underground piping in service water and fuel oil systems. This program assures the protective coatings on the underground piping will continue to protect the external surfaces of the piping. Section 3 of this LRA provides matrices of the affected components/item groupings and the aging effects mitigated by the monitoring program. The Buried Pipe Inspection Program is consistent with the ten attributes of an aging management program for XI.M8, Outer Suface of Buried Piping and Components, specified in GALL (August 2000 – DRAFT) Chapter XI, except as discussed below.

Exception to GALL Requirements

[*plant name*] takes exception to the recommended one year sampling frequency requirement identified in GALL (August 2000 – DRAFT) Chapter XI.M8. The [*plant name*] inspection program does not include scheduled excavation and inspection to meet the sampling frequency since the process for excavation of buried piping for inspection would increase the possibility of damage to the coatings on the buried piping. The Buried Piping Inspection Program will be based on random excavations associated with required maintenance activities, usually to facilitate repairs. These are not scheduled activities. [*specific examples would be provided here*] estimates buried piping will be excavated every five to ten years. Acceptance criteria for integrity of the coatings will be defined in plant procedures. Corrective actions and actions to preclude recurrence of aging effects, if discovered, will be determined in accordance with 10 CFR Part 50, Appendix B, Quality Assurance requirements.

Operating Experience and Demonstration

Operating experience has shown that buried piping coatings are effective barriers to prevent aging. Based on this experience, the continued implementation of the Buried Pipe Monitoring Program provides reasonable assurance that aging effects will be managed so that buried pipes will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

Buried Pipe Inspections will be performed to ensure that a loss of material due to externals surface corrosion of buried piping is adequately managed.

The safety-related portions of underground carbon steel piping on the service water and fuel oil systems are within the scope of this inspection. The aging effect addressed by the Buried Pipe Inspection is a loss of material due to corrosion of the external surfaces of pipe caused by loss of the protective coating. This inspection will be initiated prior to the end of the initial 40-year license term.

GALL Demonstration

Appendix B Program Descriptions And FSAR Sections

Plant Specific Programs

FIELD ERECTED TANKS INTERNAL INSPECTION

As discussed in Chapter 3, the Field Erected Tanks Internal Inspection is credited for aging management of field erected tanks in the following systems: Auxiliary Feedwater, Condensate Storage, Feedwater, Blowdown, and Safety Injection

Scope

This is a one-time inspection of the two condensate storage tanks, two refueling water storage tanks, and the shared demineralized water storage tank. The Field Erected Tanks Internal Inspection is credited with managing the aging effect of loss of material due to corrosion of the tanks within the scope. The one-time inspection of selected internal areas, including surface welds, will determine the extent of internal corrosion in the listed tanks. The visual inspection will consist of direct (e.g., divers) or remote (e.g., television cameras, fiber optic scopes, periscopes) means. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Preventive Actions

Internal tank surfaces are coated to reduce corrosion. Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited in the determination of the aging effects requiring management.

Parameters Monitored or Inspected

The material condition of the internal surfaces of accessible areas of the tanks will be visually inspected.

Detection of Aging Effects

The presence of corrosion that could lead to loss of material will be determined by visual inspection of the accessible areas of the field erected tanks. Internal surfaces will be examined for evidence of flaking, blistering, peeling, discoloration, pitting, or excessive corrosion.

Monitoring and Trending

As noted above, this is a one-time inspection, therefore, monitoring or trending is not anticipated. Results of the inspection will be evaluated to determine if additional actions are required.

Acceptance Criteria

The results of the one-time inspection will be evaluated. Specific acceptance criteria will be provided in the implementing procedure.

Confirmation Process

Any follow-up inspection required will be based on the evaluation of the inspection results and will be documented in accordance with the corrective action program.

Operating Experience and Demonstration

Visual inspections have been performed at Pant X for several years. This technique has proven successful for identifying material defects on the surface of field erected tanks.
This inspection is a new activity that will use techniques with demonstrated capability and a proven industry record to detect corrosion. This inspection will be performed utilizing approved procedures and qualified personnel.

Based upon the above, the implementation of the Field Erected Tanks Internal Inspection will provide reasonable assurance that loss of material due to corrosion will be managed such that the structures and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

FIELD ERECTED TANKS INTERNAL INSPECTION

A one-time visual inspection to determine the extent of corrosion on the internal surfaces of the field erected tanks for both units -- including the Condensate Storage Tanks, the Demineralized Water Storage Tank, and the Refueling Water Storage Tanks -- will be performed. The results of these inspections will be evaluated to determine the need for additional inspections/programmatic corrective actions. These inspections will be implemented prior to the end of the initial operating license terms for Plant X.

BURIED PIPING INSPECTION PROGRAM

The purpose of the buried pipe inspection program procedure is to assure that the effects of aging of buried piping are being effectively managed for the period of extended operation under current licensing basis design loading conditions. Loss of material is detectable by visual techniques and, based on operating experience, inspection of a sample of buried components provides for detection of aging effects.

The buried pipe program will enable the site to efficiently develop, modify, and execute the decision-making necessary to:

Define what, if any, action is necessary to provide reasonable assurance through the period of extended operation that loss of material does not result in the DFO or AFW buried piping losing the ability to perform their intended function.

Execute the mitigation and/or discovery activities identified as necessary.

Systems:
Auxiliary Feedwater (AFW)
Diesel Fuel Oil (DFO)

Scope

The buried pipe inspection program applies to plant engineering activities involved in inspecting and maintaining the buried sections of piping for the AFW and DFO systems. The buried pipe program could also be used to inspect all metallic buried piping at XXNPP.

Preventive Actions

External surfaces of carbon steel buried pipe are coated and have cathodic protection to minimize corrosion. Although coatings and cathodic protection minimize corrosion by limiting exposure to the environment and reducing the effects of corrosion to the piping, conservatively they are not credited in the determination of the aging effects that require management.

Parameters Monitored or Inspected

This program will consider variations in environmental conditions (including cathodic protection) to select representative samples of the buried piping for inspection to ensure that the pipe coating/wrapping and cathodic protection system are adequately protecting the pipe from external Aging Effects Requiring Management (AERMs).

The parameters monitored should include the cathodic protection system performance, cathodic protection tap settings, monthly voltage and amperage readings, and quarterly cathodic protection potential profile. Plant XX already monitors these parameters in addition to coating damage observed during inspections of buried pipe sections.

Detection of Aging Effects

The aging effect of concern is loss of material, which is detected by visual observation during piping inspections. Areas of pipe where the coating is missing and the soil surrounding the pipe is wet should be carefully examined for evidence of loss of material.

Monitoring and Trending

The AERMs, if present, would be discovered by regular visual inspections of representative piping sections. The approach for identifying corrosion-related aging effects follows:

1) Buried pipe should be inspected when pipe is excavated during other maintenance and in areas with a history of corrosion problems.

2) Selected areas of buried pipe will be inspected during the last five (5) years of the current operating license term.

3) The locations of such inspections are based on previous inspections and such inspections are not done on a regular schedule.

Trending, if needed, is provided by the site corrective action program.

Acceptance Criteria

Plant procedures provide criteria for determining the acceptability of as-found conditions and for initiating the appropriate corrective action. The acceptance criteria and guidance are geared toward avoiding unacceptable degradation that could threaten the component intended functions.

Confirmation Process

Unacceptable inspection and observation results are evaluated and addressed in the site corrective action process. The corrective process calls for follow-up and confirmation steps.

Corrective Action

The system engineer is responsible for coordinating any necessary repairs to the wrapping and coating of exposed buried piping. Repairs shall be made in accordance with Plant XX procedures and specifications.

Repairs will be inspected by a qualified NDE Inspector and an NDE report will be issued.

Administrative Controls

The procedures governing inspections and observations for buried pipe program are included in the population of procedures subject to 10 CFR 50.59 for control of changes.

Operating Experience

On two separate occasions, plant personnel inspected the DFO buried piping and found that the programs in place to mitigate the aging effects are effective. Specifically, in September 1994 the coatings on a 2-inch and a 3-inch pipe were visually inspected and no degradation of the pipe was found. In November 1996 four 25 foot sections of buried DFO lines were inspected, two 6-inch pipes, one 3-inch pipe, and one 2-inch pipe. During excavation, rocks, stone and concrete were removed (the backfill material was not consistent with the specification which required it to be free of sharp and hard objects). The inspections (visual and a high voltage holiday spark test) found holidays in the coating. At these holiday locations the coatings were removed, the pipe cleaned and inspected. All four pipes were found to be in pristine condition. No evidence of pitting or corrosion damage was found in these areas.

Demonstration

Loss of material must be managed for buried pipe because the carbon steel material used in its construction is susceptible. The aggressiveness of this aging effect is particularly dependent on the overall corrosiveness of the environment and the materials of construction.

Long term exposure to a wet environment may result in localized and/or general area materials loss and, if left unmanaged, could eventually result in loss of pressure retaining capability under CLB design loading conditions. Soil resistivity (or conductivity), chloride and sulfate presence, oxygen content and soil aeration, pH, moisture content of the soil and wet/dry cycles, and microbe activity affect these aging. Damaged protective coatings/wrappings, holidays or disbonded areas in coating/wrapping, and leakage around caulking can allow these aging effects to develop on the exterior surfaces of the pipe and at the interface where the pipes penetrate the concrete walls.

Based on the above, the continued implementation of the existing inspections and observations for signs of degradation on buried pipes and for conditions that can cause degradation provides reasonable assurance that the aging effect, loss of material, will be properly managed. The buried pipe inspection program will manage piping inspections such that certain systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

The Buried Pipe Inspection Program

The Buried Pipe Inspection Program manages the aging effect loss of material. The program applies to plant engineering activities involved in inspecting and maintaining the buried sections of piping for the AFW and DFO systems. The program provides for visual observations during piping inspections identifying degradation in pipe coating/wrapping.

GENERAL CORROSION OF EXTERNAL SURFACES FOR LICENSE RENEWAL PROGRAM

The General Corrosion of External Surfaces for License Renewal Program is credited for aging management of specific non-structural components/commodity groups in the following systems:

Systems:
Auxiliary Feedwater (AFW)
Diesel Fuel Oil and Diesel Lube Oil (DFO & DLO)
Main Steam (MS)
Component Cooling Water (CCW)

Scope

The General Corrosion of External Surfaces for License Renewal Program consists of several activities that manage the aging effects of loss of material for selected systems and non-structural components within the scope of license renewal. The program provides for visual inspection and observation of accessible external surfaces of certain carbon and low-alloy steel components, including piping, valves, supports, tanks, and bolting.

Preventive Actions

External surfaces of most carbons steel and cast iron components are coated to minimize corrosion. Although coatings minimize corrosion by limiting exposure to the environment, they are not credited in the determination of the aging effects that require management.

Parameters Monitored or Inspected

Surface conditions of components are monitored through visual observation and inspection to detect signs of external corrosion and to detect conditions that can result in external corrosion, such as fluid leakage.

Detection of Aging Effects

The aging effect of concern is loss of material which is detected by visual observation and inspection of external surfaces for evidence of leaking fluids, significant coating damage, or significant corrosion. Inspection for evidence of leaking fluids also provides indirect monitoring of certain components that are not routinely accessible.

Monitoring and Trending

Various plant personnel including operators and system engineers perform periodic material condition inspections outside containment. These inspections are performed in accordance with approved plant procedures. Evidence of fluid leaks, significant coating damage, or significant corrosion is documented.

Inspections and observations are performed at intervals based on previous inspections and industry experience. Operator rounds occur several times daily and System Engineer walkdowns occur at least quarterly. Inspections inside containment are conducted each refueling outage by a team that includes knowledgeable subject matter experts from Design Engineering and Quality Control. The in-containment inspections for corrosion are part of the containment coatings inspections established in response to Reg Guide 1.54 (1973) and reviewed by NRC under Generic Letter 98-04.

Acceptance Criteria

Plant procedures provide criteria for determining the acceptability of as-found conditions and for initiating the appropriate corrective action. The acceptance criteria and guidance are related to avoiding unacceptable degradation of the component intended functions, and include existence of leakage, presence of corrosion products, coating defects, and the presence of boric acid crystals. Appropriate provisions of NRC and industry guidance are incorporated.

Confirmation Process

Unacceptable inspection and observation results are evaluated and addressed in the site corrective action process.

Corrective Action

The corrective action process provides measures to verify completion and effectiveness of corrective action.

Administrative Controls

The procedures governing inspections and observations for external corrosion are included in the population of site procedures that are subject to systematic control of changes.

Operating Experience

The activities relied on to detect corrosion of accessible carbon and low-alloy steel and cast iron external surfaces and the precursors thereof are a subset of a larger number of inspection activities that result in redundant inspections. The activities credited for license renewal were selected based on their effectiveness as indicated by a review of site corrective action documents.

The activities are elements of established programs that have been ongoing for years. They have been enhanced over the years based on site and industry experience and are relied on to support implementation of Reg Guide 1.54 for coatings inside containment and the Maintenance Rule (10 CFR 50.65). Review of plant records indicates they are effective in detecting loss of material due to corrosion and its precursors for accessible external surfaces. These findings are consistent with the findings of recent internal and external assessments of these activities, such as audits and NRC inspections.

Demonstration

Loss of material due to corrosion of carbon steel, low allow steel, and cast iron is readily observable for accessible external surfaces. The effect is minimal for coated and uncoated components that are not routinely wetted by humidity, condensation, precipitation, spray, or leakage.

Prompt identification and correction of leakage will minimize the effect for accessible and inaccessible components that are potentially exposed to the leakage. Operator rounds occur several times daily and provide discovery and correction of significant corrosion and of conditions that cause it for components in accessible areas. Periodic system engineer walkdowns augment the operator rounds and provide an independent assessment. Refueling interval inspections provide for discovery of corrosion and of conditions that can cause it for components inside containment.

The effectiveness of these inspection and observation activities is supported by the excellent plant material condition and by site records that show high sensitivity to material condition, housekeeping, and to fluid leakage in particular.

Based on the above, the continued implementation of the existing inspections and observations for signs of external corrosion and for conditions that can cause it provide reasonable assurance that loss of material due to corrosion of external surfaces will be managed such that systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

General Corrosion of External Surfaces Program

The General Corrosion of External Surfaces for License Renewal Program manages loss of material due to general corrosion of external surfaces of non-structural carbon steel, low alloy steel, and cast iron components that are (1) inside containment or (2) in normally accessible areas outside containment. The program uses systematic inspections and observations to detect corrosion of external surfaces and conditions that can result in corrosion such as damaged coatings and fluid leaks. Inspections and observations include (1) rounds by operators, (2) system engineer walkdowns, and (3) refueling interval inspections inside containment in accordance with Reg Guide 1.54.

TANK INSPECTION PROGRAM

The Tank Inspection Program is credited for aging management of specific non-structural components/commodity groups in the following systems:

System:
Diesel Fuel Oil (DFO)

Scope

The tank inspection program applies to plant engineering activities involved in inspecting and maintaining tank internal materials per XXNPP's license renewal commitments. The XXNPP Tank Internal Inspection Program is intended to provide assurance that the aging effects are being effectively managed.

Preventive Actions

Fuel oil is not corrosive to carbon steel under the normal conditions present in the Fuel Oil Storage Tanks (FOST). Significant rates of corrosion-related Aging Effects Requiring Management (AERM) occur only when water is present with the fuel oil in the tank. While the presence of water in the tank cannot be totally prevented, the amount of water and the length of time it may be present in the tank can be minimized. The minimal amount of water and length of time the water is present is an effective method of mitigating the aging effects. Corrosion inhibitors, if required, are added to new fuel oil to maintain a non-corrosive environment in the tank.

Another method of mitigating the effects of aging on the tank interior is to apply a protective coating, which prevents contact between the metal surfaces of the tank and the system fluid or contaminant fluid. By preventing contact, the AERMs cannot occur. Although coatings minimize corrosion by limiting exposure to the environment and reducing the effects of corrosion to the tank, conservatively they are not credited in the determination of the aging effects that require management.

Parameters Monitored or Inspected

The Diesel FOST Internal Inspection Program will manage the aging effect, loss of material. The inspections will monitor for flaking, blistering, or damaged sections of coating and inspect the welds. These inspections will include the following:

A visual assessment of the condition of the tank interior in accordance with the American Petroleum Institute (API) Standard 653 for FOST inspections;
Measurements of the thickness of the tank interior coating at several locations in the tank, in accordance with the American Society of Testing Materials Standard ASTM D-1186, for coating thickness measurements; and

Observations for voids and pinholes in the tank coating, in accordance with guidance provided in the National Association of Corrosion Engineers' recommended practice NACE RP0188, "Discontinuity (Holiday) Testing of Protective Coating."

By monitoring the tank in these areas, the inspection program will reduce the possibilities of age-related degradation of the internals in the tank.

Detection of Aging Effects

The AERM are detectable by visual and other non-destruction techniques. Since corrosion of the carbon steel interior surface of the tank cannot occur without degradation of the coating, observing and confirming that the coating is intact constitutes an effective method to ensure that the AERMs have not occurred. The tank coating does not contribute to the tank's intended function. Therefore, observing the coating for degradation provides an alert condition which triggers corrective action before degradation that affects the tank's ability to perform its intended function can occur.

Monitoring and Trending

Under the Tank Inspection Program, XXNPP will perform an internal inspection of the FOSTs at periodic intervals based on results of previous inspections.

The site corrective action program will, if needed, provide trending.

Acceptance Criteria

Plant procedures provide criteria for determining the acceptability of as-found conditions and for initiating the appropriate corrective action. The acceptance criteria and guidance are geared toward avoiding unacceptable degradation of a component, which would cause a loss of intended function.

Confirmation Process

Unacceptable inspection and observation results are evaluated and addressed in the site corrective action process, which calls for follow-up and confirmation steps.

Corrective Action

If degradation is found, corrective actions will be implemented. Future inspections may be scheduled, if appropriate, based on the level and degree of degradation and the specific corrective actions that were implemented.

Administrative Controls

The procedures governing inspections and observations for the Tank Internal Inspection Program are included in the population of procedures subject to 10 CFR 50.59 for control of changes.

Operating Experience

The DFO System has performed well, exhibiting no age-related degradation that impaired the system functions over its history to date.

On November 1, 1995, No. 11 FOST was inspected. The inspection revealed that the tank is in good condition with negligible coating deterioration after approximately 20 years of service. The inspection included a series of ultrasonic tests to measure the thickness of the bottom plates. Since the coating on the tank internal surfaces was found to be intact, no contact between the system fluid and the internal surfaces of the tank is occurring. The inspection concluded that: no deficiencies were observed during tank visual (interior and exterior) inspections; no flaking, blistering, or damaged sections of coating was observed; no deficiencies were observed during vacuum box inspection of welds; and the minimum floor thickness measurement was 0.251 inches, consistent with the original nominal thickness specification for the 1/4 inch plate. No corrosion of tank surfaces was found. Therefore, it can be concluded that no age-related degradation of the carbon steel material of construction has occurred.

On April 13, 1997 No. 21 FOST was inspected and found to be in a similarly good condition.

Demonstration

Carbon steel diesel FOST internal surfaces and internals are susceptible to various aging effects. These aging effects may be compounded by the presence of sludge/deposits at the bottom of the tank where water, if present, will generally collect. Although, the interior surfaces of the FOSTs are covered with a protective coating of a self-curing, inorganic zinc primer (trade name Carbo Zinc 11), no credit is taken for this coating when determining AERM.

If the diesel fuel oil is contaminated with water and comes into contact with the metal surfaces of the tank, loss of material could occur.

Based on the above, the continued implementation of the existing inspections and observations for loss of material and for conditions that can cause it provide reasonable assurance that loss of material of tank internal surfaces will be managed such that certain systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

Tank Inspection Program

The Diesel FOST Internal Inspection Program will manage the aging effect, loss of material. The inspections will monitor for flaking, blistering, or damaged sections of coating and inspect the interior tank welds. These inspections include (1) a visual assessment of the condition of the tank interior (2) measurements of the thickness of the tank interior coating (3) observations for voids and pinholes in the tank coating. The inspections and observations are conducted in accordance with the guidelines in API Standard 653, ASTM D-1186 and NACE RP0188.

GALL Demonstration

GALL References In Body Of Text With Use Of Six Column Tables

3.0 AGING MANAGEMENT REVIEW RESULTS

For those structures and components that are identified as being subject to an aging management review, 10 CFR 54.21(a)(3) requires demonstration that the effects of aging will be adequately managed so that their intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. The information provided in this chapter provides essential input to the required aging management review as it identifies and discusses the aging effects requiring management.

This chapter describes the results of the aging management reviews of the components and structures, identified in Chapter 2, "Structures and Components Subject to Aging Management Review." This chapter:

- provides references to the descriptions of common aging management programs
- identifies the components and structural components subject to aging management review, and their intended functions
- discusses the materials and internal and external environments
- describes or references the processes used to identify aging effects
- describes industry and plant-specific operating experiences with respect to the aging effects
- identifies the aging effects requiring management
- lists the aging management programs for aging effects requiring management.

Common aging management programs are contained in Section 3.1. For those structures and components identified as being subject to an aging management review, the results are contained in Section 3.2 for Reactor Coolant Systems, Section 3.3 for Engineered Safety Features Systems, Section 3.4 for Auxiliary Systems, Section 3.5 for Steam And Power Conversion Systems, Section 3.6 for structures and structural components (Subsection 3.6.1 for Containment and Subsection 3.6.2 for other structures), and Section 3.7 for electrical and instrumentation and controls. Aging management program descriptions are contained in Appendix B.

Tables 3.0-1 and 3.0-2 contain descriptions of the internal and external service environments at Plant X, which will be used in subsequent sections of this chapter. The environments used in the aging management reviews are listed in the "Environment" column in Tables 3.0-1 and 3.0-2. Within this Application, some of the internal environments have been subdivided into groups based on the fluid chemistry. The subgroups are identified in the "Description" column in Table 3.0-1.

TABLE 3.0-1
INTERNAL SERVICE ENVIRONMENTS

Environment	Description
Air/Gas	Includes atmospheric air, dry/filtered instrument air, nitrogen, hydrogen, carbon dioxide, and Halon
Treated water	Base water for all clean systems. Demineralized water that can be deaerated, or include corrosion inhibitors, biocides, and boric acid, or any combination of these treatments Within this Application, treated water has been subdivided into groups based on the chemistry of the water: Treated water – primary – Normal operating Reactor Coolant System chemistry Treated water – secondary – Normal operating secondary chemistry, including Main Steam, Feedwater, and Blowdown Systems Treated water – borated – Systems that contain borated water except those included in treated water – primary, including Chemical and Volume Control, Spent Fuel Cooling, and Emergency Core Cooling Systems Treated water – All other treated water systems, including Component Cooling Water, Emergency Diesel Generator Cooling, and Chilled Water Systems
Raw water	Water that enters the plant from the cooling water canals, ocean, bay, or city water source that has not been demineralized. In general, the water has been rough filtered to remove large particles and may contain a biocide for control of micro-organisms and macro-organisms. Although city water is purified for drinking purposes, it is conservatively classified as raw water for the purposes of aging management review. Within this Application, raw water has been subdivided into groups based on the chemistry of the water: Raw water – cooling canals – Salt water used as the ultimate heat sink Raw water – city water – Potable water supplied to the water treatment plant and the Fire Protection System Raw water – floor drainage – Fluids collected in building drains. The fluids can be treated water (primary, secondary, borated, or other), raw water (cooling water canals or city water), fuel oil, or lubricating oil
Fuel oil	Emergency diesel generator, diesel fire pump, and standby steam generator feedwater pump fuel oil
Lubricating oil	Lubricating oil for emergency diesel generators, pumps, and other components
Ohmic heating	Thermal stress on power cable materials can be due to ohmic heating resulting from electrical current

TABLE 3.0-2
EXTERNAL SERVICE ENVIRONMENTS

Environment [1]	Description
Outdoor [2]	Moist, salt-laden atmospheric air, temperature 30ºF-95ºF, humidity 5%-95%, exposed to weather, including precipitation and wind
Indoor – not air conditioned[2]	Atmospheric air, temperature 104ºF (40ºC) maximum, humidity 5%-95ºF%, not exposed to weather
Indoor – air conditioned[2]	Atmospheric air, specific temperature/humidity range dependent on building/room. Typically, temperature 70ºF-79ºF, humidity 60%-80%, not exposed to weather
Containment air [2]	Atmospheric air, temperature 120ºF maximum, humidity 5%-95%, total integrated dose rate – 1 rad/hour (excluding equipment located inside the reactor cavity), not exposed to weather Note: Safety-related equipment in the containment has been analyzed to 122ºF (50ºC) continuous and 125ºF for 2 weeks/year
Borated water leaks	Exposed to leakage from borated water systems
Buried	Above groundwater elevation, exposed to soil/fill. Below groundwater elevation, exposed to soil/fill and groundwater. Groundwater contains aggressive chemicals that can attack susceptible materials
Embedded/Encased	Reinforcing or embedded steel or piping in concrete

NOTES: 1. For certain components and structural components that are submerged, the applicable environment in Table 3.0-1 is specified.

2. Where wetted conditions exist (e.g., condensation), the item is annotated with the applicable external environment in Chapter 3 system and structures tables.

3.5 STEAM AND POWER CONVERSION SYSTEMS

The following systems are included in this section:

- Main Steam and Turbine Generators
- Feedwater and Blowdown
- Auxiliary Feedwater and Condensate Storage

Extraction steam, which is included in the GALL Report, was not identified as a system requiring an aging management review at Plant X.

Subsection 2.3.4 provides a description of these systems and identifies the components requiring an aging management review for license renewal. Appendix C contains the process that identified the aging effects requiring management for non-Class 1 components.

3.5.1 MATERIALS AND ENVIRONMENT

The Steam and Power Conversion Systems are exposed to internal environments of treated water - secondary, treated water, lubricating oil, and air/gas; and external environments of outdoor, containment air, buried, and potential borated water leaks (see Tables 3.0-1 and 3.0-2). The identified environments are consistent with the GALL Report.

The only parts of systems or components considered to be inaccessible for inspection are those that are buried or embedded/encased in concrete. These environments are addressed as part of the aging management review process; see Table 3.0-2, "External Service Environments." Potential aging effects associated with these environments are reviewed and those aging effects requiring management are identified along with the credited aging management program(s). All other parts of systems and components can be accessed, if required. The only Steam and Power Conversion System containing inaccessible piping parts is the Standby Steam Generator Feedwater System, which contains sections of buried stainless steel piping.

The tanks, pumps, heat exchangers, piping, tubing, valves, and associated components and commodity groups for these systems are constructed of carbon steel, stainless steel, low alloy steel, cast iron, and brass. Low alloy steel, cast iron, and brass are plant specific materials that were not included in the Steam and Power Conversion Section of the GALL Report. The components and commodity groups, their intended functions, the materials, and environments for the Steam and Power Conversion Systems are summarized in Tables 3.5-1 through 3.5-3.

3.5.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Tables 3.5-1 through 3.5.-3. The aging effects requiring management for each system are summarized in the following paragraphs.

Main Steam and Turbine Generators - The aging effects requiring management are loss of material for carbon steel and stainless steel components, and cracking for certain stainless steel components and heat exchanger tubing. The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity. Fatigue, which is identified as aging effect requiring management in the GALL Report, is addressed as a time-limited aging analysis in Section 4.3.

Feedwater and Blowdown - The aging effects requiring management are loss of material for carbon steel and stainless steel components, and cracking for certain stainless steel components. The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity. Fatigue, which is identified as aging effect requiring management in the GALL Report, is addressed as a time-limited aging analysis in Section 4.3.

Auxiliary Feedwater and Condensate Storage - The aging effect requiring management is loss of material for cast iron, admiralty brass, carbon steel, low alloy steel, and stainless steel components.

3.5.3 OPERATING EXPERIENCE

3.5.3.1 INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to Steam and Power Conversion Systems includes the following:

- NRC Bulletin 79-03, "Longitudinal Weld Defects in ASME SA-312 Type 304 Stainless Steel Pipe"
- NRC Bulletin 79-13, "Cracking in Feedwater System Piping"
- NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants"
- NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants"
- NRC Bulletin 89-02, "Stress Corrosion Cracking of High Hardness Type 410 Stainless Steel Internal Preloaded Bolting In Anchor Darling Model S530W Swing Check Valves or Valves of Similar Design"
- NRC Generic Letter 79-20, "Information Requested on PWR Feedwater Lines"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety Related Equipment"
- NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning"
- NRC Generic Letter 91-17, "Generic Safety Issue 29, Bolting Degradation or Failure in Nuclear Power Plants"
- NRC Information Notice 80-05, "Chloride Contamination of Safety Related Piping and Components"
- NRC Information Notice 80-29, "Broken Studs on Terry Turbine Steam Inlet Flanges"
- NRC Information Notice 81-04, "Cracking in Main Steam Lines"
- NRC Information Notice 84-32, "Auxiliary Feedwater Sparger and Pipe Hanger Damage"

- NRC Information Notice 84-87, "Piping Thermal Deflection Induced by Stratified Flow"
- NRC Information Notice 85-56, "Inadequate Environment Control for Components and Systems in Extended Storage"
- NRC Information Notice 86-106, "Feedwater Line Break"
- NRC Information Notice 87-28, "Air Systems Problems at U.S. Light Water Reactors"
- NRC Information Notice 87-36, "Significant Unexpected Erosion of Feedwater Lines"
- NRC Information Notice 88-17, "Summary of Responses to NRC Bulletin 87-01, Thinning of Pipe Walls in Nuclear Power Plants"
- NRC Information Notice 88-37, Flow Blockage of Cooling Water to Safety System Components"
- NRC Information Notice 89-01, "Valve Body Erosion"
- NRC Information Notice 89-53, "Rupture of Extraction Steam Line on High Pressure Turbine"
- NRC Information Notice 89-76, "Biofouling Agent: Zebra Mussel"
- NRC Information Notice 89-80, "Potential for Water Hammer, Thermal Stratification, and Steam Binding in High-Pressure Coolant Injection Piping"
- NRC Information Notice 90-65, "Recent Orifice Plate Problems"
- NRC Information Notice 91-18, "High-Energy Piping Failures Caused by Wall Thinning"
- NRC Information Notice 91-19, "Steam Generators Feedwater Distribution Piping Damage"
- NRC Information Notice 91-28, "Cracking in Feedwater System Piping"
- NRC Information Notice 91-38, "Thermal Stratification in Feedwater System Piping"
- NRC Information Notice 92-07, "Rapid Flow-Induced Erosion/Corrosion of Feedwater Piping"
- NRC Information Notice 93-20, "Thermal Fatigue Cracking of Feedwater Piping to Steam Generators"

- NRC Information Notice 93-21, "Summary of Observations Compiled During Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs"
- NRC Information Notice 94-59, "Accelerated Dealloying of Cast Aluminum-Bronze Valves Caused by Microbiologically Induced Corrosion"
- NRC Information Notice 94-79, "Microbiologically Influenced Corrosion of Emergency Diesel Generator Service Water Piping"
- NRC Information Notice 95-11, "Failure of Condensate Piping Because of Erosion/Corrosion at a Flow-Straightening Device"
- NRC Information Notice 99-19, "Rupture of the Shell Side of a Feedwater Heater at the Point Beach Plant"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.5.2.

3.5.3.2 PLANT-SPECIFIC EXPERIENCE

Plant X operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of Plant X non-conformance reports, licensee event reports, and condition reports for any documented instances of Steam and Power Conversion Systems component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.5.2.

3.5.4 CONCLUSION

The review of industry information, NRC generic communications, and Plant X operating experience identified no additional aging effects beyond those discussed in Subsection 3.5.2. Tables 3.5-1 through 3.5-3 contain the results of the aging management review for the Steam and Power Conversion Systems and summarize the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs, which agree with the GALL Report except as noted:

- Auxiliary Feedwater Pump Oil Coolers Inspection (GALL Report specifies a plant specific aging management program)
- Auxiliary Feedwater Steam Piping Inspection Program (GALL Report specifies a plant specific aging management program)
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Field Erected Tanks Internal Inspection (aging management program not included in GALL Report)
- Flow Accelerated Corrosion Program
- Galvanic Corrosion Susceptibility Inspection Program (aging management program not included in GALL Report)
- Systems and Structures Monitoring Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the Steam and Power Conversion Systems components listed in Tables 3.5-1 through 3.5-3 are maintained consistent with the current licensing basis for the period of extended operation.

TABLE 3.5-1
MAIN STEAM AND TURBINE GENERATORS

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
			Internal Environment		
Unit 4 Main Steam Isolation Valve instrument air accumulator tanks	Pressure boundary	Carbon steel	Air/Gas	None	None required
Main process piping: Valves Piping/fittings	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program
Steam traps: Valves Piping/fittings Steam traps	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Treated water - secondary	Loss of material Cracking	Chemistry Control Program
Valves Tubing/fittings Filters Flex hoses Rupture disks	Pressure boundary	Stainless steel	Air/Gas	None	None required
Instrument air 3-way valves	Pressure boundary	Brass	Air/Gas	None	None required
Flow elements	Pressure boundary Throttling	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program

TABLE 3.5-1 (continued)
MAIN STEAM AND TURBINE GENERATORS

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Unit 4 Main Steam Isolation Valve instrument air accumulator tanks	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Main process piping: Valves Piping/fittings	Pressure boundary	Carbon steel	Containment air Outdoor	None[1]	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Steam traps: Valves Steam traps Piping/fittings	Pressure boundary	Carbon steel	Outdoor	Loss of material	Flow Accelerated Corrosion Program[2]
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Containment air	None	None required
Valves Tubing/fittings Filters Flex hoses Rupture disks	Pressure boundary	Stainless steel	Outdoor	None	None required
Instrument air 3-way valves	Pressure boundary	Brass	Outdoor	None	None required

NOTES:
1. Carbon steel components that normally operate at high temperatures are not susceptible to loss of material.
2. Flow Accelerated Corrosion Program addresses external general corrosion via use of radiographic examinations.

TABLE 3.5-1 (continued)
MAIN STEAM AND TURBINE GENERATORS

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Flow elements	Pressure boundary Throttling	Carbon steel	Containment air Outdoor	None[1]	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

NOTE: 1. Carbon steel components that normally operate at high temperatures are not susceptible to loss of material.

TABLE 3.5-2
FEEDWATER AND BLOWDOWN

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Demineralized water storage tank	Pressure boundary	Carbon steel	Air/Gas	Loss of material	Field Erected Tanks Internal Inspection
			Treated water	Loss of material	Chemistry Control Program Field Erected Tanks Internal Inspection
Standby steam generator feedwater pumps	Pressure boundary	Carbon steel	Treated water	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
#6 Feedwater heater shells, tube sheets, and covers	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program Galvanic Corrosion Susceptibility Inspection Program
#6 Feedwater heater tubes[1]	Pressure boundary	Stainless steel	Treated water - secondary (inside and outside diameters)	Loss of material Cracking	Chemistry Control Program

NOTE: 1. Heat transfer is not a license renewal intended function for this component.

TABLE 3.5-2 (continued)
FEEDWATER AND BLOWDOWN

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Valves Piping/fittings (main feedwater and blowdown)	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program Galvanic Corrosion Susceptibility Inspection Program
Tubing/fittings Thermowells (feedwater)	Pressure boundary	Stainless Steel	Treated water – secondary	Loss of material Cracking	Chemistry Control Program
Valves Piping/fittings Tubing/fittings Thermowells (blowdown)	Pressure boundary	Stainless steel	Treated water - secondary	Loss of material Cracking	Chemistry Control Program
Instrument air solenoid valves	Pressure boundary	Brass	Air/Gas	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Treated water - secondary	Loss of material Cracking	Chemistry Control Program
Strainers	Pressure boundary	Stainless steel	Treated water	Loss of material	Chemistry Control Program
Valves Piping/fittings Tubing/fittings (standby steam generator feedwater pump suction)	Pressure boundary	Stainless steel	Treated water	Loss of material	Chemistry Control Program

TABLE 3.5-2 (continued)
FEEDWATER AND BLOWDOWN

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Orifices	Pressure boundary	Stainless steel	Treated water	Loss of material	Chemistry Control Program

TABLE 3.5-2 (continued)
FEEDWATER AND BLOWDOWN

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Demineralized water storage tank	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Standby steam generator feedwater pumps	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
#6 Feedwater heater shells and covers	Pressure boundary	Carbon steel	Outdoor	None[1]	None required
Valves Piping/fittings (main feedwater and blowdown)	Pressure boundary	Carbon steel	Containment air	None[1]	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Tubing/fittings	Pressure boundary	Stainless steel	Containment air	None	None required
Valves Piping/fittings (from standby steam generator feedwater pumps to main feedwater piping)	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program

NOTE: 1. Carbon steel components that normally operate at high temperatures are not susceptible to loss of material.

TABLE 3.5-2 (continued)
FEEDWATER AND BLOWDOWN

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Valves Piping/fittings (main feedwater and blowdown)	Pressure boundary	Carbon steel	Outdoor Indoor – not air-conditioned	None[1]	None required
Valves Piping/fittings Tubing/fittings Thermowells (blowdown)	Pressure boundary	Stainless steel	Outdoor Indoor – not air-conditioned	None	None required
Valves Piping/fittings Tubing/fittings Strainers (standby steam generator feedwater pump suction)	Pressure boundary	Stainless steel	Outdoor	Loss of material Cracking[2]	Systems and Structures Monitoring Program
Piping (standby steam generator feedwater pump suction)	Pressure boundary	Stainless steel	Buried	None	None required

NOTES: 1. Carbon steel components that normally operate at high temperatures are not susceptible to loss of material.
2. Plant experience has identified the potential for cracking in non-stress relieved heat affected zones of weld joints for this piping.

TABLE 3.5-2 (continued)
FEEDWATER AND BLOWDOWN

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Instrument air solenoid valves	Pressure boundary	Brass	Outdoor	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Outdoor	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.5-3
AUXILIARY FEEDWATER AND CONDENSATE STORAGE

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Condensate storage tanks	Pressure boundary	Carbon steel	Air/Gas	Loss of material	Field Erected Tanks Internal Inspection
			Treated water	Loss of material	Chemistry Control Program Field Erected Tanks Internal Inspection
Auxiliary feedwater pumps	Pressure boundary	Low alloy steel	Treated water	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program[1]
Auxiliary feedwater pump turbine casings	Pressure boundary	Carbon steel	Treated water - secondary Air/Gas	Loss of material	Auxiliary Feedwater Steam Piping Inspection Program
Auxiliary feedwater pump lube oil cooler and governor oil cooler tube sheets	Pressure boundary	Carbon steel	Treated water	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program[1]
			Lubricating oil	None	None required

NOTE: 1. Galvanic corrosion only at carbon steel contact points with stainless steel, brass, and low alloy steel for these components.

TABLE 3.5-3 (continued)
AUXILIARY. FEEDWATER AND CONDENSATE STORAGE

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Auxiliary feedwater pump lube oil cooler and governor oil cooler channels and covers	Pressure boundary	Cast iron	Treated water	Loss of material	Chemistry Control Program Auxiliary Feedwater Pump Oil Coolers Inspection
Auxiliary feedwater pump lube oil cooler and governor oil cooler shells Lube oil pump casings Lube oil reservoirs Piping/fittings	Pressure boundary	Carbon steel	Lubricating oil	None	None required
Auxiliary feedwater pump lube oil cooler and governor oil cooler tube bundles	Pressure boundary Heat transfer	Admiralty brass Stainless steel	Treated water (inside diameter)	Loss of material	Chemistry Control Program
			Lubricating oil (outside diameter)	None	None required
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Treated water	Loss of material	Chemistry Control Program

TABLE 3.5-3 (continued)
AUXILIARY FEEDWATER AND CONDENSATE STORAGE

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Valves Piping/fittings	Pressure boundary	Carbon steel Low alloy steel	Treated water	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program[1]
Valves Piping/ fittings Steam traps	Pressure boundary	Carbon steel	Treated water - secondary Air/Gas	Loss of material	Auxiliary Feedwater Steam Piping Inspection Program
Valves Piping/fittings (upstream of MOVs 3/4 1403, 1404, and 1405	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program
Valves Piping/fittings Tubing/fittings Flex hoses Rupture disks	Pressure boundary	Stainless steel	Air/Gas	None	None required
Orifices	Pressure boundary Throttling	Stainless steel Carbon steel	Treated water	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program[1]

NOTE: 1. Galvanic corrosion only at carbon steel contact points with stainless steel, brass, and low alloy steel for these components.

TABLE 3.5-3 (continued)
AUXILIARY FEEDWATER AND CONDENSATE STORAGE

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Condensate storage tanks	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Auxiliary feedwater pumps	Pressure boundary	Low alloy steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Auxiliary feedwater pump turbine casings	Pressure boundary	Carbon steel	Outdoor	Loss of material	Auxiliary Feedwater Steam Piping Inspection Program
Auxiliary feedwater pump lube oil cooler and governor oil cooler shells and channels	Pressure boundary	Carbon steel Cast iron	Outdoor	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings Steam traps (non-insulated)	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings (insulated)	Pressure boundary	Carbon steel	Outdoor	Loss of material	Auxiliary Feedwater Steam Piping Inspection Program

TABLE 3.5-3 (continued)
AUXILIARY FEEDWATER AND CONDENSATE STORAGE

Component / Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Valves Piping/fittings Tubing/fittings Orifices Rupture disks Flex hoses	Pressure boundary	Stainless steel	Outdoor	None	None required
Orifices	Pressure boundary Throttling	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Outdoor	None	None required

GALL Demonstration

Use Of SRP – LR Table Format

Use Of Five Column Table For Items Not Covered In GALL

Chapter 2: Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results

2.3 SCOPING AND SCREENING RESULTS: MECHANICAL SYSTEMS

The determination of mechanical systems within the scope of license renewal is made by initially identifying Plant X mechanical systems and then reviewing them to determine which ones satisfy one or more of the criteria contained in 10 CFR 54.4. This process is described in Section 2.1 and the results of the mechanical systems review are contained in Section 2.2. Section 2.1 also provides the methodology for determining the components within the scope of 10 CFR 54.4 that meet the requirements contained in 10 CFR 54.21(a)(1). The components that meet these screening requirements are identified in this section. These identified components subsequently require an aging management review for license renewal.

The screening results are provided below in four subsections:

- Reactor Coolant Systems
- Engineered Safety Features Systems
- Auxiliary Systems
- Steam and Power Conversion Systems.

2.3.4 STEAM AND POWER CONVERSION SYSTEMS

The Steam and Power Conversion Systems act as a heat sink to remove heat from the reactor and convert the heat generated in the reactor to the plant's electrical output. The following systems are included in this subsection:

- Main Steam
- Feedwater and Blowdown
- Auxiliary Feedwater

2.3.4.1 FEEDWATER

The Feedwater System consists of a supply line to each steam generator. A feedwater isolation valve in each steam generator supply line is located just outside the containment penetration. These valves are motor operated, closing automatically on a Steam Generator Isolation Signal (SGIS). A check valve in each supply line, located inside containment, prevents uncontrolled blowdown from the affected steam generator in the event of a feedwater line break.

The license renewal boundary also includes the piping from the steam generators to the isolation valves for the Blowdown and Primary Sampling Systems.

The Feedwater System boundary is denoted by License Renewal (LR) flags on the following drawing:

- 11405-M-253 Sheet 1, Flow Diagram Steam Generator Feedwater and Blowdown P & ID

The list of Feedwater System component types subject to aging management review and their intended functions is shown in Table 2.3.4.1.

Table 2.3.4.1
Feedwater System Component Types Subject to Aging Management Review and their Intended Functions

Component Type	Intended Functions
PIPES and FITTINGS	Pressure Boundary
VALVES	Pressure Boundary
BOLTING	Pressure Boundary

2.3.4.2 AUXILIARY FEEDWATER

The Auxiliary Feedwater (AFW) System supplies feedwater to the steam generators whenever the reactor coolant system temperature is above 300 deg F and the main feedwater system is not in operation. The AFW System contains one safety-related emergency feedwater storage tank, two safety-related pumps, one non-safety-related pump, plus related piping, valves, and instrumentation. One safety-related pump is electric motor driven, and the other is steam turbine driven. The non-safety-related pump is diesel engine driven. The AFW System can supply the steam generators through two different flow paths. One flow path is through an interconnection with the main feedwater piping upstream of the feedwater regulating valves, after which the water enters the each steam generator through the normal feed ring. This flow path is typically used during normal plant heatup and cooldown evolutions. The other flow path connects to the AFW nozzles on the steam generators. Either safety-related AFW pump can pump water from the EFWST to the steam generators. The non-safety-related AFW pump may be used to pump water from the condensate storage tank to the steam generators. In the event of automatic initiation, such as when the steam generator low level setpoint is reached, the AFW System is designed to automatically start both safety-related AFW pumps and to direct flow to the steam generators via the flow path to the AFW nozzles.

The AFW System boundary is highlighted on the following drawings:

- 11405-M-253 sh. 1, Flow Diagram Steam Generator Feedwater & Blowdown P&ID
- 11405-M-253 sh. 4, Flow Diagram Steam Generator Feedwater & Blowdown P&ID
- 11405-M-254 sh. 2, Flow Diagram Condensate P&ID
- E-4144, FW-10 Lube Oil Schematic P & ID
- EM-1109/1110, Instrument & Control Equipment List
- EM-1368/1369, Instrument & Control Equipment List
- EM-1038, Instrument & Control Equipment List
- EM-1039, Instrument & Control Equipment List
- EM-1117, Instrument & Control Equipment List

The list of Auxiliary Feedwater System component types subject to aging management review and their intended functions is shown in Table 2.3.4.2.

Table 2.3.4.2
Auxiliary Feedwater System Component Types Subject to Aging Management Review and their Intended Functions

Component Type	Intended Functions
ACCUMULATOR	Pressure Boundary
CONTROLLER	Pressure Boundary
FILTER / STRAINER	Pressure Boundary Only
FILTER / STRAINER	Pressure Boundary & Filtration
FLOW ELEMENT / ORIFICE	Pressure Boundary & Flow Measurement
HEAT EXCHANGER	Pressure Boundary
INDICATOR/ RECORDER	Pressure Boundary
PIPE & FITTINGS	Pressure Boundary
PUMP	Pressure Boundary

Table 2.3.4.2 Auxiliary Feedwater System Component Types Subject to Aging Management Review and their Intended Functions	
Component Type	**Intended Functions**
TRANSMITTER/ ELEMENT	Pressure Boundary
TURBINE	Pressure Boundary
VALVE	Pressure Boundary
TANK	Pressure Boundary
BOLTING	Pressure Boundary
CONTROLLER	Pressure Boundary
FLOW ELEMENT / ORIFICE	Pressure Boundary Only
INDICATOR / RECORDER	Pressure Boundary

2.3.4.3 MAIN STEAM AND TURBINE STEAM EXTRACTION

The Main Steam and Turbine Steam Extraction System consists of piping from each steam generator that penetrates the Containment (steam generators are addressed in Sections 2.3.1.3 and 3.2.3). Main steam isolation valves are located in each pipe just outside containment. These pipes connect to a common header which leads to the four turbine stop valves and the Main Steam Isolation Valve (MSIV) in each pipe. Also included in the Main Steam and Turbine Steam Extraction System boundary is the piping to the turbine-driven auxiliary feedwater pump and the associated drains and vents. The MSIV packing leakoff line isolation valve is the boundary prior to the low pressure heaters.

The Main Steam and Turbine Steam Extraction System boundary is highlighted on the following drawing:

- 11405-M-252 Sheet 1, Flow Diagram Steam P & ID

The list of Main Steam and Turbine Steam Extraction System component types subject to aging management review and their intended functions is shown in Table 2.3.4.3.

Table 2.3.4.3
Main Steam and Turbine Steam Extraction System Component Types Subject to Aging Management Review and their Intended Functions

Component Type	Intended Functions
FILTERS/STRAINERS	Pressure Boundary & Filtration
PIPES & FITTINGS	Pressure Boundary
VALVES	Pressure Boundary
BOLTING	Pressure Boundary

Chapter 3 AGING MANAGEMENT REVIEW RESULTS

For those structures and components that are identified as being subject to an aging management review, 10 CFR 54.21(a)(3) requires demonstration that the effects of aging will be adequately managed so that their intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. The information provided in this chapter provides essential input to the required aging management review as it identifies and discusses the aging effects requiring management.

This chapter describes the results of the aging management reviews of the components and structures, identified in Chapter 2, Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results. This chapter:

- provides references to the descriptions of common aging management programs
- identifies the components and structural components subject to aging management review, and their intended functions
- discusses the materials and internal and external environments
- describes or references the processes used to identify aging effects
- describes industry and plant-specific operating experiences with respect to the aging effects
- identifies the aging effects requiring management
- lists the aging management programs for aging effects requiring management.

For those structures and components identified as being subject to an aging management review, the results are contained in Section 3.1 for Reactor Coolant Systems, Section 3.2 for Engineered Safety Features Systems, Section 3.3 for Auxiliary Systems, Section 3.4 for Steam And Power Conversion Systems, Section 3.5 for structures and structural components, and Section 3.6 for electrical and instrumentation and controls. Aging management program descriptions are contained in Appendix B.

3.4 Aging Management of Steam and Power Conversion System

The Plant X systems evaluated in this section of the application consist of the main steam and extraction steam systems, the main and auxiliary feedwater systems, condensate system, steam generator blowdown system and associated components.

The Main Steam System consists of piping from each steam generator that penetrates the containment wall to the main steam isolation valves that are located in each pipe just outside containment. The Extraction Steam System consists of steam lines leading from the turbine to the feedwater heaters including drains. Also included in the Main Steam and Extraction Steam System boundary is the piping to the turbine-driven auxiliary feedwater pump and the associated drains and vents.

The Feedwater System consists of a supply line to each steam generator. A feedwater isolation valve in each steam generator supply line is located just outside the containment penetration. These valves are motor operated, closing automatically on a Steam Generator Isolation Signal (SGIS). A check valve in each supply line, located inside containment, prevents uncontrolled blowdown from the affected steam generator in the event of a feedwater line break. The Feedwater System boundary also includes the piping from the steam generators to the isolation valves for the Blowdown and Primary Sampling Systems.

The Auxiliary Feedwater (AFW) System supplies feedwater to the steam generators whenever the reactor coolant system temperature is above 300 degrees F and the main feedwater system is not in operation. The AFW System contains one safety-related emergency feedwater storage tank (EFWST), two safety-related pumps, one non-safety-related pump, plus related piping, valves, and instrumentation. One safety-related pump is electric motor driven, and the other is steam turbine driven. The non-safety-related pump is diesel engine driven. The AFW System can supply the steam generators through two different flow paths. One flow path is through an interconnection with the main feedwater piping upstream of the feedwater regulating valves, after which the water enters the each steam generator through the normal feed ring. This flow path is typically used during normal plant heatup and cooldown evolutions. The other flow path connects to the AFW nozzles on the steam generators. Either safety-related AFW pump can pump water from the EFWST to the steam generators. The non-safety-related AFW pump may be used to pump water from the condensate storage tank to the steam generators. In the event of automatic initiation, such as when the steam generator low level setpoint is reached, the AFW System is designed to automatically start both safety-related AFW pumps and to direct flow to the steam generators via the flow path to the AFW nozzles.

OPERATING EXPERIENCE:

Site: Searches were conducted of pertinent site records, including the Condition Report (CR) system, and discussions were held with appropriate site personnel. These efforts revealed no evidence of additional aging effects requiring management.

Industry: Searches were conducted of industry records. These reviews revealed no evidence of additional aging effects requiring management.

3.4.1 Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Table 3.4.1 shows the component groups (combinations of materials and environments), and aging management programs evaluated in the GALL Report that are relied on for license renewal of the Steam and Power Conversion System for Plant X.

3.4.1.1 Further Evaluation of Aging Management as Recommended by GALL

3.4.1.1.1 Thermal Fatigue

Fatigue was not identified as a TLAA for Plant X. Thermal fatigue was identified as an aging effect requiring management. The Fatigue Monitoring Program described in Appendix B manages fatigued.

3.4.1.1.2 Water Chemistry

GALL Report Sections VIII G1.1 and VIII G1.2 indicate that the verification of the effectiveness of the water chemistry program should be conducted with an inspection of stagnant flow locations within the systems. These inspections are either being conducted in accordance with the Periodic Surveillance and Preventive Maintenance Program or will be conducted in accordance with the Age-Related Degradation Inspection Program prior to expiration of the current license. Both programs are described in Appendix B.

3.4.1.1.3 Carbon steel components of oil coolers in oil

The loss of material due to microbiologically influenced corrosion is only applicable to carbon steel components of oil coolers at Plant X because the environment for auxiliary feedwater piping is only treated water. If there is a potential for water contamination and water pooling in a lube oil system, loss of material due to general corrosion and microbiologically influenced corrosion are concerns for carbon steel. Corrosion is therefore considered to be an aging effect requiring management due to the need to

Table 3.4.1

Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	***Aging Effect / Mechanism***	***Aging Management Program***	***GALL Further evaluation recommended***	***Discussion***
Piping and fittings in main feedwater line and in steam line	Cumulative fatigue damage	Fatigue Monitoring Program	Yes, TLAA.	See Section 3.4.1.1.1
Carbon steel piping, valve bodies, pump casing, and tanks. (except main steam system)	Loss of material	Water Chemistry	Yes, detection of aging effects should be further evaluated	This group includes low alloy steel components at Plant X. See Section 3.4.1.1.2 for discussion of further evaluation.
Oil coolers	Loss of material from general and microbiologically influenced corrosion	Periodic Surveillance and Preventive Maintenance	Yes, plant specific	See Section 3.4.1.1.3
Carbon steel piping, valve bodies, and pump casings	Wall thinning from flow-accelerated corrosion	Flow Accelerated Corrosion	No	The information in the GALL report bounds Plant X
Carbon steel piping and valve bodies in main steam system	Loss of material from crevice and pitting corrosion	Water Chemistry	No	This group includes low alloy steel components at Plant

Table 3.4.1

Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	Aging Effect / Mechanism	Aging Management Program	GALL Further evaluation recommended	Discussion
				X. The information in the GALL report bounds Plant X
External surface of carbon steel components	Loss of material from atmospheric corrosion	General Corrosion of External Surfaces		Aging management program is different from that described in GALL – see Section 3.4.1.2.1
Closure bolting in high-pressure or high-temperature systems	Loss of material from atmospheric corrosion and crack initiation and growth from cyclic loading, stress corrosion cracking.	General Corrosion of External Surfaces		Aging management program is different from that described in GALL – see Section 3.4.1.2.2

employ periodic lube oil sampling to ensure that water is not present, thereby confirming that the condition which could potentially cause this aging effect does not exist.

As discussed in Appendix B the Periodic Surveillance and Preventive Maintenance ensures water is not present in lubricating oil and that the oil is changed on a refueling frequency.

3.4.1.2 Aging Management Programs or Evaluations that Are Different from those Described in the GALL Report

3.4.1.2.1 External surfaces of carbon steel components

Carbon steel items (with or without an external coating) in a plant indoor air external environment are susceptible to external general corrosion, although such corrosion would be minimal if the carbon steel remains in a dry condition. As discussed in Appendix B the General Corrosion of External Surfaces Program manages this aging effect.

3.4.1.2.2 Pressure boundary bolting on treated water or oil systems

Crack initiation and growth from cyclic loading, stress corrosion cracking has not been observed in closure bolting on systems containing non-borated treated water and on systems containing oil located in a plant indoor air external environment.

General corrosion is an aging effect requiring management for closure bolting due to the potential for external leakage of the process fluid, although external leakage of non-borated treated water would not be expected to rapidly corrode bolting.

No aging effects requiring management were identified for pressure boundary bolting on oil systems because (1) the bolting is routinely exposed to a plant indoor air environment which is not conducive to any aging effects, and (2) external leakage of oil will not corrode carbon or low-alloy steel bolting materials.

As discussed in Appendix B the General Corrosion of External Surfaces Program manages this aging effect.

3.4.2 Components or Aging Effects that Are Not Addressed in the GALL Report

Table 3.4.2 contains Steam and Power Conversion System aging management review results for internal and external environments. These tables include the component types, materials, environments, aging effects requiring management, and the programs and activities for managing aging.

The following combinations of materials and environments exist for the components subject to aging management in the Steam and Power Conversion System.

- Aluminum in Oil
- Copper Alloy in Oil
- Copper Alloy in Treated Water
- Glass in Oil or Treated Water
- Stainless Steel in Treated Water and Saturated steam
- Stainless Steel in Oil
- Aluminum in Plant Indoor Air
- Copper Alloy in Plant Indoor Air
- Stainless Steel in Plant Indoor Air
- Glass in Plant Indoor Air

3.4.2.1 Aluminum in Oil

Component Group Description:

This group includes aluminum and aluminum alloy items with a lubricating oil internal environment.

Aging Effects Requiring Management, and Mechanisms:

Loss of Material

If there is a potential for water contamination and water pooling in a lube oil system, loss of material is a concern. Loss of material is therefore an aging effect requiring management due to the need to employ periodic lube oil sampling to ensure that water is not present.

Aging Management Program

As discussed in Appendix B the Periodic Surveillance and Preventive Maintenance ensures water is not present in lubricating oil and that the oil is changed on a refueling frequency.

3.4.2.2 Copper Alloy in Oil

Component Group Description:

This group includes copper and copper alloy items in a lubricating oil internal environment.

Aging Effects Requiring Management, and Mechanisms:

Loss of Material

There is a potential for loss of material of copper alloys in a treated water environment if the zinc content of the material is greater than 15%. Loss of material is identified as an aging effect requiring management for items in this group because their specific zinc content could not be confirmed to be in a range where loss of material aging effects are not plausible.

Aging Management Program

As discussed in Appendix B the Periodic Surveillance and Preventive Maintenance ensures water is not present in lubricating oil and that the oil is changed on a refueling frequency.

3.4.2.3 Copper Alloy in Treated Water

Component Group Description:

Includes copper & copper alloy items in treated water as an internal environment.

Aging Effects Requiring Management, and Mechanisms:

Loss of Material

If there is a potential for water contamination and water pooling in a lube oil system, loss of material is a concern. Loss of material is therefore an aging effect requiring management due to the need to employ periodic lube oil sampling to ensure that water is not present

Aging Management Program

As discussed in Appendix B the Periodic Surveillance and Preventive Maintenance ensures water is not present in lubricating oil and that the oil is changed on a refueling frequency.

3.4.2.4 Glass in Oil or Treated Water

Component Group Description:

This AMR group covers glass items, such as sight glasses, where the glass functions as part of a fluid pressure boundary, and the internal environment is oil or water.

Aging Effects Requiring Management, and Mechanisms:

Sight glasses are used in applications such as local tank level indicators and pipe flow indicators. The glass functions as part of the pressure boundary of the respective system.

Glass is an amorphous inorganic oxide cooled to a rigid condition without crystallization. Depending on the desired properties of the glass, varying amounts of modifiers, fluxes, and stabilizers are added. Glass is susceptible to hydrofluoric and caustic attack and it is subject to slight attack by hot water. It is hydrolytically decomposed during hot water attack rather than dissolved. Its resistance to hot water is dependent on the composition of the glass (e.g., modifiers, fluxes, and stabilizers). Uniform or selective attack can occur.

The glass of level gauges and flow indicators is exposed to chemically controlled DI water in various plant tanks and pipelines at essentially ambient temperature. It is not exposed to hot water, hydrofluoric, or caustic conditions.

The glass is not exposed to conditions that may degrade it. Glass is unaffected by aging mechanisms and is not subject to any aging effects requiring management.

3.4.2.5 Stainless Steel in Treated Water and Saturated Steam

Component Group Description:

This group includes stainless steel components with an internal environment of treated water.

Aging Effects Requiring Management, and Mechanisms:

Loss of Material - Pitting Corrosion

Pitting corrosion is not a plausible aging effect for stainless steel in a treated water environment if halogens are less than 150 ppb and sulfates are less than 100 ppb. Pitting corrosion is considered to be an aging effect requiring management due to the need to adhere to chemistry limits for treated water which ensure that these parameters are in a range where this mechanism is not plausible.

Loss of Material - Crevice Corrosion

Crevice corrosion is not a plausible aging effect for stainless steel in a treated water environment if the dissolved oxygen level is less than 100 ppb. Crevice corrosion is considered to be an aging effect requiring management due to the need to adhere to chemistry limits for treated water which ensure that these parameters are in a range where this mechanism is not plausible.

Cracking

Cracking is not a plausible aging effect for stainless steel in a treated water environment if halogens are less than 150 ppb and sulfates are less than 100 ppb.

Cracking is considered to be an aging effect requiring management due to the need to adhere to chemistry limits for treated water which ensure that these parameters are in a range where this mechanism is not plausible.

Aging Management Program

As discussed in Appendix B the Water Chemistry and Closed-Cycle Cooling Water Program ensures water chemistry limits are maintained.

3.4.2.6 Stainless Steel in Oil

Component Group Description:

This group includes stainless steel items with lubricating oil as an internal environment.

Aging Effects Requiring Management, and Mechanisms:

Loss of Material

If there is a potential for water contamination and water pooling in a lube oil system, loss of material due to pitting & crevice corrosion is a concern. Loss of material due to galvanic corrosion can also be a concern if the stainless steel is in contact with a more cathodic material such as brass/bronze; however, galvanic corrosion is not an issue if there is no water present to provide an electrolytic environment. Loss of material is therefore conservatively identified as an aging effect requiring management due to the need to employ periodic lube oil sampling to ensure that water is not present, thereby confirming that the condition which could potentially cause this aging effect does not exist.

Aging Management Program

As discussed in Appendix B the Periodic Surveillance and Preventive Maintenance ensures water is not present in lubricating oil and that the oil is changed on a refueling frequency.

3.4.2.7 Aluminum in Plant Indoor Air

Component Group Description:

This group includes aluminum and aluminum alloy items with an external environment of plant indoor air.

Aging Effects Requiring Management, and Mechanisms:

None

No aging effects were identified for aluminum in an air environment. Aluminum in an indoor air environment is not susceptible to galvanic corrosion due to absence of significant electrolyte in plant indoor air. Items in this group are not susceptible to a wetted environment.

3.4.2.8 Copper Alloy in Plant Indoor Air

Component Group Description:

This group includes copper and copper alloy items (e.g., brass, bronze) with an external environment of plant indoor air.

Aging Effects Requiring Management, and Mechanisms:

None

No aging effects for copper alloy in an indoor air environment were identified. Galvanic corrosion is not a concern because plant indoor air is not a significant electrolytic environment. Copper alloy is not susceptible to a wetted (water) external environment.

3.4.2.9 Stainless Steel in Plant Indoor Air

Component Group Description:

This group includes all 300 series, stainless steel items exposed only to plant indoor air (i.e., valve bodies, bolts,etc.).

Aging Effects Requiring Management, and Mechanisms:

None

No aging effects were identified for stainless steel in plant indoor air. Other chemicals must also be present (i.e., halide ions, bromides, chlorides, etc.) which are not present in sufficient quantity to justify aging effects for this material/environment.

3.4.2.10 Glass in Plant Indoor Air

Component Group Description:

This group includes glass items (e.g., sight glasses, level glasses) with an external environment of plant indoor air.

Aging Effects Requiring Management, and Mechanisms:

None

The glass is not exposed to conditions that may degrade it. Glass is unaffected by aging mechanisms and is not subject to any aging effects requiring management.

3.4.3 Conclusion

The aging effects requiring management are adequately managed by the following programs:

Water Chemistry and Closed-Cycle Cooling Water Program
General Corrosion of External Surfaces Program
Age Related Degradation Inspection Program
Periodic Surveillance and Preventive Maintenance Program

These programs are described in Appendix B.

Table 3.4.2 Steam and Power Conversion System Component Types Subject to Aging Management				
Component Types	**Material**	**Environment**	**AERMs**	**Program/Activity**
Pipes, Fittings and Valves	Stainless Steel	Treated Water (greater than 200 deg F)	Loss of Material	Water Chemistry and Closed-Cycle Cooling Water Program
Bolting	Stainless Steel	Containment Air/Plant Indoor Air	None	None Required
Pipes, Fittings, Valves Filter/Strainer, Heat Exchanger, Flow Element/Orifice, Transmitter Element	Stainless Steel	Containment Air/Plant Indoor Air	None	None Required
Pipes, Fittings and Valves	Stainless Steel	Saturated Steam	Cracking	Water Chemistry and Closed-Cycle Cooling Water Program
Pipes, Fittings and Valves	Stainless Steel	Saturated Steam	Loss of Material	Water Chemistry and Closed-Cycle Cooling Water Program
Pump	Aluminum	Lubricating Oil possibly contaminated with water	Loss of Material	Periodic Surveillance and PM Program
Pump	Aluminum	Plant Indoor Air	None	None Required
Heat Exchanger	Copper Alloy	<90°C(194°F) Treated Water	Loss of Material - Selective Leaching	Age-Related Degradation Inspection (ARDI)
Heat Exchanger	Copper Alloy	<90°C(194°F) Treated Water	Loss of Material - Wear	Age-Related Degradation Inspection (ARDI)
Pipes, Fittings, Valves Filter/Strainer, Heat Exchanger	Copper Alloy	Lubricating Oil possibly contaminated with water	Loss of Material	Periodic Surveillance and PM Program

Table 3.4.2 Steam and Power Conversion System Component Types Subject to Aging Management				
Component Types	**Material**	**Environment**	**AERMs**	**Program/Activity**
Pipes, Fittings, Valves Filter/Strainer, Heat Exchanger	Copper Alloy	Plant Indoor Air	None	None Required
Indicator/Recorder	Glass	<90°C(194°F) Treated Water	None	None Required
Indicator/Recorder	Glass	Lubricating Oil possibly contaminated with water	None	None Required
Indicator/Recorder	Glass	Plant Indoor Air	None	None Required
Pipes, Fittings, Valves Filter/Strainer, Heat Exchanger, Flow Element/Orifice, Transmitter Element	Stainless Steel	<90°C(194°F) Treated Water	Cracking	Water Chemistry and Closed-Cycle Cooling Water Program Age-Related Degradation Inspection (ARDI)
Pipes, Fittings, Valves Filter/Strainer, Heat Exchanger, Flow Element/Orifice, Transmitter Element	Stainless Steel	<90°C(194°F) Treated Water	Loss of Material	Water Chemistry and Closed-Cycle Cooling Water Program Age-Related Degradation Inspection (ARDI)
Filter/Strainer	Stainless Steel	Lubricating Oil possibly contaminated with water	Cracking	Water Chemistry and Closed-Cycle Cooling Water Program

Process to Develop LRA Using LRSRP

- Database contains "six column" component level information
  - Component
  - Intended function
  - Material
  - Environment
  - Aging effect
  - Aging management program

Process to Develop LRA Using LRSRP Chapter 2

- Component level intended functions included in Chapter 2 tables for each system within scope of license renewal

Process to Develop LRA Using LRSRP Chapter 3

- Chapter Sections include
  - Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal
    - Further Evaluation of Aging Management as Recommended by GALL
    - Aging Management Programs or Evaluations that Are Different from those Described in the GALL Report
  - Components or Aging Effects that Are Not Addressed in the GALL Report

Process to Develop LRA Using LRSRP Chapter 3 Referencing GALL

- For each line item from six column table identify comparable GALL line item for same material, environment, aging effect and aging management program
  - Identify any aging management evaluations that are different than GALL
  - Identify any aging management programs that are different than GALL

Process to Develop LRA Using LRSRP Chapter 3 Referencing GALL

- Group GALL line items consistent with the GALL Volume 1 tables and SRP tables
- Develop LRA Tables 3.X.1 and applicable discussion

Process to Develop LRA Using LRSRP Chapter 3 Plant Specific

- Group plant specific line items in a manner similar to that of GALL Volume 1 tables and SRP tables
- Develop LRA Tables 3.X.2 and applicable discussion showing
  - Component Group
  - Material
  - Environment
  - Aging Effect
  - Aging Management Program