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BGE

May 23, 1997

U. S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318
Request for Review and Approval of System and Commodity Reports for License Renewal

REFERENCES:

(a) Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated August 18, 1995, Integrated Plant Assessment Methodology

(b) Letter from Mr. D. M. Crutchfield (NRC) to Mr. C. H. Cruse (BGE), dated, April 8, 1996, Final Safety Evaluation (FSE) Concerning The Baltimore Gas and Electric Company Report entitled, Integrated Plant Assessment Methodology

(c) Letter from Mr. S. F. Newberry (NRC) to Mr. C. H. Cruse (BGE), dated April 15, 1996, License Renewal Demonstration Program Site Visit, Calvert Cliffs Nuclear Power Plant Trip Report

(d) Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated May 22, 1996, Request for Review and Approval of License Renewal IPA System and Commodity Reports

(e) Letter from Mr. S. C. Flanders (NRC), dated March 4, 1997, "Summary of Meeting with Baltimore Gas and Electric Company (BGE) on BGE License Renewal Activities"

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This letter forwards the attached Integrated Plant Assessment (IPA) System and Commodity Reports for review and approval in accordance with 10 CFR Part 54, the license renewal rule. Should we apply for License Renewal, we will reference IPA System and Commodity Reports as meeting the requirements of 10 CFR 54.21(a), "Contents of application-technical information," and the demonstration required by 10 CFR 54.29(a)(1), "Standards for issuance of a renewed license."

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The information in these reports is accurate as of the dates of the references listed therein. Per 10 CFR 54.21(b), an amendment or amendments will be submitted that identify any changes to the current licensing basis that materially affect the content of the license renewal application.

In Reference (a), Baltimore Gas and Electric Company submitted the IPA Methodology for review and approval. In Reference (b), the Nuclear Regulatory Commission (NRC) concluded that the IPA Methodology is acceptable for meeting 10 CFR 54.21(a)(2) of the license renewal rule, and if implemented, provides reasonable assurance that all structures and components subject to an aging management review pursuant to 10 CFR 54.21(a)(1) will be identified. Additionally, the NRC concluded that the methodology provides processes for demonstrating that the effects of aging will be adequately managed pursuant to 10 CFR 54.21(a)(3) that are conceptually sound and consistent with the intent of the license renewal rule.

As part of the Nuclear Energy Institute (NEI) Demonstration Project, the NRC visited the Calvert Cliffs Nuclear Power Plant site and reviewed sample license renewal results. In Reference (c), the NRC forwarded their report of observation of Baltimore Gas and Electric Company's implementation of NEI 95-10, Revision 0, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule." In both References (b) and (c), we received comments regarding the level of detail in our IPA System and Commodity Reports. In Reference (d), we forwarded five IPA reports for review and approval with the understanding that they would be resubmitted along with the rest of the reports after format and content issues had been resolved. In Reference (e), the NRC stated that they were prepared to begin the technical review. We look forward to your comments on the reports as they are submitted and your continued cooperation with our license renewal efforts.

Should you have questions regarding this matter, we will be pleased to discuss them with you.

Very truly yours,

STATE OF MARYLAND :
: **TO WIT:**
COUNTY OF CALVERT :

I, Charles H. Cruse, being duly sworn, state that I am Vice President, Nuclear Energy Division, Baltimore Gas and Electric Company (BGE), and that I am duly authorized to execute and file this response on behalf of BGE. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other BGE employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Subscribed and sworn before me, a Notary Public in and for the State of Maryland and County of Calvert, this 23 day of May, 1997.

WITNESS my Hand and Notarial Seal: Michelle D Hall
Notary Public

My Commission Expires: February 2, 1998
Date

CHC/SJR/dlm

Attachments:
(1) Appendix A - Technical Information; 4.3 - Reactor Vessel Internals System
(2) Appendix A - Technical Information; 5.7 - Diesel Fuel Oil System
(3) Appendix A - Technical Information; 5.9 - Feedwater System
(4) Appendix A - Technical Information; 5.14 - Radiation Monitoring System

cc: D. A. Brune, Esquire
J. E. Silberg, Esquire
Director, Project Directorate I-1, NRC
A. W. Dromerick, NRC
S. C. Flanders, NRC
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Resident Inspector, NRC
R. I. McLean, DNR
J. H. Walter, PSC

ATTACHMENT (1)

APPENDIX A - TECHNICAL INFORMATION

4.3 - REACTOR VESSEL INTERNALS SYSTEM

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
May 23, 1997

4.3 Reactor Vessel Internals

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Applic on (LRA), addressing the Reactor Vessel Internals (RVI) System. The RVI System was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

4.3.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Normally in the IPA process, component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. This scoping is to determine components subject to aging management review (AMR) and begins with a listing of passive intended functions. Then the component types would be dispositioned as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report. For the RVI, a slightly different approach was used for component level scoping.

Section 4.3.1.1 presents the results of the system level scoping. Section 4.3.1.2 discusses the approach used for component level scoping of the RVI. Section 4.3.1.3 presents the results of scoping to determine which components were subject to an AMR.

Historical operating experience, judged to be pertinent, is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, and through documented discussions with currently-assigned, cognizant CCNPP personnel.

4.3.1.1 System Level Scoping

This section begins with a description of the system, which includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

System Description/Conceptual Boundaries

When the RVI System was scoped, it included the reactor core and the RVI structures, which together provide the heat source and direct the flow of coolant through the reactor vessel. The system also included reactor component handling equipment. [Reference 1, Table 1, System 84]

The major components of the reactor core are 217 fuel assemblies and 77 control element assemblies (CEAs, also called the control rods). The major components of the RVI structures are the core support barrel (CSB), the lower core support structure (including the core shroud [CS]), and the upper guide structure (UGS) (including the 65 CEA shrouds and incore instrumentation [ICI] guide tubes). The reactor component handling equipment includes the reactor vessel head lifting rig, the RVI lifting rigs, and the surveillance capsule retrieval tool. [Reference 1, Table 1, System 84]

The reactor coolant enters the upper section of the reactor vessel, flows downward between the inside of the reactor vessel wall and the outside of the CSB, passes through the flow skirt (also called the baffle), and into the lower plenum. The coolant then flows upward through the RVI and the reactor core removing heat from the fuel rods in the fuel assemblies, and exits the reactor vessel. [Reference 2, Section 3.1]

The reactor's fuel assemblies are arranged to approximate a right circular cylinder with an equivalent diameter of 136 inches and an active height of 136.7 inches. Each fuel assembly consists of 176 rods (pins) and five guide tubes. The pins contain fuel or neutron poison materials. An assembly is held together by spacer grids, and top and bottom end fittings. Lateral support and positioning of the fuel rods within an assembly is provided by leaf spring spacer grids welded to the five full-length guide tubes. The guide tubes provide channels to guide CEAs over their entire length and also form the longitudinal structure of the assembly. In selected fuel assemblies, the central guide tube houses ICI. [Reference 2, Section 3.1]

The RVI are designed to: 1) support and orient the fuel assemblies and CEAs; 2) absorb the CEA dynamic loads and transmit these and other loads to the reactor vessel flange; 3) direct reactor coolant flow through the reactor core; and 4) support and orient ICI. [Reference 3, Section 1.1.1]

Section 3.3.3 of the Updated Final Safety Analysis Report (UFSAR) provides a description of the RVI structures. Figures 3.3-1, 3.3-6, 3.3-11, 3.3-13, and 3.3-14 of the UFSAR depict components of the RVI. Table 4-10 of the UFSAR identifies that the RVI are constructed of Type 304 stainless steel and nickel-chromium-iron (Ni-Cr-Fe) alloy steels. These materials were chosen during the design effort since they had shown satisfactory performance in operating reactor plants. [Reference 2, Section 4.1.4.2.1]

The major support member of the RVI is the core support assembly, which consists of the CSB, the lower core support structure, and the CS. The core support assembly is supported by the upper flange of the CSB, which rests on a ledge in the reactor vessel flange. The lower flange of the CSB supports and positions the lower core support structure, which consists of a core support plate (CSP), vertical columns, horizontal beams, and an annular skirt. The weight of the core is supported by the CSP, which transmits the load through the columns to the beams to the skirt to the lower flange of the CSB. The CSP provides support and orientation for the fuel assemblies. The CS, which provides lateral support for the peripheral fuel assemblies, is also supported by the CSP. The lower end of the CSB is restrained radially by six CSB snubbers. [Reference 2, Section 3.3.3.1] The core support assembly normally remains in the reactor vessel during refueling.

The UGS assembly consists of the upper support plate, 65 CEA shrouds, a fuel assembly alignment plate, and a hold-down ring (HDR). The UGS assembly aligns and laterally supports the upper end of the fuel assemblies, maintains the CEA spacing, prevents fuel assemblies from being lifted out of position during a severe accident condition, and protects the CEAs from the effect of coolant cross-flow in the upper plenum. The UGS is handled as a unit and is removed during refueling to gain access to the fuel assemblies in the reactor core. [Reference 2, Section 3.3.3.6]

Operating experience for components of the RVI includes two events that had the potential for a system-wide failure due to an age-related degradation mechanism (ARDM). The first event occurred at another reactor plant and the second occurred at CCNPP. The first event caused one change to one RVI component at CCNPP, the HDR. To date there has been no identified aging effect from the second event, and none is expected.

The event at another plant that was relevant to the CCNPP RVI demonstrates sharing of operating experience and lessons-learned based on specific experience from other pressurized water reactors (PWRs) supplied by Combustion Engineering, Inc. (CE). It is also indicative of the broader sharing of operating event information based on industry-wide experience with water-cooled reactors, and based on experience applicable to just PWRs. Concerns with components at one reactor have generally been considered for all other reactors through cooperative event evaluation efforts.

Early operation of CE's PWRs led to the introduction of a more substantial HDR in the CCNPP units. Originally, CE supplied a component called an expansion compensating ring with their RVI systems. This ring was to preload the UGS against the CSB flange and thereby preload that flange against the vessel support ledge. At the Palisades Plant in the early 1970s, operating experience showed that the expansion compensating ring provided inadequate clamping force on the RVI and would not prevent their movement under normal operating hydraulic loads. This movement resulted in rocking of the RVI and wear of the support ledge in that vessel.

Also around that time, CE determined that irradiation induced growth of zircalloy fuel rods, and grid cage guide tubes may not have been adequately accounted for in the original design. Together, these findings caused CE to review their system's flow loadings on the RVI, the space available for fuel assemblies, and the impact on the expansion compensating ring for the RVI.

The result was a replacement of CE's original design for the expansion compensating ring with one providing increased force to prevent motion and resulting wear. Calvert Cliffs Unit 1 started operations with the redesigned expansion compensating ring and with a spacer shim to accommodate CE's new growth projections for the length of the fuel assemblies.

By the end of Unit 1's first cycle of operation, CE had again redesigned the expansion compensating ring, this time to be the current design of the HDR, which has a larger structural cross-section and develops more preload when the closure head is installed. During the first refueling outage, the Unit 1 expansion compensating ring was removed and replaced by a HDR. Unit 2 started operations after the design of the HDR was available and has always used a HDR and shim. [Reference 4] The HDR design has been effective in eliminating wear, and no other HDR problems have been reported. [Reference 5, Section 5.2.1.3]

The second operating event with the potential for a system-wide failure due to an ARDM was injection of air into the Reactor Coolant System (RCS) and, thus, into the RVI. In 1979, a leaking valve in the Chemical Volume and Control System allowed air to enter the RCS for several weeks following an ion exchanger resin transfer. The injected oxygen depleted the normal hydrogen inventory, which caused crud deposits to collect on the hot surfaces of the core and boron was deposited with the crud. The results were observed changes in the pressure drop across the core (delta-P) and changes to the core's power distribution. The deposits were removed with hydrogen peroxide and plant operating conditions returned to normal during subsequent operations. Procedural modifications included more effective isolation of the Chemical Volume and Control System and use of nitrogen instead of air to eliminate further incidents of this type. [Reference 6]

This operating event is considered to have the potential for an aging impact on the RVI at CCNPP due to industry operating experience with irradiation assisted stress corrosion cracking (IASCC) at boiling water reactors (BWRs). The oxygen concentration in the reactor coolant for BWRs is much higher than for PWRs, and the continuous operation with more oxygen in the coolant is believed to be a major factor in the cracking of RVI components at BWRs. [Reference 7, Section 4.3.2]

In reviewing the historical record on operations at CCNPP, the air intrusion event was identified as a short time when oxygen levels were temporarily above normal concentrations while at power. The relationship between a one-time event and an ARDM occurring much later in a plant's life is not well understood, but in this case, the cause and effect relationship is not likely to be strong. Boiling water reactors have always operated at relatively higher oxygen concentrations and, in contrast, the one-time event at CCNPP represents an exposure duration to higher oxygen concentrations that is but a small fraction of the typical exposure duration for BWR RVI at full power. Since BWRs experience IASCC after many years of operation with relatively high oxygen concentrations, the difference in exposure history to elevated oxygen concentrations should have minimal effect on Unit 1's susceptibility to this aging mechanism.

In support of this position, note that periodic inservice inspections (ISIs) are performed on the CCNPP RVI and have been since the start of operations. The inspections meet the examination type and frequency requirements in the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code). Examinations performed after the event have not identified any failures or indications of adverse conditions resulting from this air intrusion event at CCNPP. Also, continuing evaluation of industry-wide events will ensure timely consideration of IASCC-related developments at other plants, and their implications for CCNPP.

System Interfaces

The reactor core and the RVI interface with three other systems. The fuel assemblies and CEAs interface with the Control Element Drive Mechanisms and Electrical System since the CEAs are driven by the control element drive mechanisms. [Reference 1, Table 1, System 84; Reference 2, Section 3.3.4.1] The RVI interface with the Reactor Pressure Vessel System since the vessel supports and positions the RVI. Both the reactor core and the RVI interface with the RCS, and are completely immersed in the RCS environment.

Section 4.1 of the BGE LRA evaluates the RCS and credits primary chemistry control as an Aging Management Program to manage plausible aging of components in the RCS. Because this chemistry program is credited for the RCS, and because the RVI are totally immersed in the RCS environment, the demonstration of the primary chemistry control program as an Aging Management Program is not repeated in this section. Instead, the aging evaluation for the RVI credits the chemically treated and controlled, demineralized water environment provided by the RCS as an initial condition of this evaluation. [Reference 3, Section 4.2.3]

The reactor component handling equipment within the scope of license renewal and their interfaces with other systems are addressed with the Fuel Handling Equipment and Other Heavy Load Handling Cranes, which is discussed in Section 3.2 of the BGE LRA.

System Scoping Results

System level scoping for the RVI System addressed the pieces of equipment included in the system's conceptual boundaries. However, only the RVI are evaluated in this section of the BGE LRA; the other equipment is either addressed in a different section of the BGE LRA or is not within the scope of license renewal.

In the reactor core, the fuel assemblies have functions during design basis events that make the assemblies within the scope of license renewal. [Reference 1, Table 2] However, the assemblies are replaced at regular intervals based on the fuel cycle of the plant. Since the assemblies are short-lived components, their aging is not discussed further below. The CEAs in the core are discussed with the Control Element Drive Mechanisms and Electrical System in Section 4.2 of the BGE LRA. [Reference 3, Section 1.1.1]

The reactor vessel head lifting rig is discussed with the Fuel Handling Equipment and Other Heavy Load Handling Cranes in Section 3.2 of the BGE LRA. The RVI lifting rigs and the surveillance capsule retrieval tool are not installed components and are not within the scope of license renewal. [Reference 3, Section 1.1.1]

The RVI were determined to be within the scope of license renewal during the system level scoping based on 10 CFR 54.4(a)(1). [Reference 3, Section 1.1.1] The intended function of the RVI was determined to be to:

- Provide structural support for the fuel assemblies, CEAs, and ICI so that they maintain the configuration and flow distribution characteristics assumed in the UFSAR Chapter 14 analyses. [Reference 3, Section 1.1.3]

The RVI will safely perform their intended function during normal operating and design basis event conditions. The RVI are designed to safely withstand forces due to deadweight, handling, temperature and pressure differentials, flow impingement, vibration, and seismic acceleration. [Reference 2, Section 3.1] All components are considered Category I for seismic design. The structural components satisfy stress values given in the ASME Code, Section III. The RVI design provides limits for deflection where this is functionally required. The limitations on stresses or deformations are employed to ensure capability of a safe and orderly shutdown in the combined event of an earthquake and major loss-of-coolant accident. For RVI structures, the stress criteria are given in Table 3.2-1 of the UFSAR. [Reference 2, Section 3.2.3.4]

4.3.1.2 Component Level Scoping

Component level scoping and component pre-evaluation were not applied to the RVI before the aging evaluation to determine which components were subject to an AMR. Instead, all components of the RVI were initially included in the scope of the AMR. During the AMR, some components were determined not to be within the scope of license renewal since they are not required for the RVI to perform their intended function. [Reference 3, Section 1.1.1]

4.3.1.3 Components Subject to Aging Management Review

This subsection describes the device types within the RVI, and those which are subject to an AMR. It begins with a listing of passive intended functions and then dispositions the device types as either evaluated in other sections of the BGE LRA, or evaluated for aging management in this section.

Passive Intended Functions

In accordance with the CCNPP IPA Methodology Section 5.1, the following intended function of the RVI was determined to be passive. [Reference 3, Section 1.1.1]

- Provide structural support for the fuel assemblies, CEAs, and ICI so that they maintain the configuration and flow distribution characteristics assumed in the UFSAR Chapter 14 analyses. [Reference 3, Section 1.1.3]

Device Types Subject to Aging Management Review

Because site database information for the RVI does not contain distinct equipment identifications for each component, a listing of component names was developed specifically for this task, using controlled plant drawings as the source of information. The 17 major RVI assemblies were designated as the device types, and the components of these major assemblies were treated as the individual components of the system. [Reference 3, Section 1.1.1] A list of the 17 device types for the RVI that were evaluated in the AMR is provided in Table 4.3-1. [Reference 3, Section 1.1.2]

As shown in the table, not all device types of the RVI are evaluated in this section of the BGE LRA. The explanations for these device types is as follows:

- The flow baffle is a structure inside of the reactor pressure vessel, but it is welded to supports that are welded to the inside of the vessel wall. The flow baffle is shown as the flow skirt in UFSAR Figure 3.1-1. Since it is welded to the vessel wall, the baffle is evaluated with other vessel components in the Reactor Vessel/Control Element Drive Mechanism System in Section 4.2 of the BGE LRA.
- The CSB snubber and snubber bolts are physically bolted to the CSB, but work with the core stabilizing lugs that are welded to the vessel wall. Together these components limit flow-induced vibrations in the CSB. The design of the CSB snubber assembly is shown in UFSAR Figure 3.3-12. Due to this mating-part relationship, the snubber and snubber bolts are evaluated with the lugs in Section 4.2 rather than in this section of the BGE LRA.
- Some components were found to be outside the scope of license renewal. For the ICI thimbles device type, the only component that is within the scope of license renewal is the ICI flange which provides a pressure retaining boundary for the RCS. Because of this function, the ICI flange is evaluated in Section 4.2 of the BGE LRA with reactor pressure vessel components that have the same function. [Reference 3, Section 1.1.2]

Although none of the RVI components are currently subject to replacement, BGE may elect to replace components for which the AMR identifies further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

TABLE 4.3-1
DEVICE TYPES REQUIRING AMR

No	Device Type Name	Addressed in License Application Section
1	CEA Shroud and Bolts (CEASB)	This Section
2	CEA Shroud Extension Shaft Guides (ESG)	This Section
3	CS	This Section
4	Core Shroud Tie Rod and Bolts (CSTR)	This Section
5	CSB	This Section
6	Core Support Barrel Alignment Key (CSBA)	This Section
7	Core Support Barrel Snubber and Snubber Bolts	Section 4.2
8	Core Support Columns (CSC)	This Section
9	CSP	This Section
10	Flow Baffle	Section 4.2
11	Fuel Alignment Pins (FAP)	This Section
12	Fuel Alignment Plate/Guide Lug Insert (FP)	This Section
13	HDR	This Section
14	ICI Thimble Support Plate (ITSP)	This Section
15	ICI Thimbles	Section 4.2
16	Lower Support Structure Beam Assembly (LSSBA)	This Section
17	Upper Guide Structure Support Plate (UGSP)	This Section

Thus, components for 3 of the 17 device types in the RVI within the scope of license renewal are discussed in the Reactor Pressure Vessel Section of the BGE LRA. The remainder of this section evaluates ARDMs for the other 14 device types listed in Table 4.3-1.

4.3.2 Aging Management

The list of potential ARDMs for the RVI is given in the first column of Table 4.3-2. [Reference 3, Table 4-1] The plausible ARDMs for each device type are identified by a check mark (✓) in the appropriate column. [Reference 3, Table 4-3] As shown in the table, the ITSP is the only device type for which no plausible ARDM was identified.

For efficiency in presenting the results of the evaluations, devices types affected by an ARDM are grouped together into seven groups. These groups are easily identified by moving across each ARDM's row in the table. Where a device type's column has a group number, that device type is in the group.

The discussions below regarding an ARDM are applicable to all devices types in the group. For some device types, not all components are susceptible to a particular ARDM. When this is the case, a note for the exception is provided in the table to explain which components are, or are not, susceptible.

TABLE 4.3-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE REACTOR VESSEL INTERNALS

ARDMs	Device Types for Which ARDM Is Plausible														Not Plausible for RVI
	CEASB	ESG	CS	CSTR	CSB	CSBA	CSC	CSP	FAP	FP	HDR	ITSP	LSSB A	UGSP	
Wear		✓ (1)(a)			✓ (1)(b)	✓ (1)			✓ (1)	✓ (1)(c)	✓ (1)			✓ (1)	
Neutron Embrittlement	✓ (2)(d)		✓ (2)	✓ (2)	✓ (2)(e)		✓ (2)	✓ (2)	✓ (2)	✓ (2)			✓ (2)		
Low Cycle Fatigue			✓ (3)(f)	✓ (3)(g)			✓ (3)	✓ (3)							
Thermal Aging	✓ (4)(h)						✓ (4)								
Stress Relaxation	✓ (5)(i)			✓ (5)(j)											
Stress Corrosion Cracking (SCC)/ Intergranular SCC (IGSCC)/ Intergranular Attack	✓ (6)(k)														
High Cycle Fatigue	✓ (7)(l)														
Erosion															X
Erosion/Corrosion															X
General Corrosion/ Uniform Attack															X
Hydrogen Damage															X

TABLE 4.3-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE REACTOR VESSEL INTERNALS

ARDMs	Device Types for Which ARDM Is Plausible														Not Plausible for RVI
	CEASB	ESG	CS	CSTR	CSB	CSBA	CSC	CSP	FAP	FP	HDR	ITSP	LSSB A	UGSP	
IASCC															X
Pitting/Crevice Corrosion															X

✓ Indicates plausible ARDM determination
(#) Indicates the group number that the device type is in for a plausible ARDM.
( ) Indicates that not all components of a device type are susceptible to the ARDM. The notes below clarify the exceptions.

	Device Type	Components
(a)	ESG	guides only
(b)	CSB	upper flange only
(c)	FP	guide lugs and guide lug inserts only
(d)	CEASB	except spanner nuts and tabs
(e)	CSB	except upper flange
(f)	CS	plates and ribs only
(g)	CSTR	tie rods, nuts, and set screws only
(h)	CEASB	shroud assembly tubes only
(i)	CEASB	shroud bolts only (also called the CEA shroud socket-head cap screws)
(j)	CSTR	tie rods, nuts, and set screws only
(k)	CEASB	shroud bolts only
(l)	CEASB	except spanner nuts, tabs, shroud bolts, retention blocks, and shaft retention pins.

A notable ARDM that is considered not plausible at CCNPP is IASCC. As noted earlier, the IASCC phenomenon has been experienced at BWRs where oxygen levels in the RCS are substantially higher than in PWRs. Although irradiation leading to SCC of austenitic stainless steels has been experienced in water environments with relatively high oxygen concentrations, it has also been hypothesized that IASCC may be a potentially significant ARDM for certain RVI components in PWRs. The most susceptible components would be those where the neutron fluence is $>5x10^{20}$ n/cm^2 for materials with low stress levels (<10 ksi), and $>1x10^{20}$ n/cm^2 for materials with moderate to high stress levels (>10 ksi). [Reference 3, Attachment 7, IASCC] A similar ARDM has been observed in PWR control element drive mechanism tips where very high strain is applied at a very low strain rate in a high fluence field. [Reference 3, Attachment 6s, Code 22]

However, for controlled water chemistry environments where the oxygen concentration is normally less than 5 ppb and the halogen concentration is normally less than 150 ppb, there is no conclusive evidence that demonstrates IASCC should be considered a plausible ARDM for austenitic stainless steels at low stress levels. [Reference 3, Attachment 7, IASCC] Irradiation assisted stress corrosion cracking has not been observed for components with the temperature, oxygen, and radiation levels present for the CCNPP RVI, either in operating plants or in laboratory tests. Therefore, this ARDM is considered not plausible at CCNPP and no specific aging management activity for IASCC is warranted at this time. [Reference 3, Attachment 6s, Code 22]

Below are the evaluation results for the plausible ARDMs. For each group, there is information on the device types that form a group, the materials and environment pertinent to the ARDM for the group of device types, the aging effects, the methods to manage aging, and the aging management program(s). The ARDMs are addressed in the order shown in Table 4.3-2: wear, neutron embrittlement, low cycle fatigue, thermal aging, stress relaxation, SCC, and high cycle fatigue.

Group 1 (Wear) - Device Types, Materials, and Environment

Table 4.3-2 shows that wear is plausible for seven device types in the RVI. This group of device types includes: ESG (guides only), CSB (upper flange only), CSBA, FAP, FP (plate, guide lugs, and guide lug inserts only), HDR, and UGSP. The surfaces of these components for which wear is a plausible ARDM are accessible for visual examination. [Reference 3, Attachment 6s, Code D]

These components are constructed of various stainless and alloy steels (American Society for Testing Materials [ASTM] A-182, A-240, and A-276). [Reference 3, ESG, CSB, CSBA, FAP, FP, HDR, and UGSP, Attachment 3s] Stellite was added to the wear surfaces of the FP guide lugs and guide lug inserts. [Reference 3, FP, Attachment 3]

The operating environment for the components of the RVI pertinent to wear is immersion in the RCS flow which results in the possibility of flow-induced vibrations. Table 3.5-1 of the UFSAR provides the design values for the thermal and hydraulic parameters at full power, and shows that the normal RCS pressure is 2250 psia. [Reference 3, Section 3.5.1] However, the RVI are not part of the RCS pressure boundary and do not withstand a pressure loading of 2250 psia. Rather, these components withstand various local pressure forces and loadings from the flow of the coolant through the vessel from the inlet to the outlet nozzles. During normal operations, there is a relatively low fluid velocity through the RVI. [Reference 3,

Attachment 6s, Code 13] The low fluid velocity minimizes flow-induced vibrations and corresponding wear on component surfaces.

Another aspect of operations that is pertinent to wear is the assembly and disassembly of the RVI for refueling as relative movement between parts occurs during these activities.

Group 1 (Wear) - Aging Mechanism Effects

Wear is considered plausible for RVI components that touch while experiencing relative motion. Wear may occur on surfaces of components that are in contact (e.g., mating flanges) or surfaces that are in close proximity to each other that come into contact and experience intermittent relative motion (e.g., rub together due to flow-induced vibration). Wear may also occur in clamped joints, where relative motion is not intended but happens due to a loss of clamping force and flow-induced vibration. Reactor vessel internals components that are in contact, in close proximity but not designed to touch, or joints that are bolted, keyed, pinned, or press-fit together are potential areas for wear to occur. [Reference 3, Attachment 7, Wear] The effect of wear is a loss of surface metal from the affected material. [Reference 3, Attachment 6s, Code D]

Wear has occurred in PWRs designed by all three U. S. suppliers. [Reference 5, Section 5.3] As discussed in Section 4.3.1.1 above, wear occurred at the CE-designed Palisades Plant. In that case, the wear resulted in replacement of the expansion compensating ring with the HDR at CCNPP Units 1 and 2.

Group 1 (Wear) - Methods to Manage Aging

Mitigation: The potential effects of wear during operation were addressed during the design of the RVI through appropriate tolerances, adequate clearances, sufficient material thickness, choices of component materials, and the use of special surface finishes. Stellite hardfacing was designed into the surfaces where wear was expected to be a concern for RVI components, (i.e., on the FP guide lug and guide lug inserts). Because wear was accounted for in design, programs are not needed for mitigation during operations.

Discovery: Wear can be discovered when the reactor vessel is opened and RVI components are examined. Visual examination techniques would normally be used and would typically include remote visual examinations utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc.

Group 1 (Wear) - Aging Management Programs

Mitigation: There are no CCNPP programs credited for mitigation of wear for the RVI.

Discovery: The Inservice Inspection Long Term Plan governs the conduct of ASME Code Section XI inspections. [Reference 3, Attachment 10] This Plan invokes the requirements of Section XI of the ASME Code, 1983 Edition through Summer 1983 Addenda, and requires inspections of the components in the RVI. [Reference 8, Section 1.2.1]

The purpose of the ISI Program is to control the methods and actions for ensuring the structural and pressure-retaining integrity of safety-related nuclear power plant components in accordance with the rules

of ASME Code Section XI. [Reference 9, Section 3.0D] The ISI Program ensures that Class 1, 2, 3, and MC components are inspected as required by 10 CFR 50.55a and ASME Code Section XI. The type of inspection, the required frequency for the inspection, the components to be inspected, and the acceptance criteria are established in ASME Code Section XI. [Reference 3, Attachment 2, Section XI ISI] The RVI components are Class 1 per ASME Code Section XI. [Reference 10, Subsection IWB]

The scope of the existing ISI Program for the RVI applies to components identified in ASME Code Section XI, Subsection IWB. [Reference 11, Section 1.2A] The ISI Program requirements and the developmental and performance references are provided in Reference 11. Under the ISI Program, the procedural steps involve nondestructive examinations of components. A nondestructive examination (NDE) is an examination and measurement of material properties and conditions to assess a component's fitness for intended use without damaging or impairing component serviceability. [Reference 11, Section 3.0.M]

Inservice inspection requirements in ASME Code Section XI provide for visual examination of accessible areas of the vessel interior, including the space above and below the reactor core that are made accessible for examination by removal of components during refueling outages. The requirements include visual examination of accessible surfaces of the core support structures, and these must be removed from the reactor vessel for examinations. [Reference 10, Table IWB-2500-1]

American Society of Mechanical Engineers Code Section XI ISI visual examinations of the RVI components determine the general mechanical and structural conditions of components and their supports, such as the presence of loose parts, debris, abnormal corrosion products, wear, erosion, corrosion, and the loss of integrity at bolted connections. Examinations may also be used to determine structural integrity, i.e., measure clearances; detect physical displacements; or determine the structural adequacy of supporting elements, the condition of connections between load-carrying structural members, or the tightness of bolting. [Reference 10, IWA-2213, Visual Examination VT-3]

The ASME Code provides requirements for timely correction of relevant abnormal conditions. [Reference 10, IWA-4130 Repair Program] Since wear between two accessible surfaces subject to relative motion is readily detectable by visual examination before the effects of wear begin to compromise the structural integrity or function of components, ISI is adequate to manage such effects. [Reference 3, Attachment 8, Wear] The corrective actions taken will ensure that the RVI components remain capable of performing their intended functions under all current licensing basis (CLB) conditions.

The ISI Program has been used to examine the accessible surfaces of the RVI in previous refueling outages. A review of the current ISI Program implementing procedures showed that the procedures will be enhanced if modified to specifically identify each component of the RVI which relies on this program for aging management for license renewal. [Reference 3, Attachment 2, Section XI ISI]

The ISI Program is subject to internal and independent assessments, and is recognized through these assessments as performing highly effective examinations and aggressively pursuing continuous improvements. Baltimore Gas and Electric Company monitors industry initiatives and trends in the area of ISI and NDE. The program is also subject to frequent external assessments by Institute of Nuclear Power Operations, NRC, and others.

Operating experience relative to the ISI Program at the CCNPP has been such that no site specific problems or events have occurred that required changes or adjustments. The program has been effective in its function of performing examinations required by ASME Code Section XI.

Specific to the visual examinations for wear of the RVI, the ISI Program has been used in previous refueling outages to examine accessible surfaces. This operating experience shows a consistent ability to identify surface indications, e.g., scratches and gouges, for evaluation against acceptance criteria. For example, the 1991 examination records for the Unit 2 CSBA identify that gouges found during the visual examinations were dispositioned as minor indications such that keyway serviceability is not affected. [Reference 12] The ISI Program records show that the gouges were again found in the subsequent required examinations performed in 1993, and the report states that the gouges were noted in previous examinations and accepted as is. [Reference 13] The minor nature of these indications, and the repeatability in finding them, provides evidence of the effectiveness of the ISI Program to identify the effects of wear.

Group 1 (Wear) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of wear on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- Wear is plausible for RVI components and results in material loss which could lead to loss of intended function.
- The CCNPP ISI Program provides for periodic visual examinations of accessible surfaces of RVI components.
- Examinations will be performed, and appropriate corrective action will be taken if significant wear is discovered.

Therefore, there is reasonable assurance that the effects of wear will be managed in order to maintain the structural integrity of RVI consistent with the CLB during the period of extended operation.

Group 2 (Neutron Embrittlement) - Device Types, Materials, and Environment

Table 4.3-2 shows that neutron embrittlement is plausible for nine device types in the RVI. This group of device types includes: CEASB (except the spanner nuts and tabs), CS, CSTR, CSB (except the upper flange), CSC, CSP, FAP, FP, and LSSBA.

These components are constructed of various stainless and alloy steels (ASTM A-182, A-193, A-194, A-240, A-269, A-276, A-351, A-451, and A-479; and Aerospace Material Specification (AMS) 5735 iron base superalloy A-286). [Reference 3, CEASB, CS, CSTR, CSB, CSC, CSP, FAP, FP, and LSSBA, Attachment 3s]

The environment pertinent to neutron embrittlement is the high energy neutron fluence experienced during normal operations. The closer a component is to the core, the larger the integrated exposure to high energy neutrons will become. Another pertinent aspect of the environment is immersion in the RCS rather than forming part of the RCS pressure boundary. The loads on the components from the coolant flow are much less than if they were RCS pressure retaining components.

Group 2 (Neutron Embrittlement) - Aging Mechanism Effects

Neutron embrittlement is considered plausible for RVI components exposed to high energy neutrons, and can cause changes in properties of stainless steel and nickel-base alloys used in these components. The extent of neutron embrittlement is a function of both temperature and neutron fluence. At reactor operating temperatures, neutron embrittlement is plausible for device types that would experience high energy neutron flux. While the components nearest the core experience such high fluxes, the fluence levels are not sufficient to cause appreciable neutron embrittlement of components located above the reactor vessel nozzles. [Reference 3, CEASB, ESG, CSB, CSBA, ITSP, and UGSP, Attachment 6s, Code 23]

The effect of neutron embrittlement is a loss of fracture toughness of the affected material (i.e., a lower resistance to crack initiation), leading to parts, bolting, or fasteners that are loose, missing, cracked, or fractured. [Reference 3, CEASB, CS, CSTR, CSB, CSC, CSP, FAP, FP, and LSSBA, Attachment 6s, Code G] These effects are the precursors to the loss of the intended function for these components.

No instances of degradation of RVI for PWRs have been recorded which have definitely been attributed to neutron embrittlement. [Reference 7, Section 4.1.2]

Group 2 (Neutron Embrittlement) - Methods to Manage Aging

Mitigation: The effects of neutron embrittlement for the RVI components could be mitigated by lowering the neutron flux from the reactor core that reaches these components through the use of low-leakage core designs. This approach is not practical for the components of the RVI which completely surround the core.

Discovery: The effects of neutron embrittlement can be discovered when the reactor vessel is opened and the RVI components are examined. Visual examination techniques would normally be used and would typically include remote visual examinations utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc. Components that are loose, missing, cracked, or fractured would be readily observable by visual examination.

Loose parts may also be detected by the Loose Parts Monitoring System which monitors the RCS for internal loose parts. The system is designed to detect a loose part striking the internal surface of RCS components with an energy level of one-half foot pound or more. [Reference 2, Section 4.4.1]

Group 2 (Neutron Embrittlement) - Aging Management Programs

Mitigation: Although CCNPP's 24-month core designs use a low leakage configuration, no aging management credit for mitigating neutron embrittlement of the RVI is given to efforts to reduce neutron leakage from the core.

Discovery: American Society of Mechanical Engineers Code Section XI ISI is the existing program credited for aging management of the effects of neutron embrittlement for the components in the RVI. [Reference 3, Attachment 8, Neutron Embrittlement] The purpose, scope, bases, operating experience, etc., for the ISI Program are described above in the subsection, Group 1 (Wear) - Aging Management Programs.

The ISI Program is adequate for control of this ARDM since the precursors of failure of a component's intended function would be parts, bolting, or fasteners that become loose, missing, cracked or fractured, and are readily observable by the required examinations. Timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions. As noted above in the subsection, Group 1 (Wear) - Aging Management Programs, the current ISI Program implementing procedures will be modified to specifically identify each component of the RVI which rely on this program for aging management for license renewal. [Reference 3, Attachment 2, Section XI ISI]

Group 2 (Neutron Embrittlement) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of neutron embrittlement on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- Neutron embrittlement is plausible for RVI components and results in a loss of fracture toughness of the affected material (i.e., a lower resistance to crack initiation), leading to loose, missing, cracked, or fractured parts, bolting, or fasteners.
- The CCNPP ISI Program provides for periodic examinations of accessible surfaces of RVI components.
- Visual examinations will be performed, and appropriate corrective action will be taken if precursors to the loss of intended function due to neutron embrittlement are discovered.

Therefore, there is reasonable assurance that the effects of neutron embrittlement will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Group 3 (Low Cycle Fatigue) - Device Types, Materials, and Environment

Table 4.3-2 shows that low cycle fatigue is plausible for four device types in the RVI. This group of device types includes: the CS (plates and ribs only), CSTR (tie rods, nuts, and set screws only), CSC, and CSP.

These components are constructed of various stainless and alloy steels (ASTM A-193, A-194, A-240, A-351, and A-479). [Reference 3, CS, CSTR, CSC, and CSP, Attachment 3s]

The environment pertinent to low cycle fatigue for the RVI during power generation is chemically treated, demineralized water that increases in temperature from 100°F or less at startup, to approximately 599°F at full power. [Reference 2, Section 4.1.1, Table 4.1] Plant transients subject the RVI to thermal stress during plant heatup, cooldown, and plant trips. However, since the RVI are relatively thin-walled parts and are immersed in the RCS, rather than thicker-walled components needing to withstand RCS pressure, the RCS transients are less severe for the RVI than for pressure retaining components. The pressure loads on the components from the coolant flow around them are much less than if they were RCS pressure retaining components. [Reference 3, Attachment 8, Low Cycle Fatigue] But RVI components that directly surround the reactor core are exposed to intense gamma heating, which leads to higher average temperatures and thermal gradients that induce higher thermal loadings than for other RVI components. [Reference 3, CS, CSTR, CSC, and CSP, Attachment 6s, Code B]

Group 3 (Low Cycle Fatigue) - Aging Mechanism Effects

Fatigue is the process of progressive localized permanent structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points, and which may culminate in cracks or complete fracture after a sufficient number of fluctuations. The fatigue life of a component is the number of cycles of stress or strain that it experiences before fatigue failure. A component subjected to sufficient cycling with significant strain rates, may develop cracking. The cracks may then propagate under continuing cyclic strains. [Reference 14] Calvert Cliffs has not discovered any low-cycle, fatigue-related failures in the RVI. Also, there have not been occurrences of fatigue damage at other CE PWRs that were identified as low-cycle fatigue failures. [Reference 7, Section 3.3.3; Reference 5, Section 5.3.3]

Plant transients apply cyclical thermal loadings that contribute to low-cycle fatigue accumulation on the RVI. The typical thermal transients of concern for RVI components potentially affected by low-cycle fatigue are changes in gamma heating due to RCS heatup, cooldown, and plant trips. The original design criteria for the RVI were not from the ASME Code, because these plants, like other early PWR plants, were designed before the development of the ASME Code requirements that are specifically applicable to RVI. Such early PWRs had the RVI designed based on criteria specific to the supplier. Although the suppliers used ASME Code Subsection NB as the guideline for development of their criteria, such plants do not have an explicit fatigue design basis. [Reference 7, Section 3.2.1]

However, the principles of similitude apply for identifying the components of these older RVI most susceptible to low-cycle fatigue. A similitude demonstration is based on a number of factors, foremost of which is the similarity of geometry and similarity of component operating history. The most-fatigue-susceptible RVI components have been identified for PWR plants of the three U.S. suppliers using design stress reports and hot functional test data for later plants. These components require further evaluation. [Reference 7, Section 1.4.2]

Low-cycle fatigue is a potential concern for these RVI components because they are nearest the reactor core and reach the highest temperatures. Since the largest plastic strains typically occur at notches, corners, and other geometric discontinuities, the effects of low cycle fatigue would be expected to become evident at such locations of high stress.

The effects of low cycle fatigue would be cumulative fatigue damage of the affected metal due to the cyclic loads applied to the material by gamma heating. The damage would be evident as fatigue cracks in highly stressed regions. Materials are damaged by low cycle fatigue when the cyclic thermal loads are sufficiently high to cause significant plastic deformation of the highly stressed regions. [Reference 3, Attachments 7 and 8, Low Cycle Fatigue]

Group 3 (Low Cycle Fatigue) - Methods to Manage Aging

Mitigation: The most significant thermal transients occur during plant heatup, cooldown, and plant trips. These are temporary modes of operation, which cannot be avoided. As part of general operating practice, plant operations minimize the effects of these transitory operational conditions.

Discovery: As discussed above, low cycle fatigue in PWR RVI was addressed in the similitude demonstrations performed to identify the components most susceptible to low-cycle fatigue. For these components, analysis can be used to determine the susceptibility of a component to low cycle fatigue. [Reference 7, Section 1.4.2]

American Society of Mechanical Engineers Code, Section III, Subsection NG, design rules for fatigue can be used to demonstrate that the effects of fatigue can be managed adequately for the fatigue-critical RVI components. [Reference 7, Section 5.7] The procedures in the Code include an exemption from detailed fatigue analysis for PWR RVI if their specified service loads satisfy certain limitations on severity. If the limits are not met entirely, detailed fatigue evaluation is required. The analysis involves determining the set of design transients associated with service loadings and their frequency of occurrence, and the calculation of the stresses and stress ranges at controlling component locations. [Reference 7, Section 5.7.1]

The Code's fatigue design procedures utilize a design fatigue curve which plots alternating stress range versus the number of cycles to failure. The curve is based on the un-notched fatigue properties of the material, modified by reduction factors that account for various geometric and moderate environmental effects. The fatigue usage factor is defined by Miner's Rule as the summation of the damage over the total number of design basis transient types. The damage for each transient type is given by the ratio of the expected number of cycles of that transient type to the allowable number of cycles for the stress ranges associated with that transient. For ASME Code acceptance, the usage factor calculated in this manner cannot exceed unity (1.0) for the design lifetime of the component. [Reference 7, Sec 4.10.2]

Alternatively, the effects could be discovered when the reactor vessel is opened and the RVI components are examined. Visual examination techniques would normally be used and would typically include remote visual examinations utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc. Components susceptible to low-cycle fatigue that have a fatigue crack initiating would be readily observable by visual examination.

The preferred aging management method would be to perform fatigue analyses to estimate the fatigue usage of the components. Current analysis techniques, such as those specified in ASME Code Section III, are capable of predicting the fatigue life of components through calculation of a cumulative usage factor. The fatigue usage factor of a component increases as the number of thermal transients experienced increases. Monitoring the cumulative usage factor over time, based on actual plant data, can be an effective method of

predicting end of fatigue life and demonstrating adequacy through the period of extended operation. [References 15 and 16]

Group 3 (Low Cycle Fatigue) - Aging Management Programs

Mitigation: As part of general operating practice, plant operators minimize the severity of transitory operational cycles. Further modification of plant operating practices to reduce the temperature ranges and/or frequencies of thermal transients would unnecessarily place additional restrictions on plant operations.

Discovery: A fatigue analysis will be performed to show that the stress ranges and expected number of transients for these components will be low enough that thermal fatigue will not impair their intended function during the period of extended operation. [Reference 3, CS, CSTR, CSC, and CSP, Attachment 6s, Code B] The stress ranges that cause these RVI components to be more susceptible than others are primarily those caused by the temperatures experienced by these components due to gamma heating from the core.

Calvert Cliffs Units 1 and 2 were both designed before the development of ASME Code requirements specifically applicable to RVI. Since the design was not based on the Code's fatigue analysis procedures, the principles of similitude were applied to identify the fatigue-critical components of the RVI using design stress reports and hot functional test data for later CE plants. The fatigue critical components require further evaluation. [Reference 7, Section 1.4.2]

The Code's fatigue design rules described above will be used to demonstrate that the effects of fatigue can be managed adequately for the RVI components. [Reference 7, Section 5.7] For acceptance under the Code, the cumulative usage factor cannot exceed 1.0.

Based on the service loadings for these components, the analysis is expected to show that the fatigue usage factor will be sufficiently low (0.5 or less) and that no further evaluations will be required for the period of extended operations. However, if the analysis shows a cumulative usage factor greater than 0.5 for any specific components, then further evaluations will be performed. For each such component, the evaluation will either provide justification that the component is bounded by other component(s) already monitored in the Fatigue Monitoring Program, or if not bounded, then the specific components will be added to the Fatigue Monitoring Program. [Reference 3, Attachment 10, Specific Fatigue Analysis]

The Fatigue Monitoring Program already identifies, tracks, and evaluates cumulative fatigue usage of limiting components in the Nuclear Steam Supply System. This existing program has eleven locations selected for monitoring fatigue usage which represent the bounding locations for the effects of thermal transients due to operating cycles. [Reference 17, Section 1.2] If the results of the initial fatigue analysis show that the predicted fatigue usage of a RVI component would warrant (i.e., would exceed 0.5 at the end of the period of extended operation), the component will be added to the Fatigue Monitoring Program for fatigue usage tracking and evaluation.

The detailed fatigue analysis will be performed because there is presently insufficient evidence to conclude that low cycle fatigue is not plausible for these components. However, with no pressure stresses, thinner

components, and lower differential temperatures than in piping components of similar materials, it is believed that low cycle fatigue of these RVI components will be shown to be insignificant. [Reference 3, Attachment 8, Low Cycle Fatigue]

If the detailed fatigue usage analysis or subsequent tracking and evaluation does not demonstrate acceptable management of low-cycle fatigue, the effects could be discovered by an examination for fatigue cracks initiating in these RVI components. Timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions.

Group 3 (Low Cycle Fatigue) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of low cycle fatigue on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- Low cycle fatigue is plausible for the RVI components and could result in fatigue cracking of the affected metal due to cyclic loads applied to the material.
- A fatigue analysis will determine that low-cycle fatigue will not affect the intended functions of these components during the period of extended operation by showing that the fatigue design basis will be adequate, or that the fatigue usage will be bounded by that of other already monitored components. Alternatively, the fatigue usage for specific RVI components will be tracked and evaluated, or specific components will be examined.

Therefore, there is reasonable assurance that the effects of low cycle fatigue will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Group 4 (Thermal Aging) - Device Types, Materials, and Environment

Table 4.3-2 shows that thermal aging is plausible for two device types in the RVI. This group includes the CEASB (only the CEA shroud assembly tube) and CSC.

The materials of these two components are cast austenitic stainless steel (CASS). The CEA shroud assembly tubes are ASTM A-451 centrifugally-cast austenitic stainless steel. [Reference 3, CEASB, Attachment 3] The CSC are ASTM A-351 statically-cast austenitic stainless steel. [Reference 3, CSC, Attachment 3]

The environment pertinent to thermal aging is the operating temperature experienced during normal operations. Normal RCS operating temperatures are 548°F for the cold leg and 599.4°F for the hot leg. [Reference 2, Section 4.1.1, Table 4.1]

Group 4 (Thermal Aging) - Aging Mechanism Effects

Thermal aging of concern is embrittlement of components made from CASS and is considered plausible for RVI components constructed of CASS. Thermal aging is time and temperature dependent, and its significance is dependent on the delta ferrite content of the CASS. The maximum rate of embrittlement occurs in the temperature range between 840°F and 930°F; however, thermal embrittlement has been observed at a temperature range as low as 550°F to 650°F. In general, low carbon grades of cast stainless steel are the most resistant to thermal aging, and molybdenum-containing high carbon grades are the most susceptible. Nickel-based alloys are resistant to thermal aging in the temperature range of the RVI. [Reference 3, Attachment 7, Thermal Aging]

The effect of thermal aging is a loss of fracture toughness of the affected metal. [Reference 3, CEASB and CSC, Attachment 6s, Code C] A loss of fracture toughness could lead to loose, missing, cracked, or fractured parts. [Reference 3, CEASB and CSC, Attachment 6s, Code G] These effects are the precursors to the loss of the intended function for these components.

Calvert Cliffs has not discovered any thermal aging-related damage for the RVI. Also, there have not been RVI damage events at other PWRs that were identified as thermal aging failures. [Reference 7, Section 3.3; Reference 5, Section 5.3]

Group 4 (Thermal Aging) - Methods to Manage Aging

Mitigation: The effects of thermal aging could be mitigated by operating below the temperature range where this ARDM occurs, but this is not practical for reactor operations.

Discovery: The impact of thermal aging on CASS material in PWR RVI has been determined to be insignificant if the delta ferrite content of the material is less than certain thresholds. Thermal aging is potentially significant for: (1) centrifugally-cast parts with a delta ferrite content above 20%; (2) statically-cast parts with a molybdenum content meeting CF3 and CF8 limits and with a delta ferrite content above 20%; and (3) statically-cast parts with a molybdenum content exceeding CF3 and CF8 limits and with a delta ferrite content above 14%. [Reference 7, Section 4.8.2]

Since thermal aging of components is considered plausible for CASS parts with delta ferrite contents above the noted values, plants can compare the delta ferrite contents of components made of CASS with these values to determine if this ARDM is potentially significant. Plants can determine the delta ferrite content of their components utilizing established techniques. [Reference 18]

The effects could also be discovered by examination of components when the reactor vessel is opened and the RVI components are examined. Visual examination techniques would normally be used and would typically include remote visual examinations utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc. Components that are loose, missing, cracked, or fractured would be readily observable by visual examination.

Loose parts may also be detected by the Loose Parts Monitoring System which monitors the RCS for internal loose parts. The system is designed to detect a loose part striking the internal surface of RCS components with an energy level of one-half foot pound or more. [Reference 2, Section 4.4.1]

Group 4 (Thermal Aging) - Aging Management Programs

Mitigation: Since there are no reasonable methods of mitigating thermal aging for the RVI, there are no programs credited with mitigation.

Discovery: The delta ferrite content will be determined for CCNPP's RVI components made from CASS, and the contents will be compared to the acceptable thresholds. Initial investigations revealed that formal calculations should show delta ferrite levels are below the established thresholds for these components. [Reference 3, Table 5-4, Delta Ferrite Calculation for CASS Components] The new calculations are expected to show that thermal aging is not plausible and would not affect the intended function of these components during the period of extended operation.

Alternatively, the effects could be discovered by an examination of components that are subject to thermal aging. Thermal aging could be discovered when the components are examined for loose, missing, cracked, or fractured components. Timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions.

Group 4 (Thermal Aging) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of thermal aging on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- Thermal aging is plausible for CASS components and could result in a loss of fracture toughness, which could lead to loose, missing, cracked, or fractured parts.
- A delta ferrite content calculation will be performed and is expected to show that the ARDM is not plausible and would not affect the intended functions of these components during the period of extended operation. If not, an examination will be performed.

Therefore, there is reasonable assurance that the effects of thermal aging will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Group 5 (Stress Relaxation) - Device Types, Materials, and Environment

Table 4.3-2 shows that stress relaxation is plausible for two device types in the RVI. This group of device types includes the CSTR (tie rods, nuts, and set screws only) and the CEASB (only the CEA shroud bolts, also referred to as CEA shroud socket-head cap screws in plant documentation). Note that the term CEA shroud bolts will be used below, although threaded structural fastener is more appropriate than bolt per the

ASME Code definition where threaded structural fasteners join components other than at a pressure boundary.

The CSTR components are constructed of ASTM A-193, A-194, and A-479 steels. The CEA shroud bolts are made of AMS 5735 iron base superalloy A-286. [Reference 3, CSTR and CEASB, Attachment 3s]

The environment characteristics pertinent to stress relaxation are operating temperatures and neutron irradiation experienced during normal operations. Normal RCS operating temperatures are 548°F in the cold leg and 599.4°F in the hot leg. [Reference 2, Section 4.1.1, Table 4-1] For high energy neutron exposures, the closer a component is to the core, the larger the integrated exposure will become.

Group 5 (Stress Relaxation) - Aging Mechanism Effects

Stress relaxation is a potential ARDM for components which rely on preload to perform their function, and is the unloading of preloaded components caused by neutron irradiation at PWR operating temperatures. This mechanism occurs under conditions of constant strain where part of the elastic strain is replaced with plastic strain. [Reference 7, Section 4.6.1] The influence of irradiation on stress relaxation behavior has been shown during laboratory experiments for stainless steel materials stressed at or above yield strength and exposed to significant irradiation (on the order of 1×10^{21} n/cm^2, >1 Mev). Therefore, when preloaded components are subject to PWR operating temperatures and significant radiation fields, stress relaxation could result in loss of preload, subsequent mechanical fatigue, and shortened life. [Reference 3, Attachment 7, Stress Relaxation] Fatigue could lead to parts that are loose, missing, cracked, or fractured. These effects are the precursors to the loss of the intended function for these components.

Calvert Cliffs has not discovered any stress-relaxation-related damage for the RVI. Also, there have not been RVI damage events at other PWRs that were identified as stress relaxation failures. [Reference 7, Section 3.3; Reference 5, Section 5.3]

Group 5 (Stress Relaxation) - Methods to Manage Aging

Mitigation: The effects of stress relaxation could be mitigated for the RVI by lowering the reactor operating temperatures or reducing the neutron fluence, neither of which is practical.

Discovery: Analyses can be performed to demonstrate that stress relaxation is not occurring or, if occurring, would have no effect on a component's intended function. The first type of analysis would show that the required combination of stress levels and radiation conditions are not present for RVI components that are preloaded during installation. For some components (e.g., certain sets of threaded structural fasteners), the installation in the RVI may be such that during normal operations the components experience forces (e.g., coolant flow and spring-loading forces) that reduce the initial tensile preload forces. When this occurs, the components would be subject to less tensile stress during operations and, thus, would not be subject to total loss of preload from stress relaxation.

Analyses could also be performed to show that, due to mechanical redundancy, a loss of preload from stress relaxation may be acceptable for certain subsets of a particular type of component during the period of extended operation. Some subassemblies of components in the RVI rely on multiple structural support

systems. These are systems where multiple components are used to connect other components (e.g., when many bolts are used to connect one part to another). Analytical demonstrations can show that failure of a limited number of such support structures is acceptable (e.g., half of the bolts holding one part to another). Such limited failures do not necessarily imply failure of the connection or of the ability of the connected components to perform their intended function, since the multiplicity of support structures provides mechanical redundancy. This type of analysis can be used to demonstrate acceptable performance of multiple support structures when used in the RVI. [Reference 7, Section 6.2.1]

The effects of stress relaxation could also be discovered by examination of components when the reactor vessel is opened and the RVI components are examined. Visual examination techniques normally used for the RVI would not be appropriate to identify significant loss of preload. However, two alternate examination methods could be considered. One is a remote ultrasonic technique proposed to determine the change in length of a component due to stress relaxation. This technique would require appropriate baseline data on the as-built dimensions of a component for comparison to the ultrasonically measured current dimensions. A difference in length would be related to the loss of preload for the component. The second method would be a mechanical technique to measure the preload still on the component (e.g., with a torque wrench).

If the loss of preload would be sufficient to have allowed vibration leading to fatigue failures, remote visual examinations would identify loose, missing, cracked, worn, or fractured components. Timely corrective actions would be taken and would ensure that the RVI components remain capable of performing their intended functions under all CLB conditions. In such cases, the loose parts may also be detected by the Loose Parts Monitoring System which monitors the RCS for internal loose parts. The system is designed to detect a loose part striking the internal surface of RCS components with an energy level of one-half foot pound or more. [Reference 2, Section 4.4.1]

Group 5 (Stress Relaxation) - Aging Management Programs

Mitigation: Since there are no reasonable methods of mitigating stress relaxation for the RVI, there are no programs credited with mitigation.

Discovery: Because the CEA shroud bolts and CSTR (tie rods, nuts, and set screws) are preloaded during initial installation, stress relaxation could affect their structural support function as a loss of preload, which could lead to vibrations and accelerated mechanical fatigue, resulting in cracking. [Reference 3, CSTR and CEASB, Attachment 6s, Code E] For each of these types of components, an evaluation will be conducted to demonstrate that this ARDM will not occur for the stress levels and radiation conditions. [Reference 3, Table 5-1, Stress Relaxation] These analyses are described below along with an alternate examination method for each type of component.

The CEA shroud bolts were initially evaluated as part of a broader investigation of the potential for stress corrosion of A-286 threaded structural fastener applications in CE Nuclear Steam Supply Systems. [Reference 17] The investigation reviewed design, fabrication methods, operating stress levels, and time in service for A-286 threaded structural fasteners as compared to those in Babcock and Wilcox RVI which had experienced failures. The investigation indicated a potential for a small percentage of stress corrosion failures, based on the Babcock and Wilcox experience. As a result, the various CE applications of A-286

threaded structural fasteners were evaluated to determine the margin available for each. The available margin was considered to be the number of such fasteners required to meet ASME Code stress allowables to withstand normal operating plus upset condition loads. [Reference 15, Section 1.0]

Combustion Engineering's evaluation for stress corrosion for all CE plants will be further developed for stress relaxation of the CEA shroud bolts in the CCNPP RVI. That is, plant-specific analysis will be performed to refine the calculated stress levels on these bolts and demonstrate that they are not subject to substantial tensile stress during normal operations, and, thus, would not be subject to loss of preload from stress relaxation at PWR operating temperatures. [Reference 3, Table 5-1, Stress Relaxation Analysis or Sampling Inspection] Initial calculations revealed that the upward flow of RCS coolant and the upward force of the fuel assembly hold-down springs would more than offset the weight of the fuel alignment plate. Thus, the tensile stress levels should be far below those which would cause stress relaxation at PWR operating temperatures. [Reference 3, Table 5-4, Stress Relaxation of CEA Shroud Bolts]

If the analysis does not show the low stress levels expected, an examination of the CEA shroud bolts would be conducted as part of an Age-Related Degradation Inspection (ARDI) Program. [Reference 3, Attachment 8, CEASB, Stress Relaxation] The type of examination, the extent of the examination, and the acceptance criteria would be determined under the ARDI Program. [Reference 3, Table 5-1, Stress Relaxation Analysis or Sampling Inspection] Timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions.

For the other device type in this group, the CSTR, an analysis will be conducted to address the tensile preloads and opposing forces acting on these components during operation. The analysis is expected to demonstrate that the fluence levels and/or stress levels are not sufficient for stress relaxation to occur to the extent where the intended function would be impaired during the period of extended operations. [Reference 3, Table 5-1, Stress Relaxation Analysis]

If the analysis does not show acceptably low stress levels, an examination of the tie rods would be conducted as part of an ARDI Program. An examination developed as part of the ARDI Program would be needed because the tie rods are located within the CS and, thus, are not accessible for visual examination. [Reference 3, Attachment 8, CSTR, Stress Relaxation] An ARDI examination could be developed to determine the actual preload using either ultrasonic or mechanical techniques. [Reference 3, Table 5-1, Stress Relaxation Analysis]

Ultrasonic examination techniques have been used at some utilities. [Reference 3, Attachment 8, CSTR, Stress Relaxation] Ultrasonic examination techniques would require development of baseline data on as-built dimensions for the tie-rods. The option of using mechanical techniques (e.g., torque wrench) for this examination is complicated by the need to first remove the locking straps to make accurate measurements of preload, and to then reinstall the straps. Both methods are technically feasible but complex. [Reference 3, Table 5-4, Stress Relaxation Analysis of Core Shroud Tie Rods and Bolts] The examination would verify that the unacceptable effects of this aging mechanism have not occurred for these bolts, or timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions.

Group 5 (Stress Relaxation) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of stress relaxation on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- Stress relaxation is plausible for RVI components and could lead to vibrations and accelerated mechanical fatigue, resulting in cracking.
- A stress relaxation analysis is expected to show that the ARDM would not affect the intended functions of these components during the period of extended operation.
- Alternatively, NDE techniques may be developed and examinations performed under an ARDI Program, and appropriate corrective action would be taken if significant damage from stress relaxation is discovered.

Therefore, there is reasonable assurance that the effects of stress relaxation will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Group 6 (Stress Corrosion Cracking) - Device Types, Materials, and Environment

Table 4.3-2 shows that SCC is a plausible ARDM for one device type, the CEASB (only for the CEA shroud bolts, also referred to as CEA shroud socket-head cap screws in plant documentation).

The CEA shroud bolts are constructed of AMS 5735 iron base superalloy A-286. [Reference 3, CEASB, Attachment 3]

The environment pertinent to SCC is the chemistry of the coolant. Although there is a strict chemistry control program in effect for the RCS, the A-286 material that these bolts are made from makes them susceptible to SCC while in the coolant.

Group 6 (Stress Corrosion Cracking) - Aging Mechanism Effects

Stress Corrosion Cracking/IGSCC/Intergranular Attack are potential ARDMs for RVI components fabricated from AMS 5735 iron base superalloy A-286. [Reference 3, Attachment 7, SCC]

Initiation and propagation of SCC require three factors to be present: (1) susceptible material, (2) a corrosive environment, and (3) the presence of tensile stresses. The corrosiveness of the environment depends on the oxygen and halogen concentrations in the RCS and the magnitude of the tensile stresses must exceed a threshold value before SCC can occur. A generally accepted value for threshold stress is the yield stress of the material of the component. [Reference 3, Attachment 7, SCC]

Intergranular SCC is SCC where the grain boundaries of a susceptible material are cracked due to the aggressive environment and sufficient stress levels. Intergranular attack is similar to IGSCC except that stress is not required for intergranular attack. [Reference 3, Attachment 7, SCC]

Stress corrosion cracking is considered to be plausible for RVI components which are fabricated of a susceptible material (e.g., A-286) and are subject to substantial stresses during plant operation (e.g., bolting). The effects of SCC are the initiation and growth of surface cracks in the metal. [Reference 3, CEASB, Attachment 6, Code A] This effect is the precursor to the loss of the intended function for these components.

Stress corrosion cracking has occurred at Babcock and Wilcox, Westinghouse, and Kraftwerk Union designed plants. [Reference 5, Section 5.2.2] There have been no indications of SCC failures of CEA shroud bolts on the RVI at CCNPP or any CE plants. [Reference 15, Section 2.0]

Group 6 (Stress Corrosion Cracking) - Methods to Manage Aging

Mitigation: The effects of SCC could not be mitigated further for the RVI beyond the strict chemistry control already in use for the RCS. See the discussion of the RCS primary chemistry control program in Section 4.1 of the BGE LRA.

Discovery: Analyses can be performed to demonstrate that the stress levels needed for SCC are not present or, if SCC is occurring, analyses could show it would have no effect on a component's intended function. The first type of analysis would show that for some components, their installation in the RVI may be such that during normal operations the components experience forces (e.g., coolant flow and spring-loading forces) that reduce the initial tensile preload forces. When this occurs, the components would be subject to less tensile stress during operations and, thus, would be less susceptible to SCC.

Analyses could also be performed to show that, due to mechanical redundancy, a failure of some fraction of a particular type of component may be acceptable during the period of extended operation. For some subassemblies of RVI components that rely on multiple structural support systems, analytical demonstrations can show that failure of a fraction of the support structures is acceptable (e.g., half of the bolts are sufficient to adequately connect one part to another). This type of mechanical redundancy analysis can be used to demonstrate acceptable performance of multiple support structures in the RVI when such limited failures still maintain the ability of the connected components to perform their intended function. [Reference 7, Section 6.2.1]

The effects of SCC could also be discovered by examination of components when the reactor vessel is opened and the RVI components are examined. Ultrasonic techniques could be developed to examine bolts for indications of crack initiation.

Group 6 (Stress Corrosion Cracking) - Aging Management Programs

Mitigation: Since there are no reasonable methods of mitigating SCC for the RVI, there are no programs credited with mitigation.

Discovery: A stress analysis will be performed specifically to evaluate the potential for SCC of the CEA shroud bolts. [Reference 3, Attachment 2, SCC Analysis or Sampling Inspection] As noted in the section on stress relaxation, the stress levels in CEA shroud bolts were previously investigated by CE for their

plants and the levels were compared to those in A-286 bolting which had failed at Babcock and Wilcox plants. [Reference 15] The maximum stresses on the CEA shroud bolts were found to be "slightly below the critical stress" for SCC. [Reference 3, CEASB, Attachment 6, Code A]

Combustion Engineering's investigation for all CE plants will be further developed on a plant-specific basis to refine the calculated stress levels on the CEA shroud bolts at CCNPP. This will allow the plant-specific loads (due to flows, weights, reactions, etc.) to be used to demonstrate that these bolts are not subject to substantial tensile stress during normal operation. [Reference 3, Table 5-4, SCC Analysis of CEA Shroud Bolts]

Initial calculations have revealed that the upward flow of reactor coolant and the upward force of the fuel hold-down springs would more that offset the weight of the fuel alignment plate. Thus, the tensile stress levels should be far below those which have ever resulted in SCC of this material and one of the key factors causing SCC would not be present for these bolts. [Reference 3, Attachment 10, SCC or ARDI]

If the analysis does not show the low stress levels expected, an examination of several of the CEA shroud bolts will be performed in an ARDI Program to determine if SCC precursors are present. [Reference 3, Attachment 2, SCC Analysis or Sampling Inspection] The type of examination, the extent of the examination, and the acceptance criteria would be determined under the ARDI Program.

The examination would provide additional assurance that the effects of SCC would not prevent the performance of the intended function of the CEA shroud bolts during the period of extended operation, or ensure that timely corrective actions will be taken so that the RVI components remain capable of performing their intended functions under all CLB conditions. [Reference 3, Attachment 8, CEASB, Stress Corrosion Cracking]

Group 6 (Stress Corrosion Cracking) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of SCC on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- SCC is plausible for RVI components and could result in the initiation and growth of surface cracks in the metal.
- A stress analysis will be performed to determine if one of the key factors required for SCC is absent, and thereby show that this ARDM would not affect the intended functions of these components during the period of extended operation.
- Alternatively, an examination of CEA shroud bolts in an ARDI Program will show that no SCC precursors are present. Examinations will be performed and appropriate corrective action will be taken if significant damage from SCC is discovered.

Therefore, there is reasonable assurance that the effects of SCC will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Group 7 (High Cycle Fatigue) - Device Types, Materials, and Environment

Table 4.3-2 shows that high cycle fatigue is a plausible ARDM for one device type, the CEASB (CEA shroud tubes, supports, channels, etc.).

These components are constructed of various stainless and alloy steels (ASTM A-240, A-269, A-276, and A-451). [Reference 3, CEASB, Attachment 3]

The environment pertinent to high cycle fatigue is the flow characteristics during normal operations. The components in areas of high RCS crossflows would be most susceptible. [Reference 3, CEASB, Attachment 6, Code BA] Also pertinent were the more severe flow characteristics during the hot functional testing which induced higher flow loads on the RVI without the flow resistance of the fuel assemblies. [Reference 7, Section 4.10.2]

Group 7 (High Cycle Fatigue) - Aging Mechanism Effects

Fatigue is the process of progressive localized permanent structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points, and which may culminate in cracks or complete fracture after a sufficient number of fluctuations. The fatigue life of a component is the number of cycles of stress or strain that it experiences before fatigue failure. A component subjected to sufficient cycling with significant strain rates may develop cracking. The cracks may then propagate under continuing cyclic strains. [Reference 14]

Calvert Cliffs has not discovered any high-cycle fatigue-related failures in the RVI. High cycle fatigue has occurred at CE and Westinghouse designed plants. [Reference 5, Section 5.3] At two CE plants, flow-induced vibrations of the thermal shields resulted in damage to the base metal and welds of the thermal shield support lugs attached to the core barrel. These were removed to eliminate the problem. Programs instituted at other CE plants were successful in preventing degradation of the type experienced. [Reference 7, Section 3.3.2] The CCNPP units do not have thermal shields. [Reference 6, Table 3-1]

Fatigue is considered plausible for RVI components subjected to repeated stress/strain cycles caused by fluctuating mechanical and thermal loads. [Reference 7, Section 4.10.1] Reactor internals components have a potential for high cycle fatigue due to flow-induced vibration. High cycle fatigue occurs when cyclic loads are such that significant plastic deformation does not occur in the highly stressed regions, but the loads are of such frequency that a fatigue crack initiates. High cycle fatigue is highly dependent on the presence of stress concentrations associated with corners, notches and surface imperfections. The very large numbers of cycles associated with high cycle fatigue are generally caused by flow-induced vibrations which occur during hot functional tests or early in plant life, if at all. [Reference 3, Attachment 7, High Cycle Fatigue]

Group 7 (High Cycle Fatigue) - Methods to Manage Aging

Mitigation: The potential effects of high cycle fatigue during operation were addressed during the hot functional tests of the RVI at CCNPP and other CE-supplied reactors. A design change was made at CCNPP where high cycle fatigue was a concern for RVI components, (i.e., the thermal shields were not

installed). [Reference 19] Because high cycle fatigue was addressed in these tests and with an early design change, programs are not needed to mitigate high cycle fatigue during operations.

Discovery: The effects of high cycle fatigue can be discovered when the reactor vessel is opened and the RVI components are examined. Visual examination techniques would normally be used and would typically include remote visual examinations utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc. Components that are loose, missing, cracked, or fractured would be readily observable by visual examination.

Loose parts may also be detected by the Loose Parts Monitoring System which monitors the RCS for internal loose parts. The system is designed to detect a loose part striking the internal surface of RCS components with an energy level of one-half foot pound or more. [Reference 2, Section 4.4.1]

Group 7 (High Cycle Fatigue) - Aging Management Programs

Mitigation: There are no CCNPP programs credited for mitigation of high cycle fatigue for the RVI.

Discovery: American Society of Mechanical Engineers Code Section XI ISI is the existing program credited for aging management of the effects of high cycle fatigue for the components in the RVI. The purpose, scope, bases, operating experience, etc., for the ISI Program are described above in the subsection, Group 1 (Wear) - Aging Management Programs. Any component damage from high cycle fatigue can be detected by ASME Code Section XI ISI Program requirements for Nuclear Class I components. [Reference 3, CEASB, Attachment 6, Code BA]

The nature of high cycle fatigue is such that it normally occurs early in plant life, making it highly unlikely that components subject to this ARDM will fail during the license renewal period. The performance of hot functional tests followed by years of operations without high cycle fatigue failures indicates that the stresses in the RVI components are well below the endurance limits for the materials. Without modifications to the design of the RVI, high cycle fatigue is a minor concern for the existing components.

Visual examination of the accessible areas of these components during normal refueling operation will be adequate to manage this ARDM. [Reference 3, Attachment 8, CEASB, High Cycle Fatigue] Timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions. As noted above in the subsection, Group 1 (Wear) - Aging Management Programs, the current ISI Program implementing procedures will be modified to specifically identify RVI components which rely on this program for aging management for license renewal. [Reference 3, Attachment 2, Section XI ISI]

Group 7 (High Cycle Fatigue) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of high cycle fatigue on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.

- High cycle fatigue is plausible for RVI components and could result in the initiation of a fatigue crack in highly stressed regions due to high frequency loads.
- The CCNPP ISI Program provides for periodic examinations of accessible surfaces of RVI components.
- Visual examinations will be performed, and appropriate corrective action will be taken if a fatigue crack is discovered.

Therefore, there is reasonable assurance that the effects of high cycle fatigue will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Conclusion

The programs discussed for the RVI are listed in Table 4.3-3. The existing program is, and the new analyses and program will be, administratively controlled by a formal review and approval process. As has been demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the components of the RVI will be maintained consistent with the CLB during the period of extended operation.

The analysis/assessment, corrective action, and confirmation/documentation processes for license renewal are in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

Table 4.3-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE REACTOR VESSEL INTERNALS

	Program	Credited As
Modified	Inservice Inspection of ASME Code Section XI Components, existing program implementing procedures for MN-3-110	Detection and management of the effects of wear (Group 1), neutron embrittlement (Group 2), and high cycle fatigue (Group 7) to show these ARDMs would not affect the intended function of components during the period of extended operation.

	Program	Credited As
New	Low-Cycle Fatigue Analysis of Components Subject to Gamma Heating	Discovery of the effects of low cycle fatigue (Group 3) by showing whether this ARDM would affect the intended function of the components during the period of extended operation, or if fatigue usage is bounded by monitored components. The analysis may show specific components need to have fatigue usage tracked, or that an examination is needed.
New	Delta Ferrite Calculation for CASS Components	Discovery of the effects of thermal aging (Group 4) by showing whether this ARDM would affect the intended function of the components during the period of extended operation, or that an examination is needed.
New	Stress Relaxation Analysis	Discovery of the effects of stress relaxation (Group 5) by showing whether this ARDM would affect the intended function of the components during the period of extended operation, or that NDE techniques need to be developed and performed.
New	SCC Analysis of CEA Shroud Bolts	Discovery of the effects of SCC (Group 6) by showing whether this ARDM would affect the intended function of the components during the period of extended operation, or that an examination is needed.
New	ARDI Program	Detection and management of the effects of ARDMs for which analysis is not able to demonstrate that an ARDM would not affect the intended function of the components during the period of extended operation (Groups 5 and 6).

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17. CCNPP Procedure EN-1-300, Implementation of Fatigue Monitoring, Revision 0, February 28, 1996
18. NUREG/CR-6177, "Assessment of Thermal Embrittlement of Cast Stainless Steels," May 1994
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ATTACHMENT (2)

APPENDIX A - TECHNICAL INFORMATION

5.7 - DIESEL FUEL OIL SYSTEM

5.7 DIESEL FUEL OIL SYSTEM

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing the Diesel Fuel Oil (DFO) System. The DFO System was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

5.7.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to aging management review (AMR) begins with a listing of passive intended functions, and then dispositions the component types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.7.1.1 presents the results of the system level scoping, 5.7.1.2 the results of the component level scoping, and 5.7.1.3 the results of scoping to determine components subject to an AMR.

Historical operating experience, judged to be pertinent, is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, and through documented discussions with currently-assigned, cognizant CCNPP personnel.

5.7.1.1 System Level Scoping

This section begins with a description of the system which includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

System Description/Conceptual Boundaries

The DFO System provides a reliable supply of DFO to the emergency diesel generators (EDGs), the auxiliary heating boiler, the station blackout diesel generator, and the diesel-driven fire pump. The fuel oil system for the three EDGs consists of two (Nos. 11 and 21) Seismic Category I, aboveground fuel oil storage tanks (FOSTs) and associated piping and valves. A portion of the DFO piping is buried underground (see Figure 5.7-1). This buried piping includes:

- The portion of the supply headers between Nos. 11 and 21 FOSTs;
- Three pairs of branch lines from the supply headers into the three diesel generator rooms;
- Auxiliary boiler supply header from the FOSTs to the auxiliary boiler room in the Turbine Building; and
- The portion of the piping from the fill line to the fire pump fuel oil tank. [Reference 1, Section 8.4.1; Reference 2].

Number 21 FOST is protected from tornado-generated missiles and tornado winds by a Seismic Category I concrete structure.

Internally, each FOST is equipped with a standpipe from which fuel oil is provided to the auxiliary heating boilers and diesel-driven fire pump. The combined volume of fuel oil below the standpipes in the FOSTs is reserved exclusively for the EDGs, and ensures a minimum of seven days of fuel oil is available for EDG operation, assuming the design basis load. In the event No. 11 FOST fails as a result of a tornado/missile event, the minimum volume of fuel required by Technical Specification is administratively maintained in No. 21 FOST, thus ensuring that at least a seven-day supply of fuel oil is available, assuming the design basis loading. [Reference 1, Section 8.4.1]

A tornado/missile event is not assumed to occur simultaneously with a design basis accident, such as a loss-of-coolant accident. Therefore, both tanks are assumed to be available under design basis accident conditions. The seven-day minimum Technical Specification volume of fuel oil for design basis accidents is divided between the two tanks (per design features of the tanks), such that approximately three days of fuel oil is maintained below the standpipe in No. 11 FOST, and four days of fuel oil is maintained below the standpipe in No. 21 FOST. [Reference 1, Section 8.4.1]

The FOSTs are redundant, with the exception of the concrete enclosure around No. 21 FOST and the elevation of the standpipes. Redundant diesel supply headers interconnect the two independent tanks, and manual valves are positioned such that each tank normally supplies a different header. A check valve in each supply header ensures that failure of No. 11 FOST will not drain No. 21 FOST. Through manual valves located in the Auxiliary Building, each EDG has the capability to obtain fuel from either of the redundant tanks through the redundant headers. A failure of one tank will not result in failure of the redundant tank.

Figure 5.7-1 is a simplified diagram of the DFO System and is provided for information only. This figure shows the DFO System which is addressed in this section and the primary process flow system interfaces. [Reference 1, Section 8.4.1]

The DFO System has, in general, performed well and has exhibited 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 were 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 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. Number 21 FOST is scheduled to be inspected during the refueling outage of 1997.

During the installation of underground utilities for new diesel generators, in September 1994, three excavations were made. Visual inspection of the coating on a two-inch and a three-inch diameter fuel oil pipe line revealed no degradation except for construction defects of the coating due to rocks and stones in backfill. The piping was found to be not damaged. The factory-applied coating was completely removed from each excavated section. The surfaces of each pipe were cleaned with solvent and recoated with Polyken Cold Primer TC # 1027 wrapped with Tapecoat 934. A 12,500 Volts DC holiday (thin spots, skipped areas, or where coating degradation has occurred) testing of the recoated pipe was performed in accordance with the National Association of Corrosion Engineers procedure NACE RP-0274.

In November 1996, portions of the four buried pipe lines between Nos. 11 and 21 FOSTs were inspected. It was discovered that the pipe wrap (trade name "TRUE COAT", an extruded polyvinyl coating covered with a black tape) was slightly damaged during backfilling at the time of construction, but the piping was in pristine condition after approximately 20 years of operation. Hydrostatic test of the exposed piping, three of four pipes, revealed that there was no leakage.

System Interfaces:

The DFO System has interfaces with five plant systems. These system interfaces with DFO piping are as follows [Reference 2]:

- Lines to Y-strainers upstream of the EDG fuel oil transfer pump — These lines are within the scope of license renewal. Y-strainers and fuel oil transfer pumps are within the scope of license renewal of the EDG system, discussed in Section 5.8 of the BGE LRA.
- Line to station blackout diesel generator day tank — This line is not within the scope of license renewal. The station blackout day tank is sized to provide sufficient fuel for the entire station blackout coping duration.
- Line to diesel fire pump — This line is within the scope of license renewal of the Fire Protection System discussed in Section 5.10 of the BGE LRA.
- Line to auxiliary boiler oil pumps — This line is not within the scope of license renewal.
- Non-safety-related line to diesel generating room waste oil collection tank No. 11 — This line is not within the scope of license renewal.

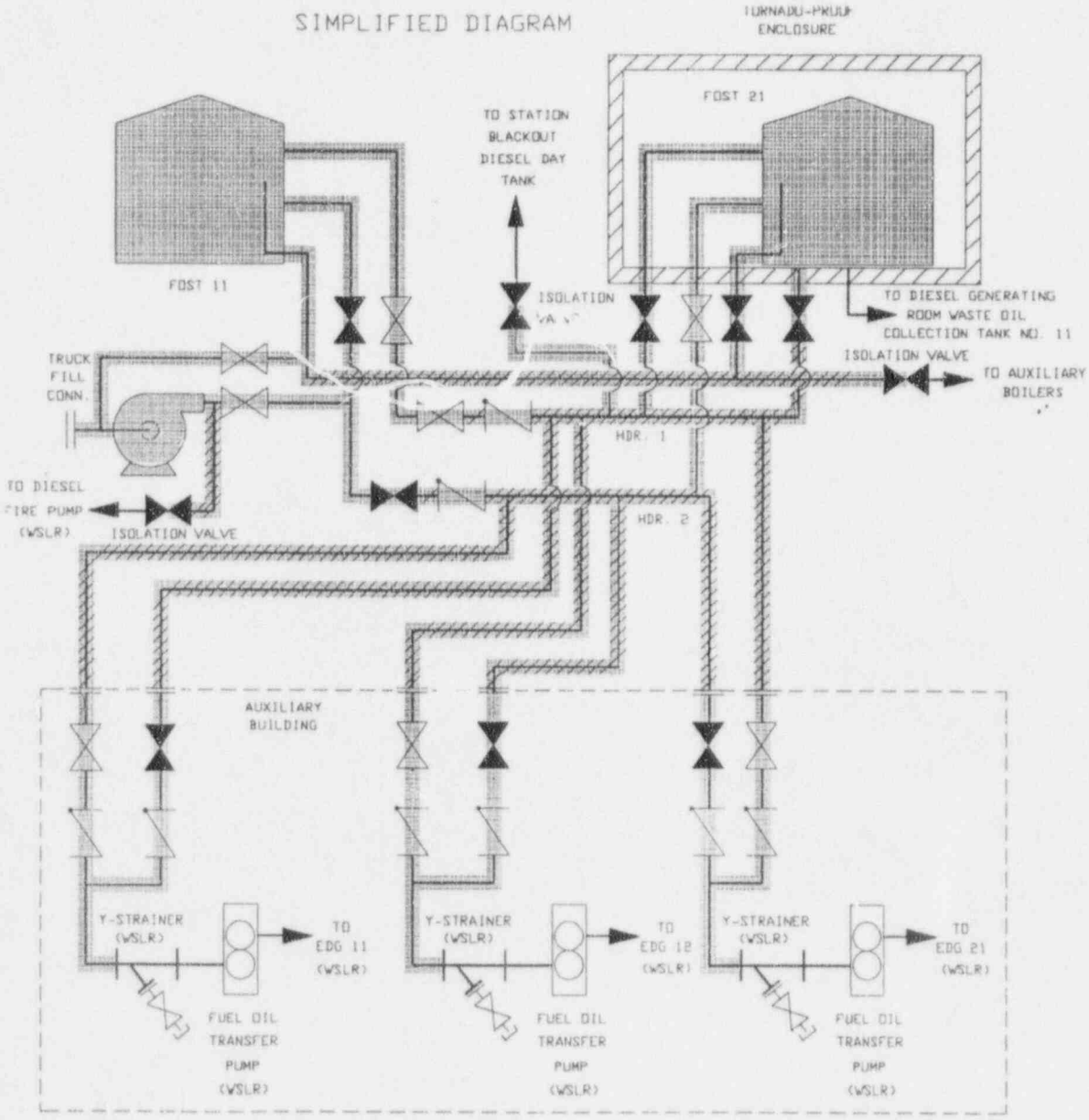

FIGURE 5.7-1

CCNPP DIESEL FUEL OIL SYSTEM
SIMPLIFIED DIAGRAM
(FOR INFORMATION ONLY)

System Scoping Results

The DFO System is within the scope of license renewal based on 10 CFR 54.4(a). The following intended functions of the DFO System were determined based on the requirements of §54.4(a)(1) and (2) in accordance with the CCNPP IPA Methodology Section 4.1.1. [Reference 3, Table 1]

- Provide vital auxiliary function to the power distribution system by supplying fuel oil to the EDGs during design basis events; and
- Maintain the pressure boundary of the system.

The following intended functions of the DFO System were determined based on the requirements of §54.4(a)(3): [Reference 3, Table 1]

- For fire protection (§50.48) — Provide essential fuel oil to EDGs and the diesel fire pump to ensure safe shutdown in the event of a postulated severe fire. (Includes isolation of non-essential auxiliary boiler and station blackout DFO.) [Reference 3, Table 1]

5.7.1.2 Component Level Scoping

Based on the intended functions listed above, the portions of the DFO System that are within the scope of license renewal include all components (electrical, mechanical, and instrument) and their supports from the unloading station to the FOSTs, the FOSTs, supply headers including cross-connects, and piping to just upstream of the Y-strainer installed in the suction pipe to the diesel generator fuel oil transfer pumps. The fuel oil transfer pump suction line, the transfer pumps, and the day tanks are evaluated as part of the EDG system. Figure 5.7-1 indicates the portion of the DFO System within the scope of license renewal that are addressed in this section. [Reference 4, Section 1.1.2]

The following 13 device types in the DFO System have at least one intended function:

- Piping Above and Underground
- Check Valves
- Hand Valves
- Diesel FOSTs
- Basket Strainers
- Fuses
- Hand Switches
- Level Switches
- Motors
- Pump
- Relays
- Transformers
- Indicating Lamps

Several device types are common to many plant systems and perform the same passive functions regardless of system. These device types are:

- Structural supports for piping, cables and components;
- Electrical control and power cabling; and
- Process and instrument tubing, instrument tubing manual valves, and tubing supports for components.

5.7.1.3 Components Subject To AMR

This section describes the components within the DFO System which are subject to an AMR. It begins with a listing of passive intended functions, and then dispositions the device types as either only associated with active functions, subject to replacement, evaluated in other reports, evaluated in commodity reports, or remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with the CCNPP IPA Methodology Section 5.1, the following DFO System function was determined to be passive:

Maintain the pressure boundary of the system [Reference 3, Attachment 1]

Device Types Subject to AMR

- Six device types (Fuse, Hand Switch, Motor, Relay, Transformer, and Indicating Lamp) have only active intended functions.
- The basket strainer device type is part of the DFO unloading station and fire pump fuel oil tank piping, which only contributes to the fire protection function of the DFO System; therefore, the basket strainer device type is addressed in the Fire Protection Commodity Evaluation in Section 5.10 of the BGE LRA.
- The fuel oil pump only contributes to the fire protection function of the DFO System; therefore, the pump is also addressed in the Fire Protection Commodity Evaluation.
- Level switches for the DFO System are evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of the BGE LRA.
- Structural supports for piping, cables and components in the DFO System that are subject to AMR are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA.
- Electrical control and power cabling for components in the DFO System that are subject to AMR are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of the BGE LRA.
- Instrument tubing and piping and the associated supports, instrument valves and fittings (generally everything from the outlet of the final root valve up to and including the instrument), and the pressure boundaries of the instruments themselves, are all evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

The remaining four device types that require an AMR are listed in Table 5.7-1. These are the subject of the rest of this section. Unless otherwise annotated, all components of each listed type are covered. [Reference 4, Table 3-2]

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

TABLE 5.7-1

DEVICE TYPES REQUIRING AMR FOR DFO SYSTEM

Above and Underground Piping*
Check Valves*
Hand Valves*
Diesel FOSTs**

* Includes those hand valves, check valves, and piping that are not included in the scope of the Fire Protection Commodity Evaluation; and only those hand valves that are not included in the scope of the Instrument Line Commodity Evaluation.

** FOST for new EDG not included in this technical report.

5.7.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the DFO System components is given in Table 5.7-2. [Reference 4, Table 4-2], with plausible ARDMs identified by a check mark (✓) in the appropriate component type column. For efficiency in presenting the results of these evaluations in this report, ARDM/device type combinations are grouped together where there are similar characteristics, and the discussion is applicable to all components within that group. Exceptions are noted where appropriate. Table 5.7-2 also identifies the group to which each ARDM/device type combination belongs. The following groups have been selected for the DFO System.

Group 1 includes the external surfaces of aboveground piping (pipe, fittings, flanges, bolts, nuts, welds), check valves (body/bonnet, bolts, nuts), and hand valves (body, nuts, stem), and covers crevice corrosion, general corrosion, and pitting.

Group 2 includes the external surfaces of underground carbon steel piping (pipe, fittings, and welds), and covers crevice corrosion, general corrosion, pitting, galvanic corrosion, and microbiologically induced corrosion (MIC).

Group 3 includes the diesel FOST internal surfaces, and covers crevice corrosion, general corrosion, pitting, fouling, and MIC.

Group 4 includes the diesel FOST shell and bottom external exposed surfaces, and covers crevice corrosion, general corrosion, pitting, and weathering.

Note that the internal surfaces of piping, hand valves, and check valves were determined to be not subject to any plausible ARDMs because DFO with negligible water content is non-corrosive for the carbon steel piping and carbon steel and alloy steel fastener materials.

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods of managing aging, aging management program(s), and aging management demonstration.

TABLE 5.7-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE DFO SYSTEM

Potential ARDMs	Device Types for Which ARDM is Plausible				Not Plausible for System
	Piping	Check Valve	Hand Valve	Tank	
Cavitation Erosion					x
Corrosion Fatigue					x
Crevice Corrosion	✓ (1,2)	✓ (1)	✓ (1)	✓ (3,4)	
Erosion Corrosion					x
Fatigue					x
Fouling				✓ (3)	
Galvanic Corrosion	✓ (2)				
General Corrosion	✓ (1,2)	✓ (1)	✓ (1)	✓ (3,4)	
Hydrogen Damage					x
Intergranular Attack					x
MIC	✓ (2)			✓ (3)	
Particulate Wear Erosion					x
Pitting	✓ (1,2)	✓ (1)	✓ (1)	✓ (3,4)	
Radiation Damage					x
Rubber Degradation					x
Saline Water Attack					x
Selective Leaching					x
Stress Corrosion Cracking					x
Stress Relaxation					x
Thermal Damage					x
Thermal Embrittlement					x
Wear					x
Weathering				✓ (4)	

✓ - Indicates plausible ARDM determination

(#) - Indicates the group(s) in which this ARDM/device type combination is evaluated

Group 1 (External Surfaces of Aboveground Piping, Check Valves, and Hand Valves) - Materials and Environment:

The aboveground piping material in the DFO System is seamless carbon steel with forged fittings and flanges. The weld material for piping is carbon steel. The body/bonnet material for check valves and hand valves within the scope of AMR is cast or forged carbon steel. Alloy steel is used for valve stems and bolts. [Reference 4, Attachment 4]. For the purposes of aging management discussion, all materials in Group 1 are conservatively assumed to be carbon steel.

The external surfaces are exposed to humid, moist, or wet environments. The external coating of the pipe is exposed to sun, weather, and ambient air. [Reference 4, Attachment 6]

Group 1 (External Surfaces of Aboveground Piping, Check Valves, and Hand Valves) - Aging Mechanism Effects:

Carbon steel is susceptible to general, crevice, and pitting corrosion mechanisms in a humid or wet environment. These ARDMs are plausible because the external carbon steel surfaces are exposed to a humid, moist, or wet environment. Sun and weather will deteriorate the protective paint coating of the exposed pipes and could lead to accelerated corrosion mechanisms of steel components exposed to moisture. The check valves and some pipes are protected from the direct effects of sun and weather by a concrete enclosure or pit with a cover. However, the steel surfaces are still exposed to changes in humidity and temperature, requiring the protection of paint. [Reference 4, Attachment 6]

General corrosion is thinning (wastage) of a metal by chemical attack (dissolution) by an aggressive environment at the surface of the metal. The consequences of the damage are loss of load-carrying ability due to loss of cross-sectional area. If unmitigated, general corrosion could eventually result in the loss of pressure-retaining capability under current licensing basis (CLB) design loading conditions. [Reference 4, Attachment 7]

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. Crevice corrosion is closely related to pitting corrosion and can initiate pits in many cases, as well as lead to stress corrosion cracking (SCC). If unmitigated, crevice corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Pitting is a form of localized attack with greater corrosion rates at some locations than at others. Pitting produces holes of varying depth to diameter ratios in steel. If unmitigated, pitting corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Group 1 (External Surfaces of Aboveground Piping, Check Valves, and Hand Valves) - Methods to Manage Aging Effects:

Mitigation: The effects of corrosion can be mitigated by minimizing the exposure of external surfaces of carbon steel and alloys to an aggressive environment, and protecting the surface with paint or other protective coatings.

Discovery: The effects of plausible aging mechanisms are detectable by visual techniques. Since corrosion of the carbon steel exterior surface of the piping and valves cannot occur without degradation of paint/coating, observing and confirming that this paint/coating is intact is an effective method to ensure that the effects of the plausible ARDMs have not occurred. Since the paint/coating does not contribute to the piping and valves' intended function, observing paint/coating for degradation provides an alert condition which triggers corrective action before degradation that affects the piping's or valve's ability to perform its intended function could occur. The degradation of paint that does occur can be discovered and managed by periodically inspecting the paint on exposed external surfaces, and by carrying out repairs as necessary.

Group 1 (External Surfaces of Aboveground Piping, Check Valves, and Hand Valves) - Aging Management Program(s):

Mitigation: The CCNPP procedure "Paint and Other Protective Coatings," MN-3-100, mitigates crevice corrosion, general corrosion, and pitting by addressing degraded paint areas discovered through visual inspection techniques under the CCNPP Plant Engineering Guideline, PEG-7, Plant Engineering Section, System Walkdowns" and the CCNPP "Issue Reporting and Assessment Procedure," QL-2-100, which defines requirements for initiation, review, and processing of issue reports . [Reference 4, Attachment 8]

Discovery: CCNPP Plant Engineering Guideline, PEG-7, "System Walkdowns," provides for discovery of degraded paint that could permit crevice corrosion, general corrosion, and pitting by providing for system walkdowns by visual inspection, reporting the walkdown results, and initiating corrective action. Under this program, inspection items typically related to aging management include identifying poor housekeeping conditions (such as degraded paint), and identifying system and equipment stress or abuse (such as thermal insulation damage, bent or broken hangers, etc.). Excessive vibration, unusual noise, and excessive temperatures are some other examples of potential equipment stress. Conditions identified as adverse to quality are documented on Issue Reports in accordance with QL-2-100. [Reference 5]

Under PEG-7, the system engineer performs periodic walkdowns; walkdowns before, during, and after outages; and walkdowns related to a specific plant modification(s). [Reference 5, Section 5.0]

PEG-7 promotes familiarity of the systems by the system engineers, and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance alone. As a result of experience gained, PEG-7 has been improved over time to provide guidance regarding specific standard activities that should be included in program walkdowns.

Group 1 (External Surfaces of Aboveground Piping, Check Valves, and Hand Valves) - Demonstration of Aging Management:

Based on the information presented above, the following conclusions can be reached with respect to general corrosion, crevice corrosion, and pitting of external surfaces of aboveground piping, check valves, and hand valves of the DFO System.

- The external surfaces of the aboveground piping, check valves, and hand valves contribute to the pressure boundary function.

- The construction material for components in this group is carbon steel. The external surfaces of piping and valves are coated with paint.
- Crevice corrosion, general corrosion, and pitting are plausible ARDMs for this group of components because external carbon steel surfaces and coating are exposed to sun, and to a humid, moist, or wet environment. If unmitigated, these ARDMs could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- These effects will be managed by employing a combination procedures MN-3-100, PEG-7, and QL-2-100.
- Therefore, there is a reasonable assurance that the effects of aging will be adequately managed for the aboveground DFO piping, check valves, and hand valves such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation under all design loading conditions.

Group 2 (External Surfaces of Underground Piping) - Materials and Environment:

The material used for underground piping (buried piping) in the DFO System is seamless carbon steel with forged fittings. The weld material for piping is carbon steel. [Reference 4, Attachment 4]. For the purposes of aging management discussion, all materials in Group 2 are conservatively assumed to be carbon steel.

The external surfaces of the piping are protected, per standard industry practice, with external coating and wrapping and an impressed current cathodic protection system. The underground piping is surrounded by soil. The backfill material is compacted soil. [Reference 4, Attachment 6]

Group 2 (External Surfaces of Underground Piping) - Aging Mechanism Effects:

Carbon steel is susceptible to crevice corrosion, general corrosion, galvanic corrosion, MIC, and pitting corrosion mechanisms when buried under soil. The aggressiveness of these ARDMs is dependent on soil resistivity (or conductivity), chloride and sulfate presence, oxygen content and soil aeration, pH, moisture content of soil, wet dry cycles, and microbe activity. [Reference 4, Attachment 6]

Holidays (thin spots, skipped areas, or areas where coating degradation has occurred) or disbonded areas of the wrapping can lead to crevice corrosion, general corrosion, pitting, and MIC given a conducive environment. [Reference 4, Attachment 8]

General corrosion is thinning (wastage) of a metal by chemical attack (dissolution) by an aggressive environment at the surface of the metal. The consequences of the damage are loss of load-carrying cross-sectional area. If unmitigated, general corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Galvanic corrosion is an accelerated corrosion caused by dissimilar metals in contact in a conductive solution. It requires two dissimilar metals in physical or electrical contact, a developed potential (material dependent), and a conducting solution. If unmitigated, galvanic corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. Crevice corrosion is closely related to pitting corrosion and can initiate pits, as well as lead to SCC. If unmitigated, crevice corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Pitting is a form of localized attack with greater corrosion rates at some locations than at others. Pitting produces holes of varying depth to diameter ratios in steel. If unmitigated, pitting corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Microbiologically induced corrosion is accelerated corrosion of materials resulting from surface microbiological activity. Microbiologically induced corrosion most often results in pitting followed by excessive deposition of corrosion products. If unmitigated, MIC could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Group 2 (External Surfaces of Underground Piping) - Methods to Manage Aging Effects:

Mitigation: Protective wrapping and coatings can mitigate corrosion by protecting the metal surface from contact with a corrosive environment. Cathodic protection also mitigates corrosion by counteracting galvanic activity.

Discovery: The effects of these plausible aging mechanisms are detectable by visual techniques. Since corrosion of carbon steel exterior surface of the piping cannot occur without the degradation of wrapping and coating, observing and confirming that the wrapping and coating on the buried piping are intact provides an alert condition which triggers corrective action before degradation that affects the underground piping's ability to perform its intended function could occur. The corrosion that does occur can be discovered and managed by periodically inspecting the wrapping and by carrying out repairs as necessary.

Group 2 (External Surfaces of Underground Piping) - Aging Management Program(s):

Mitigation: The external surfaces of underground piping are protected from contact with the soil by protective coatings. This is a design feature of the system that mitigates the effects of age-related degradation. Inspections have verified that these coatings remain in excellent condition after 20 years of exposure.

Although the underground piping is protected by a cathodic protection system, no credit is taken for this system when determining plausible aging mechanisms, nor for the aging management of buried piping.

Discovery: A new program for buried pipe inspection will include DFO and will provide additional assurance that the effects of plausible aging are being effectively managed for the period of extended operation under CLB design loading conditions. 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 ARDMs. [Reference 4, Attachment 8]

Group 2 (External Surfaces of Underground Piping) - Demonstration of Aging Management:

Based on the information presented above, the following conclusions can be reached with respect to corrosion of underground piping of the DFO System.

- The external surfaces of underground piping contribute to the pressure boundary function provided by underground piping.
- The construction material for underground piping is carbon steel and the piping is surrounded by soil.
- Crevice corrosion, general corrosion, pitting, galvanic corrosion, and MIC are plausible ARDMs for the underground piping external surfaces. The consequences of the damage are loss of load-carrying cross-sectional area, formation of localized pits, cracking, and deposition of excessive corrosion materials. If unmitigated, these ARDMs could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- The external surfaces of the piping are protected with external coating, wrapping, and cathodic protection.
- Through a new CCNPP DFO buried pipe inspection program, the plausible ARDMs, if present, would be discovered by regular inspections of representative piping sections through visual inspection.

Therefore, there is reasonable assurance that the effects of aging will be adequately managed for the underground DFO piping such that it will be capable of performing its intended functions, consistent with the CLB, during the period of extended operation under all design loading conditions.

Group 3 (Diesel FOST Internal Surfaces) - Materials and Environment:

The material of the diesel FOST and tank internals (shell side, nozzle/penetrations, anchor bolts/nuts, manway bolts/nuts, stairs/platforms, roof, and shell bottom) is carbon steel. [Reference 4, Attachment 4]

The tank is normally filled with fuel oil. Above the level of oil, the surfaces are exposed to ambient air and fuel vapors. Below the oil level the surfaces are exposed only to oil. Water, if present, and sediment collect at the bottom surface of the tank. A diesel fuel/water interface may be present inside the diesel FOST, and tank internals may be exposed to it. [Reference 4, Attachment 6]

Group 3 (Diesel FOST Internal Surfaces) - Aging Mechanism Effects:

Carbon steel diesel FOST internal surfaces and internals are susceptible to general, crevice, pitting, MIC, and fouling mechanisms. These ARDMs may be compounded by the presence of sludge/deposits at the bottom of the tank where water, if present, will generally collect. [Reference 4, Attachment 6] 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 plausible aging mechanisms. However, this coating plays an important role in the aging management of tanks.

If the diesel fuel oil is contaminated with water and comes into contact with the metal surfaces of the tank, general corrosion, crevice corrosion, pitting and MIC could occur, and may result in uniform or localized loss of material from the tank interior surfaces. The effects of fouling would be a layer of deposits on tank interior surfaces that could lead to increased rates of pitting and general corrosion.

General corrosion is thinning (wastage) of a metal by chemical attack (dissolution) by an aggressive environment at the surface of the metal. The consequences of the damage are loss of load-carrying cross-sectional area. If unmitigated, general corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. Crevice corrosion is closely related to pitting corrosion, and can initiate pits in many cases, as well as lead to SCC. If unmitigated, crevice corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Pitting is a form of localized attack with greater corrosion rates at some locations than at others. Pitting produces holes of varying depth to diameter ratios in steel. If unmitigated, pitting corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Microbiologically induced corrosion is accelerated corrosion of materials resulting from surface microbiological activity. Microbiologically induced corrosion most often results in pitting, followed by excessive deposition of corrosion products. If unmitigated, MIC could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Fouling is the deposit of foreign substances (such as microbes, silts, corrosion products) on system surfaces. These substances interact with and/or collect within the system and components. If unmitigated, fouling results in increased corrosion, which eventually could result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Group 3 (Diesel FOST Internal Surfaces) - Methods to Manage Aging Effects:

Mitigation: Corrosion-related ARDMs occur only when tank metal surfaces come into contact with a fluid which may be corrosive. In order to mitigate the effects of crevice corrosion, general corrosion, pitting, fouling and MIC, the conditions present within the tank that cause these ARDMs can be controlled. 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. Without such contact, the plausible ARDMs cannot occur.

Fuel oil is not corrosive to carbon steel under the normal conditions present in the FOSTs. Significant rates of corrosion-related ARDMs 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, minimizing the amount of water and the length of time it may be present in the tank is an effective method of mitigating the effects of general corrosion, crevice corrosion, pitting, MIC and fouling. Corrosion inhibitors can be added to new fuel oil to maintain a non-corrosive environment in the tank.

Discovery: The effects of the plausible aging mechanisms are detectable by visual and sampling techniques. Since corrosion of the carbon steel interior surface of the tank cannot occur without degradation of the coating, observing and confirming that this coating is intact constitutes an effective method to ensure that the effects of the plausible ARDMs 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 could occur. Since MIC is possible only if microbiological activity is present in the tank, sampling the tank for biological growth and taking appropriate action if positive indications are discovered is an effective technique to manage the effects of MIC.

Group 3 (Diesel FOST Internal Surfaces) - Aging Management Program(s):

The following CCNPP aging management programs are used to manage crevice corrosion, general corrosion, pitting, fouling, and MIC of internal surfaces of the diesel FOSTs.

Mitigation: Under the CCNPP procedure PEO-0-023-2-O-M, "Drain Water From 11 & 21 FOST," water which may collect at the tank bottom is periodically drained. If the amount of drained water or fuel chemistry is found not to meet the established standards, corrective action is implemented as required. [Reference 6, See cross-referenced procedure OI-21D, "Fuel Oil Storage and Supply," Revision 1, Sections 6.4.2 & 6.4.3] Draining the water will minimize the corrosion of the internal surface of the carbon steel tank bottom, and will also minimize the possibility of MIC since microbes require water to survive and multiply. If more than one gallon of water is drained, the operator is required to notify the shift supervisor, and the situation will be investigated to determine and correct the source of the water. [Reference 4, Attachment 8]

Under CCNPP procedure CP-226, "Oil Receipt Inspection and Fuel Oil Storage Tank Surveillance," fuel oil chemistry is controlled, including testing for the presence of biologics. The procedure establishes surveillance frequencies, fuel oil specifications (e.g., viscosity, % water and sediment, particulate contamination, and biologics), and corrective actions. Sampling and analysis are performed on new fuel prior to unloading from fuel trucks. This procedure specifies limits for viscosity, water, and sediment for both receipt inspection and Technical Specification surveillance, in accordance with the standard ASTM D975-81. The CCNPP Technical Specifications related to CP-226 are Specifications 4.7.11.1.2.b and 4.8.1.1.2.

This procedure now requires the addition of a stabilizer/corrosion inhibitor prior to unloading fuel oil into the FOSTs. Prior to adoption of this new approach, the stabilizer/inhibitor was being added in 55 gallon batches with initial tank fill, after being emptied for surveillance. The new approach provides a better assurance that the desired ratio of inhibitor to fuel oil exists. Corrosion inhibitor is added to the fuel to control corrosion of any exposed metal surfaces in the tank. A biocide is also added to the FOSTs for the initial addition, or if the presence of biological activity has been confirmed. [Reference 7, Attachment 2]

Calvert Cliffs' procedure CP-973, "Determination of Particulate Contamination in Diesel Fuel Oil," provides instructions to quantify insoluble particulate contamination in diesel fuel. This procedure was developed based on industry standards including the following [Reference 8, Section 3.0]:

- ASTM D-2276-89, Standard Test Method for Particulate Containment in Aviation Fuel; and

- EPRI Guidelines: Storage and Handling of Fuel Oil for Standby Diesel Generator Systems, Revision 1.

Under this procedure, the analytical data generated from the fuel oil sample is submitted to the Supervisor-Chemistry Environmental Services for review and approval. [Reference 8] Diesel fuel in the tank is sampled and analyzed quarterly. Fuel oil is drawn from several levels of the tank for analyses.

Since August 1989, chemistry procedure CP-226 has been revised to incorporate a new criteria, in accordance with the standard ASTM D270-65, for taking quarterly samples from the diesel FOSTs. This revision involves taking multilevel samples from each FOST rather than sampling only from the tank outlet, as it was done previously.

Discovery: Draining water and chemistry testing/control of fuel oil provide a high degree of confidence that the effects of the plausible ARDMs will be minimized. However, the internal surfaces of the tank are not accessible during system walkdowns; therefore, a new CCNPP Tank Internal Inspection Program is intended to provide assurance that the effects of plausible aging are being effectively managed. Under this program, CCNPP will perform an internal inspection of the FOSTs at periodic intervals based on results of previous inspections. If degradation mechanisms are found, corrective actions will be implemented. Future inspections may be scheduled, if appropriate. [Reference 4, Attachment 8] This inspection includes the following features:

- A visual assessment of the condition of the tank interior in accordance with 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 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."

The results of this inspection will be documented and used to assess the overall condition of the tank and the appropriate interval until the next inspection.

The system description section of this report provides the results of the November 1995 inspection of No. 11 FOST. Based on the results of this inspection, it can be concluded that no age-related degradation of the carbon steel material of construction has occurred. Number 21 FOST is scheduled to be inspected during the refueling outage of 1997.

Group 3 (Diesel FOST Internal Surfaces) - Demonstration of Aging Management:

Based on the information presented above, the following conclusions can be reached with respect to the FOST internal surfaces:

- The internal surfaces of the FOSTs contribute to the pressure boundary function provided by the FOSTs.
- Crevice corrosion, general corrosion, pitting, MIC, and fouling are plausible for the internal FOST surfaces. Crevice corrosion, general corrosion, MIC, and pitting can cause uniform or localized loss of material from the tank interior surface, which can lead to loss of pressure boundary. In addition, fouling can lead to accelerated rates of pitting and general corrosion.
- The effects of crevice corrosion, general corrosion, pitting, MIC, and fouling can be mitigated by controlling the conditions present in the tank (i.e., minimizing the amount of water and biologics present and adding a corrosion inhibitor). In addition, providing a barrier (i.e., protective coating) to prevent contact between the metal surfaces of the tank and the system fluid precludes the occurrence of the identified ARDMs, as without such contact these ARDMs cannot occur.
- The procedure CP-226 requires sampling for viscosity, water, and sediment upon receipt and quarterly afterwards, and includes target and action values for these parameters. Periodic sampling of the tanks also includes a check for biologics. If values given in the procedures are exceeded, appropriate corrective actions are taken, including (when appropriate) a technical evaluation. The procedure also requires that corrosion inhibitors be added at the time of fuel oil receipt. A biocide will also be added to the FOSTs for the initial addition, or if the presence of biological activity has been confirmed. [Reference 7, Attachment 2] In addition, a protective coating has been applied to the internal surfaces of the FOST, and this protective coating will be visually inspected periodically (at intervals to be determined by the results of previous inspections) for surface degradation, and selected thickness measurements of the coating are taken to ensure its integrity. [Reference 7]
- Results of a recent inspection, performed after 20 years of operation, confirmed that there is no degradation of No. 11 FOST which is located outdoors.

Therefore, there is reasonable assurance that the effects of aging will be adequately managed for the internal surfaces of the tanks such that the FOSTs will be capable of performing their intended functions consistent with the CLB during the period of extended operation under all design conditions.

Group 4 (FOST Shell and Bottom External Exposed Surfaces) - Materials and Environment:

The material for the diesel FOST shell and bottom is carbon steel. External surfaces of the tank shell are covered by protective coating. The tank bottoms are coated with bitumastic superblack. All weld seams are covered with asbestos strips to prevent contact between these welds and any aggressive soil environment. The tanks are set on a three-inch layer of oil-soaked, compacted sand, which provides a benign environment for aging of any carbon steel that would come into contact with it. The outer edge of the tanks are anchored to a concrete ring, and any voids between the tank bottoms and the concrete ring are filled with grout and the joint is sealed with a fibrated cold plastic coal tar pitch flashing. The tanks are

located with their bottoms at an elevation of 46 feet, which is above the groundwater table elevation of 10 to 20 feet, thereby preventing any direct contact between the tank bottom and the ground water table. The tank bottoms are also protected by an impressed current cathodic protection system. Therefore, the FOST bottoms are determined to be not subject to any plausible ARDMs. [Reference 4, Attachment 6] In addition, No. 21 FOST is located inside a protective enclosure. No. 21 FOST perimeter seal is also covered in Section 3.3 of the BGE LRA.

Group 4 (FOST Shell and Bottom External Exposed Surfaces) - Aging Mechanism Effects:

Crevice, general, and/or pitting corrosion are plausible ARDMs for the carbon steel diesel FOST shell external exposed surfaces, including that of exposed portions of anchor bolts and nuts. If the carbon steel was directly exposed to a humid moist, or wet external environment, the effects of crevice corrosion, general corrosion and pitting would be uniform or localized loss of material from the accessible external surfaces of the tank. Sun and weather may deteriorate the protective paint coating of the No. 11 FOST and lead to accelerated corrosion mechanisms of carbon steel components exposed to moisture. The No. 21 FOST is protected from the direct effects of sun and weather by a concrete enclosure. However, the carbon steel surfaces are still exposed to changes in humidity and temperature, requiring the protection of paint. The embedded portions of anchor bolts have been evaluated to be adequately protected by the quality of the concrete. [Reference 4, Attachment 6]

General corrosion is thinning (wastage) of a metal by chemical attack (dissolution) by an aggressive environment at the surface of the metal. The consequences of the damage are loss of load-carrying cross-sectional area. If unmitigated general corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. Crevice corrosion is closely related to pitting corrosion and can initiate pits in many cases, as well as lead to SCC. If unmitigated, crevice corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Pitting is a form of localized attack with greater corrosion rates at some locations than at others. Pitting produces holes of varying depth to diameter ratios in steel. If unmitigated, pitting corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 4, Attachment 7]

Weathering ARDM takes place when material of construction is fully exposed to the natural elements, which include fluctuating temperature and humidity, sunlight, rain, freezing rain, ice, and snow. In the case of caulking and sealant, the effects are evidenced by a decrease in elasticity, increased hardness, and shrinkage. [Reference 4, Attachment 6]

Fibrated cold plastic coal tar pitch flashing is susceptible to weathering ARDM when fully exposed to fluctuating temperature and humidity, sunlight, rain, freezing rain, ice and snow. Therefore caulking and sealant of Nos. 11 and 21 FOSTs will deteriorate under the constant exposure to severe weather conditions. [Reference 4, Attachment 6]

Group 4 (FOST Shell and Bottom External Exposed Surfaces) - Methods to Manage Aging Effects:

Mitigation: The effects of corrosion can be mitigated by minimizing the exposure of external surfaces of carbon steel and alloys to an aggressive environment, and protecting the external surfaces with paint or other protective coatings.

Discovery: The corrosion that does occur can be discovered and monitored by periodic inspection of paint on exposed external surfaces and carrying out repairs as necessary.

The effects of the ARDMs that were determined to be plausible are detectable by visual techniques. The accessible external metal surfaces of the tank are covered by a protective coating; therefore, observing and confirming that this coating is intact is an effective method of ensuring that aging effects have not occurred. Since the coating does not contribute to the intended function of the tank, observing the coating for degradation provides an alert condition. This alert condition would trigger corrective action before degradation could occur.

Caulking and sealant do not contribute to the intended function of the tank. However, they play a role in mitigating corrosion of the tank bottom. Visually inspecting and probing caulking and sealant for degradation at periodic intervals provides an alert condition. This alert condition would trigger corrective action before degradation could occur.

Group 4 (FOST Shell and Bottom External Exposed Surfaces) - Aging Management Program(s):

Mitigation: Procedure MN-3-100 mitigates crevice corrosion, general corrosion, and pitting by addressing degraded paint areas discovered through visual inspection techniques under procedures PEG-7, and QL-2-100. [Reference 4, Attachment 8] A discussion of the attributes of these programs was provided in the Group 1 section, above.

Discovery: A new CCNPP Caulking and Sealant Inspection Program will provide requirements and guidance for the identification, inspection, and maintenance of caulking and sealants used throughout the plant to ensure that their condition is maintained at a level which allows them to perform their intended function. [Reference 4, Attachment 8]. This program will be developed in accordance with the resolution to Issue Report No. IR199501698 (Inspect and Replace or Repair Defective Joints). This program will provide for baseline inspection along with periodic future inspections at appropriate intervals, depending upon the degree of harshness of caulking or sealant environment. Items that are in an exterior harsh environment may be inspected periodically as repetitive maintenance tasks. The seals will be assigned unique identification numbers and cataloged. The program will involve visual inspection and probing to determine that caulking or sealant is satisfactorily attached to the surface and is flexible. This program works in conjunction with system walkdowns (PEG-7). The perimeter seals of Nos. 11 and 21 FOSTs will be covered under this program. The No. 21 FOST tank perimeter seal is also covered by Section 3.3, Structures, of the BGE LRA. [Reference 4, Attachment 10]

Group 4 (FOST Shell and Bottom External Exposed Surfaces) - Demonstration of Aging Management:

Based on the information presented above, the following conclusions can be reached with respect to the FOST external surfaces:

- The external surfaces of the FOSTs contribute to the pressure boundary function provided by the tanks.
- Crevice corrosion, general corrosion, and pitting are plausible ARDMs for the external surface of the FOSTs. Crevice corrosion, general corrosion, and pitting can lead to uniform or localized wall thinning, which in turn can lead to a loss of pressure boundary integrity.
- Providing a barrier (i.e., protective coating) to prevent contact between the carbon steel external surfaces of the tanks and the external environment precludes the occurrence of the plausible ARDMs.
- The external surfaces of the tanks are painted. The combination of PEG-7, MN-3-100, and QL-2-100 ensures that the paint applied to the external surface of the FOST is maintained in order to prevent long-term exposure of the tank material to the external environment. Since the construction material will not be exposed to the external environment for extended periods of time, the effects of crevice corrosion, general corrosion, and pitting will be managed.
- The external surfaces of tank bottoms are comprised of carbon steel coated with bitumastic superblack. The tank bottoms are also protected by an impressed current cathodic protection system. The tanks are set on a three-inch layer of oil soaked, compacted sand which provides a benign environment for aging of any carbon steel that would contact it. Therefore, the FOST bottoms are determined to be not subject to any plausible ARDMs.
- Recent visual inspection of No. 11 FOST, performed after 20 years of operation, observed no deficiencies in the exterior of the tank. Ultrasonic testing of the tank bottom observed minimum thickness of .251 inches for 1/4 inch plate.

Therefore, there is reasonable assurance that the effects of aging on the external surfaces of the FOST will be adequately managed such that the FOSTs will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation under all design loading conditions.

5.7.3 Conclusion

The aging management programs discussed for the DFO System are listed in the following table. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects in such a way that the intended functions of the components of the DFO System will be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 5.7-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE DFO SYSTEM

	Program	Credited As
Existing	CCNPP Plant Evaluation Guideline "System Walkdowns," PEG-7	Discovery of the effects of general corrosion, crevice corrosion, and pitting of external surfaces of (Group 1) piping, (Group 1) valves, and (Group 4) tank external surfaces.
Existing	CCNPP Chemistry Program Procedure, "Oil Receipt Inspection and Fuel Oil Storage Tank Surveillance," CP-226	Mitigating the effects of crevice corrosion, general corrosion, pitting, fouling, and MIC of (Group 3) tank internal surfaces.
Existing	CCNPP Plant Evaluation Program Procedure "Operations Performance Evaluation Requirements -- Drain Water from #11 and #21 FOST per OI-21," PEO-0-023-2-O-M	Mitigating the effects of crevice corrosion, general corrosion, pitting, fouling, and MIC of (Group 3) tank internal surfaces.
Existing	CCNPP Chemistry Program Procedure "Determination of Particulate Contamination in Diesel Fuel Oil," CP-973	Mitigating the effects of crevice corrosion, general corrosion, pitting, fouling, and MIC of (Group 3) tank internal surfaces.
New	Diesel Fuel Oil Buried Pipe Inspection Program	Discovery of the effects of general corrosion, crevice corrosion, galvanic corrosion, MIC, and pitting of external surfaces of (Group 2) buried pipe.
New	Tank Internal Inspection Program	Discovery of the effects of crevice corrosion, general corrosion, pitting, fouling, and MIC of (Group 3) tank internal surfaces.
New	Caulking and Sealant Inspection Program	Discovery of the effects of weathering of (Group 4) tank perimeter seal.

5.7.4 References

1. CCNPP Updated Final Safety Analysis Report, Revision 19
2. CCNPP Piping & Instrumentation Drawing No. 60736, Fuel Oil Storage System, Revision 37
3. CCNPP Component Level Scoping Results Report for the Diesel Fuel Oil System, Revision 2
4. CCNPP Aging Management Review Report for the Diesel Fuel Oil System, Revision 2
5. CCNPP Plant Evaluation Guideline PEG-7, "Plant Engineering Section, System Walkdowns," Revision 4, November 30, 1995
6. CCNPP Plant Evaluation Procedure PEO-0-23-2-O-M, "FOST Drain Water," Revision 2, dated August 21, 1995
7. CCNPP Chemistry Procedure CP-226, "Oil Receipt Inspection and Fuel Oil Storage Tank Surveillance," Revision 4, dated March 27, 1997
8. CCNPP Chemistry Procedure CP-973, "Determination of Particulate Contamination in Diesel Fuel Oil," Revision 3

ATTACHMENT (3)

APPENDIX A - TECHNICAL INFORMATION

5.9 - FEEDWATER SYSTEM

5.9 Feedwater System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Feedwater System (FWS). The FWS was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

5.9.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to aging management review (AMR) begins with a listing of passive intended functions, and then dispositions the component types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.9.1.1 presents the results of the system level scoping, 5.9.1.2 the results of the component level scoping, and 5.9.1.3 the results of scoping to determine components subject to an AMR.

Historical operating experience, judged to be pertinent, is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, and through documented discussions with currently-assigned, cognizant CCNPP personnel.

5.9.1.1 System Level Scoping

This section begins with a description of the system, which includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

System Description/Conceptual Boundaries

The FWS transfers condensate received from the Condensate System to the steam generators (SGs), raises the temperature of the feedwater to increase plant efficiency, and controls the rate of flow to the SGs to match the steam flow demand by the plant turbine generators. [Reference 1, Section 10.2; and Reference 2] The major components of the FWS are piping, steam-driven pumps, high pressure feedwater heaters, regulating valves, isolation valves, and header check valves. Also included are SG secondary side pressure and level instrumentation loops. This instrumentation provides SG level control information as well as the protective functions of SG isolation and auxiliary feedwater initiation. Figure 5.9-1 is a simplified diagram of the FWS and is provided for information only. This figure shows the portion of the system within the scope of license renewal and the major process flow interfaces. [References 2 and 3] The FWS component design data are included in Table 10-1 of the Updated Final Safety Analysis Report. [Reference 1, Section 10.2]

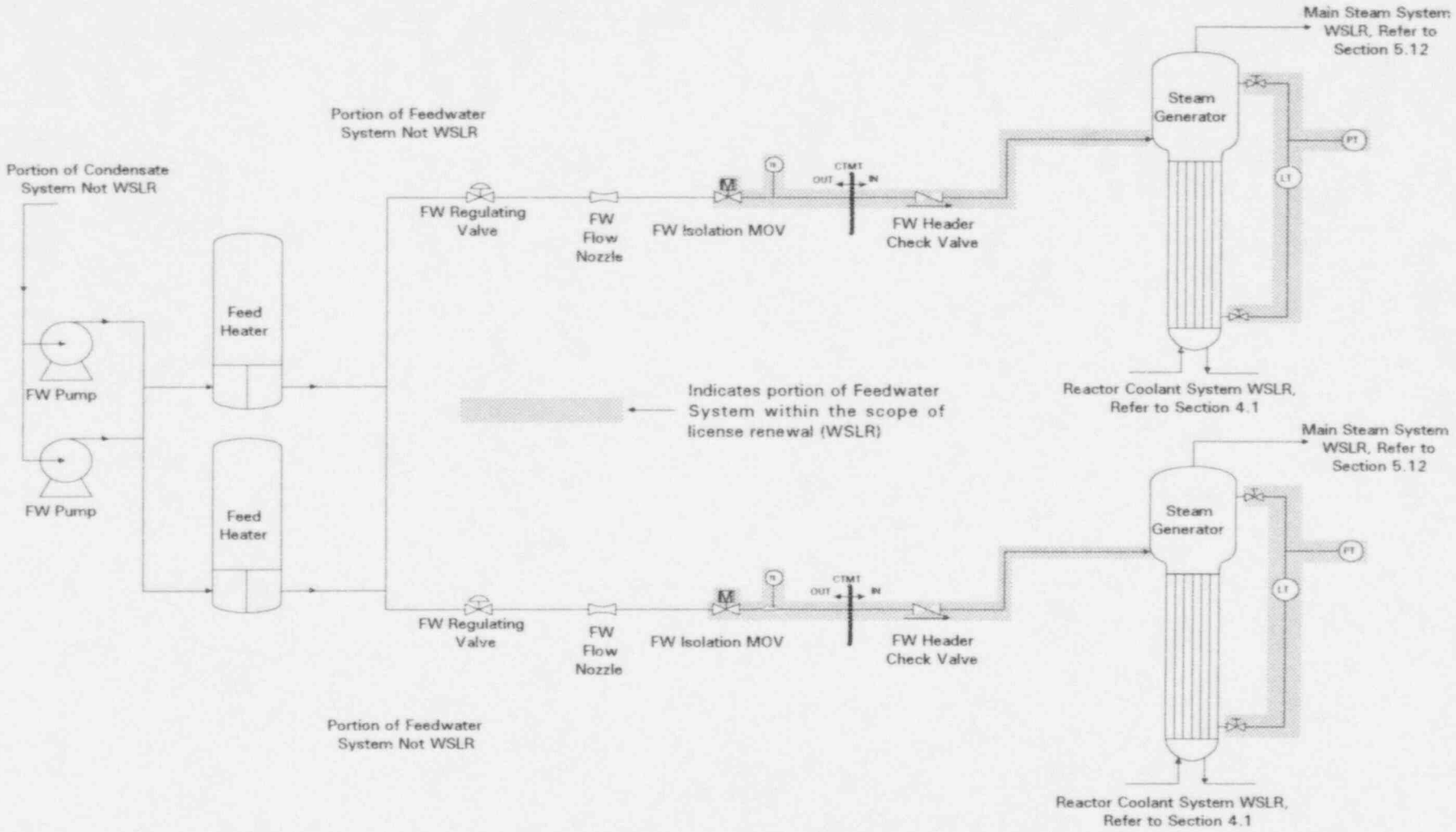

Figure 5.9-1

CCNPP FEEDWATER SYSTEM - SIMPLIFIED DIAGRAM

System Interfaces

The FWS has interfaces with the Condensate System, Main Steam System, Chemical Addition System, Engineered Safety Features Actuation System, Extraction Steam System, and Reactor Coolant System. The interfaces in the major flow path are as follows:

- Condensate lines to the suction of the feedwater pumps - These lines are not within the scope of license renewal.
- Feedwater lines to the SGs - The SGs are within the scope of license renewal for the Reactor Coolant System which is addressed in Section 4.1 of the BGE LRA.
- Main steam lines from the SGs - These lines are within the scope of license renewal for the Main Steam System which is addressed in Section 5.12 of the BGE LRA.

System Scoping Results

The FWS is within the scope of license renewal based on 10 CFR 54.4(a). The following intended functions of the FWS were determined based on the requirements of §54.4(a)(1) and (2), in accordance with the CCNPP IPA Methodology, Section 4.1.1: [Reference 4, Table 1]

- Provide containment overpressure protection;
- Prevent reverse flow from the SG via check valve closure;
- Send signals to the Engineered Safety Features Actuation System and provide SG isolation;
- Provide signals to the Reactor Protective System;
- Provide signals to the Auxiliary Feedwater Actuation System;
- Maintain the pressure boundary of the system; and
- Maintain electrical continuity and/or provide protection of the electrical system.

The following FWS intended functions were determined based on the requirements of §54.4(a)(3): [Reference 4, Table 1]

- For fire protection (§50.48) - Monitor SG level to support safe shutdown in the event of a postulated severe fire.
- For environmental qualification (§50.49) - Maintain functionality of electrical equipment as addressed by the Environmental Qualification Program, and provide information used to assess the plant and environs condition during and following an accident.
- For station blackout (§50.63) - Provide SG level indication.

All components of the FWS that meet the requirements of 54.4(a)(3) are also safety related. No components were scoped which only meet a 54.4(a)(3) criteria.

All components of the FWS that support the above functions are Seismic Category 1 and are subject to the applicable loading conditions identified in Updated Final Safety Analysis Report Section 5A.3.2 for Seismic Category 1 systems and equipment design. The feedwater piping from the isolation motor-operated valve (MOV) to the SG is designed in accordance with American Nuclear Standards Institute

(ANSI) B31.7, Class II, Nuclear Power Piping Code, 1969. The piping is considered Class 2 piping for the purposes of the American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection program. The pipe class is designated as Class DB, which has a rating of 900 psig at 850°F. [References 1, 2, 5, and 6]

Overall, the FWS has been a reliable system since plant startup. Some aging concerns have been identified through operating experience at the plant as well as through monitoring of industry activities. For example, erosion corrosion discovered in the Main Steam System has led to its discovery in the FWS. However, no age-related degradation has occurred that has prevented the components from performing their intended functions. Additional information on operating experience is provided later in the report in the specific sections where it applies.

5.9.1.2 Component Level Scoping

Based on the intended system functions listed above, the portion of the FWS that is within the scope of license renewal includes all components (electrical, mechanical, and instrument), and their supports, from the inlet side of the motor-operated feedwater isolation valves to the SG nozzle. Also included are SG secondary side water level and pressure indicating instrumentation loops, including the root isolation valves and all downstream components (valves, tubing, instruments). Figure 5.9-1 indicates the portion of the system within the scope of license renewal. [Reference 2; and Reference 4, Table 1]

The following 20 device types in the FWS were designated as within the scope of license renewal because they have at least 1 intended function:

Class DB Piping	MOV
Check Valve	Pressure Indicator
Fuse	Pressure Transmitter
Handswitch	Relay
Hand Valve	Temperature Element
Current/Current Device	Temperature Device (Relay)
Power Lamp Indicator	Transformer
Level Indicator	Power Supply
Level Recorder	Position Indicating Lamp
Level Transmitter	Position Switch

Some components in the FWS are common to many other plant systems and have been included in separate commodity AMRs which address those components for the entire plant. These components include the following:

- Structural supports for piping, cables, and components are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA.
- Electrical control and power cabling are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of the BGE LRA. This commodity evaluation completely addresses the passive intended function entitled "maintain electrical continuity and/or provide protection of the electrical system" for the Compressed Air System.
- Instrument tubing and piping and the associated supports, instrument valves and fittings (generally everything from the outlet of the final root valve up to and including the instrument), and the

pressure boundaries of the instruments themselves, are all evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

5.9.1.3 Components Subject to Aging Management Review

This section describes the components within the FWS which are subject to an AMR. It begins with a listing of passive intended functions and their dispositions the device types as either only associated with active functions, subject to replacement, evaluated in other reports, evaluated in commodity reports, or remaining to be evaluated for aging management in this report.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following FWS functions were determined to be passive:

- Maintain the pressure boundary of the system; and
- Maintain electrical continuity and/or provide protection of the electrical system

Device Types Subject to Aging Management Review

Of the 20 device types within the scope of license renewal:

- Thirteen device types have only active functions; Fuse, Hand Switch, Current/Current Device, Power Lamp Indicator, Level Indicator, Level Recorder, Pressure Indicator, Relay, Temperature Relay, Transformer, Power Supply, Position Indicating Lamp, Position Switch; and
- Two device types, the SG level transmitters and pressure transmitters, are either subject to a replacement program or are evaluated in another AMR. Eight of the 20 SG level transmitters in Unit 2 and all 8 of the pressure transmitters in Unit 2 are replaced in accordance with the Environmental Qualification Program based on a qualified life of less than 40 years. All remaining SG level and pressure transmitters in the FWS are subject to an AMR and are evaluated in the Instrument Line Commodity Evaluation in Section 6.4 of the BGE LRA. [Reference 3, Table 3-2; and Reference 7, Attachment 2]

The remaining five device types, listed in Table 5.9-1, are subject to AMR and are included in this report. Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

Maintenance of the pressure boundary of the system is the only passive intended function associated with the FWS not addressed by one of the commodity evaluations referred to above. Therefore, only the pressure retaining function for the five device types listed in Table 5.9-1 is considered in the AMR for the FWS. Unless otherwise annotated, all components of each listed type are covered.

TABLE 5.9-1
FWS DEVICE TYPES REQUIRING AMR

Piping
Check Valves
Hand Valves*
MOVs
Temperature Elements

* Instrument line manual drain, equalization, and isolation valves in the FWS that are subject to AMR are evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of the BGE LRA. Instrument line manual root valves are evaluated in this report. [Reference 7, Attachments 4 and 4A]

5.9.2 Aging Management

The list of potential age-related degradation mechanisms (ARDMs) identified for the FWS components is given in Table 5.9-2, with plausible ARDMs identified by a check mark (✓) in the appropriate component type column. [Reference 3, Table 4-2] For efficiency in presenting the results of these evaluations in this report, ARDM/device type combinations are grouped together where there are similar characteristics, and the discussion is applicable to all components within that group. Exceptions are noted where appropriate. Table 5.9-2 also identifies the group to which each ARDM/device type combination belongs. The following groups have been selected for the FWS:

Group 1 includes crevice corrosion, general corrosion, and pitting for all components subject to AMR.

Group 2 includes low cycle fatigue for the horizontal run of piping adjacent to the SG.

Group 3 covers erosion corrosion for piping, check valves, MOVs, and temperature elements.

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion on materials and environment, aging mechanism effects, methods to manage aging, aging management program(s), and aging management demonstration.

TABLE 5.9-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE FEEDWATER SYSTEM

Potential ARDMs	Device Types					Not Plausible for System
	Piping	Check Valve	Hand Valve	MOV	Temperature Element	
Cavitation Erosion						x
Corrosion Fatigue						x
Crevice Corrosion	✓ (1)	✓ (1)	✓ (1)	✓(1)	✓(1)	
Dynamic Loading						x
Erosion Corrosion	✓ (3)	✓ (3)		✓ (3)	✓ (3)	
Fatigue	✓ (2)					
Fouling						x
Galvanic Corrosion						x
General Corrosion	✓ (1)	✓ (1)	✓ (1)	✓ (1)	✓ (1)	
Hydrogen Damage						x
Intergranular Attack						x
Microbiologically Induced Corrosion						x
Particulate Wear Erosion						x
Pitting	✓ (1)	✓ (1)	✓ (1)	✓ (1)	✓ (1)	
Radiation Damage						x
Saline Water Attack						x
Selective Leaching						x
Stress Corrosion Cracking						x
Thermal Damage						x
Thermal Embrittlement						x
Wear						x

✓ - indicates plausible ARDM determination
(#) - indicates the group in which this SC/ARDM combination is evaluated

Group 1 (crevice corrosion, general corrosion, and pitting for all component types) - Materials and Environment

The large bore (diameter above two inches) FWS main line piping is seamless carbon steel, and the small bore (diameter of two inches and below) drain and instrument tap piping is seamless carbon steel with forged fittings. Piping joints are butt-welded for large bore piping and socket welded for small bore piping. [Reference 2; Reference 3, Attachment 3 for Pipe; and Reference 5] Some segments have been replaced with chromium-molybdenum (Cr-Mo) alloy steel, which provides increased resistance to erosion-corrosion over carbon steel. Since only some segments have been replaced, no distinction is made between Cr-Mo and carbon steel piping for aging management demonstration. [Reference 8] This assumption results in the same conclusions for Cr-Mo pipe as for carbon steel pipe, which is a more conservative approach. The use

of Cr-Mo piping, however, will be considered when identifying locations for performing the periodic inspections discussed later under erosion corrosion.

The FWS valves consist of the SG feedwater header check valves, feedwater isolation motor-operated gate valves (MOVs), small hand-operated gate valves for feedwater header drains, and hand-operated globe valves for SG instrumentation root isolation service. The valves are constructed of carbon steel material. [Reference 3, Attachment 3 for Hand Valve, Check Valve, and MOV]

The Unit 1 SG feedwater inlet temperature instruments are installed in thermowells in the main feedwater piping. The thermowells are fabricated of Cr-Mo alloy steel material and are welded to the piping via a carbon steel half-coupling fitting. The Unit 2 temperature elements are located upstream of the feedwater flow nozzles, and therefore, are not within the scope of license renewal. [Reference 3, Attachment 3 for Temperature Element]

The internal environment for the FWS components during power generation is chemically treated, demineralized, high pressure water that increases in temperature with plant power level from 100°F or less to approximately 435°F at full power. System flow rates and fluid velocities are high at full power conditions. During all normal modes of plant operation, the system bulk fluid is subcooled water. [Reference 1, Section 10.2; and Reference 3, Attachments 3, 6 and 7] During plant shutdown conditions, the system may be drained or maintained completely filled with water.

Group 1 (crevice corrosion, general corrosion, and pitting for all component types) - Aging Mechanism Effects

Carbon steel is susceptible to general and localized (crevice and pitting) corrosion mechanisms in a water environment. The aggressiveness of these corrosion mechanisms are particularly dependent on local water chemistry conditions and oxygen levels. During shutdown periods, the FWS equipment is placed into either wet layup or dry layup in accordance with standard layup practices. [Reference 9] The chemically treated, demineralized water may have an oxygen level and water chemistry which is outside of the acceptable range during plant outages. During plant operation, the chemistry is controlled and the flow rates in the main flow lines are adequate to ensure proper mixing. In areas which are not exposed to the main flowstream, local fluid chemistry conditions may deviate substantially from bulk fluid system chemistry. The areas where there are stagnant conditions, e.g. drain lines and crevices, are the locations most susceptible to these corrosion mechanisms. [Reference 3, Attachments 6 and 7]

Long-term exposure to these environments may result in localized pitting and/or general area material loss and, if unmanaged, could eventually result in loss of the pressure-retaining capability under current licensing basis (CLB) design loading conditions. Therefore, general corrosion, crevice corrosion, and pitting corrosion have been determined to be plausible ARDMs for which aging effects must be managed for the FWS. For the check valves and manual root valves, the degradation is not considered for the disk and seat because they are not relied on for pressure boundary in the closed position. For the manual drain valves, the degradation is not plausible for the disk and seat because of the chromium content in their trim material which provides resistance to crevice corrosion, general corrosion, and pitting, particularly in the controlled chemistry feedwater environment. Corrosion is also not plausible for any of the bolts, because they are not exposed to water. [Reference 3, Attachments 6 and 7]

Group 1 (crevice corrosion, general corrosion, and pitting for all component types) Methods to Manage Aging

Mitigation: The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of the carbon steel components and the piping material to an aggressive environment. [Reference 3, Attachments 6 and 7]

Maintaining a feedwater environment of purified water, with a controlled pH and with dissolved oxygen and other impurities maintained at low levels during normal plant operation, results in limited corrosion reactions. The formation of a passive oxide layer (magnetite) also protects the pipe interior surface by minimizing the exposure of bare metal to water. [Reference 3, Attachments 6 and 7]

Discovery: The effects of corrosion on system components can be discovered and monitored through non-destructive examination techniques such as visual inspections. [Reference 3, Attachment 8] Inspections at susceptible locations can be used to assess the need for additional inspections at less susceptible locations. Based on piping/component geometry and fluid flow conditions, areas most likely to experience corrosion can be determined and evaluated. The inspections must be performed on a frequency that is sufficient to ensure that minimum wall thickness requirements will be met until at least the next examination is performed.

Group 1 (crevice corrosion, general corrosion, and pitting for all component types) - Aging Management Program(s)

Mitigation: The CCNPP Chemistry Program has been established to: minimize impurity ingress to plant systems; reduce corrosion product generation, transport, and deposition; reduce collective radiation exposure through chemistry; improve integrity and availability of plant systems; and extend component and plant life. [Reference 10, Section 6.1.A] The scope of the Chemistry Program procedure which controls FWS chemistry, Reference 11, includes the SGs, condensate storage tanks, feedwater, condensate, Main Steam System, heater drain tanks, condensate demineralizer effluent, SG blowdown ion exchanger effluent, and condensate precoat filters. [Reference 11, Section 2.C] The program is based on References (12) through (18).

The Chemistry Program controls fluid chemistry in order to minimize the concentration of corrosive impurities (chlorides, sulfates, oxygen) and optimizes fluid pH. Control of fluid chemistry minimizes the corrosive environment for FWS components, and limits the rate and effects of corrosion. [Reference 3, Attachment 8] The rate of corrosion is also reduced by the buildup of a passive oxide layer (magnetite) that minimizes bare metal exposure to water. [Reference 3, Attachment 6]

Secondary chemistry parameters (e.g., pH, dissolved oxygen levels) are measured at procedurally-specified frequencies (e.g., continuously, daily, weekly). The measured parameter values are compared against "target" values which represent a goal or predetermined warning limit. If a measured value is out of bounds, corrective actions are taken (e.g., power reduction, plant shutdown) in accordance with the plant secondary chemistry procedure. Remedial actions are specified to minimize corrosion degradation of components and to ensure that secondary system integrity is maintained. [Reference 11, Sections 6.0 and 2.C]

As discussed in the plant Technical Specifications Bases, the plant is expected to be operated in a manner such that the secondary coolant chemistry parameters will be maintained within those limits found to result in minimal corrosion of the SG tubes. To assure this goal is met, the Secondary Chemistry Program has the target and action values based on chemistry guidelines provided by Electrical Power Research Institute (EPRI), Institute for Nuclear Power Operations (INPO), and Nuclear Steam Supply System vendor. These values ensure a timely response to chemical and radiochemical excursions, with appropriate corrective actions. [Reference 11]

The Chemistry Program is subject to internal assessment activity both within the Chemistry Department and through the site performance assessment group. This helps to maintain highly effective secondary chemistry control, and facilitates continuous improvements through monitoring industry initiatives and trends in the area of secondary systems corrosion control. The program is also subject to frequent external assessments by INPO and others.

Operating experience relative to the Chemistry Program at CCNPP has been such that no major site-specific events related to these aging mechanisms are known to have occurred that required changes or adjustments to the program. It has been effective in its function of mitigating corrosion, and thereby preventing corrosion-related failures and problems. The main focus of the program is SG chemistry. It has been demonstrated that, as long as SG chemistry is carefully monitored and controlled, the rest of the secondary cycle is maintained within acceptable chemical control. Calvert Cliffs has been proactive in making programmatic changes to the secondary chemistry program over its history, largely in response to developments within the industry, such as successful experimentation with a new alternate amine.

Discovery: Crevice corrosion, general corrosion, and pitting of FWS components can be readily detected through non-destructive examination techniques. These types of corrosion occur over a long period of time and will be evident prior to minimum wall thickness reaching an unacceptable value. As such, an inspection program to identify occurrence of corrosion is an effective means of determining if corrective actions are required for managing these aging mechanisms. [Reference 3]

All components will be included within a new plant program to accomplish the needed inspections for crevice corrosion The hand valves, check valves, MOVs, and temperature elements will be included in the new plant program to accomplish the needed inspections for general corrosion. This program is considered an Age-Related Degradation Inspection (ARDI) Program as defined in the CCNPP IPA Methodology presented in Section 2.0 of the BGE LRA.

The elements of the ARDI program will include:

- Determination of the examination sample size based on plausible aging effects;
- Identification of inspection locations in the system/component based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective, considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of unacceptable examination findings, including consideration of all design loadings required by the CLB and specification of required corrective actions; and

- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

The corrective actions will be taken in accordance with the CCNPP Corrective Action Program, and will ensure that the components will remain capable of performing the system pressure boundary integrity function under all CLB conditions.

Group 1 (crevice corrosion, general corrosion, and pitting for all component types) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to crevice corrosion, general corrosion, and pitting of FWS components:

- The FWS components provide the system pressure retaining boundary and their integrity must be maintained under CLB design conditions.
- Crevice corrosion, general corrosion, and pitting are plausible for the components, and result in material loss which, if left unmanaged, can lead to loss of pressure retaining boundary integrity.
- The rate of attack is affected by the local fluid chemistry, but the CCNPP Secondary Chemistry Program provides controls for system bulk fluid chemistry in order to mitigate the overall effects of corrosion; however, localized corrosion (crevice corrosion and pitting) may be more prevalent than general corrosion in areas of low flow velocity and in crevices.
- To provide assurance that corrosion is not significant, the FWS components will be included in the scope of an ARDI Program. Inspections will be performed, and appropriate corrective action will be taken if significant corrosion is discovered.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, and pitting on FWS components will be managed in such a way as to maintain the components' pressure boundary integrity, consistent with the CLB, during the period of extended operation.

Group 2 (low cycle fatigue of piping) - Materials and Environment

The large bore FWS main line piping is seamless carbon steel, and the small bore drain and instrument tap piping is seamless carbon steel with forged fittings. Piping joints are butt-welded for large bore piping and socket welded for small bore piping. [Reference 2; Reference 3, Attachment 3 for Pipe; and Reference 5]

The internal environment for the FWS piping during power generation is chemically treated, demineralized, high pressure water that increases in temperature with plant power level from 100°F or less to approximately 435°F at full power. Plant transients subject the FWS to thermal stress during plant heatups, cooldowns, and plant trips. The horizontal segment of FWS piping adjacent to the SG inlet nozzle is also subject to thermal stratification during hot standby and at power levels less than 10%. At low power levels, the feedwater flow rate can vary, resulting in rapid shifts in the stratified layers, thereby causing temperature changes in the piping. Thermal stratification has resulted in measured top-to-bottom temperature differences of up to approximately 420°F. [Reference 19] During all normal modes of plant operation, the system bulk fluid is subcooled water. [Reference 1, Section 10.2; and Reference 3,

Attachments 3, 6, and 7] During plant shutdown conditions, the system may be drained or maintained completely filled with water.

Group 2 (low cycle fatigue of piping) - Aging Mechanism Effects

Fatigue is the process of progressive localized permanent structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points, and which may culminate in cracks or complete fracture after a sufficient number of fluctuations. The fatigue life of a component is the number of cycles of stress or strain that it experiences before fatigue failure. A component subjected to sufficient cycling with significant strain rates may develop cracking. The cracks may then propagate under continuing cyclic strains. [References 3 and 20] Baltimore Gas and Electric Company has not discovered any low cycle fatigue-related failures in the FWS. However, there have been occurrences at other facilities, including through-wall cracks in feedwater piping to the SGs at Tennessee Valley Authority's Sequoyah plant and Indiana Michigan Power Company's D. C. Cook plant. [Reference 21]

Plant transients apply cyclical thermal loading that contributes to low cycle fatigue accumulation on the entire section of piping within the scope of license renewal. The typical thermal transients of concern for this piping are FWS heatups, cooldowns, and secondary plant transients. The original design code for this piping is ANSI B31.7 Class II, which utilizes the methodology in ANSI B31.1 to account for fatigue usage. American Nuclear Standards Institute B31.1 uses a stress range reduction factor to account for the number of anticipated cycles and stress ranges for fatigue loading. The stress range reduction factor used in the feedwater piping design is 1, which corresponds to 7000 or less full range stress cycles for the operating life. This Code requirement of 7000 or less full range thermal cycles conservatively envelopes the number of expected transients through the period of extended operation. Feedwater system heatups and cooldowns cannot exceed 500 each, because the number of Reactor Coolant System heatups and cooldowns are limited to 500 each. The number of secondary transients that would affect fatigue life either cause or are the result of a reactor trip. The allowable number of reactor trips is 400. The total number of thermal transients allowed which are of primary concern for the feedwater piping is 1400. Therefore, except for the horizontal section leading to the SG feedwater nozzle, low cycle fatigue is not a concern for the feedwater piping, including the check valves, since the number of plant transients will not exceed 7000 for the period of extended operation. [References 19 and 22]

Low cycle fatigue is a known concern for the horizontal section of piping connecting to the SG nozzles. In addition to the transients described above, this portion of piping is subjected to cyclical thermal stratification and through-wall thermal stresses during low feedwater flow conditions. This occurs during Reactor Coolant System heatups, cooldowns, and hot standby operations. The effects of local cyclical thermal stratification do not extend beyond the first elbow to the vertical pipe run. Above 10% power operations, the volume of feedwater flow is sufficient to eliminate this cyclical condition. This section of piping bounds all other feedwater components. [References 19 and 23]

Cyclical thermal stratification and through-wall thermal stresses increase the rate of fatigue usage accumulation. This increased rate of fatigue usage accumulation may result in more severe fatigue damage during the extended period of operation than was accounted for in the original ANSI B31.1 analysis, which was based on 7000 full range thermal cycles. Subsequent analysis has shown the need to manage low cycle fatigue usage for this section of piping to ensure pressure boundary integrity. If left unmanaged, this

section of piping could develop fatigue cracking that could affect the ability of the piping to maintain the integrity of the system pressure boundary. [Reference 3, Attachments 6 and 7; and Reference 23]

Corrosion fatigue is not considered plausible, due to the water quality controls and the lack of crevices or low flow areas in the piping subject to thermal stratification. [Reference 3, Attachments 6 and 7]

Group 2 (low cycle fatigue of piping) - Methods to Manage Aging

Mitigation: There are two methods of mitigating the effects of low cycle fatigue. One method is to reduce the number and severity of thermal transients; the other method is to replace the affected piping components. The most significant thermal transients occur during plant heatup and cooldown, during hot standby, or at power operation less than 10%. These are temporary modes of operation, which cannot be avoided. [Reference 3] As part of general operating practice, plant operators minimize the length of these transitory operational conditions. If necessary, a design change could be initiated to replace the affected piping components.

Discovery: As discussed above, low cycle fatigue is accounted for in the original design in accordance with ANSI B31.1. The thermal cycles having the greatest effect on the fatigue life of feedwater piping are plant heatups, cooldowns, and reactor trips. In the absence of thermal stratification, the Code requirement of 7000 or less full range thermal cycles should conservatively envelop the number of expected transients through the period of extended operation. [Reference 19] To demonstrate that the plant is continuing to operate within the CLB, the number of these specific cycles must be counted and then projected through the period of extended operation to assure they remain below 7000.

For the horizontal section of piping adjacent to the SG, the increased rate of cycle usage due to thermal stratification could potentially result in more than 7000 full range cycles during the period of extended operation. For this section of pipe, cycle counting cannot be solely relied on to effectively manage aging. Additional methods must be employed to assure the piping will continue to perform its intended function.

One additional method is to discover the onset of crack formation by non-destructive examination. Ultrasonic testing (UT) could be performed to detect any cracking that may occur either on the pipe surface or internal to the pipe or welds. If cracking is detected, the pipe can be replaced or repaired.

The preferred aging management method would be to perform additional fatigue analyses to estimate the fatigue usage of critical locations. Current analysis techniques, such as those specified in ASME Section III, are capable of predicting the fatigue life of components through calculation of a cumulative usage factor. The fatigue usage factor of a component increases as the number of thermal transients experienced increases. Monitoring the cumulative usage factor over time, based on actual plant data, can be an effective method of predicting end of fatigue life and demonstrating adequacy through the period of extended operation. [References 24 and 25]

Group 2 (low cycle fatigue of piping) - Aging Management Programs

Mitigation: As part of general operating practice, plant operators minimize the length and severity of transitory operational cycles. Further modification of plant operating practices to reduce the magnitude and/or frequency of thermal transients would unnecessarily place additional restrictions on plant

operations. This is because the detection and monitoring activities discussed below are deemed adequate for effectively managing low cycle fatigue in the feedwater piping.

Discovery: Cycle counting is performed as part of the CCNPP Fatigue Monitoring Program which records and tracks the number of critical thermal and pressure test transients. The data for thermal transients is collected, recorded, and analyzed using FatiguePro software, which is a safety-related software package. FatiguePro is used to verify that the data represents real transients and to predict the number of transients for 40 and 60 years of plant operation based on the historical records. This information is used to verify that the feedwater piping, with the possible exception of the piping exposed to thermal stratification, will not experience more than 7000 full range stress cycles. [Reference 19] The Improved Standard Technical Specifications for CCNPP, which will be implemented in 1997, will contain a requirement for tracking cyclic and transient occurrences to ensure that components are maintained within the design limits.

Since thermal stratification is a significant contributor to fatigue usage for the SG nozzle and adjacent piping, CCNPP has initiated extensive analyses to determine the extent of low cycle fatigue due to oscillating thermal stratification, and to implement the most appropriate methods of managing the effects of this ARDM.

During the 1995 refueling outage of Unit 2, the piping adjacent to one SG was instrumented with thermocouples to obtain temperature data around the circumference of the pipe. Temperature data was collected on this pipe along with other parameters related to thermal fluctuations, such as feedwater flow and SG levels. The data was used to confirm that thermal stratification was occurring and to measure the severity of the temperature fluctuations. The top to bottom temperature differential was measured to be approaching 420°F in this section of pipe. [Reference 19]

This thermal data was also used, along with other data on plant parameters such as flow rates and pressures, to further analyze this section of piping for low cycle fatigue. A finite element analysis was performed to determine the most critical location for fatigue. The most critical location was determined to be the safe end-to-reducer weld. This location envelopes all feedwater piping. The safe end-to-reducer weld was then added as a critical location in the Fatigue Monitoring Program, as described below. [Reference 23]

A model was also developed for this section of piping to characterize the thermal stratification and temperature cycling occurring at the low power levels. This model was used to develop algorithms, which are used by the FatiguePro software to perform the stress-based analysis, to determine the cumulative fatigue usage factor at this weld. Other modifications were made to FatiguePro, as described below, to further refine its ability to accurately calculate the cumulative fatigue usage factor. [References 19 and 23]

To provide additional input to the evaluations being performed, the schedule for the normal inservice inspection was modified to inspect the critical welds at the next refueling outage. An ultrasonic test and magnetic particle examination were performed, in accordance with ASME Section XI, on the critical welds for Unit 1 in 1996. The test showed no flaws with sizes above the critical flaw sizes as specified in the ASME Code. The Unit 2 welds are scheduled for inspection during the 1997 refueling outage. [Reference 26]

CCNPP Fatigue Monitoring Program

The CCNPP Fatigue Monitoring Program has been established to monitor and track fatigue usage of limiting components of the Nuclear Steam Supply System and the SGs. Eleven locations in these systems have been selected for monitoring for fatigue usage. These represent the most bounding locations for critical thermal and pressure transients and operating cycles. [Reference 25] The program is currently being modified to include the critical weld in the FWS as a location requiring fatigue monitoring. Modifications to the FatiguePro software have already been implemented, as discussed below. The program is based on References (27) through (30).

The Fatigue Monitoring Program utilizes two methods to track fatigue usage. One method is to track the number of critical thermal and pressure test transients and compare them to the number allowed in the piping design analysis. The piping design analysis is performed assuming a particular number and severity of various transients. In accordance with either ASME Section III or ANSI B31.1, the analysis demonstrates that the component has an acceptable design as long as the assumptions remain valid. Therefore, if the actual number and severity of transients experienced by the component remains below the number assumed in the analysis, then the component remains within its design basis.

The other method is to track the cumulative usage factor to verify that it remains below 1.0. For components designed to the ASME Boiler and Pressure Vessel Code, Section III, a cumulative usage factor is calculated based on the same set of assumed transients discussed above. The cumulative usage factor can be calculated and tracked through plant life through thermal cycle counting, or it can be calculated using stress-based analysis techniques and actual plant operating data. The usage factor for several locations, including the bounding SG nozzle weld location, is calculated through stress-based analysis, which is the more rigorous method and which provides a more realistic cumulative fatigue usage factor. In accordance with the Code, the component remains within its design basis for allowable fatigue life if the cumulative usage factor remains less than or equal to 1.0. [References 19 and 25]

Plant parameter data is collected on a periodic basis and reviewed to ensure that the data represents actual transients. Valid data is entered into FatiguePro, which counts the critical transient cycles and calculates the cumulative usage factors. The cumulative usage factors and critical cycles are tracked on a semi-annual basis, which provides a readily predictable approach to the alert values. This data is tracked in accordance with procedures that are governed by the CCNPP Quality Assurance Program, which meets 10 CFR Part 50, Appendix B, criteria. In order to stay within the design basis, corrective action is initiated well in advance of reaching the allowable number of transient cycles or a usage factor of 1.0. [Reference 25]

The CCNPP Fatigue Monitoring Program has been inspected by the Nuclear Regulatory Commission (NRC), which noted that this monitoring system can be used to identify components where fatigue may challenge the remaining and extended life of the components, and can provide a basis for corrective action where necessary. The program is controlled in accordance with the administrative procedures of the Life Cycle Management Program, and is under the direct review of the supervisor of that program. [Reference 24]

Since the Fatigue Monitoring Program has been initiated, no locations have reached the limit on fatigue usage and no cracking due to low cycle fatigue has been discovered. Following extensive data collection and analysis, the program has been modified, and is in the design owners acceptance review process, to

specifically monitor fatigue usage at the critical location in the feedwater piping. Specifically, the SG stress-based analysis algorithms were modified to include the effects of thermal stratification. As part of the modification to FatiguePro, extensive baselining activities were performed. These activities included a review of all past operations during low feedwater flow conditions to account for past fatigue usage resulting from thermal stratification. Additionally, a review was performed of all critical thermal transients to ensure they were properly accounted for in FatiguePro. Calvert Cliffs now has an effective tool for monitoring fatigue usage of the critical feedwater piping location for thermal stratification. [Reference 19]

Additional modifications have been made to the program based on lessons learned. For example, analysis techniques, such as stress-based analysis, have been implemented for locations that have unique thermal transients or involve unique geometry. Other modifications have been made to reflect plant operating conditions more accurately. The plant design change process has also been modified to require notification to the Life Cycle Management Unit of any proposed changes to the critical locations being monitored. [References 19 and 31]

Evaluation of Thermal Fatigue Effects to Address Generic Safety Issue 166

Generic Safety Issue 166, Adequacy of Fatigue Life of Metal Components, identifies concerns identified by the NRC which must be evaluated as part of the license renewal process. The NRC staff concerns about fatigue for license renewal fall into five categories: (1) adequacy of the fatigue design basis when environmental effects are considered; (2) adequacy of both the number and severity of design basis transients; (3) adequacy of inservice inspection requirements and procedure to detect fatigue indications; (4) adequacy of the fatigue design basis for Class I piping components designed in accordance with ANSI B31.1; and (5) adequacy of actions to be taken when the fatigue design basis is potentially compromised. [References 32 and 33]

To fully address fatigue for license renewal, CCNPP has initiated an additional evaluation, in conjunction with EPRI, to evaluate the effects of low cycle fatigue on the FWS, the pressurizer surge line, and the charging/letdown lines. The evaluation will apply industry-developed methodologies to identify fatigue sensitive component locations which may require further evaluation or inspection for license renewal, and evaluate environmental effects as necessary. The evaluation objective includes the development and justification of aging management practices for fatigue at various component locations for the renewal period. [Reference 33]

Specifically for the FWS, the evaluation will: (1) identify those specific components that are considered fatigue sensitive (i.e., those components that exceed criteria established for normal thermal transients and/or other thermal conditions, such as thermal stratification); (2) utilize tracking data for the SG feedwater nozzle to determine if the anticipated fatigue usage is acceptable for license renewal and bounds the anticipated fatigue usage of the connected ANSI B31.1 piping; (3) assess the impact of environmental effects for those components that are projected to be bounded by the CLB through the period of license renewal; (4) perform an analysis using the methodology identified in the ASME Section XI non-mandatory Appendix L on fatigue evaluation for those components not bounded by the CLB through the period of license renewal; and (5) address the conclusions drawn in SECY-95-245 (completion of the Fatigue Action plan) with respect to components/locations considered in NUREG/CR-6260 relative to the issue of environmental effects. [Reference 33]

Group 2 (low cycle fatigue of piping) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to low cycle fatigue of FWS piping:

- The FWS piping is part of the system fluid pressure retaining boundary, and therefore, its integrity must be maintained under CLB design loading conditions.
- Low cycle fatigue is plausible for the horizontal run of piping adjacent to the SG nozzles, and it is affected by the severity of plant transients and thermal stratification.
- If left unmanaged, low cycle fatigue could result in crack initiation and growth, which could lead to loss of pressure retaining boundary integrity.
- The CCNPP Fatigue Monitoring Program includes thermal cycle counting and tracking of cumulative usage factors to monitor fatigue usage of critical components for the approach to the end of their fatigue life.
- The program includes periodic evaluations with acceptance criteria based on the ASME Boiler and Pressure Vessel Code, Section III, which assures that effective and timely corrective action will be taken prior to the point where fatigue damage would cause a breach of the pressure boundary.
- To fully address the fatigue concerns for license renewal raised in Generic Safety Issue 166, including consideration of environmental effects, an additional activity will be performed to evaluate the effects of thermal fatigue for the FWS and other plant locations. This evaluation will provide additional justification for, or modifications of, the aging management practices relied on for the license renewal period.

Therefore, there is reasonable assurance that the effects of low cycle fatigue in feedwater piping adjacent to the SG will be managed in such a way as to maintain the piping pressure boundary integrity, consistent with the CLB, during the period of extended operation.

Group 3 (erosion corrosion of piping, check valves, MOVs, and temperature elements) - Materials and Environment

The materials and environment discussion for Group 1 encompasses all materials and environments for this group.

Group 3 (erosion corrosion of piping, check valves, MOVs, and temperature elements) - Aging Mechanism Effects

The occurrence of erosion corrosion is highly dependent on construction material and fluid flow conditions. Carbon or low alloy steels are particularly susceptible when they are in contact with high-velocity turbulent flow (single or two phase) of water with low oxygen content and a pH less than 9.3. Erosion corrosion has been recognized throughout the industry as a concern for FWSs, particularly after the pipe rupture incident at Virginia Power's Surry Power Station. [Reference 34] Erosion corrosion has also been discovered in the feedwater check valves at CCNPP. After a failed back seat leakage test of the check valves, an inspection showed that erosion corrosion was occurring inside the valve body that could affect the pressure boundary capabilities of the valve. Based on the materials and environment of the FWS and operating experience, erosion corrosion of internal surfaces was determined to be a plausible ARDM for which the

effects of aging must be managed. Erosion corrosion is not plausible for the bolting in the check valves or MOVs, nor for any parts of the hand valves, because they are not in the flow stream. [Reference 3, Attachments 6 and 7]

Erosion corrosion can result in material loss in areas which are subject to disturbances in the flowstream, such as those caused by bends, tees, valves, thermowells, pumps, and localized internal surface irregularities. These flow disturbances lead to erosion of the metal surfaces, usually the protective passive corrosion film, and exposes fresh metal to corrosion. This process can result in significant wall thickness reduction and failures in a relatively short time. Erosion corrosion can reduce the component wall thickness and result in grooves, gullies, waves, holes, and valleys on the metal surface. [Reference 3, Attachments 6 and 7] If left unmanaged, it could result in the loss of the pressure retaining capability under CLB design loading conditions.

Group 3 (erosion corrosion of piping, check valves, MOVs, and temperature elements) - Methods to Manage Aging

Mitigation: The effects of erosion corrosion can be mitigated by proper considerations in the design stage and by maintaining optimal fluid chemistry conditions. Carbon or low alloy steels are particularly susceptible when they are in contact with high velocity turbulent flow (single or two phase) of water with low oxygen content and a pH less than 9.3. The original piping design Code, ANSI B31.7, took materials of construction and erosion and corrosion allowances into consideration. [Reference 35] As the plant is operated, fluid chemistry parameters such as dissolved oxygen concentration and fluid pH level can be controlled to minimize the effects of erosion corrosion. [Reference 3, Attachments 7 and 8]

Discovery: The effects of erosion corrosion on system components can be discovered through measurement and monitoring of wall thickness and/or through visual inspections. The results of measurements and inspections at susceptible locations can be used to assess the need for measurements and inspections at less susceptible locations. Based on piping geometry and fluid flow conditions, areas of the system most likely to experience erosion corrosion can be determined and evaluated. The measurements and inspections must be performed on a frequency that is sufficient to ensure that minimum wall thickness requirements will be met until at least the next examination is performed. [Reference 3, Attachment 8; and Reference 35]

Group 3 (erosion corrosion of piping, check valves, MOVs, and temperature elements) - Aging Management Programs

Mitigation: The CCNPP Secondary Chemistry Program discussed in Group 1 for corrosion specifically considers erosion corrosion. The limits for impurity concentration and fluid pH are set to minimize corrosion in the system.

Discovery:

CCNPP Erosion Corrosion Monitoring Program -

The Erosion Corrosion Monitoring Program is intended to ensure nuclear and personnel safety by early identification and prevention of secondary pipe wall thinning caused by accelerated corrosion, cavitation, or erosion that could lead to ruptures in high energy piping. All of the FWS piping subject to AMR, as well

as all the piping in the system not subject to AMR, are included in this program. The program is based on EPRI and NRC documents, References (34), (36), and (37). [Reference 35]

All piping within the scope of the program is evaluated and categorized to determine inspection points where thickness measurements will be taken. Inspection points are determined through evaluations of site-specific data, failures at other plant sites, and modeling of piping systems by the CHECWORKS software developed by EPRI. An ultrasonic non-destructive examination is used to determine the wall thickness at a number of grid locations for each inspection point. These data are used with a predictive model to determine additional inspection points, to adjust an inspection point's priority, or to estimate the time remaining before an inspection point's wall thickness reaches the minimum allowable. The results are then analyzed to determine the need to replace components. [Reference 35]

Class II feedwater piping has predetermined minimum wall thickness values that are based on the allowable stresses as defined in the applicable revision of the nuclear power piping code ANSI B31.7. Analyses performed in accordance with this code consider all the design loading conditions required under the CLB. American Nuclear Standards Institute B31.7 refers to ANSI B31.1 for Class II piping design criteria, which includes an additional thickness allowance to compensate for erosion and other mechanical considerations. This additional thickness value is specified by Design Engineering at CCNPP, and it provides an additional margin of safety since the pipe is not allowed to reach this minimum wall thickness, as discussed below. Therefore, the Code-based design and tracking of minimum wall thickness assure that the pressure boundary integrity will be maintained under CLB conditions. [Reference 35]

Inspection data is tracked and extrapolated to estimate the time until the minimum wall thickness will be reached. When an inspection point is estimated to be within 48 to 72 months of the minimum wall thickness, it is placed on a "Yellow Alert." When an inspection point is estimated to be within 24 to 48 months of minimum wall thickness, it is placed on a "Red Alert." When an inspection point is estimated to be within 24 months of the required minimum thickness, it is classified as "Unsatisfactory." If any of the alert values are reached, corrective actions are initiated in accordance with the inspection procedure. [Reference 35]

Baltimore Gas and Electric Company has been proactive in the management of erosion corrosion at CCNPP. The Erosion Corrosion Monitoring Program was started formally in 1984 after the failure of non-safety-related extraction steam piping, and prior to the 1986 feedwater break incident at Surry Power Station. Prior to initiation of the formal program, periodic UT inspections were being performed on a less formal basis. The program has undergone modifications based on industry experience. For example, CCNPP is a member of the CHECWORKS Users group, which is an industry organization that shares industry information and provides training on methods and technology. CHECWORKS software provides a systematic method for identifying locations particularly susceptible to erosion corrosion, and for documenting and tracking the inspection results. This software has been updated to reflect current knowledge and experience.

The NRC periodically performs an inspection and review of the erosion/corrosion program. In the past, site visits included the use of the NRC's own examination equipment to verify data that was collected by CCNPP Erosion Corrosion Monitoring Program personnel. The inspections are followed by a formal report of the results. In the past, the NRC has made recommendations, which Baltimore Gas and Electric Company has incorporated to improve the program. [Reference 38]

Other assessments include those performed by INPO and by the CCNPP Nuclear Performance Assessment Department. Institute for Nuclear Power Operations performs periodic independent assessments and provides recommended enhancements based on good practices utilized in the industry. [Reference 39] Internal reviews have been performed by the site Nuclear Performance Assessment Department several times in the past in accordance with 10 CFR Part 50, Appendix B, criteria. All of these controls provide reasonable assurance that the Erosion Corrosion Monitoring Program will continue to be an effective method of monitoring the effects of erosion corrosion on the piping, and ensuring that corrective actions are taken prior to a piping section reaching its minimum allowable wall thickness.

Regarding operating experience, CCNPP had experienced piping failures in the past which were documented in Licensee Event Reports and reported to the NRC. Since the extraction steam system failures and the inception of the formal erosion/corrosion program, there have been no further major failures. The data collected during the inspections has served to build an extensive data base for piping system evaluations.

CCNPP Preventive Maintenance Program -

The Preventive Maintenance Program has been established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimize equipment failure, and extend equipment and plant life. The program covers all preventive maintenance activities for nuclear power plant structures and equipment within the plant, including the FWS components within the scope of license renewal. [Reference 40] It is based on INPO documents, References (27) through (29).

Baltimore Gas and Electric Company initiated a Preventive Maintenance Task following the discovery of erosion corrosion occurring in the feedwater check valves in 1988. [Reference 41] This task requires that a periodic valve inspection be performed, including an ultrasonic test to determine wall thickness. It is implemented in accordance with the safety-related Preventive Maintenance Program procedures. [References 40 and 42]

The preventive maintenance includes visual inspection within the valve body for indications of washout and measures wall thickness using non-destructive techniques, i.e., ultrasonic testing, at selected locations. The CCNPP Materials Engineering and Inspection Unit perform the UT in accordance with special process procedures which are controlled by a 10 CFR Part 50, Appendix B, quality assurance program. Test data is provided to the system engineer who is responsible for evaluating and monitoring the condition of the valve, including the wall thickness. If the system engineer determines erosion corrosion is becoming excessive, corrective action is initiated to restore the wall thickness or to have the valve replaced, and the next inspection is scheduled to ensure it occurs prior to the wall thickness reaching the minimum allowable thickness. The check valve preventive maintenance will be modified to provide clearly defined acceptance criteria that ensure timely corrective actions. [References 40 and 42]

Class II feedwater components have predetermined minimum wall thickness values that are based on the allowable stresses, as addressed in the original design Code, ANSI B31.7. American Nuclear Standards Institute B31.7 refers to ANSI B31.1 for Class II piping component design criteria, which specifies acceptable dimensional requirements. [References 6 and 43]

The Preventive Maintenance Program undergoes periodic evaluation by the NRC during Plant Performance Reviews, which serve as input to the NRC Systematic Assessment of Licensee Performance and senior management meeting reviews. [Reference 44] The plant Maintenance Program, itself, has numerous levels of management review, all the way down to the specific implementation procedures. For example, the Principal Engineer - Reliability Engineering Unit and Principal Engineer - Maintenance/Component Engineering Unit both have specific responsibilities for evaluating and upgrading the Preventive Maintenance Program. The System Engineer and System Manager have specific responsibilities for initiating changes to the check valve inspection procedures or Preventive Maintenance Program based on results of the inspections. [Reference 40] These controls provide reasonable assurance that the Preventive Maintenance Program will continue to be an effective method of monitoring the effects of erosion corrosion on the wall thickness of the check valves. The CCNPP Corrective Action Program will then be used to take the necessary corrective actions to ensure that the check valves will remain capable of performing their pressure boundary function under all CLB loading conditions.

Operating experience has demonstrated that erosion corrosion of the FWS check valves must be managed. The initial discovery of erosion corrosion degradation on the check valve in 1988 led to its replacement when the wall thickness was found below the minimum limit in some locations. [Reference 41] This was discovered and corrected before any breach of the pressure boundary. Since then, three additional check valves have been replaced due to erosion corrosion effects. Each of these valves were replaced prior to any breach of the pressure boundary.

CCNPP Age-Related Degradation Inspection Program -

Feedwater System MOVs and temperature elements are not in the erosion corrosion program, nor do they have a Preventive Maintenance like the check valves do. However, erosion corrosion will be readily detectable for these components through non-destructive examination techniques. As such, an inspection program to detect the occurrence of wall thinning due to erosion corrosion is an effective means of managing this aging mechanism.

A new plant program will be developed to include the MOVs and temperature elements in an inspection program. The new program will be considered an ARDI Program, as defined in the CCNPP IPA Methodology presented in Section 2.0 of the BGE LRA.

The elements of the ARDI Program will include:

- Determination of the examination sample size based on plausible aging effects;
- Identification of inspection locations in the system/component based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of adverse examination findings, including consideration of all design loadings required by the CLB and specification of required corrective actions; and
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

The corrective actions taken for the MOVs and temperature elements as part of the ARDI Program will ensure that these components will remain capable of performing the system pressure boundary integrity function under all CLB conditions.

Group 3 (erosion corrosion of piping, check valves, MOVs, and temperature elements) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to erosion corrosion of FWS piping, check valves, MOVs, and temperature elements:

- The FWS components and piping provide the system pressure retaining boundary and their integrity must be maintained under all CLB design conditions.
- Erosion corrosion is plausible for the subject components and piping and may result in wall thinning, which, if left unmanaged, can lead to loss of pressure retaining boundary integrity.
- The CCNPP Chemistry Program provides controls for system fluid chemistry in order to minimize the effects of corrosion. While degradation is not entirely prevented, the rate, and therefore the predictions of when minimum wall thickness will be reached, are related to the system chemistry.
- The CCNPP Erosion Corrosion Program monitors the effects of erosion corrosion on piping through measurement of pipe wall thickness on a frequency dependent upon the computed rate of degradation. The program requires the performance of corrective actions before a pipe wall thins to below the minimum required wall thickness established by the original construction code.
- Periodic inspections of the check valves are performed in accordance with the Preventive Maintenance Program during refueling outages to monitor valve degradation. If the system engineer determines erosion corrosion is becoming excessive, corrective action is initiated through the CCNPP Corrective Action Program.
- The Preventive Maintenance Program will be modified to provide clearly defined acceptance criteria that ensure corrective actions are taken in a timely manner.
- To ensure that the MOVs and temperature elements are being managed for erosion corrosion, they will be included in the scope of an ARDI Program. Inspections will be performed, and appropriate corrective action will be taken if significant degradation is encountered.

Therefore, there is reasonable assurance that the effects of erosion corrosion will be managed to maintain the FWS components pressure boundary integrity under all design loadings required by the CLB during the period of extended operation.

5.9.3 Conclusion

The programs discussed for the FWS are listed in Table 5.9-3. These programs are (and will be for new programs) administratively controlled by a formal review and approval process. As has been demonstrated in the above section, these programs will manage the aging mechanisms and their effects such that the intended functions of the components of the FWS will be maintained, consistent with the CLB, during the period of extended operation.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

Table 5.9-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE FEEDWATER SYSTEM

	Program	Credited As
Existing	CCNPP Chemistry Program Procedure "Specifications and Surveillance - Secondary Systems," CP-0217	Mitigating the effects of crevice corrosion, general corrosion, pitting and erosion corrosion of FWS Group 1 components
Existing	CCNPP Erosion Corrosion Program Procedure "Erosion/Corrosion Monitoring of Secondary Piping," MN-3-202	Detection and management of the effects of erosion corrosion of FWS Group 3 piping
Modified	CCNPP Fatigue Monitoring Program Procedure "Implementation of Fatigue Monitoring," EN-1-300	Monitoring and management of the effects of low cycle fatigue of FWS Group 2 piping in the horizontal run adjacent to the SGs
Modified	CCNPP Maintenance Program Procedure "Preventive Maintenance Program," MN-1-102	Detection and management of the effects of erosion corrosion of the FWS Group 3 check valves
New	ARDI Program	Detection and management of the effects of crevice corrosion, general corrosion, and pitting of FWS Group 3 components in stagnant and low flow areas, and erosion corrosion of feedwater isolation MOVs and temperature element thermowells
New	CCNPP Evaluation of the Thermal Fatigue Effects on Systems Requiring AMR for License Renewal	Management of the effects of low cycle fatigue at of FWS Group 2 piping in the horizontal run adjacent to the SGs.

5.9.4 References

1. "CCNPP Updated Final Safety Analysis Report," Revision 19
2. CCNPP Drawing No. 60702SH0004, "Condensate and FWS Operations Drawing," Revision 31, October 21, 1996
3. "CCNPP FWS Aging Management Review Report," Revision 2, January 1997
4. "Component Level Screening Results for the FWS, System No. 045, CCNPP," Revision 2, December 16, 1996
5. CCNPP Drawing No. 92767SH-DB-1, "M-600 Piping Class Sheets," Revision 63, November 12, 1996
6. CCNPP Drawing No. 92769SH-Z-3, "M-601 Piping Class Summary," Revision 24, December 28, 1995
7. CCNPP "Pre-Evaluation Results for the Main FWS (#045)," Revision 1, March 11, 1996
8. CCNPP Drawing No. 83270, "M-600C Chromium Moly Piping Lines," Revision 12, March 23, 1996
9. CCNPP Administrative Procedure CH-1-104, "Plant Layup and Equipment Preservation," Revision 0, January 4, 1995
10. CCNPP Administrative Procedure CH-1, "Chemistry Program," Revision 1, December 13, 1995.
11. CCNPP Technical Procedure CP-0217, "Specifications and Surveillance: Secondary Chemistry," Revision 5, December 18, 1995
12. ANSI N45.2.1, "Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants," February 26, 1973
13. U. S. Nuclear Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," March 16, 1973
14. INPO 88-021, "Guidelines for Chemistry at Nuclear Power Stations," Revision 1, September 1991
15. INPO 85-021, "Control of Chemicals in Nuclear Power Plants," June 1985
16. EPRI NP-6239, 5405-2, "PWR Secondary Water Chemistry Guidelines," Final Report, Revision 2, December 1988
17. EPRI TR-102134, Projects 2493, 5401, "PWR Secondary Water Chemistry Guidelines," Final Report, Revision 3, May 1993
18. Combustion Engineering CENPD-28, "Combustion Engineering Chemistry Manual," Revision 3, September 1982
19. "CCNPP Fatigue Monitoring Report for 1995," Final Report for 1995 generated by CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring"
20. "Metal Fatigue in Engineering," H. O. Fuchs and R. I. Stephens, John Wiley & Sons, Copyright 1980

21. NRC Information Notice 93-20, "Thermal Fatigue Cracking of Feedwater Piping to Steam Generators," March 24, 1993

22. Combustion Engineering Specification No. 8067-31-1, "Engineering Specification for a Reactor Vessel Assembly for CCNPP," Revision 7, August 31, 1990

23. Calculation No. BGE-05Q-316, "Feedwater Nozzle Transfer Functions," by Structural Integrity Associates, Inc., Revision 0, September 25, 1995

24. Letter from Mr. J. P. Durr (NRC) to Mr. C. Stoiber *(sic)* (BGE), dated February 11, 1993, "Inspection Report Nos. 50-317/92-32 and 50-318/92-32"

25. CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring," Revision 0, February 28, 1996

26. CCNPP "Spring 1996 Inservice Examination of Selected Class 1 and Class 2 Components at CCNPP Unit 1, Final Report," September 1996

27. INPO 85-032, "Preventive Maintenance," December 1988

28. INPO 85-037, "Reliable Power Station Operation," October 1985

29. INPO Good Practice MA-319, "Preventive Maintenance Program Enhancement," August 1980

30. Combustion Engineering Owners Group Report, CE-NPSD-634-P, "Fatigue Monitoring Program for CCNPP Units 1 and 2," April 1992

31. CCNPP Engineering Standard ES-020, "Specialty Input Screens for the Engineering Service Process," Revision 1, May 1, 1996

32. Generic Safety Issue 166, "Adequacy of Fatigue Life of Metal Components," Revision 1, June 30, 1995

33. CCNPP Specification No. 6422284S, "Technical Services to Evaluate Thermal Fatigue Effects on CCNPP Systems Requiring Aging Management Review for License Renewal," Revision 0, July 29, 1996

34. NRC Generic Letter 89-08, "Erosion/Corrosion Induced Pipe Wall Thinning," May 2, 1989

35. CCNPP Administrative Procedure MN-3-202, "Erosion/Corrosion Monitoring of Secondary Piping," Revision 1, July 1, 1996

36. EPRI NP-3944, "Erosion/Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines," April 1985

37. Letter from Mr. G. C. Creel (BGE) to NRC Document Control Desk, dated February 26, 1990, "Implementation of the Erosion/Corrosion Program Controlling Procedure-Generic Letter 89-08,"

38. NRC Inspection Report Nos. 50-317-90-01 and 50-318-90-01, "Inspection of Activities Related to Modification, Erosion Corrosion, and Inservice Activities," April 9, 1990

39. INPO Report, "Evaluation of CCNPP," September 1989

40. CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," Revision 5, September 27, 1996

41. NRC Inspection Report Nos. 50-317/88-05 and 50-318/88-06, May 11, 1988

42. CCNPP Preventive Maintenance Program, Repetitive Tasks 10452052, 10452503, 20452043, and 20452044, "Feedwater Check Valve Inspections"

43. CCNPP Drawing No. 12399-0035, "Cast Steel Horizontal and Vertical Tilting Disk Check Valve General Assembly Size 16 Figure B970(WC6)YT5, Revision 0, October 30, 1986

44. Letter from Mr. R. W. Cooper, II (NRC) to Mr. C. H. Cruse (BGE), dated May 31, 1996, "Calvert Cliff's Plant Performance Review Results"

ATTACHMENT (4)

APPENDIX A - TECHNICAL INFORMATION

5.14 - RADIATION MONITORING SYSTEM

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
May 23, 1997

5.14 RADIATION MONITORING SYSTEM

This is a section of the Baltimore Gas and Electric (BGE) License Renewal Application (LRA), addressing the Radiation Monitoring System (RMS). The RMS was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. The results are presented below. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

5.14.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to aging management review (AMR) begins with a listing of passive intended functions, and then dispositions the component types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.14.1.1 presents the results of the system level scoping, 5.14.1.2 the results of the component level scoping, and 5.14.1.3 the results of scoping to determine components subject to an AMR.

Historical operating experience, judged to be pertinent, is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, and through documented discussions with currently-assigned, cognizant CCNPP personnel.

5.14.1.1 System Level Scoping

This section begins with a description of the system which includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

System Description / Conceptual Boundaries

The purpose of the RMS is to warn operating personnel of an increasing radiation level or abnormal radioactivity concentrations at selected points in the plant. This warning system may also indicate a system or component malfunction which needs operator action, or it may perform automatic protective actions to correct and/or isolate an abnormal condition to prevent an uncontrolled release of radioactive material to the environment. The RMS also assures that releases of radioactive effluents from the plant do not exceed allowable limits in accordance with 10 CFR Part 20, are monitored in accordance with criterion 64 of Appendix A to 10 CFR Part 50, and are maintained ALARA in accordance with Appendix I to 10 CFR Part 50. [Reference 1, Section 11.2.3.1; Reference 2, Section 1.1]

The RMS is divided into two subsystems: the Area RMS and the Process RMS. The Area RMS includes area radiation monitors located throughout the plant, four containment area radiation monitors, and two containment high range gamma radiation monitors. The Process RMS includes the plant main vent radiation monitors, wide range effluent gas radiation monitors, containment atmosphere radiation monitors, waste gas discharge radiation monitor, liquid waste processing discharge radiation monitor, condenser air

removal discharge radiation monitor, Component Cooling System (CCS) radiation monitor, Service Water (SRW) System radiation monitor, steam generator blowdown tank discharge radiation monitor, steam generator blowdown recovery radiation monitor, atmosphere radiation monitors (includes the Control Room ventilation radiation monitor as well as other ventilation radiation monitors), and main steam effluent radiation monitors. [Reference 1, Section 11.2.3; Reference 2, Section 1.1]

The RMS is comprised of the following types of equipment: piping/tubing (provides system flowpath and maintains pressure boundary), pumps (provide motive force to move fluids being sampled), valves (provide containment isolation and system alignment/isolation), filters (filter air to protect downstream components), and instrumentation/elements (provide information to operators and signals to control equipment). [Reference 2, Section 1.1.2]

The RMS interfaces with the following systems and components:

- Plant Vent;
- Waste Gas System;
- Liquid Waste System;
- Condenser Air Removal System;
- Main Steam System;
- Containment Ventilation;
- CCS;
- SRW System; and
- Control Room Heating, Ventilation, and Air Conditioning (HVAC) System.

[Reference 2, Section 1.1.2]

System Scoping Results

The RMS is in scope for license renewal based on §54.4(a). In accordance with Section 4.1.1 of the CCNPP IPA Methodology, a detailed list of system intended functions was determined. The following RMS intended functions were determined based on the requirements of §54.4(a)(1) and (2):

- Provide containment area radiation signal to Engineered Safety Features Actuation System for containment isolation and radiological release control;
- Provide containment high range radiation signal for containment environment monitoring and to isolate the containment vent/hydrogen purge lines;
- Maintain the pressure boundary of the system;
- Provide containment isolation of the containment atmosphere and purge air monitor sampling line;
- Monitor and record wide range gaseous activity/release rate through the main plant vent and provide indications/alarms in the Control Room;

- Monitor and record radiation levels indicative of effluent activity in the main steam lines and provide indications/alarms in the Control Room;
- Provide testing capability and prevent spurious actuation of Control Room radiation monitoring circuitry;
- Maintain electrical continuity and/or provide protection of the electrical system; and
- Provide seismic integrity and/or protection of safety-related components.

[Reference 3, Table 1]

The following RMS intended functions were determined based on the requirements of §54.4(a)(3):

- Provide information to assess the environs and plant condition during and following an accident, and
- Maintain functionality of electrical equipment as addressed by the Environmental Qualification Program.

[Reference 3, Table 1]

5.14.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the RMS within the scope of license renewal consists of piping, components, component supports, instrumentation, panels, and cables associated with the following radiation monitors: containment area radiation monitors, containment high range gamma radiation monitors, wide range effluent gas radiation monitors, containment atmosphere radiation monitors, CCS radiation monitor, SRW System radiation monitor, Control Room ventilation radiation monitor, and main steam effluent radiation monitors. The shaded areas of Figures 5.14-1 through 5.14-8 indicate the portions of the system within the scope of license renewal. Note, these figures are simplified representations of the RMS and are for information only. Their use is intended only as a visual means of depicting the RMS scoping. [Reference 2, Section 2.2; Reference 3, Table 2; and References 4, 5, 6]

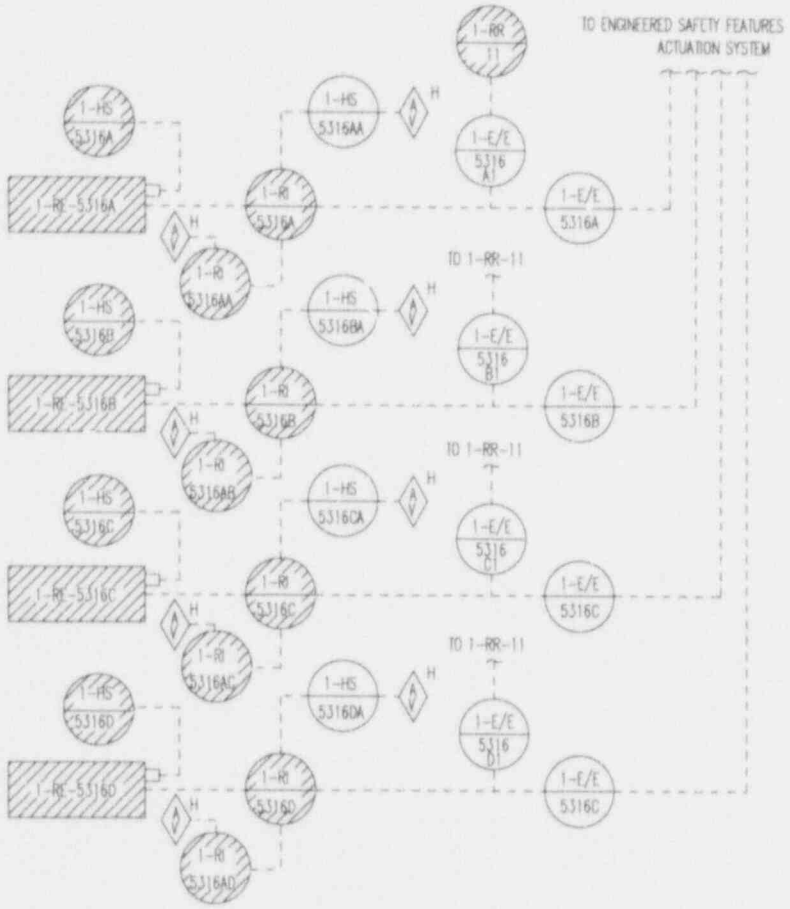

FIGURE 5.14-1

CCNPP UNIT 1 - CONTAINMENT AREA RADIATION MONITORS

(TYPICAL FOR UNIT 2)

Note: Shaded areas indicate components within the scope of license renewal for the RMS. All shaded components on this figure only have active intended functions.

SIMPLIFIED DIAGRAM
(FOR INFORMATION ONLY)

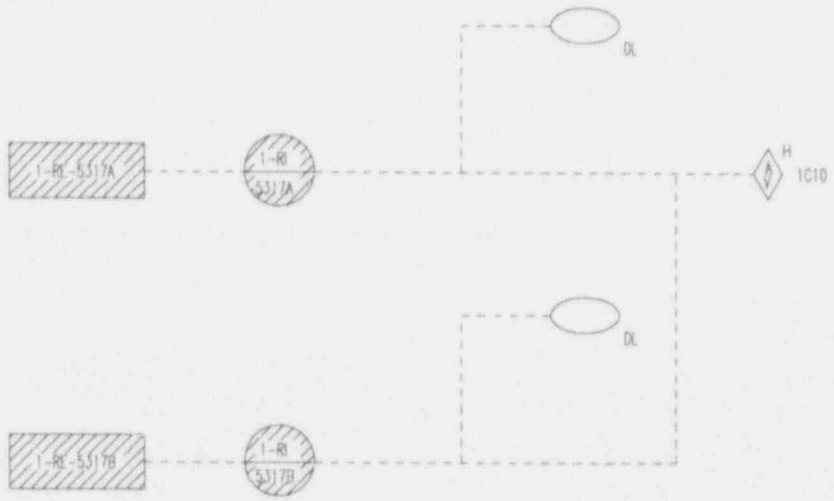

FIGURE 5.14-2

CCNPP UNIT 1 - CONTAINMENT HIGH RANGE GAMMA RADIATION MONITORS

(TYPICAL FOR UNIT 2)

Note: Shaded areas indicate components within the scope of license renewal for the RMS. All shaded components on this figure only have active intended functions.

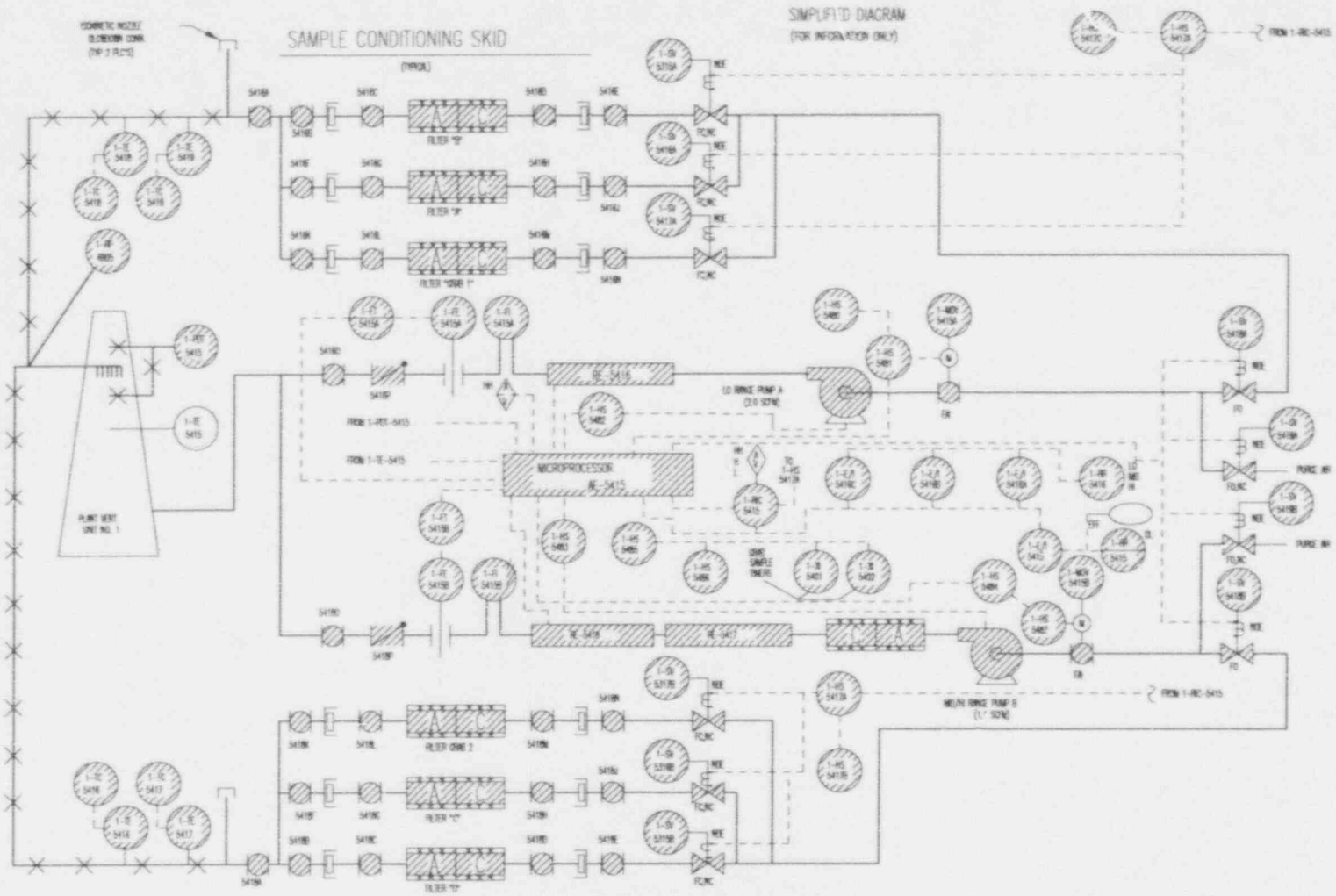

FIGURE 5.14-3
CCNPP UNIT 1 - WIDE RANGE EFFLUENT GAS RADIATION MONITORS
(TYPICAL FOR UNIT 2)

Note: Shaded areas indicate components within the scope of license renewal for the RMS. All valves, flow elements, flow indicators, radiation elements, filters, and radiation test point are evaluated in the RMS AMR. The pressure differential transmitter is evaluated in the instrument lines commodity evaluation. The pumps are subject to replacement. All other shaded components have active intended functions. All process lines on this figure consist of tubing which is included in the instrument lines commodity evaluation.

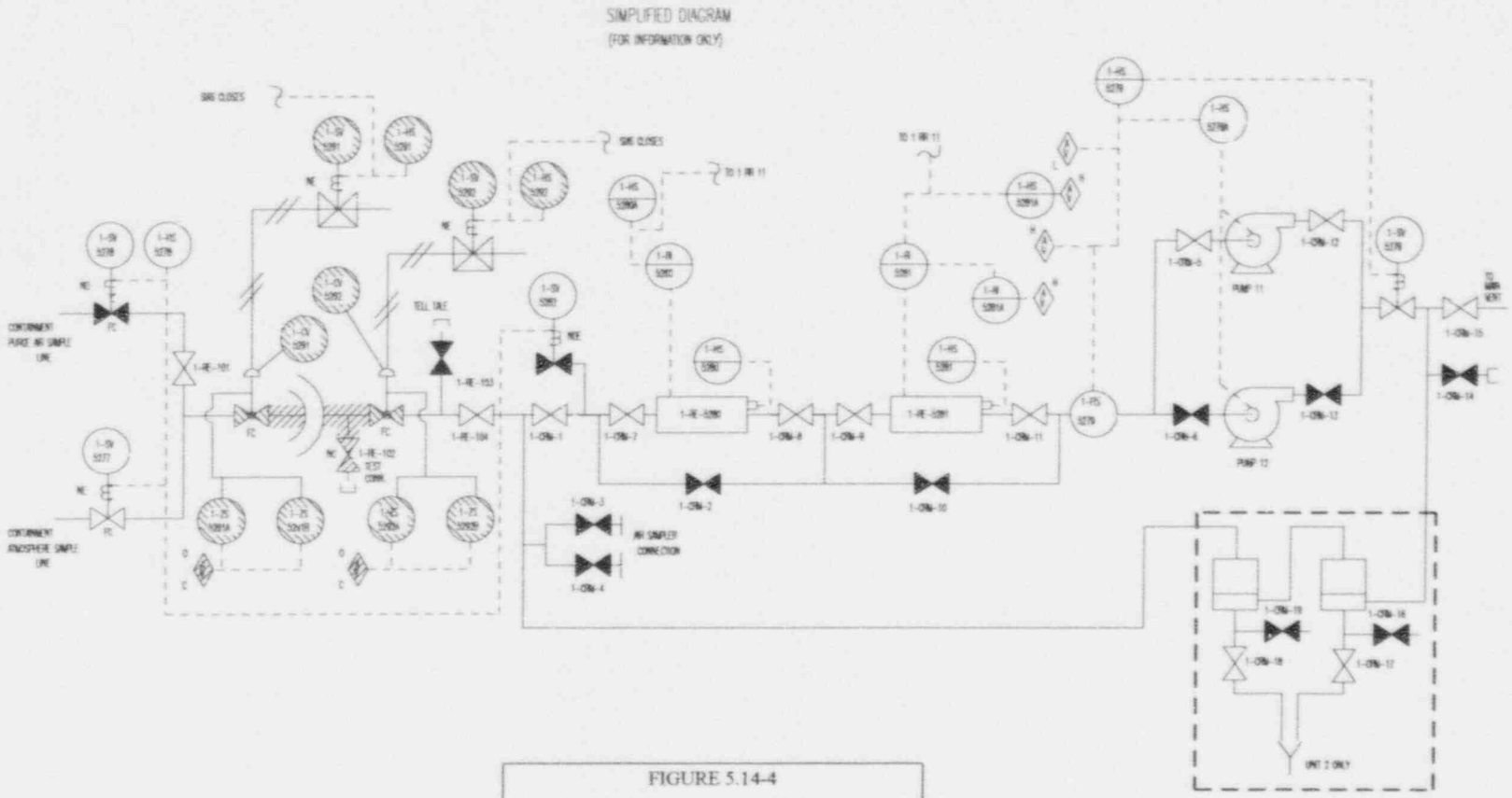

FIGURE 5.14-4

CCNPP UNIT 1 - CONTAINMENT ATMOSPHERE RADIATION MONITORS

(TYPICAL FOR UNIT 2)

Note: Shaded areas indicate components within the scope of license renewal for the RMS. Shaded pressure retaining components are included in the RMS AMR, all other shaded components (i.e., HS, SV, ZS) only have active intended functions.

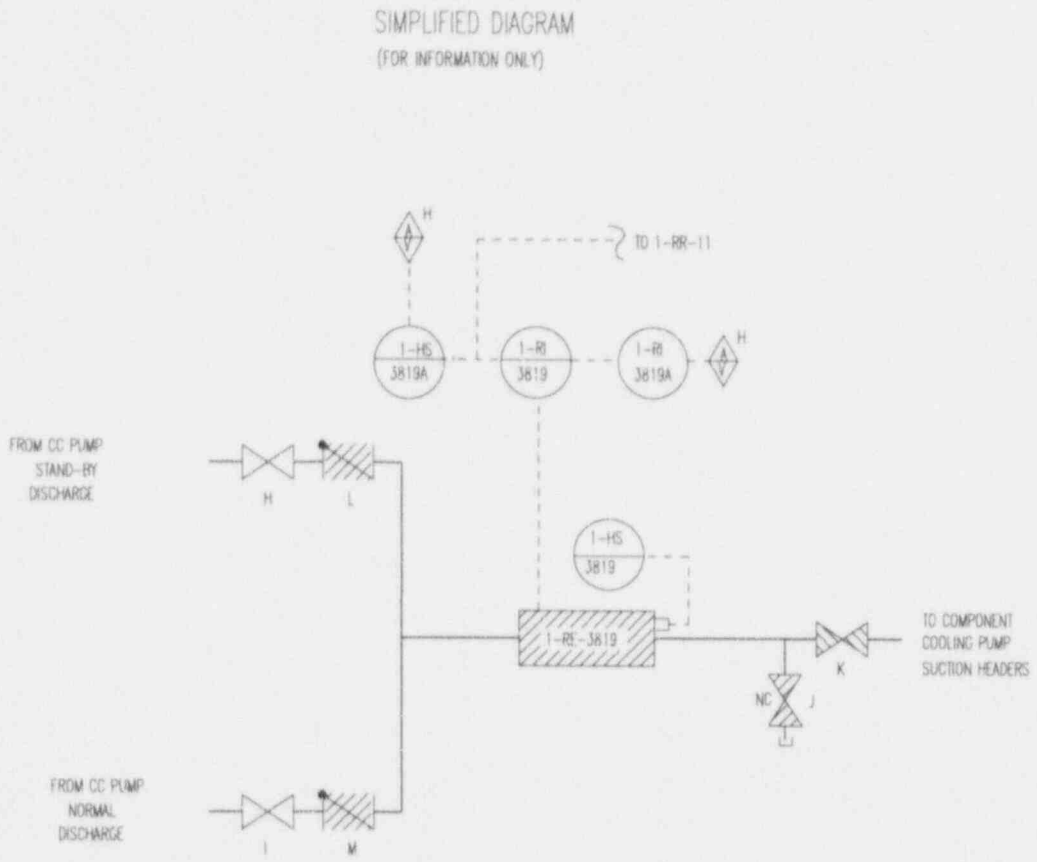

FIGURE 5.14-5

CCNPP UNIT 1 - COMPONENT COOLING SYSTEM
RADIATION MONITOR

(TYPICAL FOR UNIT 2)

Note: Shaded areas indicate components within the scope of license renewal for the RMS. All shaded components on this figure (and the associated piping) are evaluated as part of the CCS AMR. Valves H and I are within the scope of license renewal for the CCS.

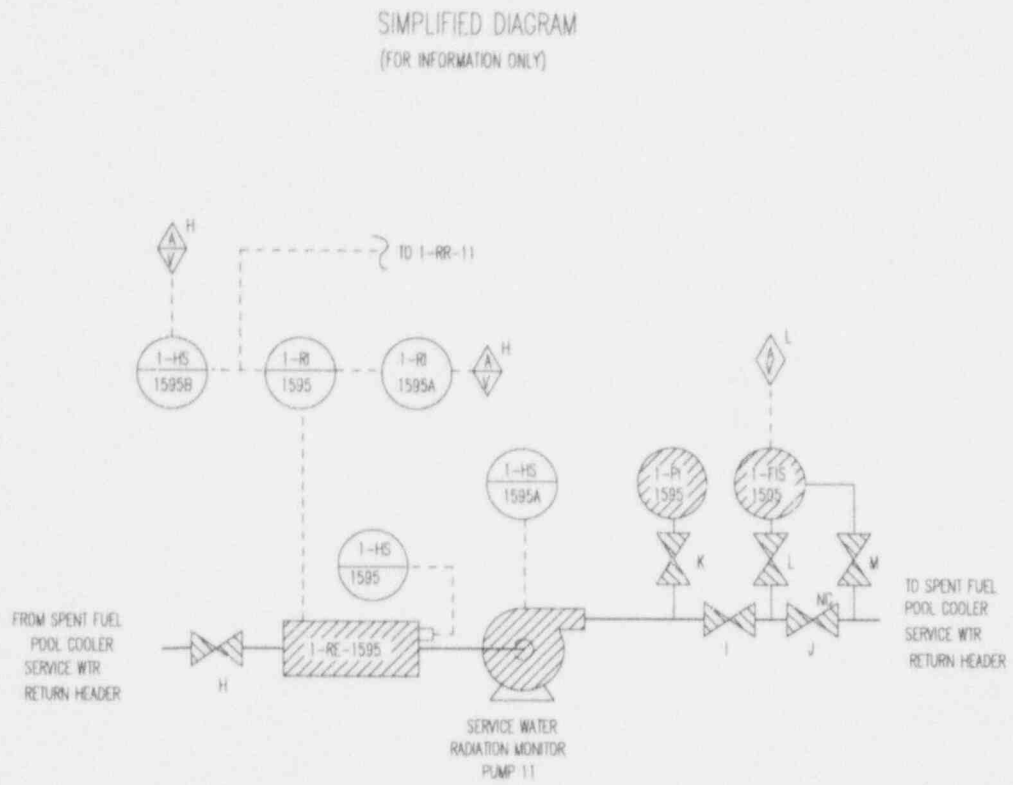

FIGURE 5.14-6

CCNPP UNIT 1 - SERVICE WATER SYSTEM RADIATION MONITOR

(TYPICAL FOR UNIT 2)

Note: Shaded areas indicate components WSLR for the RMS. Hand valves, radiation element, pump, and associated piping are evaluated as part of the SRW System AMR. Pressure indicator and flow indicating switch are evaluated in the Instrument Lines Commodity Evaluation.

SIMPLIFIED DIAGRAM
(FOR INFORMATION ONLY)

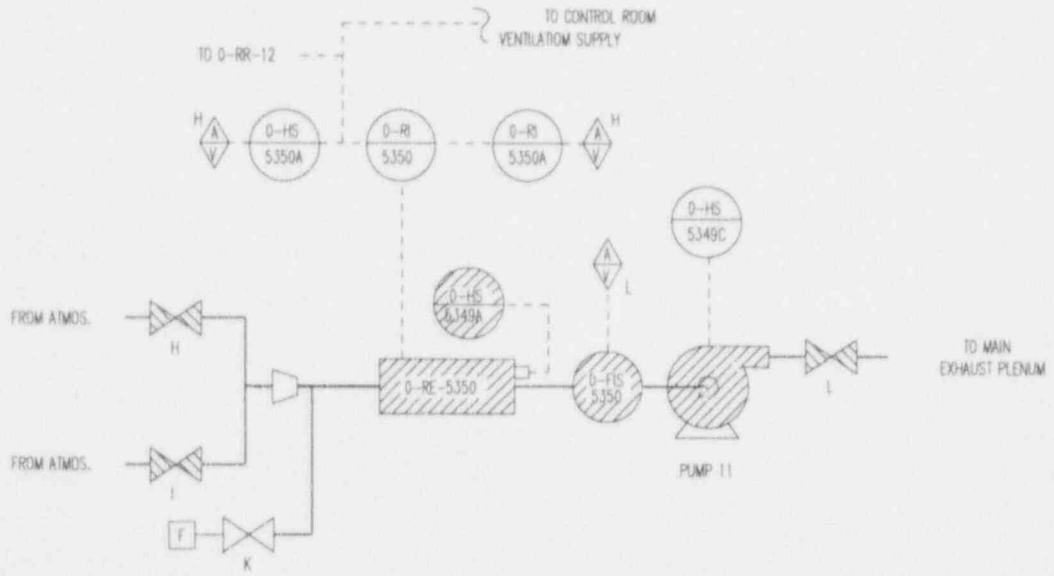

FIGURE 5.14-7

CCNPP - CONTROL ROOM VENTILATION RADIATION MONITOR

(COMMON FOR BOTH UNITS)

Note: Shaded areas indicate components within the scope of license renewal for the RMS. Hand valves H, I, and L are evaluated in the RMS AMR. Radiation element and pump (and all piping between valves H, I, and L) are evaluated as part of the Control Room HVAC AMR. Flow indicating switch is evaluated in instrument lines commodity evaluation. Hand switch only has an active function. Hand valve K is within the scope of license renewal for the Control Room HVAC System.

SIMPLIFIED DIAGRAM
(FOR INFORMATION ONLY)

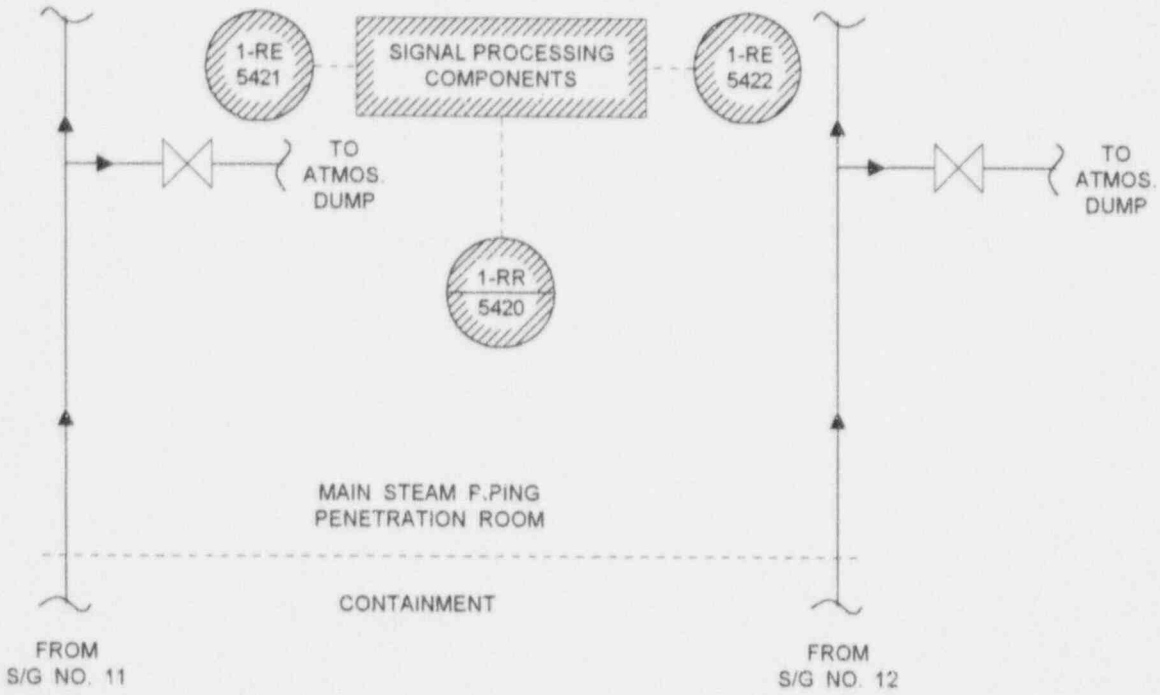

FIGURE 5.14-8

CCNPP UNIT 1 - MAIN STEAM EFFLUENT RADIATION MONITORS

(TYPICAL FOR UNIT 2)

Note: Shaded areas indicate components within the scope of license renewal for the RMS. All shaded components on this figure only have active intended functions.

5.14.1.3 Components Subject to Aging Management Review

This section describes the components within the RMS which are subject to an AMR, and begins with a listing of passive intended functions. The components that have passive intended functions are then dispositioned as either components within the scope of the RMS AMR, components subject to replacement, components evaluated in other system AMRs, or components evaluated in a commodity report.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following RMS functions were determined to be passive:

- Maintain the pressure boundary of the system;
- Provide containment isolation of the containment atmosphere and purge air monitor sampling line;
- Maintain electrical continuity and/or provide protection of the electrical system; and
- Provide seismic integrity and/or protection of safety-related components.

[Reference 2, Table 3-1]

Components Within the Scope of the RMS AMR

The components of the RMS were reviewed and those that have passive intended functions were identified. Of the 33 device types within the scope of license renewal for this system, 16 device types were determined to have passive intended functions. Five of those 16 were not evaluated as part of the RMS AMR, either because they are subject to a replacement program, they are evaluated in an AMR for another system, or they are evaluated in a commodity evaluation. The remaining 11 device types requiring an AMR specifically within the scope of the RMS are listed in Table 5.14-1. [Reference 2, Table 3-2]

Components Subject to Replacement

Specific RMS components requiring AMR that are subject to a replacement program are as follows:

- Wide Range Effluent Gas Radiation Monitors - Both the low range and mid/high range pumps shown in Figure 5.14-3 are subject to maintenance replacement programs. The entire low range pump is replaced every 96 weeks, and the entire mid/high range pump is replaced every 10 years. [Reference 7]

Components Evaluated in Other AMRs

Specific RMS components requiring AMR that are evaluated in an AMR for another system are as follows:

- Component Cooling System Radiation Monitor - The check valves, radiation element, and hand valves shown in Figure 5.14-5 are evaluated in the CCS AMR. The CCS is evaluated in Section 5.3 of the BGE LRA. [Reference 8, Attachment 3s for Group IDs 015-CKV-01, 015-RE-01, 015-HV-01, 015-HV-03]

- Service Water System Radiation Monitor - The hand valves, radiation element, and pump shown in Figure 5.14-6 are evaluated in the SRW System AMR. The SRW System is evaluated in Section 5.17 of the BGE LRA. [Reference 9, Attachment 3s for Group IDs 011-HV-01, 011-HV-03, 011-RE-01, 011-PUMP-02]

- Control Room Ventilation Radiation Monitor - The radiation element and pump shown in Figure 5.14-7 are evaluated in the Control Room HVAC System AMR. The Control Room HVAC is evaluated in Section 5.11 of the BGE LRA. [Reference 10, Attachment 3s for Group IDs 030-RE-01, 030-PUMP-01]

Component Types Part of Separate Commodity Report

Several component types are common to many plant systems and perform the same passive intended functions. These are addressed separately in commodity evaluations and are not included within the scope of the RMS AMR. The disposition of these commodity components is as follows:

- Structural supports for piping, cables, and components in the RMS that are subject to AMR are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA. The wide range gas monitor skids (included in RMS as component type "panel") are also evaluated as part of the Component Supports Commodity AMR. The wide range gas monitor skids provide structural support for RMS components. This commodity evaluation completely addresses the RMS passive intended function, "Provide seismic integrity and/or protection of SR components." [Reference 2, Table 3-2; Reference 3, Function Catalog for LR077-012; Reference 11, Attachment 1]
- Electrical cabling for components in the RMS is evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of the BGE LRA. This commodity evaluation completely addresses the RMS passive intended function, "Maintain electrical continuity and/or provide protection of the electrical system." [Reference 2, Section 3.2]
- Radiation Monitoring System instrument lines (i.e., tubing and small bore piping), and the associated fittings, instrument valves (e.g., equalization, vent, drain, isolation), and supports are evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of the BGE LRA. Note, this commodity report does not include the instrument line root valve (i.e., first isolation valve off of the process line). Root valves are included as part of the RMS AMR under the component type "hand valve." Specific RMS instruments also included as part of the Instrument Line Commodity Evaluation include the differential pressure transmitter associated with the wide range effluent gas radiation monitors, as shown in Figure 5.14-3; the pressure indicator and flow indicating switch associated with the SRW System radiation monitor, as shown in Figure 5.14-6; and the flow indicating switch associated with the Control Room ventilation radiation monitor, as shown in Figure 5.14-7. This commodity evaluation partially addresses the RMS passive intended function, "Maintain the pressure boundary of the system." [Reference 2, Section 3.2; Reference 11, Attachment 4A]

The only passive functions associated with the RMS which are not completely addressed by one of the commodity evaluations referred to above are:

- Maintain the pressure boundary of the system, and
- Provide containment isolation of the containment atmosphere and purge air monitor sampling line.

[Reference 2, Attachment 1]

Therefore, only the pressure retaining and containment isolation functions for the following device types are within the scope of the AMR for the RMS.

TABLE 5.14-1

RMS DEVICE TYPES REQUIRING AMR

Piping
Check Valve
Control Valve
Hand Valve
Motor-Operated Valve
Flow Element
Flow Indicator
Radiation Element
Filter
Radiation Test Point
Solenoid Valve

Specific components requiring AMR (within the scope of the RMS AMR) for each of the device types shown in Table 5.14-1 are as follows:

Piping - containment penetration piping associated with the containment atmosphere radiation monitors, as shown on Figure 5.14-4;

Check Valve - check valves associated with the wide range effluent gas radiation monitors, as shown on Figure 5.14-3;

Control Valve - containment isolation valves associated with the containment atmosphere radiation monitors, as shown on Figure 5.14-4;

Hand Valve - hand valves associated with the wide range effluent gas radiation monitors, containment atmosphere radiation monitors, and Control Room ventilation radiation monitor, as shown on Figures 5.14-3, 5.14-4, and 5.14-7.

Motor-Operated Valve - motor-operated valves associated with the wide range effluent gas radiation monitors, as shown on Figure 5.14-3;

Flow Element - flow elements associated with the wide range effluent gas radiation monitors, as shown on Figure 5.14-3;

Flow Indicator - local process flow indicators associated with the wide range effluent gas radiation monitors, as shown on Figure 5.14-3;

Radiation Element - radiation elements associated with the wide range effluent gas radiation monitors, as shown on Figure 5.14-3;

Filter - filters associated with the wide range effluent gas radiation monitors, as shown on Figure 5.14-3;

Radiation Test Point - isokinetic nozzle (and its associated support) on the plant vent associated with the wide range effluent gas radiation monitors, as shown on Figure 5.14-3; and

Solenoid Valve - solenoid valves associated with the wide range effluent gas radiation monitors as shown, on Figure 5.14-3.

[Reference 2, Attachment 3s]

The hand valve and the control valves associated with the containment penetration for the containment atmosphere radiation monitors have the containment isolation passive intended function. All of the other components discussed above have the pressure boundary passive intended function. [Reference 2, Attachment 1]

5.14.2 Aging Management

The list of potential age-related degradation mechanisms (ARDMs) for the RMS components is given in Table 5.14-2, with plausible ARDMs identified by a check mark (✓) in the appropriate component type column. For efficiency in presenting the results of these evaluations in this report, component/ARDM combinations are grouped where there are similar characteristics, and the discussion is applicable to all components within that group. Exceptions are noted where appropriate. The following groups have been selected for the RMS. Table 5.14-2 also identifies the group assigned to each component/ARDM combination.

Group 1 includes crevice corrosion, general corrosion, and pitting for the containment penetration piping associated with the containment atmosphere radiation monitors, the test connection isolation hand valve which connects to this piping outside containment, and the control valves (one inside and one outside containment) that isolate this piping. For the piping, all three ARDMs are plausible for the piping, fittings, and welds. For the hand valve, crevice corrosion and pitting are plausible for the body/bonnet, stem, disk, and seat. General corrosion is plausible only for the hand valves' body/bonnet. For the control valves, crevice corrosion, general corrosion, and pitting are plausible for the body/bonnet. [Reference 2, Attachment 1; Attachments 5, 6, and 7 (for Group IDs 077-HB-01, 077-HV-02, and 077-CV-01)]

Group 2 includes wear of the control valves (one inside and one outside containment) that isolate the containment penetration piping for the containment atmosphere radiation monitors. This ARDM is plausible only for the plug and seat. [Reference 2, Attachment 1, Attachments 5 and 6 (for Group ID 077-CV-01)]

The components covered by Groups 1 and 2 above include all the shaded pressure retaining components shown on Figure 5.14-4. The hand valve and control valves are safety-related and Seismic Category I. The penetration piping is Seismic Category I and is designed in accordance with ANSI B31.7, Class II. The piping is considered Class MC for the purposes of the ASME Section XI Inservice Inspection program. [Reference 1, Section 5A.2.1.2.c; Reference 12]

All other hand valves and all component types not associated with the containment atmosphere radiation monitor penetration piping (and within the scope of the RMS AMR) were determined to not be subject to

any plausible ARDMs, because the material of construction (generally stainless steel) is not subject to aging in an air environment.

The following discussion of the aging management demonstration process is presented by group and covers materials and environment, aging mechanism effects, methods to manage aging, aging management program(s), and demonstration of aging management.

Operating experience relative to the RMS has shown that there have been no known failures or instances of significant degradation due to aging of passive, long-lived RMS components.

Group 1 (Crevice Corrosion, General Corrosion, and Pitting for Piping, Hand Valve, and Control Valves) - Materials and Environment

The piping is seamless carbon steel with forged carbon steel fittings and carbon steel welds. [Reference 2, Attachment 4 for Group ID 077-HB-01]

The hand valve body/bonnet is constructed of cast or forged carbon steel material. The hand valve stem material is alloy steel, and the disk and seat are alloy steel/stellite. [Reference 2, Attachment 4 for Group ID 077-HV-02]

The control valves body/bonnet is constructed of carbon steel. [Reference 2, Attachment 4 for Group ID 077-CV-01]

The internal environment for the piping, hand valve, and control valves is the ambient atmospheric air in the Containment Building. [Reference 1, Figure 5-10, Sheet 11] The maximum normal ambient air conditions in the containment are 120°F and 70% relative humidity. [Reference 1, Table 9-18; Reference 13, Attachment 1 page 13]

TABLE 5.14-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE RMS

Potential ARDMs	Component Types											Not Plausible for System
	Piping	Check Valve	Control Valve	Hand Valve	Motor-Operated Valve	Flow Element	Flow Indicator	Radiation Element	Filter	Radiation Test Point	Solenoid Valve	
Cavitation Erosion												x
Corrosion Fatigue												x
Crevice Corrosion	✓(1)		✓(1)	✓(1)								
Erosion Corrosion												x
Fatigue												x
Fouling												x
Galvanic Corrosion												x
General Corrosion	✓(1)		✓(1)	✓(1)								
Hydrogen Damage												x
Intergranular Attack												x
MIC												x
Particulate Wear Erosion												x
Pitting	✓(1)		✓(1)	✓(1)								
Radiation Damage												x
Rubber Degradation												x
Saline Water Attack												x
Selective Leaching												x
Stress Corrosion Cracking												x
Stress Relaxation												x
Thermal Damage												x
Thermal Embrittlement												x
Wear			✓(2)									

✓ - indicates plausible ARDM determination

(#) - indicates the group in which this structures and components/ARDM combination is evaluated

Group 1 (Crevice Corrosion, General Corrosion, and Pitting for Piping, Hand Valve, and Control Valves) - Aging Mechanism Effects

Carbon steel is susceptible to general and localized (crevice and pitting) corrosion mechanisms in a warm, humid air environment. Long-term exposure to these mechanisms may result in uniform corrosion of the internal surfaces, causing pipe wall and valve body wall thinning and localized attack resulting in pits and crack initiation. Pitting and cracking of the piping are most likely at low points in the pipe and crevices between socket welded fittings and the pipe. Pitting and cracking of the hand valve is most likely at crevices in the body/bonnet joint, stem to bonnet/packing area, and at the valve seat area. Pitting and cracking of the control valves is most likely at low points in the valve and crevices within the valve body. [Reference 2, Attachment 6 for Group IDs 077-HB--01, 077-HV-02, and 077-CV-01]

These aging mechanisms, if unmanaged, could eventually lead to loss of system pressure boundary integrity for the piping, and/or loss of containment isolation integrity for the hand valve and control valves under current licensing basis (CLB) conditions. Therefore, crevice corrosion, general corrosion, and pitting were determined to be plausible ARDMs for which aging effects must be managed for the piping, hand valve, and control valves. [Reference 2, Attachments 1 and 8]

Group 1 (Crevice Corrosion, General Corrosion, and Pitting for Piping, Hand Valve, and Control Valves) - Methods to Manage Aging

Mitigation: The effects of corrosion cannot be completely prevented, but can be mitigated by minimizing exposure of the carbon steel components to an aggressive environment. The occurrence of crevice corrosion, general corrosion, and pitting is expected to be limited due to the air internal environment of the components (i.e., minimal amount of moisture expected) and is not expected to result in rapid degradation of the carbon steel materials. Modifying the environment (i.e., reduction of humidity) or replacing the carbon steel components with a different material is not reasonable due to the expected limited nature of these effects. Therefore, no methods are deemed necessary to mitigate the effects of crevice corrosion, general corrosion, and pitting of the piping, hand valve, or control valves. [Reference 2, Attachment 8]

Discovery: The corrosion that does occur can be discovered and monitored through visual inspections of the internal surfaces of the piping, hand valve, and control valves. [Reference 2, Attachment 8]

Group 1 (Crevice Corrosion, General Corrosion, and Pitting for Piping, Hand Valve, and Control Valves) - Aging Management Program(s)

Mitigation: Since no methods are deemed necessary to mitigate the effects of crevice corrosion, general corrosion, and pitting of the piping, hand valve, or control valves, there are no programs credited with mitigating the aging effects due to these ARDMs.

Discovery: To verify that no significant crevice corrosion, general corrosion, or pitting is occurring for the piping, hand valve, and control valves, a new plant program will be developed to provide requirements for inspections of representative components. The program is considered an Age-Related Degradation Inspection (ARDI) program, as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA).

The elements of the ARDI program will include:

- Determination of the examination sample size based on plausible aging effects;
- Identification of inspection locations based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective, considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of adverse examination findings, including consideration of all design loadings required by the CLB and specification of required corrective actions; and
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

The corrective actions taken as part of the ARDI program will ensure that the piping remains capable of performing its system pressure boundary function, and the hand valve and control valves remain capable of performing their containment isolation function under all CLB conditions.

Group 1 (Crevice Corrosion, General Corrosion, and Pitting for Piping, Hand Valve, and Control Valves) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to crevice corrosion, general corrosion, and pitting for the piping, hand valve, and control valves:

- The piping provides the system pressure boundary function, and the hand valve and control valves provide the containment isolation function for the containment atmosphere radiation monitors containment penetration piping under CLB conditions.
- Crevice corrosion, general corrosion, and pitting are plausible for the piping, hand valve, and control valves, causing pipe wall and valve body wall thinning, pitting, and cracking, which could eventually lead to loss of system pressure boundary integrity and/or loss of containment isolation integrity under CLB conditions.
- The CCNPP ARDI program will conduct inspections to detect the effects of crevice corrosion, general corrosion, and pitting; and will contain acceptance criteria that ensure corrective actions will be taken such that there is reasonable assurance that system pressure boundary function and containment isolation function will be maintained.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, and pitting will be managed in order to maintain the system pressure boundary function, as provided by the piping, and the containment isolation function, as provided by the hand valve and control valves, consistent with the CLB, during the period of extended operation.

Group 2 (Wear for Control Valves) - Materials and Environment

The control valves plug and seat are constructed of Type 316 stainless steel. [Reference 2, Attachment 4 for group ID 077-CV-01]

The internal environment for the control valves is the ambient atmospheric air in the Containment Building. [Reference 1 Figure 5-10, Sheet 11] The maximum normal ambient air conditions in the containment are 120°F and 70% relative humidity. [Reference 1, Table 9-18; Reference 13, Attachment 1 page 13]

Group 2 (Wear for Control Valves) - Aging Mechanism Effects

The control valves are subject to wear of the plug and seat due to valve operation, and this wear is dependent on the frequency of operation. Seating surface wear causes the leak tightness of the valve to decrease with time. [Reference 2, Attachment 6 for Group ID 077-CV-01]

This aging mechanism, if unmanaged, could eventually lead to a loss of containment isolation integrity under CLB conditions. Therefore, wear was determined to be a plausible ARDM for which the aging effects must be managed for the control valves. [Reference 2, Attachments 1 and 8]

Group 2 (Wear for Control Valves) - Methods to Manage Aging

Mitigation: Since the wear of the control valves seating surfaces is due to valve operation, decreased use of the valve would slow the degradation of the valve leak tightness. However, this method is not feasible from a plant operations standpoint. Therefore, it is concluded that there are no reasonable methods of mitigating wear of the control valves seating surfaces.

Discovery: The effects of wear on the control valves seating surfaces can be managed by the discovery of seat leakage by performing periodic leak rate testing. [Reference 2, Attachment 8]

Group 2 (Wear for Control Valves) - Aging Management Program(s)

Mitigation: Since there are no reasonable methods of mitigating wear of the control valves seating surfaces, there are no programs credited with mitigating the aging effects due to this ARDM.

Discovery: The CCNPP Local Leak Rate Test (LLRT) program is part of the overall CCNPP Containment Leakage Rate Program. The CCNPP Containment Leakage Rate Program was established to implement the leakage testing of the containment, as required by 10 CFR 50.54(o) and 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B. Appendix J specifies containment leakage testing requirements, including the types of tests required, frequency of testing, test methods, test pressures, acceptance criteria, and reporting requirements. Containment leakage testing requirements include performance of Integrated Leakage Rate Tests, also known as Type A tests, and LLRTs, also known as Type B and C tests. Type A tests measure the overall leakage rate of the containment. Type B tests are intended to detect leakage paths and measure leakage for certain containment penetrations (e.g., airlocks, flanges, and electrical penetrations). Type C tests are intended to measure containment isolation valve leakage rates. [Reference 14, Section 6.5.6; References 15 and 16]

The CCNPP LLRT program is based on the requirements of CCNPP Technical Specifications 3.6.1.2, 4.6.1.2, and 6.5.6. The scope of the program includes Type B and C testing of containment penetrations. The control valves that isolate the containment penetration piping for the containment atmosphere radiation

monitors are included in the scope of this program as part of the leakage testing for containment penetration 15. [References 14, 17, and 18]

The LLRT is performed at a frequency in accordance with 10 CFR Part 50, Appendix J, Option B. Per References (17) and (18), currently the LLRT includes the following procedural steps:

- Leak rate monitoring test equipment is connected to the appropriate test point.
- Test volume is pressurized to at least 53 ± 1 psig above atmospheric pressure. The LLRT program test pressure is conservative with respect to the 10 CFR Part 50, Appendix J, test pressure requirements. Appendix J requires testing at a pressure "P_a," which is the peak calculated containment internal pressure related to the design basis accident. For CCNPP, P_a is 49.4 psig, as stated in CCNPP Technical Specification 6.5.6.
- Leak rate, pressure, and temperature are monitored at the frequency specified by the LLRT procedure, and the results are recorded.
- The maximum indicated leak rate is compared against administrative limits which are more restrictive than the maximum allowable leakage limits.
- "As found" leakage equal to or greater than the administrative limit, but less than the maximum allowable limit, is evaluated to determine if further testing is required, and/or if corrective maintenance is to be performed.
- For "as found" leakage that exceeds the maximum allowable limit, the Shift Supervisor and the Containment System Engineer are notified, and they determine if Technical Specification Limiting Condition for Operation 3.6.1.2.b has been exceeded. Technical Specification 3.6.1.2.b contains the maximum allowable combined leakage for all penetrations and valves subject to the Type B and C tests. Corrective action is taken as required to restore the leakage rates to within the appropriate acceptance criteria.
- If any maintenance is required on a penetration boundary, an "as left" test must be performed on the penetration to ensure leakage rates are acceptable.

Although not related to the RMS, operating experience relative to the LLRT program includes cases of unacceptable leakage through some of the electrical penetrations. Modifications to the penetrations did not adequately correct the leakage problems, and the affected penetrations have been replaced.

The corrective actions taken as part of the LLRT program will ensure that the control valves remain capable of performing their containment isolation function under all CLB conditions.

Group 2 (Wear for Control Valves) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to wear for the control valves:

- The control valves provide the containment isolation function for the containment atmosphere radiation monitors containment penetration piping under CLB conditions.
- Wear is plausible to the control valves seating surfaces causing a decrease in leak tightness, which could eventually lead to a loss of containment isolation integrity under CLB conditions.

- The CCNPP Local Leak Rate Test program performs leakage testing which can detect the effects of wear on the control valves seating surfaces, and contains acceptance criteria that ensures corrective actions will be taken such that there is a reasonable assurance that the containment isolation function will be maintained.

Therefore, there is reasonable assurance that the effects of wear will be managed in order to maintain containment isolation function, as provided by the control valves, consistent with the CLB, during the period of extended operation.

5.14.3 Conclusion

The programs discussed for the RMS are listed in Table 5.14-3. These programs are (or will be for new programs) administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the components of the RMS will be maintained, consistent with the CLB, during the period of extended operation.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to Appendix B and covers all structures and components subject to AMR.

TABLE 5.14-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE RMS

	Program	Credited For
Existing	CCNPP LLRT Program Procedure STP-M-571E-1, "Local Leak Rate Test, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64" (Unit 1) Procedure STP-M-571E-2, "Local Leak Rate Test, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64" (Unit 2)	Management of the effects of seating surface wear of the control valves that isolate the containment penetration piping for the containment atmosphere radiation monitors (i.e., Group 2).
New	ARDI Program	Management of the effects of crevice corrosion, general corrosion, and pitting of the containment penetration piping associated with the containment atmosphere radiation monitors, the test connection isolation hand valve which connects to this piping outside containment, and the control valves that isolate this piping (i.e., Group 1).

5.14.4 References

(1) CCNPP Updated Final Safety Analysis Report, Revision 19

(2) CCNPP Aging Management Review Report for the Area and Process Radiation Monitoring System (077/079), Revision 2, January 1997

(3) CCNPP Component Level Scoping Results for the Area & Process Radiation Monitoring System, Revision 1, May 22, 1995

(4) CCNPP Drawing 60738SH0001, "Area & Process Radiation Monitoring System," Revision 49, December 17, 1996

(5) CCNPP Drawing 60738SH0002, "Area & Process Radiation Monitoring System," Revision 13, January 15, 1997

(6) CCNPP Drawing 60722SH0001, "Auxiliary Building Ventilation Systems," Revision 40, January 16, 1997

(7) CCNPP Preventive Maintenance Program, Repetitive Tasks 10771025, 10771026, 20771027, and 20771028

(8) "CCNPP Aging Management Review Report for the Component Cooling Water System (015)," Revision 1, November 7, 1996

(9) "CCNPP Aging Management Review Report for the Service Water System (011)," Revision 1, October 27, 1996

(10) "CCNPP Aging Management Review Report for the Control Room HVAC System (030)," Revision 0, February 16, 1996

(11) "CCNPP Pre-Evaluation Results for the Area & Process Radiation Monitoring Systems (077 & 079)," Revision 1, March 14, 1996

(12) CCNPP Drawing 92769, Sheet HB-7, "M-601 Piping Class Summary," Revision 21, October 26, 1994

(13) CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0, November 8, 1995

(14) CCNPP Unit 1(2) Technical Specifications, Amendment No. 217(194), December 10, 1996

(15) 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors"

(16) Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, "License Amendment Request: Adoption of 10 CFR Part 50, Appendix J, Option B for Type A Testing," January 16, 1996

(17) CCNPP Surveillance Test Procedure STP-M-571E-1, "Local Leak Rate Test, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64" (Unit 1), Revision 0, May 17, 1991

(18) CCNPP Surveillance Test Procedure STP-M-571E-2, "Local Leak Rate Test, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64" (Unit 2), Revision 0, October 17, 1991