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5.5 Containment Isolation Group

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing the Containment Isolation (CI) Group. The CI Group was evaluated in accordance with the Calvert Cliff 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.

5.5.1 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 device types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.5.1.1 presents the results of the system level scoping, 5.5.1.2 the results of the component level scoping, and 5.5.1.3 the results of scoping to determine components subject to an AMR.

Representative historical operating experience pertinent to aging 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.

5.5.1.1 System Level Scoping

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

System Description/Conceptual Boundaries

There are numerous systems that have the CI function and, therefore, contain containment isolation valves (CIVs), containment penetrations, and the associated piping and test connections. The components that perform the CI function in systems that are evaluated in other sections of the BGE LRA are included within those aging management sections; e.g., the containment penetration portions of the Auxiliary Feedwater System are in Section 5.1 of the BGE LRA. The CI Group largely consists of those CIVs, containment penetrations, and the associated piping and test connections in systems that either have no other components within the scope of license renewal or have components that are evaluated in other sections of the BGE LRA (e.g., the Fire Protection [FP] section).

There are two systems, the Waste Gas (WG) System and the Demineralized Water (DW) System, that have a system pressure boundary intended function in addition to the CI intended function. The scope of this report for the WG System includes the WG decay tanks and associated piping, isolation valves, and instrumentation that provide a pressure boundary for the stored WG. A ruptured WG decay tank is a Design Basis Event analyzed for CCNPP. The scope of this report does not include DW System components beyond those that perform the CI function. Other DW System components support of Auxiliary Feedwater System operation and are included in the AMR for the Auxiliary Feedwater System. [Reference 1, Section 1.1.1; References 2 and 3]

Figure 5.5-1 is simplified diagram showing those portions of systems included in the CI Group. It is provided for information only.

Five of the systems, the FP, Plant Heating (PH), DW, Plant Drains (PD), and Liquid Waste (LW) Systems, have FP intended functions in addition to the CI intended function. This report does not include any additional components from these systems because of FP alone. Components in these systems that have only FP intended functions are evaluated in Section 5.10, Fire Protection, of the BGE LRA. [Reference 1, Section 1.1.1]

The CI Group is comprised of portions of the following systems: [Reference 1, Section 1.1.1]

FP	PD
PH	WG
DW	LW
Plant Water (PW)	

Each of the seven systems comprising the CI Group provide fluid penetrations for the Containment Building consisting of piping and valves, which meet design basis double barrier criteria. The design basis governing isolation valve requirement is to minimize fluid leakage through penetrations, not serving engineered safety feature systems, by a double barrier so that no single, credible failure or malfunction of an active component can result in loss of isolation or intolerable leakage. The installed double barriers take the form of closed piping systems, both inside and outside the Containment Building, and various types of isolation valves. [Reference 2, Section 5.2.1]

Containment isolation valves are designed to ensure leak-tightness and reliability of operation. Containment isolation globe, check, and gate valves meet the requirements of Manufacturers Standardization Society Specification MSS-SP-61, and CI butterfly valves meet the requirements of American Water Works Association C-504. Required valve closing times are achieved by appropriate selection of valve, operator type, and operator size. [Reference 2, Section 5.2.1]

System Interfaces

The CI Group interfaces with the following plant systems and components: [Reference 1, Section 1.1.2]

- Containment Structure;
- Containment Penetrations;
- Reactor Coolant System (RCS);
- Reactor Coolant and Waste Process Sampling;
- Gas Analyzing Sampling; and
- Engineered Safety Features Actuation System.

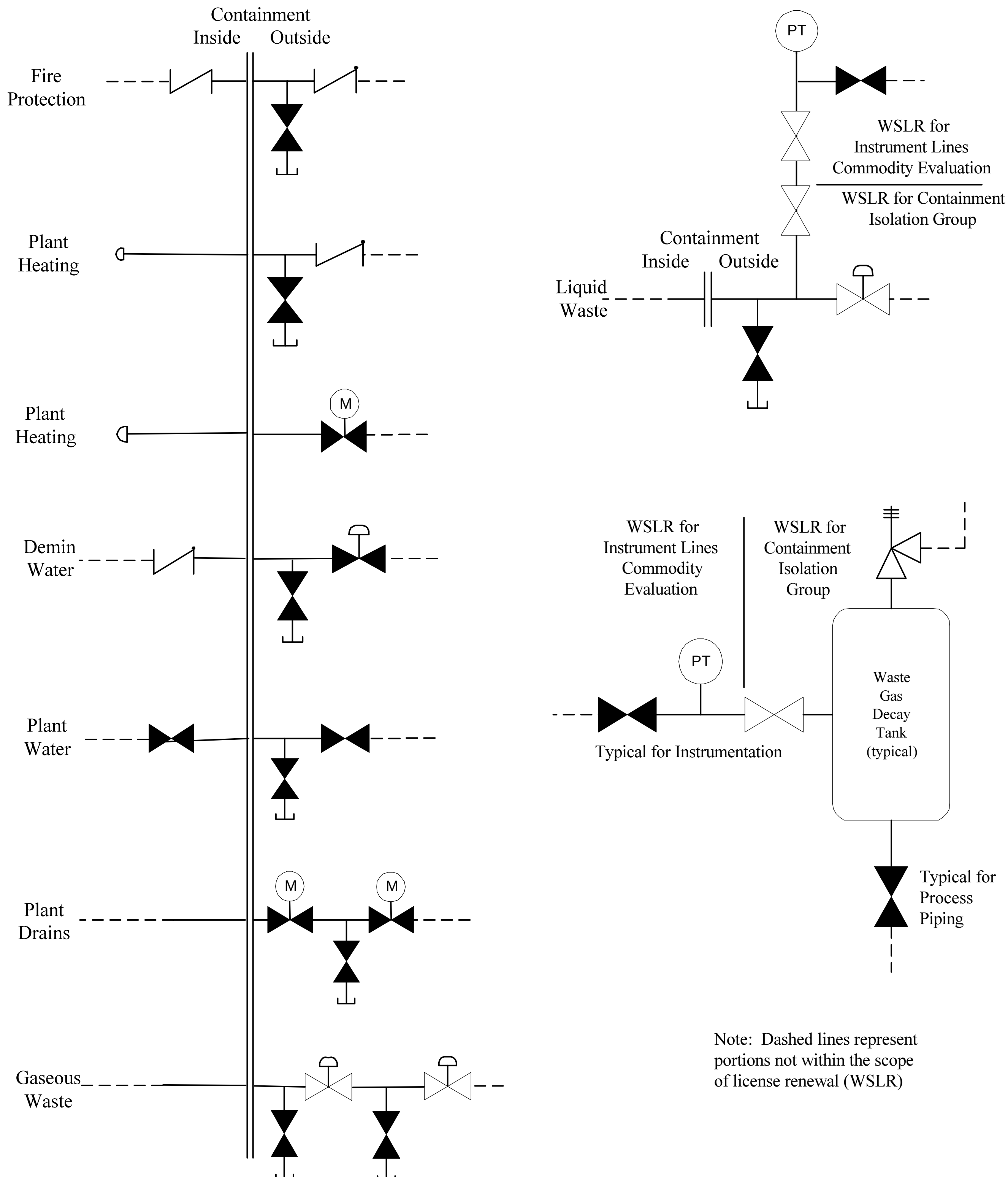


Figure 5.5-1
Containment Isolation Group

System Scoping Results

The CI Group is within the scope of license renewal based on 10 CFR 54.4(a). The following intended functions of CI Group systems were determined based on the requirements of §54.4(a)(1) and (2), in accordance with the CCNPP IPA Methodology: [Reference 1, Section 1.1.3]

- Provide CI (applies to all seven systems);
- Maintain the pressure boundary of the system (liquid and/or gas) for mitigation of Design Basis Events (applies to WG and DW Systems); and
- Maintain electrical continuity and/or provide protection of the electrical system.

The following intended functions of the CI Group systems were determined based on the requirements of 10 CFR 54.5(a)(3): [Reference 1, Section 1.1.3]

- For Environmental Qualification (10 CFR 50.49) - Maintain functionality of electrical components as addressed by the Environmental Qualification Program, provide information used to assess the environs and plant conditions during and following an accident, and provide CIV position indication.

All seven systems in the CI Group also have FP functions that meet the requirements of 10 CFR 54.4(a)(3). Portions of each of these systems are included in the FP evaluation, discussed in Section 5.10 of the BGE LRA, for their role in performing passive FP functions. [Reference 1, Sections 1.1.1 and 1.1.3]

All components of the CI Group that support the above functions are safety-related and Seismic Category 1, and are subject to the applicable loading conditions identified in the Updated Final Safety Analysis Report (UFSAR) Section 5A.3.2 for Seismic Category 1 systems and equipment design. [References 1, 4, and 5]

The containment penetration piping up to the first outside CIV is designed in accordance with American National Standards Institute (ANSI) B31.7, Power Piping Code, Class II. For those penetrations consisting of two outside CIVs, the piping between the first and second outside valves is designed in accordance with ANSI B31.7, Class III. Penetrations and associated piping are considered either Class II or Class MC for the purposes of the American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection Program. The portion of the piping associated with the WG decay tanks that does not provide a CI function is designed to ANSI B31.7, Class III and is considered non-Class for ASME Section XI. [Reference 1, Attachment 3s for pipe; References 6 through 11]

Operating Experience

The CCNPP Containment Leakage Rate Testing Program has been inspected by the NRC on numerous occasions through routine inspections and during reviews of Technical Specification amendment requests. These inspections have not identified any aging-related concerns that need to be addressed in the AMR of CI Group components. Overall, the Containment Leakage Rate Testing Program has maintained the CI portions of the CI Group within the requirements of 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors."

Baltimore Gas and Electric Company has requested and received Technical Specification amendments for revising the containment Type C testing schedule required under 10 CFR Part 50, Appendix J; e.g., to adopt the performance-based requirements of Option B to Appendix J. During the reviews of these requests, significant analysis of past operating experience was performed for CCNPP and the industry as a whole. The NRC has indicated, based on their reviews of Type C performance history, and the wear-out portion of the component life has not been reached, and may not be reached provided good maintenance practices continue to be followed. [References 12 through 19] Additional information on operating experience is provided in the Group 3 discussion of aging management programs.

5.5.1.2 Component Level Scoping

Based on the intended system functions listed above, the portion of the CI Group that is within the scope of license renewal includes all safety-related components (electrical, mechanical, and instrument), and their supports, comprising the containment penetration pressure boundary for the FP, PH, PW, PD, LW, DW, and WG Systems. Also included are the safety-related components (electrical, mechanical, and instrument), and their supports, associated with the WG decay tank pressure boundary. It should be noted that some non-safety-related portions of the FP, PH, DW, PD, and LW Systems are included in the Fire Protection Evaluation, discussed in Section 5.10 of the BGE LRA, for their role in performing FP functions. [References 3, 4, 5 and 20 through 27]

The CI Group component types were scoped using controlled plant drawings, the UFSAR, and the NUCLEIS Equipment Technical Database. The UFSAR was used to determine which containment fluid penetrations were used by systems that do not perform a mitigating function other than CI for Design Basis Events. For these systems, the purpose of the component level scoping was to identify all system components that support the intended functions of the system. This method and the process described in the CCNPP IPA Methodology are equivalent for component level scoping of systems. [Reference 1, Section 2.1]

The following list of 10 device types are within the scope of license renewal for the CI Group: [Reference 1, Table 2-1]

- Piping Class HB (carbon steel)
- Piping Class HC (stainless steel)
- Check Valve
- Control Valve
- Hand Valve
- Level Switch
- Motor-Operated Valve (MOV)
- Pressure Transmitter
- Relief Valve
- Tank

Some components in the CI Group are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 1, Section 3.2]

- Structural supports for piping 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 Cables 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 CI Group.

- Instrument tubing and piping and the associated tubing 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 evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

5.5.1.3 Components Subject to AMR

This section describes the components within the CI Group that are subject to 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 commodity evaluations, or remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following CI Group functions were determined to be passive: [Reference 1, Table 3-1]

- Maintain the pressure boundary of the system (liquid and/or gas) (applies to WG System only);
- Provide CI (applies to all seven systems); and
- Maintain electrical continuity and/or provide protection of the electrical system (applies to DW and WG Systems only).

Device Types Subject to AMR

Of the 10 device types within the scope of license renewal, two device types, level switch and pressure transmitter, are evaluated in the Instrument Line Commodity Evaluation in Section 6.4 of the BGE LRA. [Reference 1, Table 3-2,]

The remaining eight device types are listed in Table 5.5-1 and are subject to AMR. Unless otherwise annotated, all components of each listed device type are subject to AMR.

TABLE 5.5-1

CI GROUP DEVICE TYPES REQUIRING AMR

Piping Class HB	Hand Valve *
Piping Class HC	MOV
Check Valve	Relief Valve
Control Valve	Tank

* Instrument line manual drain, equalization, and isolation valves in the CI Group 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 26, Attachment 3]

5.5.2 Aging Management

A list of potential age-related degradation mechanisms (ARDMs) identified for the CI Group components is given in Table 5.5-2. The plausible ARDMs are identified in the table by a check mark (✓) in the appropriate device type column. For AMR, some device types have a number of subgroups associated with them because of the diversity of material used in their fabrication or differences in the environments to which they are subjected. A check mark indicates that the ARDM applies to at least one subgroup for the device type listed.

For efficiency in presenting the results of the evaluations in this section, 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 in the discussions where appropriate. Table 5.5-2 identifies the group in which each ARDM/device type combination belongs. The following groups have been selected for the CI Group. [Reference 2, Table 4-2]

Group 1 includes crevice corrosion, general corrosion, microbiologically-induced corrosion (MIC), and pitting for device types exposed to well water and subject to AMR. The affected device types include piping, check valves, hand valves, and MOVs.

Group 2 includes crevice corrosion, general corrosion, and pitting for device types exposed to treated water or gaseous waste and subject to AMR. The affected device types include piping, check valves, control valves, hand valves, MOVs, relief valves, and tanks.

Group 3 includes wear for all valves subject to AMR, with the following exceptions: (1) check valves and MOVs in the PH System piping sections that are retired in place and capped off; and (2) all relief valves, i.e., WG decay tank relief valves.

Group 4 includes crevice corrosion, general corrosion, and pitting for the external bolting of the MOVs in the containment normal sump drain lines. These MOVs are the only components in the CI Group with an aging management concern for the external surfaces because they are the only carbon steel subcomponents potentially exposed to boric acid from system leakage.

TABLE 5.5-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE CI GROUP

	Device Types[1]								Not
Potential ARDMs	**HB[2]**	**HC[3]**	**CKV**	**CV**	**HV**	**MOV**	**RV**	**TK**	**Plausible**
Cavitation Erosion									x
Corrosion Fatigue									x
Crevice Corrosion	✓(1)	✓(2)	✓(1,2)	✓(2)	✓(1,2)	✓(1,2,4)	✓(2)	✓(2)	
Dynamic Loading									x
Erosion Corrosion									x
Fatigue									x
Fouling									x
Galvanic Corrosion									x
General Corrosion	✓(1)		✓(1,2)	✓(2)	✓(1,2)	✓(1,2,4)			
Hydrogen Damage									x
Intergranular Attack									x
MIC	✓(1)		✓(1)		✓(1)	✓(1)			
Particulate Wear Erosion									x
Pitting	✓(1)	✓(2)	✓(1,2)	✓(2)	✓(1,2)	✓(1,2,4)	✓(2)	✓(2)	
Radiation Damage									x
Rubber Degradation									x
Saline Water Attack									x
Selective Leaching									x
Stress Corrosion Cracking									x
Thermal Damage									x
Thermal Embrittlement									x
Wear			✓(3)	✓(3)	✓(3)	✓(3)			

✓ - Indicates that the ARDM is plausible for component(s) within the device type
(#) - Indicates the Group(s) in which this ARDM/device type combination is evaluated

Notes:

(1) Not every component included within the device types listed here may be susceptible to a given ARDM. This is because components within a device type are not always fabricated from the same materials or subjected to the same environments. Exceptions for each device type will be indicated in the aging management section for each ARDM discussed in this report.

(2) Class HB piping is carbon steel piping with well water as the internal fluid.

(3) Class HC piping is stainless steel piping with treated water as the internal fluid.

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 to manage aging, aging management program(s), and aging management demonstration.

Group 1 (crevice corrosion, general corrosion, MIC, and pitting for all components exposed to well water) - Materials and Environment

Group 1 is comprised of carbon steel piping and components exposed to well water. Portions of the following systems are included: [References 4, 21, and 22]

- FP - containment penetration portion of the fire main header supply to the containment hose stations;
- PH - containment penetration portion of the supply and return lines for the containment unit heaters (currently retire-in-place and capped inside containment); and
- PW - containment penetration portion of the supply line to the reactor head washdown area.

Check valves, hand valves, and MOVs in these lines are primarily constructed of carbon steel with some internal parts, i.e., wedge, seat, trim, hangers, and internal bolting, also constructed of alloy steels, stellited carbon steel, and stainless steel. In all cases, the valve disks/seats are also relied on for containment pressure boundary. The valves are normally in the closed position because the containment penetration portions of these systems are not normally in use during plant power operation. The PH System containment penetration components are currently retired in place. However, they are still considered susceptible to the subject ARDMs. [Reference 1, Attachment 4s and 6s]

The Group 1 components are exposed to well water that is drawn from local wells. The water is normally pretreated by filtering through an activated carbon filter to remove suspended solids and chlorine from the fluid and to improve the taste, odor, and color of the water. However, microbes are not removed or destroyed by the process. Water may occasionally flow directly, i.e., bypass the carbon filters, to the storage tanks from the wells if the standby pump is started due to a low level in the storage tanks. During normal power operation, the water in these lines is stagnant because the systems are not operating. [Reference 1, Attachment 3s; References 4, 21, 22, and 28]

Group 1 (crevice corrosion, general corrosion, MIC, and pitting for all components exposed to well water) - Aging Mechanism Effects

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. General corrosion requires an aggressive environment and materials susceptible to that environment. Wastage is not a concern for austenitic stainless steel alloys and some high alloy steels. The consequences of the damage are loss of load-carrying cross-sectional area. [Reference 1, Attachment 6s and 7s]

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. Crevice corrosion is closely related to pitting corrosion and can initiate pits in many cases, as well as leading to stress corrosion cracking. [Reference 1, Attachment 6s and 7s]

Pitting is another form of localized attack with greater corrosion rates at some locations than at others. Pitting can be very insidious and destructive, with sudden failures in high pressure applications (especially in tubes) occurring by perforation. This form of corrosion essentially produces holes of varying depth-to-diameter ratios in the steel. Deep pitting is more common with passive metals, such as austenitic stainless steels, than with non-passive metals. Pits are generally elongated in the direction of gravity. [Reference 1, Attachment 6s and 7s]

Microbiologically-induced corrosion is accelerated corrosion of materials resulting from surface microbiological activity. Sulfate reducing bacteria, sulfur oxidizers, and iron oxidizing bacteria are most commonly associated with these corrosion effects. Microbiologically-induced corrosion most often results in pitting followed by excessive deposition of corrosion products. Stagnant or low flow areas are most susceptible. Essentially all systems using untreated water and most commonly used materials are susceptible. Consequences range from leakage to excessive differential pressure and flow blockage. Microbiologically-induced corrosion is generally observed in systems utilizing raw untreated water. [Reference 1, Attachment 6s and 7s]

For Group 1 components, long-term exposure to the well water environment may result in localized 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. The areas where there are stagnant conditions, e.g., drain lines and crevices, are the locations most susceptible to these corrosion mechanisms. All of the ARDMs are plausible for carbon steel, alloy steel, and stellited carbon steel subcomponents. Subcomponents constructed of stainless steel are only susceptible to crevice corrosion, MIC, and pitting because the stainless steel material is resistant to general corrosion. Since the valves in this group are required to maintain pressure boundary while in the closed position, degradation of the internal surfaces of all subcomponents required for the pressure-retaining function must be managed. [Reference 1, Attachment 4s, 5s, and 7s]

Group 1 (crevice corrosion, general corrosion, MIC, and pitting for all components exposed to well water) - Methods to Manage Aging

Mitigation: For systems containing well water and whose flow is low or stagnant, water treatment and/or periodic flushings will mitigate the corrosive processes described above. However, the occurrence of crevice corrosion, general corrosion, MIC, and pitting is expected to be limited and not likely to affect the intended function of the Group 1 components. The discovery techniques described below are deemed adequate for effectively managing aging of the subject components so that no mitigation techniques are required at this time. [Reference 1, Attachment 6s]

Discovery: The effects of corrosion (crevice corrosion, general corrosion, MIC, and pitting) on CI Group 1 components can be discovered and monitored through non-destructive examination techniques such as visual inspections. [Reference 1, Attachment 8] These types of corrosion occur over a long period of time and can be discovered prior to wall thickness reaching an unacceptable value. Inspection results from representative samples of 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.

If corrosion is occurring on valve seating surfaces, the degradation can be detected through pressure tests of the valves in the closed position. Corrosion would cause loss of material that can lead to valve leakage. Pressure testing for valve leakage would provide an early indication of degradation of the valve seating surfaces so that corrective actions can be taken prior to the valves loosing their ability to satisfactorily perform their intended function. [Reference 1, Attachment 8]

Group 1 (crevice corrosion, general corrosion, MIC and pitting for all components exposed to well water) - Aging Management Program(s)

Mitigation: Since there are no mitigation techniques deemed necessary at this time, there are no mitigation programs credited for managing corrosion of Group 1 components.

Discovery: For Group 1 components, crevice corrosion, general corrosion, MIC, and pitting can be readily detected through non-destructive examination techniques. However, the occurrence of crevice corrosion, general corrosion, MIC, and pitting is expected to be limited and not likely to affect the intended function of the Group 1 components. To provide the additional assurance needed to conclude that the effects of corrosion are being effectively managed, the Group 1 components exposed to well water will be included in the scope of an ARDI Program. In addition, the CIVs will periodically be leak tested to provide an early indication of degradation of the valve seating surfaces. [Reference 1, Attachment 8]

All Group 1 components will be included within a new plant program to accomplish the needed inspections for 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.

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

In addition to the ARDI Program, the CI check valves for the FP System containment penetrations and the manual valves for the PW System containment penetrations will be subject to periodic pressure testing for valve leakage. These components are subject to local leak rate testing under the CCNPP Surveillance Test Procedures in accordance with 10 CFR Part 50, Appendix J. [Reference 1, Attachment 8; References 29 through 33] Continued local leak rate testing on a periodic basis will assure acceptable leak tightness at the seating surfaces of these valves and will also ensure that any leakage remains within the guidelines of the Technical Specifications.

The local leak rate test (LLRT) is part of the overall CCNPP Containment Leakage Rate Testing Program, which is implemented through Surveillance Test Procedures. The CCNPP Containment Leakage Rate Testing Program is discussed in detail below for Group 3. The corrective actions taken as part of the Containment Leakage Rate Testing Program will ensure that corrosion of the seating surfaces does not begin to affect the capability of the CIVs to perform their containment pressure boundary integrity function under all CLB conditions.

Group 1 (crevice corrosion, general corrosion, MIC and pitting for all components exposed to well water) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to crevice corrosion, general corrosion, MIC, and pitting of CI Group components exposed to well water:

- The Group 1 components provide a system pressure-retaining boundary and their integrity must be maintained under all CLB conditions.
- Crevice corrosion, general corrosion, MIC, and pitting are plausible for the scoped components and result in material loss which, if left unmanaged, can lead to loss of pressure-retaining boundary integrity.
- The occurrence of crevice corrosion, general corrosion, MIC, and pitting is expected to be limited and not likely to affect the intended function of the Group 1 components.
- To provide the additional assurance needed to conclude that the effects of corrosion are being effectively managed, the Group 1 components exposed to well water 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.
- In addition to the ARDI Program, the CI check valves for the FP System containment penetrations and the manual valves for the PW System containment penetrations will be subject to periodic pressure testing for valve leakage. Pressure testing for valve leakage would provide an early indication of degradation of the valve seating surfaces so that corrective actions can be taken prior to the valves loosing their ability to satisfactorily perform their intended function.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, MIC, and pitting on Group 1 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 (crevice corrosion, general corrosion, and pitting for all components exposed to treated water or gaseous waste) - Materials and Environment

Group 2 is comprised of stainless steel piping and components that are exposed to treated water or gaseous waste. Portions of the following systems are included: [References 1, 3, 5 and 23 through 27]

- WG - containment penetration portion of the reactor coolant drain tank vent header to the WG surge tank, and pressure boundary portion of the WG decay tanks and associated piping and valves;
- PD - containment penetration portion of the drain line for the containment normal sump;
- LW - containment penetration portion of the drain line for the RCS drain tank; and
- DW - containment penetration portion of the line supplying DW to the quench tank.

The valve bodies of check valves, control valves, hand valves, MOVs, and relief valves in these systems are constructed of either stainless steel or carbon steel. Internal parts, i.e., wedge, seat, trim, hangers, and internal bolting, are constructed of a combination of steels including carbon steel, alloy steels, stellited carbon steel, and stainless steel. [Reference 1, Attachment 4s]

The WG decay tanks are constructed of carbon steel and are internally clad with stainless steel. Flanges and couplings are stainless steel and the bolting is carbon and low alloy steel. All of these subcomponents support the pressure boundary function and are subject to AMR. [Reference 1, Attachment 4 for TK]

The Group 2 component internal surfaces are exposed to water and gas from a number of sources including reactor coolant drains, DW lines, containment normal sump drain, and gaseous waste lines. The water and gas is from process systems that use treated water from the DW System as makeup water. The DW System reduces the concentration of oxygen and removes mineral salts and ions thereby providing a source of pure water to minimize the corrosive environment of plant process streams. Further, chemistry controls are placed on several of the systems, such as the RCS, which helps to minimize the corrosiveness of the environment. However, the containment normal sump drain lines and RCS drain tank drain lines may contain water from a number of sources, including the Reactor Coolant and Chemical and Volume Control Systems that contain boric acid, which is corrosive to some steels. [Reference 1, Attachment 3s; References 3, 5, and 23 through 27]

Group 2 (crevice corrosion, general corrosion, and pitting for all components exposed to treated water or gaseous waste) - Aging Mechanism Effects

Steels are 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 including oxygen levels and on the component construction materials. The areas where there are stagnant conditions, e.g., drain lines and crevices, are the locations most susceptible to these corrosion mechanisms. Refer to the discussion for Group 1 above for a detailed discussion of the effects of crevice corrosion, general corrosion, and pitting of steels. [Reference 1, Attachment 6s and 7s]

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 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 internal surfaces of Group 2 components. All of the ARDMs are considered plausible for carbon steel, alloy steel, and stellited carbon steel subcomponents. Subcomponents constructed of stainless steel are only susceptible to crevice corrosion and pitting. They are not subject to general corrosion because stainless steel is resistant to general corrosion. Corrosion due to exposure to boric acid is not plausible because all subcomponents exposed to water that contains boric acid are constructed of stainless steel or high alloy steel. [Reference 1, Attachment 4s, 5s, and 7s]

Degradation resulting from these ARDMs must be managed for all internal surfaces and subcomponents of the piping, tanks, and valves. This includes the disks/seats for the valves, with the exception of some hand valves in instrument lines, because the valves are required to maintain pressure boundary while in the closed position. The stainless steel valve trim for the control valves also supports the pressure boundary function and is subject to crevice corrosion and pitting. All other valves with trim do not rely on the trim to support the pressure boundary function and, therefore, the trim is not subject to AMR. [Reference 1, Attachment 4s, 5s and 6s]

Group 2 (crevice corrosion, general corrosion, and pitting for all components exposed to treated water or gaseous waste) - Methods to Manage Aging

Mitigation: For systems containing treated water or gaseous waste, crevice corrosion, general corrosion, and pitting are considered plausible, especially in areas where the flow is low or stagnant and in cracks and crevices. However, the occurrence of crevice corrosion, general corrosion, and pitting is expected to be limited and not likely to affect the intended function of the Group 2 components. The discovery technique described below is deemed adequate for effectively managing aging of the subject components so that no mitigation techniques are required. [Reference 1, Attachment 6s]

Discovery: The effects of corrosion (crevice corrosion, general corrosion, and pitting) on CI Group 2 components can be discovered and monitored through non-destructive examination techniques such as visual inspections. [Reference 1, Attachment 8] These types of corrosion occur over a long period of time and can be discovered prior to any threat of minimum wall thickness reaching an unacceptable value. Representative samples of 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.

If corrosion is occurring on valve seating surfaces, any leakage caused by this corrosion can also be detected through pressure tests of the valves in the closed position. Pressure testing for valve leakage, such as through local leak rate testing of CIVs, would provide an early indication of degradation of the valve seating surfaces so that corrective actions can be taken prior to the valves losing their ability to satisfactorily perform their intended function. Degradation of valve seating surfaces can be discovered by either the leakage testing or visual inspection methods. [Reference 1, Attachment 8]

Group 2 (crevice corrosion, general corrosion, and pitting for all components exposed to treated water or gaseous waste) - Aging Management Program(s)

Mitigation: Since there are no mitigation techniques deemed necessary at this time, there are no mitigation programs credited for managing corrosion of Group 2 components.

Discovery: For Group 2 components, crevice corrosion, general corrosion, and pitting can be readily detected through non-destructive examination techniques. However, the occurrence of crevice corrosion, general corrosion, MIC, and pitting is expected to be limited and not likely to affect the intended function of the Group 1 components. To provide the additional assurance needed to conclude that the effects of corrosion are being effectively managed, all of the components exposed to treated water or gaseous waste will be included in the scope of an ARDI Program. In addition, the CIVs will periodically be leak tested to provide an early indication of degradation of the valve seating surfaces. [Reference 1, Attachment 8]

All Group 2 components will be included within a new plant program to accomplish the needed inspections for corrosion. This program is considered an ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program.

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.

In addition to the ARDI Program, the CIVs will be subject to periodic pressure testing for valve leakage. These components are subject to local leak rate testing under the CCNPP Surveillance Test Procedures in accordance with 10 CFR Part 50, Appendix J. Included are control valves for the vent header and drains of the reactor coolant drain tank, control valves for the DW supply to the quench tank, and MOVs for the containment normal sump drain lines. [Reference 1, Attachment 8; References 29, 30, 31, and 34 through 39] Continued local leak rate testing on a periodic basis will assure acceptable leak tightness at the seating surfaces of these valves and will also ensure that any leakage remains within the guidelines of the Technical Specifications.

The LLRT is part of the overall CCNPP Containment Leakage Rate Testing Program, which is implemented through Surveillance Test Procedures. The CCNPP Containment Leakage Rate Testing Program is discussed in detail below for Group 3. The corrective actions taken as part of the Containment Leakage Rate Testing Program will ensure that corrosion of the seating surfaces does not begin to affect the capability of the CIVs to perform their containment pressure boundary integrity function under all CLB conditions.

Group 2 (crevice corrosion, general corrosion, and pitting for all components exposed to treated water or gaseous waste) - 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 CI Group 2 components exposed to treated water or gaseous waste:

- The Group 2 components provide a system pressure-retaining boundary and their integrity must be maintained under all CLB conditions.
- Crevice corrosion, general corrosion, and pitting are plausible for the scoped components and result in material loss which, if left unmanaged, can lead to loss of pressure-retaining boundary integrity.

- The occurrence of crevice corrosion, general corrosion, and pitting is expected to be limited and not likely to affect the intended function of the Group 2 components.
- To provide the additional assurance needed to conclude that the effects of corrosion are being effectively managed, all of the components exposed to treated water or gaseous waste 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.
- In addition to the ARDI Program, the Group 2 CIVs will be subject to periodic pressure testing for valve leakage. Pressure testing for valve leakage would provide an early indication of degradation of the valve seating surfaces so that corrective actions can be taken prior to the valves loosing their ability to satisfactorily perform their intended function.

Therefore there is reasonable assurance that the effects of crevice corrosion, general corrosion, and pitting on Group 2 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 3 (wear of valves) - Materials and Environment

All check valves, control valves, hand valves, and MOVs, with the exception of some hand valves in the instrument lines, in the CI Group have disks and seats that are relied on for system pressure boundary because the valves must be in the closed position to perform the intended function. Wear is considered plausible for the disks and seats of all the CI Group valves, with the exception of those in the PH System, that are retired in place and no longer operated. Wear is also not plausible for any relief valves, i.e., relief valves for the WG decay tanks, because they operate relatively infrequently. The valve bodies are constructed of either stainless steel or carbon steel. Internal parts, i.e., wedge, seat, trim, hangers, and internal bolting, are constructed of a combination of steels including carbon steel, alloy steels, stellited carbon steel, and stainless steel. [Reference 1, Attachment 4s]

The internal environment for the Group 3 valves is treated water or reactor coolant gaseous waste. The environmental conditions for these valves are discussed above in Group 2.

Group 3 (wear of valves) - Aging Mechanism Effects

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard, abrasive particles (abrasive wear) or fluid stream (erosion), and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). Motions may be linear, circular, or vibratory in inert or corrosive environments. In addition to material loss from the above wear mechanisms, impeded relative motion between two surfaces held in intimate contact for extended periods may result in galling/self welding. Wear rates may accelerate as expanded clearances result in higher contact stresses. [Reference 1, Attachment 7 for Valves]

The disks and seats of check valves subject to AMR for wear are required to maintain containment pressure boundary integrity or system pressure boundary integrity. Wear is considered plausible for the disks and seats of Group 3 valves because they may experience cyclic relative motion at the tight fitting surfaces. Movement of the disk against the seat can result in a gradual loss of material, which could result in a small amount of leakage. If left unmanaged, wear could eventually lead to a loss of pressure boundary integrity. Wear is not plausible for the relief valves on the WG decay tanks because they change position, i.e., relieve pressure, relatively infrequently. Wear is also not plausible for the valves in the PH System because they are retired in place. [Reference 1, Attachment 4s, 5s, and 6s]

Group 3 (wear of valves) - Methods to Manage Aging Effects

Mitigation: Since the wear of valve disk and seats is due to valve operation, decreased operation of the valves would slow the degradation of the valves seating surfaces. This is not a feasible mitigation technique because it would place unnecessary restrictions on plant operation. The restrictions are unnecessary because limited leakage through the valves will not significantly impact the intended function. Furthermore, the discovery methods discussed below are deemed adequate for verifying that significant degradation is not occurring. It should be noted that galling/self welding occur when there is impeded relative motion between two surfaces held in intimate contact for extended periods. Periodic valve operation actually minimizes this phenomenon. [Reference 1, Attachment 6s]

Discovery: Wear for valve disks and seats can be detected by performing leak rate testing or including the valve component in an inspection program. [Reference 1, Attachment 8] Since wear occurs gradually over time, periodic leak testing can be used to discover leakage that may be caused by wear of the seating surfaces so that corrective actions can be taken prior to the loss of the intended function. In an inspection program, representative samples of susceptible locations can be used to assess the need for additional inspections at less susceptible locations.

Group 3 (wear of valves) - Aging Management Program(s)

Mitigation: There are no feasible methods of mitigating wear of the valve disks and seats; therefore, there are no programs credited with mitigating the aging effects due to this ARDM.

Discovery: All of the Group 3 check valves, control valves, and MOVs that perform the containment pressure boundary function, and the hand valves for the PW System containment penetration, are subject to local leak rate testing under the CCNPP Containment Leakage Rate Testing Program, as required by 10 CFR Part 50 Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B. This program is implemented in accordance with the plant Technical Specifications. The check valve in the DW System and all hand valves, with the exception of the hand valves that serve as CIVs for the PW System, are not subject to local leak rate testing. These components will be included within a new plant program, ARDI, to accomplish the needed inspections for wear. [Reference 1, Attachment 8; References 29 through 41]

CCNPP Containment Leakage Rate Testing Program

The LLRT is performed under Surveillance Test Procedures, References 30, 31, and 34 through 39, as part of the overall CCNPP Containment Leakage Rate Testing Program. The CCNPP Containment Leakage Rate Testing 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. 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 CIV leakage rates. [References 29, Section 6.5.6; References 40 and 41]

The CCNPP Containment Leakage Rate Testing Program is based on 10 CFR Part 50, Appendix J, requirements and implements the requirements in 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. [References 29 through 39]

The LLRTs are performed at a frequency in accordance with 10 CFR Part 50, Appendix J, Option B. Per References 30 through 39, the LLRT currently 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 $\pm$ 1 psig, which is conservative with respect to 10 CFR Part 50, Appendix J, test pressure requirements.
- 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 that 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 appropriate supervisory plant personnel determine if Technical Specification Limiting Condition for Operation (LCO) 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 CIV that changes the closing characteristics of the valve, an "as left" test must be performed on the penetration to ensure leakage rates are acceptable.

The CCNPP Containment Leakage Rate Testing Program has been inspected by the NRC on numerous occasions through routine inspections and during reviews of technical specification amendment requests. Routine inspections at the site included procedure reviews, leakage test witnessing, test reviews, and results evaluation of both integrated leakage rate tests and LLRTs. Inspectors noted when individual CIVs failed their leakage tests and reviewed the repair and resetting actions taken by BGE. With some specific exceptions, the inspections typically noted acceptable conditions. No aging-related deficiencies were identified. [References 12 through 15]

Baltimore Gas and Electric Company has requested, and received, Technical Specification amendments for revising the containment Type C testing schedule required under 10 CFR Part 50, Appendix J. The requests were initiated to accommodate extending the fuel cycle to 24 months, and to recognize the added Option B under Appendix J. Currently, CCNPP follows the schedule of Option B, which is a performance-based scheduling process. During the reviews of these requests, significant analysis of past operating experience was performed for CCNPP and the industry as a whole. The NRC has indicated, based on their reviews of Type C performance history, that the wear-out portion of the component life has not been reached, and may not be reached provided good maintenance practices continue to be followed. Furthermore, reviews of site-specific data indicate that the leakage rate data at the end of the CCNPP Unit 1 operating cycles falls within a typical range. [References 16 through 19]

These reviews demonstrate that CCNPP has normal and acceptable operating experience with respect to component aging of components relied on for CI. The corrective actions taken as part of the Containment Leakage Rate Testing Program will ensure that the CI check valves and MOVs remain capable of performing their containment pressure boundary integrity function under all CLB conditions.

CCNPP ARDI Program

The check valve in the DW System and all the Group 3 hand valves are not currently subject to local leak rate testing, with the exception of the hand valves that serve as CIVs for the PW System. Wear can be detected for these components through visual inspections or leakage testing. These components will be included in a new plant program to accomplish the needed inspections for wear. This program is considered an ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program. [Reference 1, Attachment 8]

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 3 (wear of valves) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to wear of Group 3 valves for the CI Group:

- The valve disks and seats maintain containment pressure boundary and their integrity must be maintained under all CLB conditions.
- Wear is plausible for valve disks and seats and results in material loss which, if left unmanaged, could eventually lead to leakage and loss of pressure boundary.
- The CIVs are subject to local leak rate testing in accordance with the CCNPP Containment Leakage Rate Testing Program.
- Leak testing will continue to be performed by these programs in accordance with the plant Technical Specifications, and appropriate corrective actions will be taken if significant leakage due to wear of the seating surfaces is discovered.
- The check valve in the DW System and all the hand valves, with the exception of the PW System CIVs, are not subject to local leak rate testing and, therefore, will be included in the scope of an ARDI Program. Inspections 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 for Group 3 valves 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 4 (crevice corrosion, general corrosion, and pitting for the external bolting of the MOVs) - Materials and Environment

This group includes crevice corrosion, general corrosion, and pitting for the external bolting of the MOVs in the containment normal sump drain lines. The MOVs in the containment normal sump drain lines contain bolts external to the process fluid that support the system pressure boundary function. These bolts are constructed of carbon and low alloy steel materials. The containment normal sump drain lines contain water from the Reactor Coolant and Chemical and Volume Control Systems, which contain boric acid. If the valves develop a leak, there is the potential for the carbon steel bolts to be exposed to corrosive boric acid. These MOVs are the only components in the CI Group with an aging management concern of the external surfaces because they are the only carbon steel subcomponents potentially exposed to boric acid from system leakage. [Reference 1, Attachments 4 and 6 for MOV]

Group 4 (crevice corrosion, general corrosion, and pitting for the external bolting of the MOVs) - Aging Mechanism Effects

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The consequences of the damage are loss of load-carrying cross-sectional area. General corrosion requires an aggressive environment and materials susceptible to that environment. This ARDM is plausible for the external surfaces of the Group 4 MOVs because susceptible materials of construction of the bolts (e.g., low alloy steel, carbon steel) are potentially exposed to borated water leakage. Additionally, crevice corrosion and pitting can occur when crevices (e.g., under nuts and/or bolt heads) are exposed to leakage. Refer to the discussion for Group 1 above for a detailed discussion of the effects of crevice corrosion, general corrosion, and pitting of steels. [Reference 1, Attachments 6 and 7 for MOVs]

Long-term exposure to this environment 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 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 external bolting of the Group 4 MOVs. [Reference 1, Attachment 6 for MOVs]

Group 4 (crevice corrosion, general corrosion, and pitting for the external bolting of the MOVs) - Methods to Manage Aging

<u>Mitigation</u>: The effects of crevice corrosion, general corrosion, and pitting, which occur due to leakage of borated water, can be mitigated by minimizing leakage so that the components are not exposed to a corrosive environment. There is no mitigation technique required because the discovery programs discussed below are deemed adequate to manage aging. [Reference 1, Attachment 8]

<u>Discovery</u>: The degradation of the Group 4 MOVs, that does occur, can be discovered and monitored by performing visual inspections of the bolting that has been subject to boric acid leakage for signs of crevice

corrosion, general corrosion, and pitting, and taking appropriate corrective action when appropriate. [Reference 1, Attachment 8; Reference 42]

Group 4 (crevice corrosion, general corrosion, and pitting for the external bolting of the MOVs) - Aging Management Program(s)

Mitigation: Since no mitigation techniques are required, there are no programs credited for mitigation.

Discovery: The CCNPP Boric Acid Corrosion Inspection (BACI) Program provides systematic requirements to ensure that boric acid corrosion does not degrade the reactor coolant pressure boundary and thereby increase the probability of abnormal leakage, rapidly propagating failure, or gross rupture. The program controls examination and test methods and actions for minimizing the loss of structural and pressure-retaining integrity of components due to boric acid corrosion. It has been established in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR *[pressurized water reactor]* Plants." [Reference 42]

The scope of the program is threefold and provides: (1) examination locations where leakage may cause degradation of the primary pressure boundary by boric acid corrosion; (2) examination requirements and methods for the detection of leaks; and (3) the requirements for initiating engineering evaluations and the subsequent proposed corrective actions. [Reference 42]

The program requires a containment walkdown, i.e., VT-2 visual exam (a type of visual examination described in ASME XI, IWA-2212), following each reactor shutdown (as soon as possible after attaining Hot Shutdown condition) to identify and quantify any leakage found in specific areas of the Containment and Auxiliary Buildings. A second walkdown is performed during heatup, prior to plant startup (after attaining normal operating pressure and temperature), if leakage was identified and corrective actions were taken. Only locations where the initial inspection identified leakage are included in this second walkdown. The walkdowns are performed in accordance with CCNPP Administrative Procedure MN-3-110, "Inservice Inspection of ASME Section XI Components," and Procedure MN-3-301, "Boric Acid Corrosion Inspection Program." A containment walkdown is not required if a reactor shutdown occurs within 30 days of a previous shutdown unless the reason for the shutdown is excessive RCS leakage. [Reference 42]

The program also requires examination of specific components for discovery of leakage during each refueling outage. Some of the components examined include carbon steel bolting on Class 1 valves, valves in systems containing borated water, which could leak onto Class 1 carbon steel components, and components that are the subject of Issue Reports where boric acid leakage has been identified. [Reference 42]

The procedures require that, if leakage or corrosion is discovered, corrective actions will be taken in accordance with the CCNPP Corrective Action Program to document and resolve the deficiency. The corrective actions address the removal of boric acid residue and inspection of the components for corrosion. Follow-up actions also address the evaluation of the component for continued service and initiation of corrective actions to prevent recurrences. The combined visual inspection and corrective action programs currently in place will ensure that the MOVs will remain capable of performing the system pressure boundary integrity function under all CLB conditions. [Reference 42]

The BACI Program has evolved over the years to account for operational experience in both CCNPP Units due to occurrences of boric acid leakage. In one case, the BACI Program was modified to include new inspection locations. In another case, the program was modified to include a requirement that all occurrences of boric acid leakage be formally evaluated within the program. Prior to that, it was possible for boric acid leakage to be corrected through other means and without a formal review within the BACI Program. [Reference 42]

The BACI Program is subject to periodic internal assessment activities, including audits that serve to provide a comprehensive, independent verification and evaluation of the quality-related activities and procedures of the BACI Program. A Master Assessment Plan is created to provide a standardized plan for assessing performance of the BACI Program. The Master Assessment Plan identifies the critical program elements, expected results, and key attributes that should be visible during field operations or assessment activities. Long-term assessment results are provided to personnel responsible for maintaining the BACI Program. The site Quality Assurance Policy requires an assessment of the BACI Program every two years. [References 43, 44, and 45]

Group 4 (crevice corrosion, general corrosion, and pitting for the external bolting of the MOVs) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 4 MOV external bolting subject to crevice corrosion, general corrosion, and pitting:

- The subject MOVs maintain containment pressure boundary and their integrity must be maintained under all CLB conditions.
- Crevice corrosion, general corrosion, and pitting are plausible for the external bolting of Group 4 MOVs due to potential leakage of borated water creating a corrosive environment around the carbon and low alloy steel bolts. If left unmanaged, corrosion could eventually result in loss of material such that the components may not be able to perform their pressure boundary function.
- The BACI Program inspections will detect signs of leakage, boric acid residue, or the effects of corrosion on the external surfaces of the Group 4 MOVs, and will ensure corrective actions will be taken such that there is reasonable assurance that the passive intended function will be maintained.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, and pitting will be managed for the external bolting of the Group 4 MOVs such that they will be capable of performing their passive intended function, consistent with the CLB, during the period of extended operation.

5.5.3 Conclusion

The programs discussed for the CI Group are listed in Table 5.5-3. 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 CI Group 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 5.5-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE CI GROUP

	Program	Credited As
Existing	CCNPP Leakage Rate Testing Program: LLRT Procedures STP-M-571A-1, STP-M-571A-2, STP-M-571D-1, STP-M-571D-2, STP-M-571E-1, STP-M-571E-2, STP-M-571G-1, STP-M-571G-2, STP-M-571M-1, and STP-M-571M-2	• Discovery and management of leakage that could be the result of the effects of crevice corrosion, general corrosion, MIC, and pitting on the seating surfaces of the CI Group CIVs that are exposed to well water (Group 1) • Discovery and management of leakage that could be the result of the effects of crevice corrosion, general corrosion, and pitting on the seating surfaces of the CI Group CIVs that are exposed to treated water or gaseous waste (Group 2) • Discovery and management of leakage that could be the result of the effects of seating surface wear on all of the CI Group CIVs (Group 3)
Existing	CCNPP BACI Program: CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program"	• Discovery and management of the effects of crevice corrosion, general corrosion, and pitting of the external bolting on CI Group MOVs that are located in borated water systems (Group 4)
New	ARDI Program	• Discovery and management of the effects of crevice corrosion, general corrosion, MIC, and pitting of the CI Group components that are exposed to well water (Group 1) • Discovery and management of the effects of crevice corrosion, general corrosion, and pitting of the CI Group components that are exposed to treated water or gaseous waste (Group 2) • Discovery and management of the effects of wear of the CI Group valves that are not CIVs, i.e., check valve in the DW System, the relief valves, and all hand valves, with the exception of the PW System CI hand valves. (Group 3)

5.5.4 References

1. CCNPP Aging Management Review (AMR) Report for the Containment Isolation Group, Revision 1, October 1997
2. CCNPP Updated Final Safety Analysis Report, Units 1 and 2, Revision 20
3. CCNPP Drawing No. 60735SH0001, "Waste Gas and Miscellaneous Waste Processing Systems," Revision 38, October 20, 1996
4. CCNPP Drawing No. 60746SH0003, "Plant Water and Air Service System," Revision 16, May 6, 1996
5. CCNPP Drawing No. 60733SH0001, "Auxiliary Building, Waste Processing Equipment, and Area Drains," Revision 24, January 22, 1997
6. CCNPP Drawing No. 92769SH-HB-5, "M-601 Piping Class Summary," Revision 28, April 29,1993
7. CCNPP Drawing No. 92769SH-HB-6, "M-601 Piping Class Summary," Revision 20, April 29, 1993
8. CCNPP Drawing No. 92769SH-HC-1, "M-601 Piping Class Summary," Revision 25, May 22, 1995
9. CCNPP Drawing No. 92769SH-HC-2, "M-601 Piping Class Summary," Revision 21, April 29, 1993
10. CCNPP Drawing No. 92769SH-HC-3, "M-601 Piping Class Summary," Revision 20, April 29, 1993
11. CCNPP Drawing No. 92769SH-HC-4, "M-601 Piping Class Summary," Revision 20, April 29, 1993
12. NRC Inspection No. 50-317/82-15, "Routine, Unannounced Inspection of the Containment Penetration Leakage Testing Program, the Containment Integrated Leakage Rate Test, Tours of Facility, and Follow-up on Previous Inspection Findings," June 16, 17, 18, 21, 22, 1982
13. Letter from Mr. T. T. Martin (NRC) to Mr. A. E. Lundvall, Jr. (BGE) dated January 20, 1983, "Inspection No. 50-318/82-26" (Routine, Unannounced Inspection of Procedure Review, Witnessing and Results Evaluation of Local Leak Rate Test and Integrated Leak Rate Test, December 15 through 18, 1982)
14. Letter from Mr. S. D. Ebneter (NRC) to Mr. A. E. Lundvall, Jr. (BGE), dated June 25, 1985, "Inspection No. 50-317/85-10" (Routine, Announced Inspection of the Containment Leakage Testing Program including Procedure Review of Containment Integrated Leakage Rate Test (CILRT) and Local Leak Rate Test (LLRT) Procedures, CILRT and LLRT Witnessing, CILRT and LLRT Test Review, On-Line Primary Containment Leakage Monitoring, and General Tours of the Facility, April 29 - May 2, and May 17 - 21, 1985)
15. Letter from Mr. S. D. Ebneter (NRC) to Mr. A. E. Lundvall, Jr. (BGE), dated December 24, 1985, "Combined Inspection Nos. 50-317/85-33 and 50-318/85-33" (November 18 through 25, 1985)

16. Letter from Mr. S. A. McNeil (NRC) to Mr. G. C. Creel (BGE), dated March 15, 1989, "Issuance of Technical Specification Amendment and Temporary Exemption Concerning Retest Schedular Requirements of Appendix J to 10 CFR Part 50 for Types B and C Local Leak Rate Tests (TAC No. 71589)" [Amendment No. 118, Unit 2]

17. Letter from Mr. D. G. McDonald, Jr. (NRC) Mr. Mr. G. C. Creel (BGE), dated February 19, 1992, "Issuance of Amendments for CCNPP Unit No. 1 (TAC No. M82213) and Unit No. 2 (TAC No. M82212)" [Amendment Nos. 168/147]

18. Letter from Mr. A. W. Dromerick (NRC) Mr. C. H. Cruse (BGE), dated February 11, 1997, "Issuance of Amendments for CCNPP Unit No. 1 (TAC No. M97341) and Unit No. 2 (TAC No. M97342)" [Amendment Nos. 219/196]

19. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated November 26, 1996, "License Amendment Request; Adoption of 10 CFR Part 50, Appendix J, Option B for Type B and C Testing"

20. CCNPP "Pre-Evaluation Results for the Containment Isolation Group (#013, 029, 037, 051, 069, 071)," Revision 0, March 19, 1997

21 CCNPP Drawing No. 60714SH0002, "Plant Fire Protection System Auxiliary and Containment Buildings," Revision 23, May 31, 1996

22. CCNPP Drawing No. 60728SH0002, "Plant Heating System Auxiliary Building and Containment," Revision 22, May 31, 1996

23. CCNPP Drawing No. 60729SH0001, "Reactor Coolant System," Revision 61, August 5, 1996

24. CCNPP Drawing No. 62729SH0001, "Reactor Coolant System," Revision 68, December 12, 1996

25. CCNPP Drawing No. 60733SH0002, "Auxiliary Building, Waste Processing Equipment, and Area Drains," Revision 23, January 22, 1997

26. CCNPP Drawing No. 60733SH0004, "Miscellaneous Containment Drains, Sump Piping, and Reactor Coolant Pump Lube Oil Collection System," Revision 8, August 15, 1996

27. CCNPP Drawing No. 60734SH0001, "Reactor Coolant Waste Processing Systems," Revision 31, September 9, 1996

28. CCNPP Drawing No. 60717SH0002, "Well Water, Pretreated Water, Demineralized Water and Condensate Storage System," Revision 33, November 26, 1996

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

30. CCNPP Surveillance Test Procedure STP-M-571G-1, "Local Leak Rate Test, Penetrations 9 (Cont Spray), 10 (Cont Spray), 23 (RC Drain Tank), 24 (PXR Quench Tank), 37 (Plant Service Water, 39 (SI Test), (Unit 1)," Revision 0, May 17, 1991.

31. CCNPP Surveillance Test Procedure STP-M-571G-2, "Local Leak Rate Test, Penetrations 9 (Cont Spray), 10 (Cont Spray), 23 (RC Drain Tank), 24 (PXR Quench Tank), 37 (Plant Service Water), 39 (SI Test), (Unit 2)," Revision 0, October 17, 1991

32. CCNPP Surveillance Test Procedure STP-M-571M-1, "Local Leak Rate Test, 44 (Fire Protection) (Unit 1)," Revision 0, May 16, 1991

33. CCNPP Surveillance Test Procedure STP-M-571M-2, "Local Leak Rate Test, 44 (Fire Protection) (Unit 2)," Revision 0, October 17, 1991

34. CCNPP Surveillance Test Procedure STP-M-571A-1, "Local Leak Rate Test, Penetrations 1A (RC & PZR Sampling), 1B (Cont Vent Header), 1C (RC Pump Seals), (Unit 1)," Revision 0, May 16, 1991

35. CCNPP Surveillance Test Procedure STP-M-571A-2, "Local Leak Rate Test, Penetrations 1A (RC & PZR Sampling), 1B (Cont Vent Header), 1C (RC Pump Seals), (Unit 2)," Revision 0, October 17, 1991

36. CCNPP Surveillance Test Procedure STP-M-571D-1, "Local Leak Rate Test, Penetration 8 (Containment Sump), (Unit 1)," Revision 0, May 16, 1991

37. CCNPP Surveillance Test Procedure STP-M-571D-2, "Local Leak Rate Test, Penetration 8 (Containment Sump), (Unit 2)," Revision 0, October 17, 1991

38. CCNPP Surveillance Test Procedure STP-M-571E-1, "Local Leak Rate Test, Penetrations 15 (Purge Air Monitor), 16, 18 (Comp Cooling Water), 38 (Demin Water), 59, 61 (Refueling Pool), 60 (STM to RX head Cleanup), 62, 64 (Unit Heaters), (Unit 1)," Revision 0, May 17, 1991

39. CCNPP Surveillance Test Procedure STP-M-571E-2, "Local Leak Rate Test, Penetrations 15 (Purge Air Monitor), 16, 18 (Comp Cooling Water), 38 (Demin Water), 59, 61 (Refueling Pool), 60 (STM to RX head Cleanup), 62, 64 (Unit Heaters), (Unit 2)," Revision 0, October 17, 1991.

40. 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors."

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

42. CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program," Revision 1/Change 0, December 15, 1994

43. "BGE Quality Assurance Policy for CCNPP," Revision 48, March 28, 1997

44. Nuclear Performance Assessment Department Guideline NPADG-5, "Master Assessment Plan (MAP) Development and Control," Revision 1, July 8, 1997

45. CCNPP Administrative Procedure QL-3-103, "Assessments," Revision 0, July 1, 1997

5.6 Containment Spray System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Containment Spray (CS) System. The CS 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.

5.6.1 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.

Representative historical operating experience pertinent to aging 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.

Section 5.6.1.1 presents the results of the system level scoping; 5.6.1.2 the results of the component level scoping; and 5.6.1.3 the results of scoping to determine components subject to an AMR.

5.6.1.1 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.

<u>System Description/Conceptual Boundaries</u>

The major function of the CS System is to limit the pressure and temperature of the containment atmosphere so the associated design limits are not exceeded following Design Basis Events (DBEs). This function is performed by spraying cold borated water into the containment atmosphere. The CS System is also utilized to remove heat from the Reactor Coolant System (RCS) during plant cooldown once RCS temperature is below 300°F, and to maintain the RCS temperature during cold shutdown and refueling operation modes. During normal plant operations, the CS System is maintained in a standby mode. [Reference 1, Section 1.1.1]

The major components of the CS System for each CCNPP Unit are two electric motor-driven pumps, two shutdown cooling heat exchangers (SDCHXs), two CS headers that include spray rings and nozzles inside containment, and associated piping, valves, controls and instrumentation. [Reference 2, Section 6.4.2]

In the early 1990s, the SDCHX tubes were found to rattle at high cooling water flowrates. [Reference 3] Initially, cooling water flow was throttled using butterfly valves at the SDCHX inlet to reduce tube rattling.

However, these valves were not capable of maintaining the desired flow rates without occasionally drifting out of position. To provide a wider control band for the valves while preventing tube rattling, the SDCHXs were disassembled during the 1992 and 1993 refueling outages (for Units 1 and 2, respectively), and the tubes were staked with helical spacers that stiffened the entire tube assembly. Plant Engineering representatives inspected the internal surfaces of the SDCHXs when the shells were removed, and no signs of excessive tube wear were noted.

In the past, the inboard containment isolation check valves in the CS ring headers have failed leakage testing. Following several analyses, the root cause of these failures was attributed to valve discs that were too light to reseat after securing flow during the tests. During the 1997 Unit 2 refueling outage, a new (heavier) disc design was incorporated in these valves. While the valves were disassembled, no signs of wear were noted on the discs or the seats.

Many other CS System components have been disassembled over the plant's operating history with no unusual or unexpected signs of wear or degradation noted.

The CS System is composed of the following general categories of equipment and devices: [Reference 1, Section 1.1.2]

Instruments	Measure and indicate system flow rates, temperatures, and pressures;
Heat Exchangers	Provide a heat sink for post-accident containment heat removal or normal shutdown cooling (SDC) operations;
Piping	Convey borated water to/from the SDCHXs and to the CS headers;
Pumps	Provide motive force to move borated water through the system; and
Valves	Control valves (CVs), check valves (CKVs), hand valves (HVs), motor-operated valves (MOVs), relief valves (RVs), and solenoid valves, which provide containment isolation and system alignment/isolation.

System Interfaces

The CS System has interfaces with eight plant systems. [References 4 through 9] These interfaces and their applicability for license renewal are discussed below.

The following interfaces with the CS System are within the scope of license renewal:

- Engineered Safety Features Actuation System (ESFAS). [Reference 1, Section 1.1.2] The ESFAS supplies control signals to CS System components in response to DBE conditions. A signal starting the CS pumps is provided when a Safety Injection Actuation Signal has been generated. A signal opening the CS header isolation CVs is provided when a Containment Spray Actuation Signal (CSAS) has been generated. [Reference 2, Section 6.4.4] This interface involves cables/conduits associated with transmitting the ESFAS signals to the CS System and controls associated with the pumps and valves.

  Safety Injection (SI) System. [Reference 1, Section 1.1.2] The CS System piping has several interfaces with the SI System. On CS pump start in response to a Safety Injection Actuation Signal, the SI System provides borated water to the CS pump suction header from the refueling water tank (RWT). Prior to initiation of a CSAS, flow from the CS pump returns to the RWT through the CS pump mini-flow return CKVs. [Reference 2, Section 6.4.4] When the inventory in the RWT is nearly depleted, a Recirculation Actuation Signal (RAS) is generated in the ESFAS. After a RAS initiation, operators may choose to divert a portion of the cooled water from the CS headers to the suction of the high-pressure SI (HPSI) pumps. [Reference 2, Section 6.3.1] In the SDC mode of operation, borated water from the low-pressure SI (LPSI) pump discharge header flows through the SDCHX to the LPSI return header on its way into the RCS cold leg. [Reference 2, Section 9.2.1] Additional connections to the SI System allow flow: (a) from the SDC return header to flow instrumentation in the SI System flowpath used during purification; (b) from the SDC return header to the RWT return header; and (c) from the CS header to the RWT return header. [Reference 10 Sections 6.11 and 6.12; Reference 11, Section 6.5; Reference 12, Section 6.2]

- Component Cooling (CC) System. [References 13 and 14] The CC System provides flow to the SDCHXs following a RAS initiation and during SDC operation. [Reference 2, Section 9.2.1]
- Spent Fuel Pool (SFP) Cooling System. [Reference 15] The CS System piping from the SDC return header interfaces with the SFP Cooling System, allowing the SDCHXs to provide additional SFP cooling when the complete core is removed from the reactor vessel and temporarily stored in the SFP. [Reference 2, Section 9.2.1; Reference 12]

The following interfaces with the CS System are not within the scope of license renewal:

- Primary Containment Heating and Ventilation System. A second CS System piping interface with the Primary Containment Heating and Ventilation System is found where the emergency dousing nozzles provide spray for the iodine removal units inside containment.
- Chemical and Volume Control System. The CS System piping leading to the emergency dousing nozzles for the iodine removal units interfaces with the excess flow CKV test connections in the Chemical and Volume Control System. [Reference 16]
- Compressed Air System. The CS System piping leading to the emergency dousing nozzles for the iodine removal units inside Unit 1 containment interfaces with a service air connection in the Compressed Air System; a similar connection in Unit 2 has been permanently capped. [Reference 17]

Figure 5.6-1 is a simplified diagram of the CS System and is provided for information only. This figure depicts the major CS System components and interfaces discussed above.

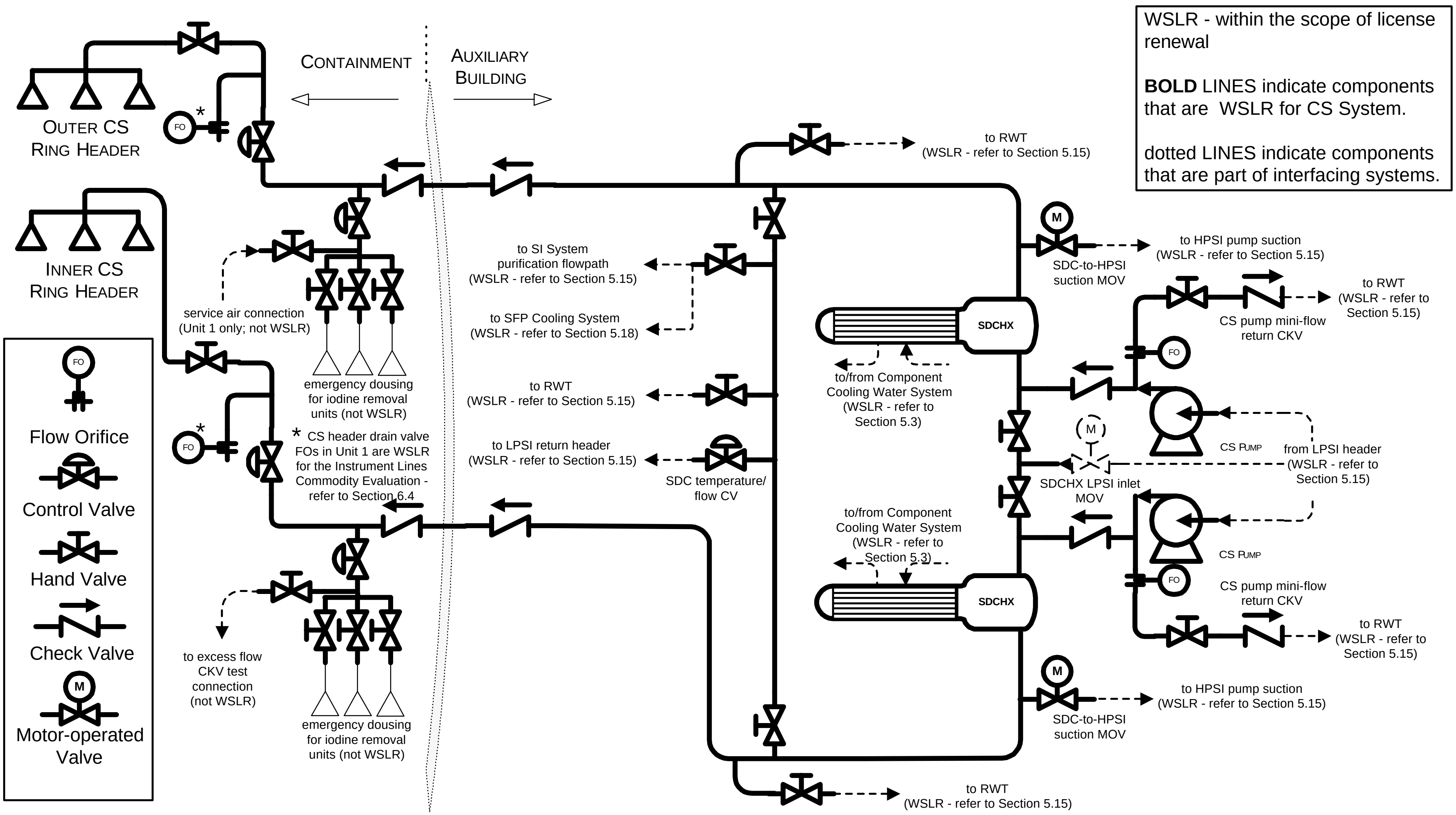


FIGURE 5.6-1

CONTAINMENT SPRAY SYSTEM
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

System Scoping Results

The CS System is in scope for license renewal based on 10 CFR 54.4(a). The following intended functions of the CS 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 18, Table 1]

- To provide containment pressure control and cooling;
- To provide containment isolation;
- To maintain electrical continuity and/or provide protection of the electrical system;
- To maintain the pressure boundary of the system (liquid and/or gas); and
- To restrict flow to specified value in support of the DBE response.

The following intended functions of the CS System were determined based on the requirements of §54.4(a)(3): [Reference 18, Table 1]

- To provide RCS heat removal to ensure safe shutdown in the event of a postulated severe fire;
- To provide information used to assess the environs and plant condition during and following an accident; and
- To maintain functionality of electrical components as addressed by the Environmental Qualification Program.

All components of the CS System that meet the environmental qualification criteria of 54.4(a)(3) are also safety-related. Some of the components that meet the fire protection criteria are non-safety-related and are within the scope of license renewal only because of the 54.4(a)(3) criteria.

All components of the CS System that perform functions based on the requirements of §54.4(a)(1) and (2) meet Seismic Category I requirements. [Reference 2, Section 6.4.4; References 4 through 9; References 16 and 19] All CS System piping complies with the design requirements for Class II piping in American Nuclear Standards Institute (ANSI) Nuclear Power Piping Code B31.7, 1969. [Reference 20, Piping Class HC-4; Reference 21, Piping Class HC-33; Reference 22, Piping Class HC-38; Reference 23, Piping Classes GC-1, GC-2, GC-3, and GC-7] The design parameters for the major CS System components are presented in Section 6.3.2.5 and 6.4.2 of the CCNPP Updated Final Safety Analysis Report.

5.6.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the CS System that is within the scope of license renewal includes all components (electrical, mechanical, and instrument) and their supports along the following system flowpaths (refer to Figure 5.6-1): [Reference 2, Sections 6.3.1 and 9.2.2; References 4 through 9; Reference 18, Table 2]

- Shutdown cooling mode flowpath (motive force provided by LPSI pumps) - from the SI System interface at the outlet of the SDCHX LPSI inlet MOV, through the SDCHXs, up to and including the SDC temperature/flow CV, which returns flow to the LPSI header;

- Minimum-flow recirculation flowpath (post-DBE operations prior to a CSAS; motive force provided by CS pumps) - from the CS pump discharge header up to and including the CS pump mini-flow return CKVs; and
- Injection mode flowpath (post-DBE operations after a CSAS; motive force provided by CS pumps) - from the SI System interface at each CS pump inlet, through the CS pumps, SDCHXs, up to and including the following:

  Through the CS headers to the nozzles installed in the inner and outer CS ring headers; or

  To the SDC-to-HPSI suction MOVs, which allow operators to return a portion of the cooled water from the CS System to the suction of the HPSI pumps during post-DBE operations after a RAS.

Additional components that form parts of the system pressure boundary along these flowpaths (e.g., piping, flow orifices, normally closed HVs) and their supports are also included within the scope of license renewal for the CS System.

The following 33 device types in the CS System have at least one intended function: [Reference 1, Table 2-1]

- Class "GC" Piping (stainless steel, primary rating 300 psig at 1125°F)
- Class "HC" Piping (stainless steel, primary rating 150 psig at 500°F)
- Check Valve
- Coil
- Control Valve
- Control Valve Operator
- Voltage/Current Device
- Flow Element
- Flow Indicator
- Flow Orifice
- Flow Transmitter
- Fuse
- Hand Indicator Controller
- Handswitch
- Hand Valve
- Heat Exchanger
- Current/Pneumatic Device
- Ammeter
- Power Lamp Indicator
- 4kV Motor
- 125/250Vdc Motor
- Motor Operated Valve
- Motor Operated Valve Operator
- Pressure Switch
- Pressure Transmitter
- Pump/Driver Assembly
- Relief Valve
- Relay
- Solenoid Valve
- Temperature Element
- Temperature Indicator
- Position Indicating Lamp
- Position Switch

Some components in the CS System are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 1, Section 3.2]

- Except for the SDCHX supports that are addressed in this report, 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 CS System.
- Instrument tubing and piping and the associated tubing 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. This commodity evaluation partially addresses the passive intended function entitled "maintain the pressure boundary of the system (liquid and/or gas)" for the CS System.

5.6.1.3 Components Subject to AMR

This section describes the components within the CS System that are subject to 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 CCNPP IPA Methodology Section 5.1, the following CS System functions were determined to be passive: [Reference 1, Table 3-1]

- To maintain electrical continuity and/or provide protection of the electrical system;
- To maintain the pressure boundary of the system (liquid and/or gas); and
- To restrict flow to specified value in support of the DBE response.

Device Types Subject to AMR

Of the 33 device types within the scope of license renewal for the CS System: [Reference 1, Table 3-2; Reference 24, Attachment 4A]

- Seventeen device types were associated with only active functions: Coil, Control Valve Operator, Voltage/Current Device, Flow Indicator, Fuse, Hand Indicator Controller, Handswitch, Current/Pneumatic Device, Ammeter, Power Lamp Indicator, 4kV Motor, 125/250Vdc Motor, Motor Operated Valve Operator, Relay, Solenoid Valve, Position Indicating Lamp, and Position Switch;
- No device types were identified as subject to periodic replacement based on a qualified life or specified time period;
- No device types in this system were evaluated in the AMR for a system addressed in another section of the BGE LRA; and
- Three device types are associated with a separate commodity evaluation. Flow Transmitters, Pressure Switches, and Pressure Transmitters in the CS System are evaluated separately in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

The remaining 13 device types, listed in Table 5.6-1, are subject to AMR and are included in the scope of this section. [Reference 1, Table 3-2] Except for HVs and FOs, all components of each listed device type are addressed in this section. The Unit 1 CS header drain valve flow orifices, as well as manual drain, equalization, and isolation valves in CS instrument lines that are subject to AMR, are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. The manual root valves that are used to isolate these components are evaluated in this section. [Reference 24, Attachments 4 and 4A]

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies that 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 5.6-1

CONTAINMENT SPRAY SYSTEM DEVICE TYPES SUBJECT TO AMR

Class “GC” Piping (-GC)
Class “HC” Piping (-HC)
Check Valve (CKV)
Control Valve (CV)
Flow Element (FE)
Flow Orifice (FO)
Hand Valve (HV)
Heat Exchanger (HX)
Motor Operated Valve (MOV)
Pump/Driver Assembly (PUMP)
Relief Valve (RV)
Temperature Element (TE)
Temperature Indicator (TI)

5.6.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the CS System components is given in Table 5.6-2, with plausible ARDMs identified by a check mark (✓) in the appropriate device type column. [Reference 1, Table 4-2] A check mark indicates that the ARDM applies to at least one component for the device type listed. 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. Table 5.6-2 also identifies the group to which each ARDM/device type combination belongs. Exceptions are noted where appropriate. The following groups have been selected for the CS System:

Group 1: general corrosion of external surfaces due to leakage of borated water; and

Group 2: general corrosion, crevice corrosion, and/or pitting of internal surfaces exposed to chemically-treated water.

Some components in the SDC flowpath experience significant thermal transients during SDC operations. Since the CS System vent/drain HVs and instruments connected to the SDC flowpath are generally thin-wall components, they do not experience large temperature gradients under SDC initiation conditions, and fatigue is not a concern. For the CS System components in the SDC flowpath (i.e., the SDCHXs, the associated piping, temperature instruments, and valves), fatigue usage is bounded by the fatigue usage of the SDC and SI nozzles that connect SI System piping to the RCS. These nozzles are among the 11 fatigue-critical locations selected for monitoring under the CCNPP Fatigue Monitoring Program, and represent the most bounding locations for the thermal transients for components in the SDC flowpath. [Reference 25; Reference 26, Sections 1.1, 1.2.A, 2.1.E, 6.0] Analysis has determined that up to 500 SDC initiation transients, each consisting of a rapid temperature rise from ambient (about 70°F) to RCS temperature (no greater than 300°F), are allowed over the service life of the components in the SDC flowpath. Partial thermal cycle analysis projections out to 60 years, based on actual occurrences to date, estimate the number of effective full cycles to be approximately 10% of the total allowable. Since the normal and design operating conditions applied to these components do not result in the quantity of cycles or the loading conditions (mechanical, vibrational, thermal, and/or pressure) necessary to cause significant degradation, fatigue is not plausible for the CS System.

Since the CS pump discharge piping and the HPSI pump suction piping from the SDCHX discharge may not have any flow due to flushing or performance testing for periods of at least 30 days during normal reactor operation, they were recognized as portions of the CS System with a high likelihood of containing stagnant oxygenated borated water. Inservice inspections and additional examinations have concluded that the integrity of welds in this piping has not been affected by service environment and residual stresses that have induced pipe cracking in the industry. [References 27 and 28]

Table 5.6-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE CONTAINMENT SPRAY SYSTEM

Potential ARDMs	Device Types													Not Plausible for System
	-GC	-HC	CKV	CV	FE	FO	HV	HX	MOV	PUMP	RV	TE	TI	
Cavitation Erosion														x
Corrosion Fatigue														x
Crevice Corrosion	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	
Dynamic Loading														x
Erosion Corrosion														x
Fatigue														x
Fouling														x
Galvanic Corrosion														x
General Corrosion	✓(1)	✓(1)	✓(1)	✓(1)			✓(1)	✓(*)	✓(1)	✓(1)				
Hydrogen Damage														x
Intergranular Attack														x
Microbiologically-Induced Corrosion														x
Particulate Wear Erosion														x
Pitting	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	
Radiation Damage														x
Rubber/Elastomer Degradation														x
Saltwater Attack														x
Selective Leaching														x
Stress Corrosion Cracking														x
Thermal Damage														x
Thermal Embrittlement														x
Wear														x

✓ indicates plausible ARDM determination for this device type
(number) indicates the group in which this ARDM/device type combination is evaluated
(*) indicates that both Groups 1 and 2 evaluate components within this ARDM/device type combination

Note: Not every component within a device type may be susceptible to a given ARDM. This is because components (and subcomponents) within a device type are not always fabricated from the same materials or subjected to the same environments. Exceptions for each device type will be indicated in the aging management subsection for each ARDM discussed in this report.

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.

Group 1 - (general corrosion of external surfaces) - Materials and Environment

Group 1 comprises the various CS System components that are exposed to climate-controlled air in the Auxiliary Building or the Containment, and whose external surfaces are subject to general corrosion. The components in this group are included in the -GC, -HC, CKV, CV, HV, HX, MOV, and PUMP device types. All of these components provide the passive intended function of maintaining the system pressure boundary. [Reference 1, Attachment 1] For the HXs, the susceptible subcomponents include alloy steel studs, carbon steel nuts and vessel supports, and the external surfaces of the carbon steel shell assembly and associated carbon steel welds. [Reference 1, Attachments 4 and 5 for HXs] The applicable subcomponents for all other device types in this group are carbon steel nuts and/or alloy steel studs. [Reference 1, Attachments 4 and 5 for -GC Piping, -HC Piping, CKVs, CVs, HVs, MOVs, and PUMPs]

The external surfaces evaluated in Group 1 are not normally exposed to a corrosive environment, but may be exposed to boric acid as a result of leakage from the associated components or nearby systems and components that contain borated water. The possible effects of such leakage include general corrosion of susceptible external surfaces. A potential source of borated water leakage is the internal environment for the components in Group 1, with maximum operating pressures as high as 450 psig, and normal operating temperatures as high as 300°F. [Reference 1, Attachment 6s for -GC Piping, -HC Piping, CKVs, CVs, HXs, HVs, MOVs, and PUMPs; Reference 20, Piping Class HC-4; Reference 21, Piping Class HC-33; Reference 22, Piping Class HC-38; Reference 23, Piping Classes GC-1, GC-2, GC-3, and GC-7]

For all components evaluated in Group 1, the external surfaces are exposed to an environment of climate-controlled air in either the Auxiliary Building or the Containment. [Reference 1, Attachment 3s] During normal operation, temperature and humidity in the Auxiliary Building do not exceed 160°F and 70%, respectively. [Reference 29, page 54] For the general areas inside Containment where CS System components are located, the maximum normal temperature and humidity values are 120°F and 70%, respectively. [Reference 29, pages 29, 30, 62, and 63]

Group 1 - (general corrosion of external surfaces) - Aging Mechanism Effects

General corrosion is thinning of a metal by the chemical attack of an aggressive environment at its surface. An important concern for pressurized water reactors is boric acid attack upon carbon steels and low alloy steels. General corrosion is not a concern for austenitic stainless steels. [Reference 1, Attachment 7s for -GC Piping, -HC Piping, CKVs, CVs, HXs, HVs, MOVs, and PUMPs]

General corrosion is plausible for all carbon steel and alloy steel subcomponents in this group. Mechanical joints in pressure boundary subcomponents provide the opportunity for leakage of borated water onto external component surfaces. The carbon steel and alloy steel surfaces are particularly susceptible to significant acceleration of corrosion when exposed to boric acid in the concentrations present in the CS System. [Reference 1, Attachment 6s for -GC Piping, -HC Piping, CKVs, CVs, HXs, HVs, MOVs, and PUMPs]

The result of this corrosion mechanism is a reduction in the integrity of the corroded parts and a resulting increase in the likelihood of mechanical failure. If unmanaged, long-term exposure to general corrosion could eventually result in loss of the pressure-retaining capability under current licensing basis (CLB) design loading conditions.

Group 1 - (general corrosion of external surfaces) - Methods to Manage Aging

Mitigation: Boric acid corrosion can be mitigated by minimizing leakage. The susceptible areas of the CS System (i.e., mechanical joints) can be routinely observed for signs of borated water leakage, and appropriate corrective action can be initiated as necessary to eliminate leakage, clean spill areas, and assess any corrosion. [Reference 1, Attachment 6s for -GC Piping, -HC Piping, CKVs, CVs, HXs, HVs, MOVs, and PUMPs]

Discovery: The effects of corrosion are generally detectable by visual techniques. Visual inspections would need to be performed to detect corrosion associated with leakage of fluids onto the external surfaces of CS System components. [Reference 1, Attachment 6s for -GC Piping, -HC Piping, CKVs, CVs, HXs, HVs, MOVs, and PUMPs]

Group 1 - (general corrosion of external surfaces) - Aging Management Program(s)

Mitigation: The CCNPP Boric Acid Corrosion Inspection (BACI) Program (MN-3-301) is credited with mitigating the effects of boric acid corrosion through timely discovery of leakage of borated water and removal of any boric acid residue that is found. [Reference 1, Attachment 8] This program requires visual inspection of the components containing boric acid for evidence of leaks, quantification of any leakage indications, and removal of any leakage residue from component surfaces. [Reference 30] Further details on the BACI Program are detailed in the Discovery subsection below.

Discovery: Discovery of boric acid leakage is ensured by the BACI Program. [Reference 1, Attachment 8] This program also requires investigation of any leakage that is found. A visual examination of external surfaces is performed for components containing boric acid. [Reference 30]

The Inservice Inspection Program required the establishment of the BACI Program to systematically ensure that boric acid corrosion does not degrade the primary system boundary. [Reference 31, Section 5.8.A.1.] The program also applies to "valves in systems containing borated water which could leak onto Class 1 carbon steel components," and it identifies other plant areas to be examined. [Reference 30, Section 5.1B] The program controls examination, test methods, and actions to minimize the loss of structural and pressure-retaining integrity of components due to boric acid corrosion. [Reference 30, Section 3.0.C] The basis for the establishment of the program is Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." [Reference 30, Section 1.1]

The scope of the program is threefold in that it: (a) identifies locations to be examined; (b) provides examination requirements and methods for the detection of leaks; and (c) provides the responsibilities for initiating engineering evaluations and necessary corrective actions. [Reference 30, Section 1.2]

During each refueling outage, inservice inspection personnel perform a walkdown inspection to identify and quantify any leakage found at specific locations inside the Containment and in the Auxiliary Building. The inservice inspection ensures that all components, where boric acid leakage has been previously documented, are also examined in accordance with the requirements of this program. A second inspection of these components is performed prior to plant startup (at normal operating pressure and temperature) if leakage was identified previously and corrective actions were taken. [Reference 30, Sections 5.1 and 5.2]

Under the BACI Program, the walkdown inspections applicable to CS System components are type VT-2 (a type of visual examination described in ASME Section XI, IWA-2212). The VT-2 visual examinations include the accessible external exposed surfaces of pressure-retaining, non-insulated components; floor areas or equipment surfaces located underneath non-insulated components; vertical surfaces of insulation at the lowest elevation where leakage may be detected, and horizontal surfaces at each insulation joint for insulated components; floor areas and equipment surfaces beneath components and other areas where water may be channeled for insulated components whose external insulation surfaces are inaccessible for direct examination; and for discoloration or residue on any surface for evidence of boric acid accumulation. [Reference 30, Section 5.2]

If either leakage or corrosion is discovered, issue reports (IRs) are generated in accordance with CCNPP procedure QL-2-100, "Issue Reporting and Assessment," to document and resolve the deficiency. Corrective actions address the removal of boric acid residue and inspection of the affected components for general corrosion. If general corrosion is found on a component, the IR provides for evaluation of the component for continued service and corrective actions to prevent recurrence. [Reference 30, Section 5.3]

The BACI Program has evolved with regard to boric acid leaks discovered during other types of walkdowns and inspections. The program specifies the minimum qualification level for inspectors evaluating boric acid leaks. Apparent leaks that are discovered during these other walkdowns/inspections are documented in IRs by the individual discovering the leak. These IRs are then routed to the inservice inspection group for closer inspection and evaluation by a qualified inspector. This approach provides for more boric acid leakage inspection coverage while still ensuring that appropriately qualified individuals assess and quantify any resultant damage.

The corrective actions taken as a result of IRs under this program will ensure that CS System components containing borated water remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Group 1 - (general corrosion of external surfaces) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to general corrosion of external surfaces for CS System components:

- The components in Group 1 contribute to maintaining the system pressure boundary, and their integrity must be maintained under all CLB design conditions.
- The materials of construction for subcomponents in this group are carbon steel or alloy steel.
- General corrosion is a plausible ARDM for this group because the susceptible external surfaces are exposed to potential boric acid leakage from mechanical joints. If unmanaged, this ARDM could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.

- The corrosive effects of boric acid leakage will be managed by means of the BACI Program. When boric acid leakage is identified, either through required program inspections or through IRs resulting from other types of walkdowns and inspections, this program will ensure that corrosion induced by boric acid is discovered and that appropriate corrective action is taken.

Therefore, there is a reasonable assurance that the effects of general corrosion will be adequately managed for external surfaces of CS System components 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 - (general corrosion, crevice corrosion, and/or pitting of internal surfaces) - Materials and Environment

Group 2 comprises the various CS System components that are exposed to chemically-treated water and whose internal surfaces are subject to general corrosion, crevice corrosion, and/or pitting. Components from all CS System device types are included in this group. The internals for the containment isolation CKVs in the CS headers provide a containment pressure-boundary function when the injection mode flowpath is not active. The remaining components provide the passive intended function of maintaining the system pressure boundary. [Reference 1, Attachment 1] The applicable subcomponents in these device types are constructed of the following materials: [Reference 1, Attachments 4 and 5 for all device types]

- Piping - internal surfaces of stainless steel fittings and flanges, as well as hidden surfaces of carbon steel nuts and alloy steel studs;
- CKVs - internal surfaces of stainless steel body/bonnet, as well as hidden surfaces of carbon steel nuts and alloy steel studs; also, stainless steel internals for containment isolation CKVs in the CS headers;
- CVs - internal surfaces of stainless steel body/bonnet and stem, as well as hidden surfaces of carbon steel nuts and alloy steel studs;
- FEs - stainless steel;
- FOs - stainless steel orifice plates;
- HVs - internal surfaces of stainless steel body/bonnet and stem, as well as hidden surfaces of carbon steel nuts and alloy steel studs, for all HVs except for normally open instrument root and seal leakoff stop HVs; also, stainless steel disc/seat for normally closed HVs;
- HVs - internal surfaces of stainless steel body/bonnet and stem, as well as hidden surfaces of carbon steel nuts and stainless steel studs for normally open instrument root and seal leakoff stop HVs;
- HXs - stainless steel tubes, channel assembly/tubesheet and welds; internal surfaces of the carbon steel shell assembly and carbon steel welds; hidden surfaces of carbon steel nuts and alloy steel studs;
- MOVs - internal surfaces of stainless steel body/bonnet and stem, as well as hidden surfaces of carbon steel nuts and alloy steel studs;
- PUMPs - internal surfaces of the mechanical seal (stainless steel, with stellited rotating face); stainless steel casing and shaft; hidden surfaces of carbon steel nuts and alloy steel studs;

- RVs - Inconel disc and guide/ring; internal surfaces of stainless steel base and cylinder;
- TEs - stainless steel; and
- TIs - stainless steel well.

Except as noted below, the internal surfaces for all components evaluated in Group 2 are exposed to the borated water environment described in subsection Group 1 - Materials and Environment, above. For the SDCHXs, the internal environment includes chemically-treated water from the CC System between the inside of the shell and the outside of the tubes that contain the borated water. The CC System has a design pressure of 150 psig and maximum operational temperature of 167°F. [Reference 1, Attachment 3s for HXs; Reference 32, Piping Class HB-23] Since the CS System is maintained in a standby mode during normal operations, stagnant conditions exist throughout the system. Stagnant conditions may allow impurities in the process fluid to concentrate. [Reference 1, Attachment 6s for all device types]

Group 2 - (general corrosion, crevice corrosion, and/or pitting of internal surfaces) - Aging Mechanism Effects

General corrosion is described in subsection Group 1 - Aging Mechanism Effects, above. Crevice corrosion and pitting are related forms of intensive, localized corrosion. Crevice corrosion occurs in crevices that are wide enough to permit liquid entry and narrow enough to maintain stagnant conditions. Such locations may include spaces under nuts and/or bolt heads, holes, gasket surfaces, lap joints, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. Pitting occurs when corrosion proceeds at one small location at a rate greater than the corrosion rate of the surrounding area. Pitting is an autocatalytic process that produces conditions that stimulate the continuing activity of the pit. In either case, the stagnant fluid within the pit or crevice tends to accumulate corrosive chemicals such as chlorides and sulfates, and thereby to accelerate the local corrosion process. Crevice corrosion can initiate pitting in many cases. Pitting can result in complete perforation of the material. [Reference 1, Attachment 7s for all device types]

Crevice corrosion and pitting are plausible for all subcomponents in this group. Additionally, general corrosion is plausible for the internal carbon steel surfaces of the SDCHXs. These ARDMs are plausible at mechanical joints (e.g., flanges, body/bonnet joints) since they present a crevice geometry at the sealing surfaces that may allow process fluids to stagnate and cause concentration of environmentally-produced impurities. [Reference 1, Attachment 6s for -GC Piping, -HC Piping, CKVs, CVs, FEs, FOs, HVs, MOVs, PUMPs, and RVs] Similar stagnation and impurity deposits are possible at other component interior crevices that are formed by close-fitting interface points at interior subcomponents (e.g., tubes/tubesheets in HXs, fittings in piping, pump shafts, valve stems, valve seating surfaces). [Reference 1, Attachment 6s for -GC Piping, -HC Piping, CVs, HVs, HXs, MOVs, PUMPs, RVs, TEs, and TIs]

Group 2 - (general corrosion, crevice corrosion, and/or pitting of internal surfaces) - Methods to Manage Aging

<u>Mitigation</u>: Control of fluid chemistry in the CS System and interfacing systems can significantly limit the effects of general corrosion, crevice corrosion, and pitting. [Reference 1, Attachment 6s for all device

types] The chemistry control program should monitor pertinent chemical parameters on a frequency that would allow for corrective actions to minimize creation of an environment conducive to corrosion.

Discovery: The effects of corrosion are generally detectable by visual techniques. Seating surface degradation can be discovered by testing the components that are susceptible to this ARDM. Pressure testing of the containment isolation CKVs in the CS headers can provide for detection of leakage that could be the result of crevice corrosion and pitting of the valve seating surfaces. Internal surfaces of components that are not routinely inspected can be subjected to inspection to determine the extent of general and/or localized degradation that may be occurring. [Reference 1, Attachment 6s for all device types]

Group 2 - (general corrosion, crevice corrosion, and/or pitting of internal surfaces) - Aging Management Program(s)

Mitigation: Maintenance of proper fluid chemistry in the CS System and interfacing systems will limit the effects of general corrosion, crevice corrosion, and pitting on internal surfaces for Group 2 subcomponents. [Reference 1, Attachment 8]

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 33, Section 6.1.A] The program is based on Technical Specifications, BGE's interpretation of industry standards, and recommendations made by Combustion Engineering. [Reference 33, Section 2.0]

Calvert Cliffs Technical Procedure CP-204, "Specification and Surveillance-Primary Systems," provides for monitoring and maintaining chemistry in the RCS and associated systems. [Reference 34, Section 2.0, Attachments 1 through 15] Control of primary water chemistry is credited with limiting the effects of crevice corrosion and pitting in CS System components. [Reference 1, Attachment 8]

Calvert Cliffs Technical Procedure CP-206, "Specifications and Surveillance-Component Cooling/Service Water Systems," provides for monitoring of CC System chemistry to control the concentrations of oxygen, chlorides, and other chemicals and contaminants. [Reference 35, Section 2.0, Attachment 1] For the SDCHXs, which are cooled by water from the CC System, control of the water chemistry provides an environment that limits the rate of degradation and its effects. [Reference 1, Attachment 8]

Each of the program procedures describes the surveillance and specifications for monitoring fluid chemistry for the applicable systems. They list the parameters to be monitored, the frequency for monitoring of each parameter, and the acceptable value or range of values for each parameter. [Reference 34, Attachments 1 through 15; Reference 35, Attachment 1] Each parameter is measured at a procedurally-specified frequency (e.g., daily, weekly, monthly) and compared against a target value that represents a goal or predetermined warning limit. [Reference 34, Section 3.0; Reference 35, Section 3.0] If a measured value is outside of its required range, corrective actions are taken (e.g., power reduction, plant shutdown) as prescribed by the procedure, thereby ensuring timely response to chemical excursions. The procedures provide for rapid assessment of off-normal chemistry parameters so that steps can be taken to return them to normal levels. [Reference 34, Section 6.0.C; Reference 35, Section 6.0.C]

The CCNPP Chemistry Program has been subject to periodic internal assessment activities. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their level of performance and safety significance, and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. [Reference 36, Section 1B.18] These activities, as well as other external assessments, help to maintain highly effective chemistry control, and facilitate continuous improvement through monitoring industry initiatives and trends in the area of corrosion control.

A review of operating experience identified no site-specific problems or events related to general corrosion, crevice corrosion, or pitting that required significant changes or adjustments to the CCNPP Chemistry Program. It has been effective in its function of mitigating corrosion and controlling corrosion-related failures and problems within acceptable limits. In 1996, CP-206 was revised to include monitoring of dissolved iron as a method for discovering any unusual corrosion of carbon steel components. Self-assessments of chemistry control performance have resulted in activities to reduce the number of times that chemistry parameters exceed action levels (e.g. additional scheduling coordination for outage evolutions that could affect CC/Service Water chemical parameters).

Discovery: Calvert Cliffs procedure CP-224, "Monitoring Radioactivity in Systems Normally Uncontaminated," provides for detection of radioactivity in the CC System. [Reference 37] Degradation of tubes in the SDCHX may result in a detectable radioactivity level in the CC System that would trigger investigations and corrective actions. Therefore, this program is credited as a method for discovery and management of general corrosion, crevice corrosion, and pitting for the SDCHXs. [Reference 1, Attachment 8]

Calvert Cliffs procedures STP M-571G-1(2), "Local Leak Rate Test, Penetrations 9, 10, 23, 24, 37, 39," which cover local leak rate testing (LLRT) for the inner and outer CS ring header containment penetrations, are part of the overall CCNPP Containment Leakage Rate Testing Program. [References 38 and 39] The CCNPP Containment Leakage Rate Testing 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, Option B, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." 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 40, Section 6.5.6; References 41 and 42]

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 CKVs that provide a containment pressure-boundary function for the inner and outer CS ring headers when the injection mode flowpath is not active are included in the scope of this program as part of the leakage testing for the associated containment penetrations. [Reference 40]

The LLRT is done on a performance-based testing schedule in accordance with Option B of 10 CFR Part 50, Appendix J, as implemented by CCNPP Technical Specifications. [References 40, 41, and 42]. Local leak rate testing presently includes the following procedural steps:

- Leak rate monitoring test equipment is connected to the appropriate test point.
- The test volume is pressurized to the LLRT Program test pressure, which 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.
- 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 that 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, plant personnel 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 containment isolation valve that changes the closing characteristic of the valve, an "as left" test must be performed on the penetration to ensure leakage rates are acceptable.

The corrective actions taken as part of the LLRT Program will ensure that the seating surfaces of the containment isolation CKVs in the CS headers remain capable of performing their intended functions under all CLB conditions during the period of extended operation.

Baltimore Gas and Electric Company will include all Group 2 components in an Age-Related Degradation Inspection (ARDI) Program to verify that unacceptable degradation of internal surfaces by general corrosion, crevice corrosion, or pitting is not occurring. [Reference 1, Attachment 8]

The ARDI Program is 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 loading conditions 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.

Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Actions Program and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 2 - (general corrosion, crevice corrosion, and/or pitting of internal surfaces) - 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 internal surfaces for CS System components that are exposed to chemically-treated water:

- The components in Group 2 contribute to maintaining the system pressure boundary. Additionally, the containment isolation CKVs in the CS headers provide a containment pressure-boundary function when the injection mode flowpath is not active. The integrity of these components must be maintained under all CLB design conditions.
- The materials of construction for subcomponents in this group are carbon steel, stainless steel, or Inconel.
- General corrosion, crevice corrosion, and pitting are plausible ARDMs for this group and, if unmanaged, these ARDMs could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- Maintenance of proper fluid chemistry in the CS System (in accordance with CP-204) will limit the effects of general corrosion, crevice corrosion, and pitting on susceptible pressure boundary subcomponents for Group 2 components. Chemistry control in accordance with CP-206 will ensure that cooling water supplied to the SDCHXs is of an appropriate chemistry to minimize corrosion.
- Monitoring CC System radioactivity in accordance with CP-224 will detect radioactivity levels that may result from tube degradation in the SDCHX and ensure that appropriate corrective action is initiated.
- The CCNPP LLRT Program performs leakage testing that could detect the effects of crevice corrosion and pitting on the seating surfaces of the containment isolation CKVs in the CS headers (i.e., degraded leak tightness). This program ensures that appropriate corrective actions will be taken if significant leakage is discovered.
- All Group 2 components will be subjected to a new ARDI Program. This program will examine a representative sample of the components for degradation, and ensure that appropriate corrective actions are initiated on the basis of the findings.

Therefore, there is a reasonable assurance that the effects of general corrosion, crevice corrosion, and/or pitting will be adequately managed for internal surfaces of CS System components exposed to chemically-treated water 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.

5.6.3 Conclusion

The aging management programs discussed for the CS System are listed in Table 5.6-3. 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 CS 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 5.6-3

AGING MANAGEMENT PROGRAMS FOR THE CONTAINMENT SPRAY SYSTEM

	Program	Credited As
Existing	CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program"	Program for mitigation and discovery of general corrosion for external surfaces of piping, CKVs, CVs, HVs, HXs, MOVs, and PUMPs (included in Group 1) that are exposed to borated water (due to leakage) by performing visual inspections.
Existing	CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems"	Program for mitigation of general corrosion, crevice corrosion, and/or pitting for internal surfaces of piping, CKVs, CVs, FEs, FOs, HVs, HXs, MOVs, PUMPs, RVs, TEs, and TIs (included in Group 2) that are exposed to borated water (as process fluid) by controlling chemistry conditions.
Existing	CCNPP Technical Procedure CP-206, "Specification and Surveillance Component Cooling/Service Water System"	Program for mitigation of general corrosion, crevice corrosion, and/or pitting for internal surfaces of the SDCHXs (included in Group 2) that are exposed to chemically-treated water from the CC System by controlling chemistry conditions in the CC System.
Existing	CCNPP Technical Procedure CP-224, "Monitoring Radioactivity in Systems Normally Uncontaminated"	Program for discovery of crevice corrosion and pitting of tubes in the SDCHXs (included in Group 2) that are exposed to borated water (as process fluid) and chemically-treated water from the CC System by detecting radioactivity in the CC System.
Existing	CCNPP Surveillance Test M-571G-1(2), "Local Leak Rate Test, Penetrations 9, 10, 23, 24, 37, 39"	Program for discovery and management of leakage that could be the result of crevice corrosion and pitting for seating surfaces of the containment isolation CKVs in the CS headers (included in Group 2).
New	ARDI Program	Program for discovery and management of general corrosion, crevice corrosion, and/or pitting for internal surfaces of piping, CKVs, CVs, FEs, FOs, HVs, HXs, MOVs, PUMPs, RVs, TEs, and TIs (included in Group 2) by identifying and correcting degraded conditions.

5.6.4 References

1. CCNPP Aging Management Review Report, "Containment Spray System," Revision 2
2. CCNPP Updated Final Safety Analysis Report (UFSAR), Units 1 and 2, Revision 21
3. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated February 26, 1990, "Licensee Event Report 90-005"
4. BGE Drawing 60731SH0001, "Safety Injection & Containment Spray Systems," Revision 65
5. BGE Drawing 60731SH0003, "Safety Injection & Containment Spray Systems," Revision 21
6. BGE Drawing 60711, "Containment Charcoal Filter Spray System," Revision 15
7. BGE Drawing 62731SH0001, "Safety Injection & Containment Spray Systems," Revision 63
8. BGE Drawing 62731SH0003, "Safety Injection & Containment Spray Systems," Revision 17
9. BGE Drawing 62711, "Containment Charcoal Filter Spray System," Revision 14
10. CCNPP Operating Instructions, OI-2D-1(2), "Purification System Operation, Unit 1(2)," Revision 3
11. CCNPP Operating Instructions, OI-3A-1(2), "Safety Injection and Containment Spray, Unit 1(2)," Revision 3
12. CCNPP Operating Instructions, OI-3B-1(2), "Shutdown Cooling, Unit 1(2)," Revision 7
13. BGE Drawing 60710SH0002, "Component Cooling System," Revision 31
14. BGE Drawing 62710SH0002, "Component Cooling System," Revision 19
15. BGE Drawing 60716, "Spent Fuel Pool Cooling, Pool Fill & Drain Systems," Revision 47
16. BGE Drawing 62730SH0002, "Chemical and Volume Control System," Revision 40
17. BGE Drawing 60746SH0002, "Plant Water & Air System Service," Revision 24
18. CCNPP Component Level Scoping Results, "System 061 - Containment Spray System," Revision 1
19. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 2
20. BGE Drawing 92769SH-HC-1, "M-601 Piping Class Summary," Revision 26
21. BGE Drawing 92769SH-HC-3, "M-601 Piping Class Summary," Revision 20
22. BGE Drawing 92769SH-HC-4, "M-601 Piping Class Summary," Revision 21
23. BGE Drawing 92769SH-GC-1, "M-601 Piping Class Summary," Revision 23
24. CCNPP Life Cycle Management Pre-Evaluation Results, "Containment Spray System (061)," Revision 2
25. Combustion Engineering Owners Group Task 571, Report No. CE-NPSD-634-P, "Fatigue Monitoring Program for Calvert Cliffs Nuclear Power Plants Units 1 and 2," April 1992
26. CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring," Revision 0

27. Letter from Mr. A. E. Lundvall, Jr. (BGE) to Mr. B. H. Grier (NRC), dated August 24, 1979, "IE Bulletin No. 79-17"
28. Letter from Mr. A. E. Lundvall, Jr. (BGE) to Mr. B. H. Grier (NRC), dated November 27, 1979, "IE Bulletin No. 79-17 Revision 1 (Pipe Cracks in Stagnant Borated Water Systems at PWR Plants)"
29. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0
30. CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program," Revision 1
31. CCNPP Administrative Procedure MN-3-110, "Inservice Inspection of ASME Section XI Components," Revision 2
32. BGE Drawing 92769SH-HB-3, "M-601 Piping Class Summary," Revision 29
33. CCNPP Nuclear Program Directive CH-1, "Chemistry Program," Revision 1
34. CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems," Revision 8
35. CCNPP Technical Procedure CP-206, "Specifications and Surveillance Component Cooling/Service Water System," Revision 3
36. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48
37. CCNPP Technical Procedure CP-224, "Monitoring Radioactivity in Systems Normally Uncontaminated," Revision 3
38. CCNPP Surveillance Test Procedure M-571G-1, "Local Leak Rate Test, Penetrations 9, 10, 23, 24, 37, 39" (Unit 1), Revision 0
39. CCNPP Surveillance Test Procedure M-571G-2, "Local Leak Rate Test, Penetrations 9, 10, 23, 24, 37, 39" (Unit 2), Revision 1
40. Letter from Mr. A. W. Dromerick (NRC) Mr. C. H. Cruse (BGE), dated February 11, 1997, "Issuance of Amendments for CCNPP Unit No. 1 (TAC No. M97341) and Unit No. 2 (TAC No. M97342)" [Amendment Nos. 219/196]
41. 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors"
42. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated November 26, 1996, "Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318 License Amendment Request: Adoption of 10 CFR Part 50, Appendix J, Option B for Types B and C Testing"

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.

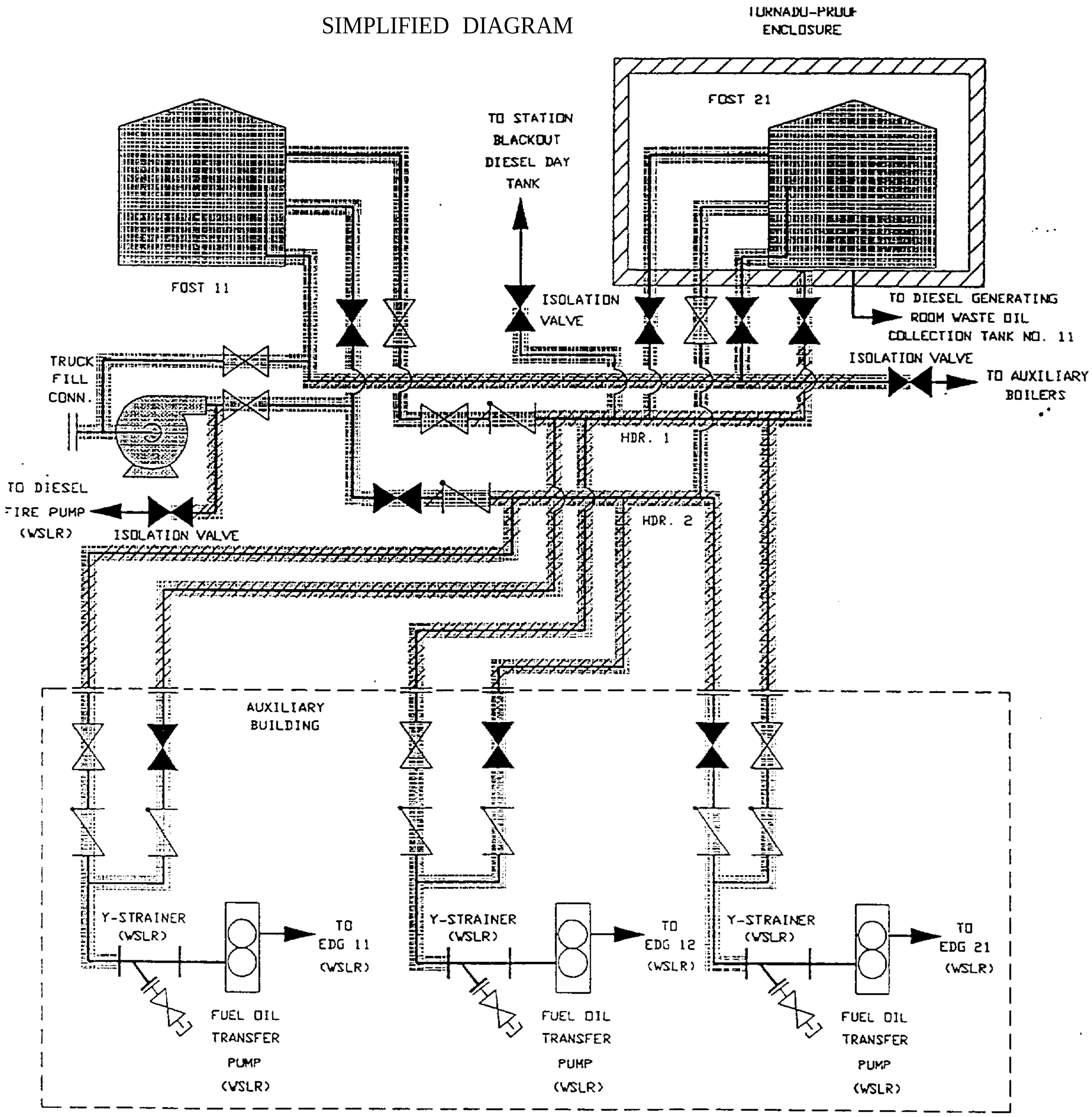
In November 1996, portions of the four buried pipe lines between Nos. 11 and 21 FOSTs were inspected. It was discovered that the pipe wrap (trade name "TRUE COAT", an extruded polyvinyl coating covered with a black tape) was slightly damaged during backfilling at the time of construction, but the piping 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.

SIMPLIFIED DIAGRAM



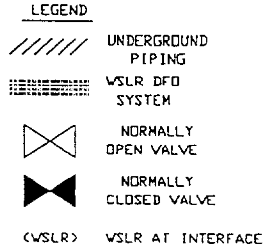


FIGURE 5.7-1

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

5.8 Emergency Diesel Generator System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Emergency Diesel Generator (EDG) System. The EDG System was evaluated in accordance with the Calvert Cliff 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.

5.8.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools that 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 device types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Representative historical operating experience pertinent to aging 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.

Section 5.8. 1.1 presents the results of the system level scoping, 5.8.1.2 the results of the component level scoping, and 5.8.1.3 the results of scoping to determine components subject to an AMR.

5.8.1.1 System Level Scoping

This section begins with a description of the system that 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 EDGs are designed to provide a dependable onsite power source capable of automatically starting and supplying the essential loads necessary to safely shut down the plant and maintain it in a safe shutdown condition under all conditions. Four EDGs (4.16 kV, three-phase, 60-cycle) are provided for the plant, although each unit requires only one diesel generator to supply the minimum power requirements for its Engineered Safety Features equipment. Emergency Diesel Generator 1A is furnished by Societe Alsacienne De Constructions Mecaniques De Mulhouse (SACM) and EDGs 1B, 2A, and 2B are furnished by Fairbanks Morse. Emergency Diesel Generator 1A (nominal continuous rating 5400 kW) is connected to 4.16 kV Bus 11, EDG 1B (nominal continuous rating 2500 kW) is connected to 4.16 kV Bus 14, EDG 2A (nominal continuous rating 3000 kW) is connected to 4.16 kV Bus 21, and EDG 2B (nominal continuous rating 3000 kW) is connected to 4.16 kV Bus 24. [Reference 1, Section 8.4]

The EDGs are designed to reach rated speed and voltage and start accepting load within 10 seconds after the receipt of a starting signal. Emergency Diesel Generators and their auxiliaries are designed to withstand Seismic Category I accelerations and are installed within Seismic Category I structures. The SACM EDG is installed in a separate and independent Category I building. Each EDG set is physically separated and electrically isolated from the other generator sets in accordance with Regulatory Guide 1.75 and Institute of Electrical and Electronic Engineers IEEE-384-1981. The diesel generators are started by either a 4.16 kV bus undervoltage or safety injection actuation signal; however, in the latter case, actual transfer to the bus is not made until the preferred offsite source of power is actually lost. When the four EDGs are available, the design provides two independently-capable and concurrently-operating systems for safety injection, containment spray, and miscellaneous 480 Volt auxiliary devices for the unit incurring the Design Basis Event. In addition, the design provides power to operate two sets of equipment for shutting down the non-accident unit. [Reference 1, Section 8.4]

The independence and redundancy of the auxiliary power system features that initiate and control the connection of EDGs to the AC emergency busses are designed in accordance with General Design Criteria 18 (February 20, 1971) to permit periodic inspection and testing. [Reference 1, Section 8.4]

During accident conditions accompanied by simultaneous loss of offsite power, the loss-of-coolant incident sequencer will start automatically to load the EDGs sequentially. Similarly, the shutdown sequencer for the non-accident unit will start automatically. At no time during the loading sequence will the frequency and voltage at the generator terminals decrease to less than 95% of normal and 75% of normal, respectively, for the Fairbanks Morse EDGs, and less than 95% of normal and 82% of normal, respectively, for the SACM EDGs. The nominal values of speed, voltage, and frequency are defined in Technical Specification 4.8.1.1.2. [Reference 1, Section 8.4]

In addition, the CCNPP site has a fifth EDG, 0C (nominal continuous rating of approximately 5000 kW). This is a non-safety-related diesel generator built by SACM to the quality standards of Regulatory Guide 1.155, Station Blackout. It can be manually aligned to four of the four 4.16 kV busses to support Station Blackout, or Engineered Safety Features loads, if necessary. It is capable of supplying the essential loads necessary to safely shut down one unit and maintain it in a safe condition during a Station Blackout Event. [Reference 1, Section 1.2.8, Section 8.4]

The auxiliary systems that support the EDGs are diesel fuel oil, lube oil, service water (SRW) cooling, starting air, keep warm systems, instrumentation/controls, and intake and exhaust air. Refer to Figures 8-8A, 8-8B, 8-8C in the CCNPP Updated Final Safety Analysis Report for more detail on these systems. [Reference 1, Section 8.4; Reference 2, Section 1.1.1]

System Boundaries

For the purposes of license renewal, this System is composed of four EDGs and one Station Blackout diesel generator, engine auxiliaries, and electrical equipment. Emergency Diesel Generators 1B, 2B, and 2A were installed during CCNPP construction, whereas EDGs 1A and 0C were recently installed. The License Renewal Rule recognizes that the diesel engines and associated generators are active and excludes them from the group of equipment that is subject to AMR [10 CFR 54.21(a)(1)(i)]. All auxiliary components supplied as part of the engine and located on the engine skid (on the engine side of the auxiliary subsystem flexible couplings) are considered part of the engine for the purposes of license renewal. The passive, long-lived components associated with the engine auxiliaries outside the skid boundary and electrical equipment are subject to AMR. The boundaries of the EDG System for this evaluation are the following: [Reference 2, Section 1.1.2]

- Diesel Fuel Oil System: The boundary between the Diesel Fuel Oil System and the EDG System is just upstream of the Y strainers installed in the suction pipe to the fuel oil transfer pumps.
- SRW System: The boundary between the SRW System and the EDG System is at the diesel cooler/SRW interface expansion joints (expansion joints are included in EDG System); and at the interface of SRW piping with the starting air subsystem air compressor.
- 4 kV Transformers and Busses System: The boundary between the EDG System and the 4 kV Transformers and Busses System is at the EDG side of the 4 kV bus breakers.
- Engineered Safety Features Actuation System: The boundary of the EDG is at the contact outputs from relay cabinets 1/2 C67/68 interface with the EDG starting logic.

The typical components associated with the EDG auxiliaries outside the skid boundary include the following: [Reference 1, Figures 8-8A, 8-8B, 8-8C]

- EDG Fuel Oil Day Tanks;
- EDG Fuel Oil Transfer Pumps;
- EDG Drip Tanks;
- EDG Drip Tank Pumps;
- EDG Starting Air Receivers;
- EDG Intake/Exhaust Mufflers; and
- EDG Intake Filters.

Refer to Figure 5.8-1 for a typical representation of the systems and components associated with the EDGs. Those portions of the EDG Systems that are in scope for license renewal are indicated in this figure. Other components in this figure are not in scope of this section (5.8) because they are evaluated in other sections or are active components outside the scope of license renewal. [Reference 1, Section 8.4, Figures 8-8A, 8-8B, 8-8C]

Operating Experience

Review of the failure detail reports on EDGs indicate that from the very beginning of commercial operation of CCNPP, the EDG System has received a very high level of attention in surveillance and maintenance. There have been instances of EDG System component failures, some of which have been due to various aging mechanisms. Examples of some of the components and failure mechanisms are described below.

Emergency diesel generator relief valves, solenoid valves (fuel oil inlet), and other components have leaked due to instances of wear. In many cases, this is considered normal wear of the component; but in some cases, the wear was considered excessive. General corrosion has also caused some of the EDG relief valves to stick open and check valves to stick shut due to buildup of corrosion products (rust) around the valve seats and disks. Cyclic fatigue has caused the failure and cracking of fuel oil injectors, check valves, switches, tubing, and other EDG components. In each case, BGE repaired, adjusted, or replaced the affected component so that it could perform its intended function. [Reference 3] Corrosion and wear in the

EDG air start distributors have caused the EDGs to fail some surveillance tests. In each case, BGE replaced and/or cleaned the affected parts and the components were successfully retested. [Reference 4]

Many of the affected components are on the EDG skid and not within the scope of AMR. Due to the built-in redundancy of the EDG System, CCNPP has not suffered a simultaneous forced outage of both units due to EDG unavailability. On several occasions, the output of one or both units was reduced or curtailed because one or more EDGs were unavailable due to EDG System component failures, limitations imposed by the failures, or reduced performance of other system components such as SRW System heat-exchangers. [Reference 3]

System Interfaces

The EDG System has interfaces with the Diesel Fuel Oil System, SRW cooling system, 4 kV Transformers and Busses, and Engineered Safety Features Actuation System Control and Interlocks. Those systems or systems' components interfacing with the EDG System that are within the scope for license renewal are noted in Figure 5.8-1. Where a system, component, commodity, or structure interface is within scope for license renewal, it is addressed by the respective section of the BGE LRA for that system, component, commodity, or structure, as listed in Figure 5.8-1. [References 5, 6, and 7]

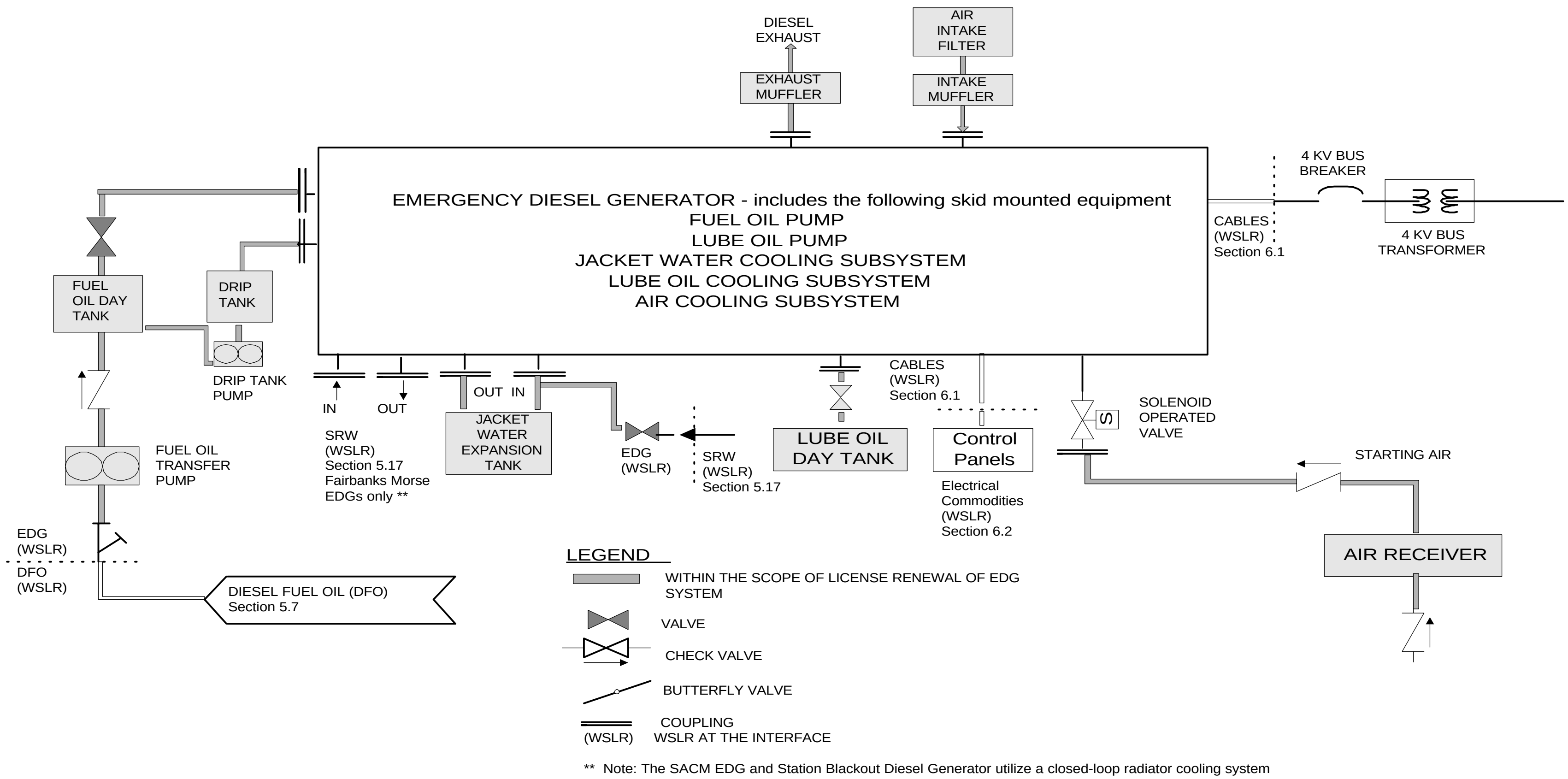


FIGURE 5-8.1

CCNPP EMERGENCY DIESEL GENERATOR SYSTEM
SIMPLIFIED DIAGRAM
(For Information Only)

System Scoping Results

The EDG System is in scope for license renewal based on 10 CFR 54.4(a). The following intended functions of the EDG 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 8, Table 1]

- Provide the vital auxiliary power supply for components used to mitigate Design Basis Events;
- To maintain the pressure boundary of the system (liquid and/or gas);
- To maintain electrical continuity and/or provide protection of the electrical system;
- To maintain mechanical operability and/or provide protection of the mechanical system; and
- To provide seismic integrity and/or protection of safety-related components.

The following intended functions of the EDG System were determined based on the requirements of §54.4(a)(3): [Reference 8, Table 1]

- For environmental qualification (§50.49) - Provide information used to assess the environs and plant condition during and after an accident.

5.8.1.2 Component Level Scoping

This report addresses the component level scoping for EDGs in two separate sections. Section 5.8.1.2.1 addresses that portion of the EDG System consisting of the three original EDGs (1B, 2A, and 2B), which were furnished by Fairbanks Morse and have been operating since before the start of commercial operation of the plant. Section 5.8.1.2.2 addresses the new diesel generators (0C and 1A) provided by SACM.

5.8.1.2.1 Component Level Scoping of Diesel Generators 1B, 2A, and 2B

Based on the intended functions listed above, the portion of the EDG System that is within the scope of license renewal consists of piping, components (e.g., heat exchangers, pumps, valves, tanks, etc.), component supports, and instrumentation and cables supporting operation of the EDGs through the diesel lube oil, diesel fuel oil, diesel starting air, diesel combustion air, and diesel cooling water subsystems. [Reference 2, Section 2.2]

The 48 EDG System device types listed in Table 5.8-1 were designated as within the scope of license renewal because they have at least one intended function: [Reference 2, Table 2-1]

TABLE 5.8-1

EDG SYSTEM DEVICE TYPES WITHIN THE SCOPE OF LICENSE RENEWAL

Device Type	Component Description	Device Type	Component Description
-HB	Piping-HB	LS	Level Switch
ACC	Accumulator	M	Motor
ANN	Annunciator	MCC	Motor Control Center
BKR	Breaker	MD	Motor
CKV	Check Valve	MO	Motor
COIL	Coil	MUFF	Muffler
CS	Control Switch	PI	Pressure Indicator
DISC	Disconnect	PNL	Panel
DT	Drain Trap	PS	Pressure Switch
E/E	Voltage Regulator	PUMP	Pump
EDG	Emergency Diesel Generator	RV	Relief Valve
EI	Isolator	RY	Relay
FAN	Fan	SC	Speed Controller
FL	Filter	SI	Speed Indicator
FU	Fuse	SS	Speed Switch
GOV	Governor	TC	Temperature Controller
HS	Hand Switch	TK	Tank
HV	Hand Valve	TS	Temperature Switch
HX	Heat Exchanger	TT	Temperature Transmitter
II	Isolator	U	Heater
JI	Indicator	X	Transformer
JKI	Indicator	XL	Indicating Lamp
JL	Indicating Light	YS	Wye Strainer
LI	Level Indicator	ZL	Position Indicating Light

Several components are common to many plant systems and perform the same passive functions regardless of system. These components include the following:

- Structural supports for piping, cables, and components;
- Electrical control and power cabling;
- 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.

5.8.1.2.2 Component Level Scoping of New Diesel Generators 0C and 1A

For the new SACM diesels, a one time procedure was used to identify the components that passively support the pressure boundary or Class 1E functions that are also common with the existing Fairbanks Morse EDG components.

The two new SACM diesel generators are excluded from AMR as previously described in the Systems Boundaries section. The equipment supplied by Fairbanks Morse, and located on the vendor-supplied skid, is identified as the diesel generator and is, therefore, excluded by the License Renewal Rule. The corresponding portions of the SACM diesels are similarly excluded.

The passive, long-lived components associated with the engine auxiliaries outside the engine skid boundary and electrical equipment are subject to AMR. The components of the new SACM diesels were mapped to their corresponding components on the Fairbanks Morse EDGs. This mapping procedure provides assurance that all SACM diesel components have been evaluated for AMR through the evaluation process used for the Fairbanks Morse EDGs. Maintenance on the Fairbanks Morse EDGs also provides a 20-year lead time for aging of new SACM diesel components.

The results of this mapping are summarized below.

Diesel Lube Oil

No plausible aging was identified for any SACM Diesel Lube Oil components.

Diesel Fuel Oil

Plausible aging was identified for the SACM Diesel Fuel Oil tanks, basket strainer, tornado damper, and flame arrestor. In each case, the material, environment, and ARDMs for these SACM components were the same as the material, environment, and ARDMs for the corresponding Fairbanks Morse components.

Diesel Starting Air

No plausible aging was identified for the SACM Diesel Starting Air components even though plausible aging was identified for the corresponding Fairbanks Morse Diesel Starting Air components. The SACM Diesel Starting Air components are stainless steel subject to dry air, while the corresponding Fairbanks Morse Diesel Starting Air components are carbon steel subject to moist air.

Diesel Combustion Air

Plausible aging was identified for the SACM Diesel Combustion Air intake air filter and piping. In each case, the material, environment, and ARDMs for these SACM components are the same as the material, environment, and ARDMs of the corresponding Fairbanks Morse components. Plausible aging was identified for the SACM Diesel Combustion Air exhaust air muffler and piping. The material, environment, and ARDMs for the SACM exhaust muffler were the same as the material, environment, and ARDMs for the corresponding Fairbanks Morse exhaust muffler. The SACM exhaust piping is chromium-molybdenum versus carbon steel exhaust piping for the Fairbanks Morse diesels. Therefore, the SACM diesel exhaust piping is subject to a subset of the ARDMs affecting the Fairbanks Morse diesel exhaust piping.

Diesel Cooling Water

Plausible aging was identified for the SACM cooling water piping, tanks, and valves. These SACM components are made of the same material and subject to the same ARDMs as the corresponding Fairbanks Morse piping, tanks, and valves even though the process fluid is different. The process fluid for the SACM cooling water system is a solution of ethylene glycol antifreeze in demineralized water. The process fluid for the jacket cooling water system for the Fairbanks Morse diesels is service water treated with hydrazine. The aging of the SACM radiators is expected to be bounded by the aging of the Fairbanks Morse jacket water cooling system piping.

In the few instances where there was not a corresponding original EDG component for a new SACM component, there were no plausible ARDMs due to the material/environment characteristics of the new SACM component.

Thus, for purposes of license renewal, the aging and the management thereof for the new SACM diesel support systems are enveloped by the aging and aging management for the corresponding Fairbanks Morse diesel support systems. Any aging discovered by the aging management program for the Fairbanks Morse diesels will result in corrective action and a review for applicability to the corresponding new SACM diesel support system.

5.8.1.3 Components Subject to AMR

This section describes the components within the EDG System that are subject to AMR. It begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions and/or is skid-mounted equipment excluded from AMR, evaluated in commodity reports, or remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following EDG System functions were determined to be passive: [Reference 8, Pre-Evaluation Section]

- Maintain the pressure boundary of the system (liquid and/or gas);
- To maintain electrical continuity and/or provide protection of the electrical system; and
- Provide seismic integrity and/or protection of safety-related components.

Device Types Subject to AMR

The components of the EDG support systems were reviewed and those that have the passive intended functions were identified. Of the 48 device types identified within scope for license renewal: [Reference 2, Table 3-2]

- Thirty device types (Annunciator, Circuit Breaker, Coil, Control Switch, Disconnect, Voltage Regulator, Emergency Diesel Generator, Isolator {EI}, Fan, Fuse, Governor, Hand Switch, Isolator{II}, Indicator{JI}, Indicator{JKI}, Indicating Light{JL}, Motor{M}, Motor{MD}, Motor{MO}, Relay, Speed Controller, Speed Indicator, Speed Switch, Temperature Controller, Temperature Switch, Temperature Transmitter, Heater, Transformer, Indicating Lamp, Position Indicating Light) are only associated with active functions. [Reference 2, Table 3-2].
- One device type (Heat Exchanger) is a skid-mounted component on the Fairbanks Morse EDG and is not considered for further aging evaluation.
- Four device types (Level Indicator, Level Switch, Pressure Indicator, Pressure Switch) are evaluated in the Instrument Line Commodity Evaluation in Section 6.4 of the BGE LRA. [Reference 2, Table 3-2]
- Two device types (Motor Control Center, Panel) are evaluated in the Electrical Commodity Evaluation in Section 6.2 of the BGE LRA. [Reference 2, Table 3-2]

- Structural supports for piping, cables and components in the EDG 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. This commodity evaluation completely addresses the passive intended function, "Provide seismic integrity and/or protection of safety-related components."
- Electrical control and power cabling for components in the EDG 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. This commodity evaluation completely addresses the passive intended function, "To maintain electrical continuity and/or provide protection of the electrical 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.

As a result of the evaluation described above, the only passive intended function associated with the EDG System is the following:

- Maintain the pressure boundary of the system (liquid &/or gas).

The remaining 11 device types that require an AMR are listed in Table 5.8-2. These are the subject of the rest of this section. Unless otherwise annotated, all components of each listed type are covered in this section. [Reference 2, 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 5.8-2

EDG SYSTEM DEVICE TYPES REQUIRING AMR

Piping (-HB)
Filter (FL)
Muffler (MUFF)
Drain Trap (DT)
Wye Strainer (YS)
Relief Valve (RV)
Check Valve (CKV)
Hand Valve* (HV)
Pump (PUMP)
Accumulator (ACC)
Tank (TK)

* Instrument line manual drain, equalization, and isolation valves in the EDG System 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 Section.

5.8.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the EDG System components is given in Table 5.8-3, with plausible ARDMs identified by a check mark (✓) in the appropriate device type column. [Reference 2, Table 4-2] For AMR, some device types have a number of groups associated with them because of the diversity of material used in their fabrication or differences in the environments to which they are subjected. A check mark indicates that the ARDM applies to at least one group for the device type listed. For efficiency in presenting the results of these evaluations in this section, the device types are grouped together based on similar ARDMs. [Reference 2, Section 4]

The following discussions present the information on plausible ARDMs. The discussions are grouped by ARDMs and address the materials and environment pertinent to the ARDM, the aging effects for each plausible ARDM, the device types that are affected by each, the methods to manage aging, the aging management program(s), and the aging management demonstration. In some groups there will be a distinction made between the programs credited with aging management for the external and internal portions of the EDG System components. The groups addressed here are:

Group 1 - General Corrosion, Crevice Corrosion, and Pitting;

Group 2 - Corrosion Fatigue, Fatigue;

Group 3 - Erosion Corrosion, Particulate Wear Erosion;

Group 4 - Microbiologically-Induced Corrosion (MIC); and

Group 5 - Wear.

TABLE 5.8-3

POTENTIAL AND PLAUSIBLE ARDMs FOR THE EDG SYSTEM

Potential ARDMs	EDG System Device Types											
	HB	FL	MUFF	DT	YS	RV	CKV	HV	PUMP	ACC	TK	Not Plausible for System
Cavitation Corrosion												x
Corrosion Fatigue	✓(2)		✓(2)									
Crevice Corrosion	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)		✓(1)	✓(1)		✓(1)	✓(1)	
Erosion Corrosion	✓(3)		✓(3)									
Fatigue	✓(2)		✓(2)									
Fouling												x
Galvanic Corrosion												x
General Corrosion	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)		✓(1)	✓(1)		✓(1)	✓(1)	
Hydrogen Damage												x
Intergranular Attack												x
MIC											✓(4)	
Oxidation												x
Particulate Wear Erosion			✓(3)									
Pitting	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)		✓(1)	✓(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				✓(5)								

✓ - indicates plausible ARDM determination
(#) - indicates the group(s) for which this ARDM is evaluated
Note: Not every group within the device types listed here may be susceptible to a given ARDM. This is because groups within a device type are not always fabricated from the same materials or subjected to the same environments. Exceptions for each device type will be indicated in the aging management section for each ARDM discussed in this Section.

Group 1 (general corrosion, crevice corrosion, and pitting) - Materials and Environment

Table 5.8-3 shows that there are several device types subject to general corrosion, crevice corrosion, and pitting. Some of these device types are susceptible to these ARDMs on both their internal and external surfaces as noted below. The device types and their material characteristics are: [Reference 2, ACC01, HB01/04/05, CKV01, HV01/02/05, DT01, FL01, MUFF01/02, TK01/02, YS01, Attachments 4, 5, 6]

External/Internal ARDMs:

- HB - EDG diesel engine exhaust piping (carbon steel);
- FL - intake filter bodies (carbon steel); and
- MUFF - exhaust muffler bodies (carbon steel).

Internal ARDMs Only:

- ACC - air accumulator vessels (carbon steel);
- CKV - bodies (carbon steel) and disk seats (low alloy steel);
- DT - drain trap bodies (cast iron);
- HB - EDG cooling water piping (carbon steel) is subject to all Group 1 ARDMs, the air intake piping, fittings, and flanges (carbon steel) are only subject to general corrosion;
- HV - bodies (carbon steel) and disk seat (stellited carbon steel);
- MUFF - air intake muffler bodies (carbon steel);
- TK - jacket water expansion tank, diesel fuel oil day and drip tanks with tank mounted level switches (carbon steel); and
- YS - diesel fuel oil wye strainer bodies (cast carbon steel).

The external environment for components subject to general corrosion, crevice corrosion, and/or pitting is the controlled environment of the Diesel Generator Buildings' (SACM 1A is housed in the "Diesel Generator Building," 0C in the "SBO Diesel Generator Building," and Fairbanks Morse 1B, 2B, 2A in the Auxiliary Building) atmosphere (for some of the these components; HV, CKV, HB, DT, MUFF, YS, ACC, TK), and outdoor ambient conditions with variable daily and seasonal changes (some of these components; HB, FL, MUFF).

The internal environments are treated SRW (some of these components; HB, HV, TK), air (HB), hot diesel engine exhaust gases containing moisture and particulates (HB, MUFF), diesel starting air (some of these components; CKV, HV, DT, ACC), ambient air containing moisture (FL), diesel intake air containing moisture (MUFF), and diesel fuel oil (YS, TK). [Reference 2, Attachments 4, 5]

Group 1 (general corrosion, crevice corrosion, and pitting) - Aging Mechanism Effects:

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The expected effects of general corrosion in an air environment would be superficial rust speckles and a slight dusting of loose passive surface rust. General corrosion in piping systems containing EDG jacket cooling water can occur due to stagnant conditions that last for extended periods of time. Moisture in the starting air and EDG air intake lines is sufficient to result in corrosion of the untreated internal carbon steel piping surfaces. Stagnant, moist conditions can also exist in the EDG exhaust piping and mufflers. General corrosion of the carbon steel exhaust material exposed to high temperatures may also be significant. The consequences of the damage from general corrosion are loss of load carrying cross-sectional area. General corrosion requires an aggressive environment and materials susceptible to that environment. [Reference 2, Attachment 7s]

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, surface deposits, and integral weld backing rings or back-up bars. Crevice corrosion is closely related to pitting corrosion and can initiate pits in many cases, as well as lead to stress corrosion cracking. In an oxidizing environment, a crevice can set up a differential aeration cell to concentrate an acid solution within the crevice. [Reference 2, Attachment 7s]

Pitting is a form of localized attack with greater corrosion rates at some locations than at others. This form of corrosion essentially produces holes of varying depth-to-diameter ratios in the steel. These pits are, in many cases, filled with oxide debris, especially in ferritic materials such as carbon steel. In many cases, erosion corrosion, fretting corrosion, and crevice corrosion can also lead to pitting. Corrosion pitting is an anodic reaction, which is an autocatalytic process. That is, the corrosion process within a pit produces conditions that stimulate the continuing activity of the pit. High concentrations of impurity anions such as chlorides and sulfates tend to concentrate in the oxygen depleted pit region, giving rise to a potentially concentrated aggressive solution in this zone. [Reference 2, Attachment 7s]

The exterior surfaces of all EDG jacket cooling water piping and piping components in the Diesel Generator Buildings are not susceptible to these corrosion mechanisms. They are located in the diesel generator room ventilated environment. The conditions are not conducive to the pooling of moisture necessary for the propagation of the mechanisms. [Reference 2, -HB, Attachment 6]

The exterior surfaces of EDG intake filter, exhaust piping and mufflers are susceptible to these same corrosion mechanisms. They are located on the Diesel Generator Building roof and are subjected to harsh environmental conditions. [Reference 2, FL, Attachment 6]

General corrosion, crevice corrosion, and pitting are plausible ARDMs for the EDG System components/subcomponents because of the nature of their material of construction and exposure to slightly moist starting and intake air; humid, moist, or wet ambient conditions; stagnant water; exhaust gases; and/or concentration of moisture and contaminants from diesel fuel oil. [Reference 2, Attachments 6s]

If unmanaged, these plausible ARDMs could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.

Group 1 (general corrosion, crevice corrosion, and pitting) - Methods to Manage Aging Effects

External

Mitigation: Though most EDG components are not susceptible to external corrosion mechanisms because they are located in the controlled environment of the Diesel Generator Building, the possibility of corrosion can be mitigated by painting the exposed surfaces.

Discovery: Aging management of exterior surfaces of the intake filter can be accomplished by visual inspections for degraded paint and the performance of any required corrective actions. [Reference 2, Attachment 8]

Internal

Mitigation: Diesel fuel oil is corrosive when water is present with the fuel oil. 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, and pitting. Draining any potential water from the carbon steel fuel oil day tank and drip tank after performing diesel run testing can contribute toward mitigating the effects of general corrosion, crevice corrosion, and pitting. Draining water from the fuel oil day tank will contribute to the mitigation of these ARDMs in the diesel fuel oil drip tank. This technique will also contribute toward mitigating the effects of MIC. [Reference 2, Attachment 8]

Maintaining fuel oil within established chemistry specifications can minimize the possibility of microbe growth, build up of sludge, and corrosive effects of water in the carbon steel tanks. [Reference 2, Attachment 8]

Maintaining the EDG jacket cooling water chemistry can minimize the possibility of corrosion and pitting on the internal surfaces of this cooling system. The other environments mentioned above do not lend themselves to mitigation of these ARDMs, so the discovery methods mentioned below are utilized to manage aging of general corrosion, crevice corrosion, and pitting on the internal surfaces of the remaining EDG System components.

Discovery: The effects of these ARDMs are detectable by visual and sampling techniques. Inclusion of EDG System components in a program that examines a representative sample of susceptible areas of the system for the signs of general corrosion, crevice corrosion, and pitting prior to the period of extended operation could discover whether these ARDMs are actually occurring in the EDG System. [Reference 2, Attachment 8]

Regular maintenance, overhaul, and inspections of EDG System components could also discover signs of general corrosion, crevice corrosion, and pitting. [Reference 2, Attachment 8]

Group 1 (general corrosion, crevice corrosion, and pitting) - Aging Management Programs

External

Mitigation: Though painting of the exterior surfaces mitigates the possibility of external corrosion, no credit is taken for this coating in mitigating external corrosion.

Discovery: Calvert Cliffs Mechanical Preventive Maintenance (MPM) MPM07117, “Inspect EDG Air Intake Filters,” is credited with the discovery of general corrosion, crevice corrosion, and pitting on the external surfaces of the EDG intake filters. Calvert Cliffs MPM13110, “Perform Visual Examination for EDG Exhaust Components,” is credited for discovery of external crevice corrosion, general corrosion, and pitting of the EDG exhaust piping and exhaust muffler. These MPMs are performed in accordance with CCNPP Administrative Procedure MN-1-102, “Preventive Maintenance Program.” Refer to the full discussion of these programs in the Discovery Section below.

Internal

Mitigation:

Calvert Cliffs Technical Procedure CP-226

Calvert Cliffs Technical Procedure CP-226, "Specification and Surveillance - Diesel Fuel Oil," is credited for mitigating the effects of crevice corrosion, general corrosion, and pitting on the interior surfaces of the EDG diesel fuel oil day tanks, and drip tanks with associated tank mounted level switches by sampling fuel oil before it is unloaded to the FOSTs. Under CCNPP Technical Procedure CP-226, 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 water, viscosity, and sediment for both receipt inspection and Technical Specification surveillance for fuel oil in the FOSTs in accordance with the standard American Society for Testing and Materials ASTM-D975-81. The procedure currently has target values and action levels that give an acceptable range or limit for a given parameter. There are two action levels associated with CP-226. Action Level 1 gives a value or range of values that are inconsistent with the goals of BGE’s Chemistry organization (indicate an adverse trend), while Action Level 2 gives a value or range of values that exceed Technical Specifications. Two of the parameters, kinematic viscosity and water/sediment, have Action Level 2 associated with them. The CCNPP Technical Specifications related to CP-226 are 4.7.11.1.2b and 4.8.1.1.2.b. [Reference 9]

This procedure now requires the addition of a stabilizer/corrosion inhibitor prior to unloading fuel oil into the fuel oil storage tanks (FOSTs). Prior to adoption of this new approach, the stabilizer/inhibitor was being added in 55 gallon batches once a year. The new approach provides a better assurance that the desired ratio of inhibitor to fuel oil exists.

In August 1989, chemistry procedure CP-226 was revised to incorporate criteria in accordance ASTM-D270-65 for taking quarterly samples from the diesel FOSTs. This revision involves taking multilevel samples from each diesel FOST rather than sampling only from the tank bottom, as was done previously.

Calvert Cliffs Chemistry Procedure CP-222

Calvert Cliffs Chemistry Procedure CP-222, "Specifications and Surveillance for Diesel Generators' Jacket Cooling Water System," is credited with mitigating the effects of general corrosion, crevice corrosion, and pitting of the cooling water piping and jacket water expansion tanks by monitoring and maintaining EDG jacket water chemistry (e.g., pH, dissolved oxygen). This procedure contains two different sets of chemistry parameters, one for the Fairbanks Morse EDGs and one for the SACM EDG. The water is treated with hydrazine or corrosion inhibitors to minimize the amount of oxygen in the water, which aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal EDG jacket water expansion tank and cooling water piping degradation. [Reference 10]

Procedure CP-222 describes the surveillance and specifications for monitoring the EDG jacket water. Procedure CP-222 lists the parameters to monitor, the frequency of monitoring these parameters, and the target and action levels for the EDG jacket cooling water parameters. Action Level 1 gives a value or range of values that are inconsistent with the goals of BGE's Chemistry organization and that indicate an adverse trend. The target level is a value or range of values for a chemical parameter that is a goal or predetermined warning limit. The parameters currently monitored by CP-222 are pH, hydrazine, dissolved oxygen, dissolved copper, dissolved iron, suspended solids, biological activity, and propylene glycol concentrations. These chemistry parameters are currently monitored on a frequency ranging from once per week to once a year. [Reference 10, Section 3, Attachments 1, 2]

Procedure CP-222 provides for a prompt review of EDG jacket water chemistry parameters so that steps can be taken to return chemistry parameters to normal levels, and thus minimize the effects of general corrosion, crevice corrosion, and pitting.

The CCNPP Surveillance Test Procedures STP-O-8A-2, STP-O-8B-1, STP-O-8B-2 are credited for mitigation of crevice corrosion, general corrosion, pitting, and MIC on the interior of the diesel fuel oil day tanks. The procedures provide for periodic draining of diesel fuel oil day tank of any water that may be present, which minimizes the corrosive effects of water on carbon steel and the drip tanks that drain to the day tanks. The tank sample is taken and visually examined for the presence of water in the fuel. This procedure is currently performed monthly after the EDGs are shut down from testing. [References 11, 12, and 13]

Discovery: The CCNPP Age-Related Degradation Inspection (ARDI) Program will be credited with the discovery of crevice corrosion, general corrosion, and pitting on EDG starting air system hand valves, EDG cooling water hand valves, drain traps, starting air accumulators, jacket water expansion tanks, diesel fuel oil day tanks and drip tanks with associated level switches, EDG cooling water piping, and EDG System exhaust piping and mufflers. [Reference 2, Attachment 1]

The ARDI Program is defined in the CCNPP IPA Methodology presented in Section 2.0 of this application.

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 ARDI Program will contain acceptance criteria that ensure corrective actions taken will be taken such that the hand valves and drain traps subject to general corrosion, crevice corrosion, and pitting remain capable of performing their intended functions under all CLB conditions.

Calvert Cliffs Preventive Maintenance (PM) Program

The CCNPP PM 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. [Reference 14, Section 1.1]

The program is governed by CCNPP Administrative Procedure MN-1-102 and covers all PM activities for nuclear power plant structures and equipment within the plant, including the EDG System components within the scope of license renewal. Guidelines drawn from industry experience and utility best practices were used in the development and enhancement of this program.

The PM Program includes periodic inspection of specific components through various maintenance activities. These activities provide an effective means to discover and manage the age-related degradation effects on these components. The program requires that an Issue Report be initiated according to CCNPP Procedure QL-2-100, “Issue Reporting and Assessment,” for deficiencies noted during performance of PM tasks. Corrective actions are taken to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions. [Reference 14, Section 5.2.B.1.f]

The PM Program undergoes periodic evaluation by the NRC as part of their routine licensee assessment activities. [Reference 15] The PM Program also has had numerous levels of management review, all the way down to the specific implementation procedures. Specific responsibilities are assigned to BGE personnel for evaluating and upgrading the PM Program and for initiating program improvements based on system performance. Issue Reports are initiated according to CCNPP Procedure QL-2-100 to request changes to the program that could improve or correct plant reliability and performance. Changes to the PM Program that require Issue Reports include changes to the PM task scope, frequency, process, and those resulting from operating experience reviews. [Reference 14, Sections 5.1.A and 5.4]

Under the PM program, general corrosion, crevice corrosion, pitting, MIC, fouling, fatigue, corrosion fatigue, wear, and/or particulate wear erosion for several EDG components are managed through existing

PM tasks and checklists, which can require inspections and overhauls. Preventive maintenance is scheduled by PM repetitive tasks. The implementation of the PM can be just the repetitive task, or a checklist, maintenance procedure, or checklist called for by a repetitive task that then calls for a maintenance procedure. [Reference 2, Attachment 1] The following summarizes the components and corresponding PM checklists that will manage ARDMs for these components.

The following CCNPP MPM checklists are credited with the discovery of the effects of general corrosion of internal piping surfaces for EDG starting air, and combustion air intake systems: [Reference 2, Attachment 1]

- Calvert Cliffs MPM01125, "Remove Relief Valve, Test and Reinstall," is currently performed every four years; [Reference 16]
- Calvert Cliffs MPM07006, "Disassemble, Inspect and Overhaul EDG Check Valve," is currently performed every 6 years; [Reference 17]
- Calvert Cliffs MPM13000, "Clean and Inspect EDG Air Start Distributor and Check Valves," is currently performed every 4 years; [Reference 18]
- Calvert Cliffs MPM13002, "Inspect EDG Air Start Valves and Filters," is currently performed every 96 weeks; and [Reference 19]

These MPMs will be modified to inspect specifically for corrosion of piping and check for the presence of debris in valves that could indicate the piping in these systems is undergoing corrosion. [Reference 2, Attachment 1]

Calvert Cliffs MPM07117, "Inspect EDG Air Intake Filters," is currently performed at approximately 4 year intervals. [Reference 20] The MPM will be modified to inspect the attached piping for signs of corrosion. [Reference 2, Attachment 1]

Checklist MPM13110 is credited with the discovery of crevice corrosion, general corrosion, and pitting of the EDG exhaust piping and exhaust muffler. This task is performed at approximately two-year intervals. [Reference 2, Attachment 1; Reference 21]

Checklist MPM07006 is credited with discovery of the effects of pitting, crevice corrosion, and general corrosion of the internal surfaces of EDG Starting Air System check valves. [Reference 2, Attachment 1; Reference 17]

Checklists MPM13003, "Clean/Inspect 2B EDG Lube Oil "Y" Strainers and Baskets," MPM13004, "Clean/Inspect 1B EDG Lube Oil "Y" Strainers," and MPM13005, "Clean/Inspect 2A EDG Lube Oil "Y" Strainers and Baskets," are credited with discovery of the effects of pitting, crevice corrosion, and general corrosion on the wye strainer internal surfaces. The MPMs will be modified to check for signs of corrosion on the wye strainer internal surfaces. These tasks are currently performed at approximately 96 week intervals. [Reference 2, Attachment 1; References 22, 23, and 24]

Checklist MPM07117 is credited with discovery of the effects of pitting, crevice corrosion, and general corrosion on internal surfaces of the EDG intake filters and intake mufflers as previously described above. This MPM will be modified to check for signs of corrosion and to specifically include the intake muffler in its scope. [Reference 2, Attachment 1; Reference 21]

Group 1 (general corrosion, crevice corrosion, and pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to general corrosion, crevice corrosion, pitting of the components of the EDG System:

- The EDG System Group 1 components listed under Materials and Environment contribute to maintaining pressure boundary function.
- General corrosion, crevice corrosion, and pitting are plausible ARDMs for both the internal and external surfaces of EDG System components because of their materials of construction and exposure to environments that contribute to these ARDMs. If unmanaged, these ARDMs could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- Calvert Cliffs Technical Procedure CP-226 mitigates the effects of crevice corrosion, general corrosion, and pitting on the interior surfaces of the EDG fuel oil day tanks through the control of fuel oil chemistry, including biologics.
- Calvert Cliffs Chemical Procedure CP-222 mitigates the effects of crevice corrosion, general corrosion, and pitting on the interior surfaces of the EDG jacket water expansion tank and cooling water piping by monitoring and maintaining the EDG jacket cooling water chemistry.
- The CCNPP ARDI Program will discover the effects of crevice corrosion, general corrosion, and pitting on the internal surfaces of EDG starting air system hand valves, SRW cooling hand valves, drain traps, starting air accumulators, jacket water expansion tanks, diesel fuel oil day tanks and drip tanks with associated tank mounted level switches, EDG cooling water piping, and EDG System exhaust piping and mufflers.
- The CCNPP Preventive Maintenance Program will discover the effects of external and internal general corrosion, crevice corrosion, and pitting for several EDG components through the use of MPMs. The ARDMs are managed through existing PM checklists, periodic inspections, and periodic overhauls. Some of the MPMs previously listed will be modified to add these ARDMs and/or EDG components to the scope of their existing surveillance.
- The CCNPP Surveillance Test Procedures STP-O-8A-2, STP-O-8B-1, and STP-O-8B-2 will mitigate the effects of crevice corrosion, general corrosion, and pitting on the interior of the diesel fuel oil day tanks by sampling these tanks for the presence of water and draining any water that is found.

Therefore, there is reasonable assurance that the effects of general corrosion, crevice corrosion, and pitting will be adequately managed for the EDG System components 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 (corrosion fatigue/fatigue) - Materials and Environment

Table 5.8-3 shows that the EDG exhaust piping and muffler are susceptible to corrosion fatigue and/or fatigue. The material characteristics of these device types are listed below: [Reference 2, Attachments 4, 5, 6, HB05, MUFF02]

- HB - exhaust piping, fittings, flanges (carbon steel), and bolting (alloy steel); and

- MUFF - exhaust muffler bodies (carbon steel).

The external environment for components subject to corrosion fatigue/fatigue is the Diesel Generator Building atmosphere and outdoor ambient air. Outdoor ambient air is variable and subject to daily and seasonal weather changes.

The internal environments for these components consist of periodic exposure to hot diesel engine exhaust gases that contain moisture and entrained particulates. High temperatures during diesel operation, wetting, and drying of the piping/muffler exterior in inclement weather provide the necessary conditions for these ARDMs to occur. [Reference 2, HB, MUFF, Attachments 4, 6]

Group 2 (corrosion fatigue/fatigue) - Aging Mechanism Effects

Corrosion fatigue occurs when plant equipment operates in a corrosive environment subjected to cyclic (fatigue) loading that may initiate cracks and/or fail sooner than when these ARDMs are applied separately. Fatigue-crack initiation and growth usually follow a transgranular path, although there are some cases where intergranular cracking has been observed. In some cases, crack initiation occurs by fatigue and is subsequently dominated by corrosion advance. In other cases, a corrosion mechanism can be responsible for crack initiation below the fatigue threshold, and the fatigue mechanism can accelerate the crack propagation. Corrosion-fatigue is a potentially active mechanism in carbon and low alloy steels. [Reference 2, Attachment 7]

Fatigue damage results from progressive, localized structural change in materials subjected to fluctuating stresses and strains. Associated failures may occur at either high or low cycles in response to various kinds of loads (e.g., mechanical or vibration loads, thermal cycles or pressure cycles). Fatigue cracks initiate and propagate in regions of stress concentration that intensify strain. [Reference 2, Attachment 7]

The EDG components listed above in the Materials and Environment Section are subjected to corrosive environments and also experience cyclic stresses during EDG operation. Therefore, these ARDMs are plausible for the these EDG components and, if unmanaged, may lead to loss of the pressure boundary function. [Reference 2, Attachment 6]

Group 2 (corrosion fatigue/fatigue) - Methods to Manage Aging

Mitigation: There are no feasible ways to prevent corrosion fatigue and fatigue from occurring on the EDG exhaust piping and mufflers other than limiting operation of the EDGs. The EDGs must be periodically operated to ensure that they are capable of performing their design functions. Therefore, there are no means to mitigate these ARDMs.

Discovery: The effects of corrosion fatigue and fatigue can be discovered by periodic examinations of the EDG exhaust piping and mufflers.

Group 2 (corrosion fatigue/fatigue) - Aging Management Programs

Mitigation: There are no CCNPP programs credited with the mitigation of corrosion fatigue and fatigue of the EDG exhaust piping and mufflers.

Discovery: The CCNPP PM Program includes MPM13110, which is credited with the discovery of corrosion fatigue and fatigue on the external surfaces of the EDG exhaust piping and exhaust muffler. This will be performed through inspections of the EDG exhaust piping and muffler. This task is currently performed at approximately two-year intervals. The PM Program is discussed in Group 1 (general corrosion, crevice corrosion, and pitting) under Aging Management Programs. [Reference 2, Attachments 8, 10; Reference 21]

The CCNPP ARDI Program will provide for the discovery of the effects of corrosion fatigue/fatigue on the internal surfaces of the EDG exhaust piping and exhaust mufflers. Refer to the previous discussion of this program in Group 1 (general corrosion, crevice corrosion, and pitting) under Aging Management Programs.

Group 2 (corrosion fatigue/fatigue) - Demonstration of Aging Management

Based on the information provided above, the following conclusions can be reached with respect to corrosion fatigue and fatigue of the EDG components:

- The EDG exhaust piping and muffler contribute to the pressure boundary function, which must be maintained under all CLB design loading conditions.
- The EDG exhaust piping and muffler are susceptible to these ARDMs due to the environmental and service conditions they are exposed to during operational testing and emergency use.
- Calvert Cliffs MPM13110 will discover the effects of corrosion fatigue and fatigue on external surfaces of the EDG exhaust piping and exhaust mufflers. This MPM will be modified to include inspection of the piping and muffler for signs of these ARDMs.
- The CCNPP ARDI Program provide for the discovery of the effects of corrosion fatigue/fatigue on the internal surfaces of the EDG exhaust piping and exhaust mufflers.

Therefore, there is reasonable assurance that the effects of corrosion fatigue and fatigue will be adequately managed for EDG System components such that it will be capable of performing their intended function consistent with the CLB during the period of extended operation under all design loading conditions.

Group 3 (erosion corrosion/particulate wear erosion) -Materials and Environment

As Table 5.8-3 shows, the EDG cooling water piping is susceptible to erosion corrosion, and the EDG exhaust mufflers are susceptible to erosion corrosion and particulate wear erosion. The material characteristics of these device types are listed below: [Reference 2, HB01, MUFF02, Attachments 4, 5, 6]

- HB - pipe and fittings (carbon steel); and
- MUFF - exhaust muffler bodies (carbon steel).

The internal environment for the EDG exhaust mufflers experience periodic exposure to hot diesel engine exhaust gases that contain moisture and entrained particles. The cooling water serving the EDGs contains chemically-controlled SRW that has reduced levels of oxygen. [Reference 2, HB01, MUFF02, Attachments 4, 6]

Group 3 (erosion corrosion/particulate wear erosion) - Aging Mechanism Effects

Erosion corrosion is the increased rate of attack on a metal because of the relative movement between a corrosive fluid and the metal surface. Mechanical wear or abrasion can be involved, characterized by grooves, gullies, waves, holes, and valleys on the metal surface. Carbon or low alloy steels are particularly susceptible when in contact with high velocity water (single- or two-phase) with regions of disturbed flow, low oxygen, and fluid pH < 9.3. The water in the SRW piping has a low oxygen content and regions of disturbed flow; therefore, erosion corrosion is plausible for this EDG piping. Hot exhaust gases with levels of particle matter and moisture may tend to erode internal EDG exhaust muffler material. [Reference 2, -HB, MUFF, Attachments 6, 7]

Particulate wear erosion is the loss of material caused by mechanical abrasion due to relative motion between a fluid (liquid or gas) and material surface. This form of erosion requires high velocity fluid, entrained particles, regions of disturbed flow, flow direction change, and/or impingement. The EDG exhaust gases at high temperatures may tend to erode certain locations in the mufflers as these gases traverse various flow paths. Although the particulate loading is not likely to result in "true" particulate wear erosion, the impact of high temperature gases with some particulate matter and moisture may tend to erode the pressure boundary material, especially in locations of flow direction changes. [Reference 2, FL, Attachment 7, MUFF, Attachment 6]

Group 3 (erosion corrosion/particulate wear erosion) - Methods to Manage Aging

Mitigation: The effects of erosion corrosion of the cooling water piping can be mitigated by control of the system's water chemistry. Maintaining higher levels of oxygen can lower the effects of erosion corrosion; however, higher oxygen levels can lead to other ARDMs such as corrosion. There are also no means of mitigating the effects of particulate wear erosion of the exhaust muffler bodies other than not operating the system. This is not a feasible solution since the EDGs must be periodically operated to ensure they are available to perform their intended functions.

Discovery: The effects of erosion corrosion on pipe internal surfaces can be discovered with a program of inspections. Similarly, inspections can discover the effects of erosion corrosion/particulate wear erosion on the internal surfaces of the EDG exhaust muffler.

Group 3 (erosion corrosion/particulate wear erosion) - Aging Management Programs

Mitigation: There are no programs credited with the mitigation of erosion corrosion or particulate wear erosion on the EDG piping or exhaust mufflers.

Discovery: The CCNPP ARDI Program provide for the discovery of the effects of erosion corrosion on the internal surfaces of the EDG cooling water piping and erosion corrosion/particulate wear erosion on the EDG exhaust mufflers. Refer to the previous discussion of this program in Group 1 (crevice corrosion, general corrosion, and pitting) under Aging Management Programs. [Reference 2, Attachments 1, 8]

Group 3 (erosion corrosion/particulate wear erosion) - Demonstration of Aging Management

Based on the information provided above, the following conclusions can be reached with respect to the erosion corrosion/particulate wear erosion of the EDG components:

- The EDG cooling water piping and muffler contribute to the passive intended pressure boundary function, which must be maintained under all CLB design loading conditions.
- The EDG cooling water piping and muffler are susceptible to erosion corrosion and particulate wear erosion for which the effects of these aging mechanisms must be managed during the period of extended operation.
- The CCNPP ARDI Program will provide for the discovery of the effects of erosion corrosion on the internal surfaces of the EDG cooling water (SRW) piping and the effects of erosion corrosion/particulate wear erosion on the EDG exhaust mufflers.

Therefore, there is reasonable assurance that the effects of erosion corrosion and particulate wear erosion will be adequately managed for EDG System components such that they will be capable of performing their intended function consistent with the CLB during the period of extended operation under all design loading conditions.

Group 4 (MIC) - Materials and Environment

As Table 5.8-3 shows, the EDG diesel fuel oil day tanks, drip tanks and their level switches, are susceptible to the effects of MIC. The material characteristics of these components are listed below: [Reference 1, TK02, Attachments 4, 5, 6]

- TK - fuel oil day tank vessels (carbon steel);
- TK - fuel oil drip tank vessels (carbon steel); and
- TK - fuel oil drip tank level switches (no material given).

The internal environment of these tanks is diesel fuel oil, diesel fuel oil vapors, and atmospheric air containing moisture. In addition, some water may condense in the tank and biological contaminants may be present. The external environment for these tanks is the controlled environment of the Diesel Generator Building atmosphere. [Reference 2, Attachments 4s, 6s]

Group 4 (MIC) - Aging Mechanism Effects

Microbiologically-induced corrosion is the accelerated corrosion of materials resulting from surface microbiological activity. Sulfate reducing bacteria, sulfur oxidizers, and iron oxidizing bacteria are most commonly associated with corrosion effects. This can often result in pitting followed by excessive deposition of corrosion products. Temperatures between about 50°F and 120°F with stagnant conditions are most conducive to MIC. In diesel fuel oil applications fungi have been known to grow into long strips, and form large mats or globules. They may grow throughout the fuel or at the interface area between the fuel and any water that is in the tank bottom. Their growth chemically alters the fuel by producing sludge, acids, and other products of metabolism. When they adhere to the fuel-containing surfaces, the water and waste products lead to corrosion. [Reference 2, ACC, Attachment 7]

Group 4 (MIC) - Methods to Manage Aging

Mitigation: Diesel fuel oil is corrosive when water (from condensation) is present with the fuel oil. Periodic draining of water from the carbon steel fuel oil day tank and drip tank after performing diesel run testing can mitigate the effects of MIC. [Reference 2, Attachment 8]

Maintaining fuel oil within established chemistry specifications can minimize the possibility of microbe growth, build up of sludge, and corrosive effects of water in the carbon steel tanks. [Reference 2, Attachment 8]

The effects of MIC can be mitigated by removing environmental factors, like water, essential for this ARDM to exist. In addition, surveillance programs that can detect and control contributing environmental factors can mitigate MIC from forming in or on the Group 4 EDG components.

Discovery: Inclusion of EDG System components in an ARDI Program, which examines a representative sample of susceptible areas of the system for the signs of MIC prior to the period of extended operation, could discover whether this ARDM is actually occurring in the EDG System. [Reference 2, Attachment 8]

Group 4 (MIC) - Aging Management Programs

Mitigation: Calvert Cliffs Technical Procedure CP-226 is credited with mitigating the effects of MIC on EDG diesel fuel oil day tanks/drip tanks interior surfaces and on the surface of the drip tank level switches. Under CP-226, fuel oil chemistry is controlled, including testing for the presence of biologics. Refer to the previous discussion of this procedure in Group 1 (general corrosion, crevice corrosion, and pitting) under Aging Management Programs.

The CCNPP Surveillance Test Procedures STP-O-8A-2, STP-O-8B-1, STP-O-8B-2 are credited for the mitigation of MIC on the interior surfaces of the diesel fuel oil day tanks/drip tanks and surface of the drip tank level switches. The procedure provides for periodic draining of diesel fuel oil day tanks for the presence of water. The tanks are completely drained of all water if any is present. Draining the day tanks of all water minimizes the corrosive effects of water on carbon steel and the drip tanks that drain to the day tanks. A drain sample is taken and visually examined for the presence of water in the fuel. This procedure is currently performed monthly after the EDGs are shut down for testing. [References 11, 12, and 13]

Discovery: The CCNPP ARDI Program will provide for the discovery of the effects of MIC on the internal surfaces of the EDG diesel fuel oil day tanks/drip tanks and surfaces of the drip tank level switches. Refer to the previous discussion of this procedure in Group 1 (general corrosion, crevice corrosion, and pitting) under Aging Management Programs

Group 4 (MIC) - Demonstration of Aging Management

Based on the information provided above, the following conclusions can be reached with respect to the effects of MIC of the EDG components:

- The EDG diesel fuel oil day tanks, and drip tanks with associated tank mounted level switches, provide the pressure boundary function of the system, which must be maintained under all CLB conditions during the period of extended operation.
- Microbiologically-induced corrosion is plausible for the EDG diesel fuel oil tanks, and drip tanks with associated level switches, because of their material of construction and exposure to environments that contribute to this ARDM. If unmanaged, this ARDM could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- Calvert Cliffs Technical Procedure CP-226 will mitigate the effects of MIC on the interior surfaces of the EDG fuel oil day tanks, and drip tanks with their associated level switches, through the control of fuel oil chemistry, including biologics and corrosion inhibitors.
- The CCNPP Surveillance Test Procedures STP-O-8A-2, STP-O-8B-1, and STP-O-8B-2 will mitigate the effects of MIC on the interior surfaces of the EDG fuel oil day tanks, and drip tanks with their associated level switches, by periodically sampling the fuel oil day tanks for the presence of water and draining them of water if any is found.
- Calvert Cliffs ARDI Program will provide for the discovery of the effects of MIC on the interior surfaces of the EDG fuel oil day tanks, and drip tanks with their associated level switches.

Therefore, there is reasonable assurance that the effects of MIC will be adequately managed for EDG System components such that it will be capable of performing their intended function consistent with the CLB during the period of extended operation under all design loading conditions.

Group 5 (wear) - Materials and Environment

As table 5.8-3 shows, only the drain traps are subject to wear in the EDG System. The materials of drain traps subcomponents susceptible to wear are: [Reference 2, Table 4-2, DT, Attachments 3, 4, 6]

- DT- disk/seat (stainless steel) and pivot rod/plugs (brass).

The internal environment for these components is that of the EDG starting air system, which is compressed air that can contain moisture. These valves are subject to periodic movement in performing their operational function.

Group 5 (wear) - Aging Mechanism Effects

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard, abrasive particles (abrasive wear, see particulate erosion) or fluid stream (erosion), and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). In addition to material loss from the above wear mechanisms, impeded relative motion between two surfaces held in intimate contact for extended periods may result from galling/self welding. Motions may be linear, circular, or vibratory in inert or corrosive environments. The most common result of wear is damage to one or both surfaces involved in the contact. Wear most typically occurs in components that experience considerable relative motion, such as valves and pumps, in components that are held under high loads with no motion for long periods (valves, flanges). Wear may proceed at an ever increasing rate with much higher contact stresses than the surfaces of the original geometry. [Reference 2, PUMP, Attachment 7]

Wear of the internals and pivot rod are possible due to the periodic relative movement of these components during equipment function. Although not operated continuously, these components are subjected to cyclic operation and are subject to these various wear mechanisms. Wear of the seating surface, if unmanaged, could lead to loss of pressure boundary integrity. [Reference 2, DT, Attachment 6]

Group 5 (wear) - Methods to Manage Aging

Mitigation: The effects of wear could be mitigated by minimizing equipment operation. However, this is not operationally feasible; therefore, the effects of wear cannot be mitigated during plant operation.

Discovery: Inclusion of the drain trap components in an ARDI Program that visually examines a representative sample of susceptible areas of the system for the signs of wear prior to the period of extended operation could discover whether wear is actually occurring in the DT components. [Reference 2, Attachment 8]

Group 5 (wear) - Aging Management Programs

Mitigation: Other than proper material selection, design, and installation, there are no programs credited with the mitigation of wear on the EDG drain trap components.

Discovery: The CCNPP ARDI Program will provide for the discovery of the effects of wear on the EDG starting air system drain trap components. The ARDI Program will include the representative inspections of the internal surfaces of the EDG starting air system drain trap components. [Reference 2, Attachment 1] Refer to the previous discussion of this ARDI Program in Group 1 (general corrosion, crevice corrosion, and pitting) under Aging Management Programs.

Group 5 (wear) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the EDG starting air system drain trap components susceptible to wear:

- The EDG drain trap components contribute to maintaining the pressure boundary that must be maintained under CLB design conditions.
- Wear is plausible for the EDG drain trap components. The internals and pivot rod may periodically experience cyclic operation. The expected effect of wear is a progressive loss of pressure boundary sealing capability.
- The CCNPP ARDI Program will provide for the discovery of any wear on the internal surfaces of EDG drain traps components.

Therefore, there is reasonable assurance that the effects of wear of EDG starting air system drain traps will be managed in order to maintain their intended function under all design loading conditions required by the CLB during the period of extended operation.

5.8.3 Conclusion

The programs discussed for the EDG System components are listed on the following table. These programs are, or will be, 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 EDG System components will be maintained consistent with the CLB during periods 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 5.8-4
LIST OF AGING MANAGEMENT PROGRAMS FOR EDG SYSTEMS

	Program	Credited as
Existing	CCNPP Specification and Surveillance Diesel Generators' Jacket Cooling System (CP-222)	Mitigation of the effects of general corrosion, crevice corrosion, and pitting (Group 1) for the EDG jacket water expansion tanks and cooling water piping.
Existing	CCNPP Specification and Surveillance - Diesel Fuel Oil (CP-226)	Mitigation of the effects of general corrosion, crevice corrosion, pitting (Group 1), and MIC (Group 4) for the interior surfaces of the diesel fuel oil day tanks, drip tanks with associated level switches.
Existing	CCNPP Surveillance Test Procedures (STP O-8A-2, STP O-8B-2, STP O-8B-1) for Testing EDGs and the 4 kV LOCA Sequencers	Mitigation of general corrosion, crevice corrosion, pitting (Group 1), and MIC (Group 4) for the interior surfaces of the diesel fuel oil day tanks/drip tanks by draining them after EDG testing for the presence of any water.
Modified	Several repetitive tasks calling for MPM01125, Remove Relief Valve, Test and Reinstall	Discovery of effects of general corrosion, crevice corrosion, and pitting (Group 1) on the internal surfaces of the EDG starting air and combustion air intake piping. The MPM will be modified to inspect for corrosion of piping and check for the presence of debris in valves that could indicate the piping in these systems is undergoing corrosion.
Modified	Several repetitive tasks calling for MPM07006, Disassemble, Inspect and Overhaul EDG Check Valve	Discovery of effects of general corrosion, crevice corrosion, and pitting (Group 1) on the internal surfaces of the EDG starting air and combustion air intake piping and starting air system check valves. The MPM will be modified to inspect for corrosion of piping and check for the presence of debris in valves that could indicate the piping in these systems is undergoing general/crevice corrosion.
Modified	Several repetitive tasks calling for MPM13000, Clean and Inspect EDG Air Start Distributor and Check Valves	Discovery of effects of general corrosion, crevice corrosion, and pitting (Group 1) on the internal surfaces of the EDG starting air and combustion air intake piping. The MPM will be modified to inspect for corrosion of piping and check for the presence of debris in valves that could indicate the piping is undergoing corrosion.
Modified	Several repetitive tasks calling for MPM13002, Inspect EDG air Start Valves and Filters	Discovery of effects of general corrosion, crevice corrosion, and pitting (Group 1) on the internal surfaces of the EDG starting air and combustion air intake piping. The MPM will be modified to inspect for corrosion of piping and check for the presence of debris in valves that could indicate the piping in these systems is undergoing corrosion.

TABLE 5.8-4
LIST OF AGING MANAGEMENT PROGRAMS FOR EDG SYSTEMS

	Program	Credited as
Modified	Several repetitive tasks calling for MPM07117, Inspect EDG Air Intake Filters	Discovery of effects of general corrosion, crevice corrosion, and pitting (Group 1) on the internal surfaces of the EDG starting air/combustion air intake piping, internal surfaces of the EDG intake filters and intake mufflers, and external surfaces of the EDG intake filters. The MPM will be modified to inspect attached piping for signs of corrosion.
Modified	Several repetitive tasks calling for MPM13003, MPM13004/MPM13005 Clean/Inspect 2B, 1B, and 2A EDG Lube Oil "Y" Strainers and Baskets	Discovery of effects of general corrosion, crevice corrosion, and pitting (Group 1) on the internal surfaces of the wye strainers. These MPMs will be modified to check for signs of corrosion on the wye strainer internal surfaces.
Modified	Several repetitive tasks calling for MPM13110, Perform Visual Examination for EDG Exhaust Components	Discovery of the effects of general corrosion, crevice corrosion, and pitting (Group 1); corrosion fatigue/fatigue (Group 2) on the external surfaces of the EDG exhaust piping and mufflers. The MPM will be modified to look for signs of corrosion fatigue/fatigue on the external surfaces of the EDG exhaust piping and exhaust mufflers.
New	CCNPP ARDI Program	Discovery of the effects of general corrosion, crevice corrosion, and pitting (Group 1) on the internal surfaces of the EDG starting air accumulators, jacket water expansion tanks, diesel fuel oil day tanks, and drip tanks with their associated tank level switches, hand valves, drain traps, exhaust piping and mufflers, and cooling water piping. It is also credited with the discovery of corrosion fatigue/fatigue (Group 2) on the internal surfaces of the EDG exhaust piping and exhaust mufflers; erosion corrosion (Group 3) on the internal surfaces of the EDG cooling water piping and erosion corrosion/particulate wear erosion on the internal surfaces of the EDG exhaust mufflers; MIC (Group 4) on the internal surfaces of the EDG fuel oil day tanks, drip tanks, and their associated tank level switches; and wear (Group 5) on the internal surfaces of the EDG drain traps.

5.8.4 References

1. Calvert Cliffs Nuclear Power Plant, Updated Final Safety Analysis Report, Revision 20
2. CCNPP Aging Management Review Report for the Emergency Diesel Generator System, Revision 1, Dated September 22, 1997
3. CCNPP Failure Detail Report for the Emergency Diesel Generators - January 1, 1980 to June 1, 1997
4. Letter from Mr. C. J. Cowgill (NRC) to Mr. R. E. Denton (BGE),), dated December 9, 1993, “NRC Region I Combined Inspection Report Nos. 50-317/318/93-30 (October 10, 1993 - November 13, 1993
5. BGE Drawing 64320, “Simplified System Drawing Diesel No. 2A Starting Air, Fuel & Lube Oil,” Revision 6, April 29, 1997
6. BGE Drawing 64321, “Simplified System Drawing Diesel No. 1B Starting Air, Fuel & Lube Oil,” Revision 3, October 3, 1996
7. BGE Drawing 64322, “Simplified System Drawing Diesel No. 2B Starting Air, Fuel & Lube Oil,” Revision 4, March 16, 1997
8. CCNPP Component Level ITLR Screening Results for the Emergency Diesel Generator System, Revision 2, September 22, 1997
9. CCNPP Chemistry Procedure CP-226, "Specification and Surveillance - Diesel Fuel Oil," Revision 4, dated March 27, 1997
10. CCNPP Chemistry Procedure CP-222, “Specifications and Surveillance Diesel Generators’ Jacket Cooling System,” Revision 3, November 4, 1996
11. CCNPP Surveillance Test Procedure STP-O-8B-1, “Test of 1B DG and 14.4KV Bus LOCA Sequencer,” Revision 12, May 21, 1997
12. CCNPP Surveillance Test Procedure STP-O-8B-2, “Test of 2B DG and 4KV Bus 24 LOCA Sequencer,” Revision 11, May 21, 1997
13. CCNPP Surveillance Test Procedure STP-O-8A-2, “Test of 2A DG and 4KV Bus 21 LOCA Sequencer,” Revision 12, May 21, 1997
14. CCNPP Administrative Procedure MN-1-102, “Preventive Maintenance Program,” Revision 5, September 27, 1996
15. Letter from Mr. R. W. Cooper II (NRC) to Mr. C. H. Cruse (BGE), dated May 31, 1996, “Calvert Cliffs Plant Performance Review Results”
16. CCNPP MPM01125 Checklist Sheet, “Remove Relief Valve, Test and Reinstall,” Revision 0, December 23, 1991
17. CCNPP MPM07006 Checklist Sheet, “Disassemble, Inspect and Overhaul EDG Check Valve,” Revision 0, November 22, 1994
18. CCNPP MPM13000 Checklist Sheet, “Clean and Inspect EDG Air Start Distributor and Check Valves,” Revision 0, October 3, 1991
19. CCNPP MPM13002 Checklist Sheet, “Inspect EDG Air Start Valves and Filters,” Revision 0, February 5, 1992

20. CCNPP MPM07117 Checklist Sheet, "Inspect EDG Air Intake Filters," Revision 0, July 14, 1993
21. CCNPP MPM13110 Checklist Sheet, "Perform Visual Examination for EDG Exhaust Components," Revision 0, May 23, 1995
22. CCNPP MPM13003 Checklist Sheet, "Clean/Inspect 2B Lube Oil "Y" Strainers and Baskets," Revision 0, November 12, 1991
23. CCNPP MPM13004 Checklist Sheet, "Clean/Inspect 1B Lube Oil "Y" Strainers," Revision 0, December 12, 1991
24. CCNPP MPM13005 Checklist Sheet, "Clean/Inspect 2A Lube Oil "Y" Strainers and Baskets," Revision 0, November 12, 1991

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]

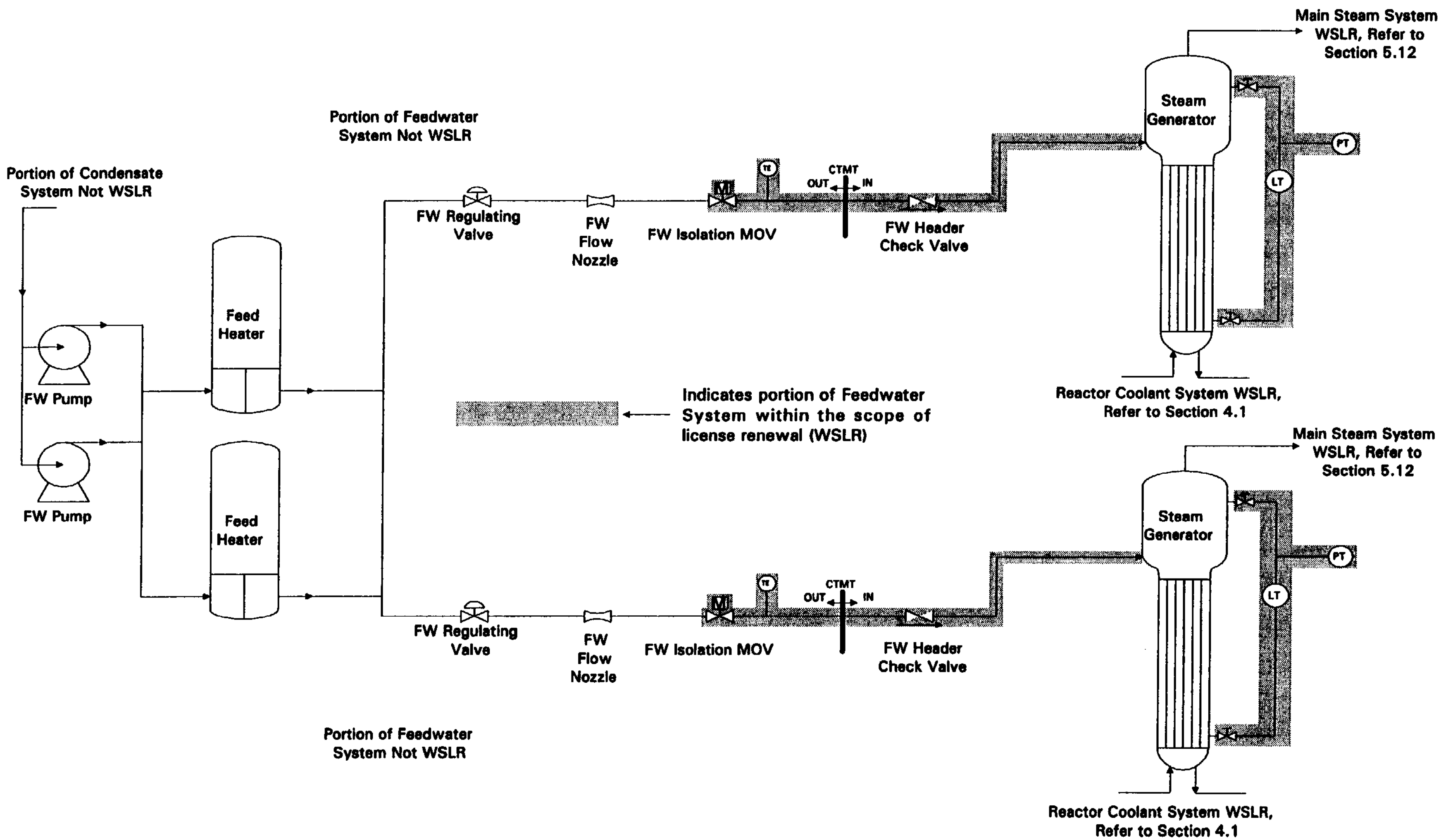


Figure 5.9-1

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 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 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 420ºF 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]

<u>Evaluation of Thermal Fatigue Effects to Address Generic Safety Issue 166</u>

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.

<u>CCNPP Preventive Maintenance Program -</u>

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"

5.10 Fire Protection

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

As discussed in Section 7.2.4 of the CCNPP IPA Methodology, due to the unique circumstances pertaining to the systems that perform FP intended functions (e.g., the degree of component level scoping completed elsewhere, similarity of FP functions, and degree of aging review already completed elsewhere), an aging management review (AMR) process separate and unique from that used for plant systems and structures was used.

Section 5.10.1 presents the results of the system and component level scoping process. Section 5.10.2 describes the methods used for AMR, and Section 5.10.3 provides summaries of the AMR results for each system evaluated for aging management in this section of the BGE LRA.

5.10.1 Scoping

Forty-two systems are credited with performing FP functions. All components required for FP in 26 of these systems are safety-related (SR), and those systems are fully addressed in other sections of the BGE LRA. Some of the remaining 16 systems also have SR components that are addressed in other sections of the BGE LRA. Thus, the focus of this section is limited to the non-safety-related (NSR) pressure-retaining portions of the remaining 16 systems. Scoping details are provided in the following subsections.

5.10.1.1 System Level Scoping

System level scoping of the 122 systems and structures at CCNPP identified that 66 were within the scope of license renewal. [Reference 1, Table 1] For these 66 systems and structures, those with FP functions were identified during the scoping process using the FP Screening Tool. The FP Screening Tool defines two categories of FP functions as follows: [References 1 and 2]

<u>FP Function</u>:

This function includes equipment and facilities important to safety that provide for detecting, fighting, and extinguishing fires. These systems are necessary to protect SR equipment and structures from fire or explosion. This function does not include FP equipment or facilities protecting NSR equipment or structures.

<u>Safe Shutdown Function</u>:

This function applies to systems that provide for safe shutdown of the plant in the event of a severe fire. Calvert Cliffs' current licensing basis (CLB) requires compliance with 10 CFR Part 50, Appendix R, Sections III.G, III.J, III.L, and III.O. Therefore, the evaluations pertaining to safe shutdown identified those components that are required for compliance with these regulations. The safe shutdown function includes the capability to provide for: [Reference 2, Section 2.0]

- Reactor Coolant System (RCS) pressure and inventory control;
- Reactivity control;

- Heat removal (hot standby or cold shutdown) from the RCS; and
- Process monitoring.

The CCNPP Updated Final Safety Analysis Report, the FP Program licensing basis documentation, and the CCNPP Interactive Cable Analysis for each unit were reviewed to identify the system functions that address regulations on FP and BGE's commitments for implementation of those regulations. [See Section 2.0 of the BGE LRA, IPA, Section 3.3.2.1]

The FP Screening Tool identified that 42 of the 66 systems and structures within the scope of license renewal have one or more FP intended functions. These 42 systems and structures are listed in Table 5.10-1. [Reference 1, Table 2]

5.10.1.2 Systems and Structures Addressed In Other Sections of the BGE LRA

Evaluation of all components required for FP for 26 of the 42 CCNPP systems and structures with passive FP intended functions are included within their respective SR system or structural AMR or in a commodity evaluation. These systems and structures fall into one of the following three categories: 1) structures with components that provide a fire barrier; 2) fluid systems with components that provide part of a pressure boundary (PB) in systems with only SR PB components; and 3) electrical systems with components that perform only active electrical functions.

Structures

The only passive FP intended functions performed by components in five systems and structures listed in Table 5.10-1 are to provide rated fire barriers to confine or retard fires from spreading to or from adjacent areas of the plant. Rated fire barriers include doors, walls, floors (and curbs), ceilings, penetration seals, and cable tray fire barrier materials. These components are in the following systems and structures: [References 3 through 8]

System 009	–	Intake Structure
System 059	–	Primary Containment
System 120	–	Barriers and Barrier Penetrations
N/A	–	Auxiliary Building
N/A	–	Turbine Building

The results of the AMR for the components in these systems and structures that perform this passive FP intended function are provided in Sections 3.3A, 3.3B, 3.3C, and 3.3E of the BGE LRA. These five systems and structures are not addressed further below. Note that the fire barrier components for the Barriers and Barrier Penetrations System are part of the four structures listed above and are, therefore, not addressed as a "system" in the IPA process, but as part of those structures. [Reference 1]

TABLE 5.10-1

SYSTEMS AND STRUCTURES WITHIN THE SCOPE OF LICENSE RENEWAL WITH FIRE PROTECTION FUNCTIONS

	System #	Description
1	002	Electrical 125 Volt DC Distribution
2	004	Electrical 4 kV Transformers and Buses
3	005	Electrical 480 Volt Transformers and Buses
4	006	Electrical 480 Volt Motor Control Centers
5	008	Well and Pretreated Water
6	009	Intake Structure
7	011	Service Water (SRW)
8	012	Saltwater
9	013	FP
10	015	Component Cooling (CC)
11	017	Instrument AC
12	018	Vital Instrument AC
13	019	Compressed Air
14	023	Diesel Fuel Oil
15	024	Emergency Diesel Generators
16	026	Annunciation
17	029	Plant Heating
18	030	Control Room Heating, Ventilation and Air Conditioning (HVAC)
19	032	Auxiliary Building and Radwaste Heating and Ventilation (H&V)
20	036	Auxiliary Feedwater (AFW)
21	037	Demineralized Water and Condensate Storage
22	041	Chemical and Volume Control
23	044	Condensate
24	045	Feedwater
25	052	Safety Injection
26	053	Plant Drains
27	055	Control Rod Drive Mechanism and Electrical
28	059	Primary Containment
29	060	Primary Containment H&V
30	061	Containment Spray
31	064	Reactor Coolant
32	071	Liquid Waste
33	074	Nitrogen and Hydrogen Gas System
34	078	Nuclear Instrumentation
35	083	Main Steam
36	093	Main Turbine
37	096	Fire and Smoke Detection
38	097	Lighting and Power Receptacles
39	100	Plant Communications

TABLE 5.10-1

SYSTEMS AND STRUCTURES WITHIN THE SCOPE OF LICENSE RENEWAL WITH FIRE PROTECTION FUNCTIONS

	System #	Description
40	120	Barriers and Barrier Penetrations
41	N/A	Auxiliary Building
42	N/A	Turbine Building

Fluid Systems

The only passive FP intended function performed by components in eight systems and structures listed in Table 5.10-1 is the PB function (e.g., piping, valve bodies, etc.). All of these components, with one exception noted below, also provide the SR PB function. Therefore, AMR of these components is included in the AMR for the passive SR PB intended functions. These systems, and the sections of the BGE LRA where the AMR results for each is provided, are as follows: [References 9 through 24]

System 012	–	Saltwater	LRA Section 5.16
System 024	–	Emergency Diesel Generators	LRA Section 5.8
System 030	–	Control Room HVAC	LRA Section 5.11C
System 032	–	Auxiliary Building H&V	LRA Section 5.11A
System 045	–	Feedwater	LRA Section 5.9
System 052	–	Safety Injection	LRA Section 5.15
System 060	–	Primary Containment H&V	LRA Section 5.11B
System 061	–	Containment Spray	LRA Section 5.6

The exception is that part of the passive FP-related PB of System 030 is not SR. However, the results of the AMR provided in Section 5.11C of the BGE LRA addresses this NSR portion, as well as the SR parts. The eight systems listed above are not addressed further below.

Electrical Systems

There are 13 electrical systems listed in Table 5.10-1 with components that perform FP intended functions that are active. Those systems require no further evaluation since the remaining intended functions that are passive, i.e., electrical continuity and component support, are addressed in other commodity evaluations. These systems are: [References 2 and 25 through 48]

System 002	–	Electrical 125 Volt DC Distribution
System 004	–	Electrical 4 kV Transformers and Buses
System 005	–	Electrical 480 Volt Transformers and Buses
System 006	–	Electrical 480 Volt Motor Control Centers
System 017	–	Instrument AC
System 018	–	Vital Instrument AC
System 026	–	Annunciation
System 055	–	Control Rod Drive Mechanism and Electrical
System 078	–	Nuclear Instrumentation
System 093	–	Main Turbine

System 096	–	Fire and Smoke Detection
System 097	–	Lighting and Power Receptacles
System 100	–	Plant Communications

These 13 systems are not addressed further in this report.

5.10.1.3 Systems and Structures Addressed as Part of FP

As described above, all components required for FP in 26 of the 42 CCNPP systems and structures with passive FP intended functions are fully addressed within their respective SR system or structural AMR or in a commodity evaluation. The remaining 16 systems are in the scope of the FP AMR and are addressed in this report. These systems fall into one of the following two categories: 1) systems that have undergone component level scoping; and 2) systems that have not been previously scoped because they primarily have only NSR functions.

5.10.1.3.1 Systems With Prior Component Level Scoping

Nine systems that perform passive FP intended functions have both SR and NSR PB components. The SR portions of these systems are addressed in other sections of the BGE LRA since these SR systems had component level scoping and AMR performed due to their non-FP intended functions. The NSR PB portions of these systems are addressed later in this report. These nine systems, and the sections of the BGE LRA where the SR PB portion of each is addressed, are as follows:

System 011	–	SRW	Section 5.17
System 015	–	CC	Section 5.3
System 019	–	Compressed Air	Section 5.4
System 023	–	Diesel Fuel Oil	Section 5.7
System 036	–	AFW	Section 5.1
System 041	–	Chemical and Volume Control	Section 5.2
System 064	–	Reactor Coolant	Section 4.1
System 074	–	Nitrogen and Hydrogen Gas System	Section 5.12
System 083	–	Main Steam	Section 5.12

5.10.1.3.2 Systems Without Prior Component Level Scoping

Seven systems rely almost entirely on NSR components to perform their passive FP intended functions, and there was no component level scoping or AMR performed for each individual system. These systems are addressed in this section of the BGE LRA and are as follows:

System 008	–	Well and Pretreated Water
System 013	–	FP *
System 029	–	Plant Heating *
System 037	–	Demineralized Water and Condensate Storage *
System 044	–	Condensate
System 053	–	Plant Drains *
System 071	–	Liquid Waste *

* These five systems also have a passive intended function, i.e., containment isolation, that is SR. The AMR results below address the NSR FP intended functions. The AMR results for the SR components in these systems are provided in the Containment Isolation Group, Section 5.5 of the BGE LRA.

5.10.1.4 Component Level Scoping

For most systems and structures within the scope of license renewal, a detailed list of components contributing to an intended function of the system or structure was produced. For some systems with passive FP intended functions, component level scoping was performed the same way, but for others, it was performed by characterizing the extent of the system that supports such functions. This was accomplished by defining the boundary (or envelope) of the important pressure-retaining features of the system in terms of major components or interfaces with other systems, and by identifying the specific device types that fell within that boundary (or envelope). [Reference 2, Appendix B, Task 1, Section 6.3] This is an acceptable method of component level scoping since the components subject to AMR can be readily determined from review of the device type lists and drawing references. [Reference 49]

5.10.1.4.1 Components Addressed in Commodity Evaluations

Some components with FP functions are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 2, Section 2.0]

- 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.
- Electrical panels that support and/or protect electrical components are evaluated for the effects of aging in the Electrical Panels Commodity Evaluation in Section 6.2 of the BGE LRA.
- Instrument tubing and piping and the associated tubing supports, instrument valves and fittings (generally everything from the outlet of the final root valve up to and including the instrument), and the PBs 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.

5.10.2 AMR Methods

During normal operation, SR systems and components typically do not operate under their design conditions. The demands placed on most SR systems and components during normal operation are much less than the demands placed on them during mitigation of design basis events. Some SR systems, such as Safety Injection and Containment Spray, do not normally operate and are maintained in a continuous standby mode. The SR systems and components on standby do not demonstrate they are capable of performing any intended functions during normal day-to-day operations. Therefore, functional tests of SR systems and components have been devised to demonstrate their ability to perform active intended functions. But these tests are not suitable for demonstrating the ability to perform passive intended functions. This is because the tests are incapable of simulating the loading conditions (e.g., seismic accelerations or other dynamic loading) under which SR components are required to perform. Therefore, methods of demonstrating aging management, such as condition assessments or inspections, are required for SR systems and components.

The above stipulations are not true for NSR components such as those being addressed in this section of the BGE LRA. The demands placed on most NSR systems and components during normal operation are the same as, or greater than, the demands placed on them during mitigation of fires. Because they are NSR, they are not designed to operate under postulated dynamic loading conditions such as seismic accelerations. Therefore, operation of the system during normal operations is an adequate test of the system for FP design loading conditions. Demonstration that the active FP intended functions are capable of being performed also demonstrates that the passive FP intended functions are capable of being performed. In other words, it can be shown that most NSR systems and components demonstrate they are capable of performing their passive FP intended functions along with their active FP intended functions during normal routine operation, testing, or inspection activities. [Reference 2, Section 2.0] As such, four different methods were applied to demonstrate aging management of these NSR components. Refer to Figure 5.10-1 on the following page for an illustration of this process.

The first three methods were applied in sequential order to demonstrate that aging effects for an entire system, or portions of it, could be adequately managed without a specific determination of Age-Related Degradation Mechanisms (ARDMs). In this manner, the scope of the system requiring further review was reduced with application of each succeeding method. Device types not addressed by any of these first three methods required an AMR that identified the plausible ARDMs and the appropriate aging management programs. It should be noted that, in some cases, system components may have aging effects managed by more than one of the four methods. However, since the end result would be the same, the approach using successive incremental methods was used without identifying all possible management alternatives. Table 5.10-2 on the following page lists the 16 systems that are evaluated for aging management in this section. [Reference 2, Table ES-1] The table has four additional columns identifying which of the four methods was used to demonstrate aging management. The methods are explained below. [Reference 2]

Representative historical operating experience pertinent to aging is included where appropriate to provide insight supporting the aging management demonstrations. This operating experience was obtained through documented discussions with currently assigned cognizant CCNPP personnel. Key-word searches of BGE's electronic database of information on the CCNPP dockets was also performed in order to obtain pertinent operating experience.

Figure 5.10-1

FP AMR Process

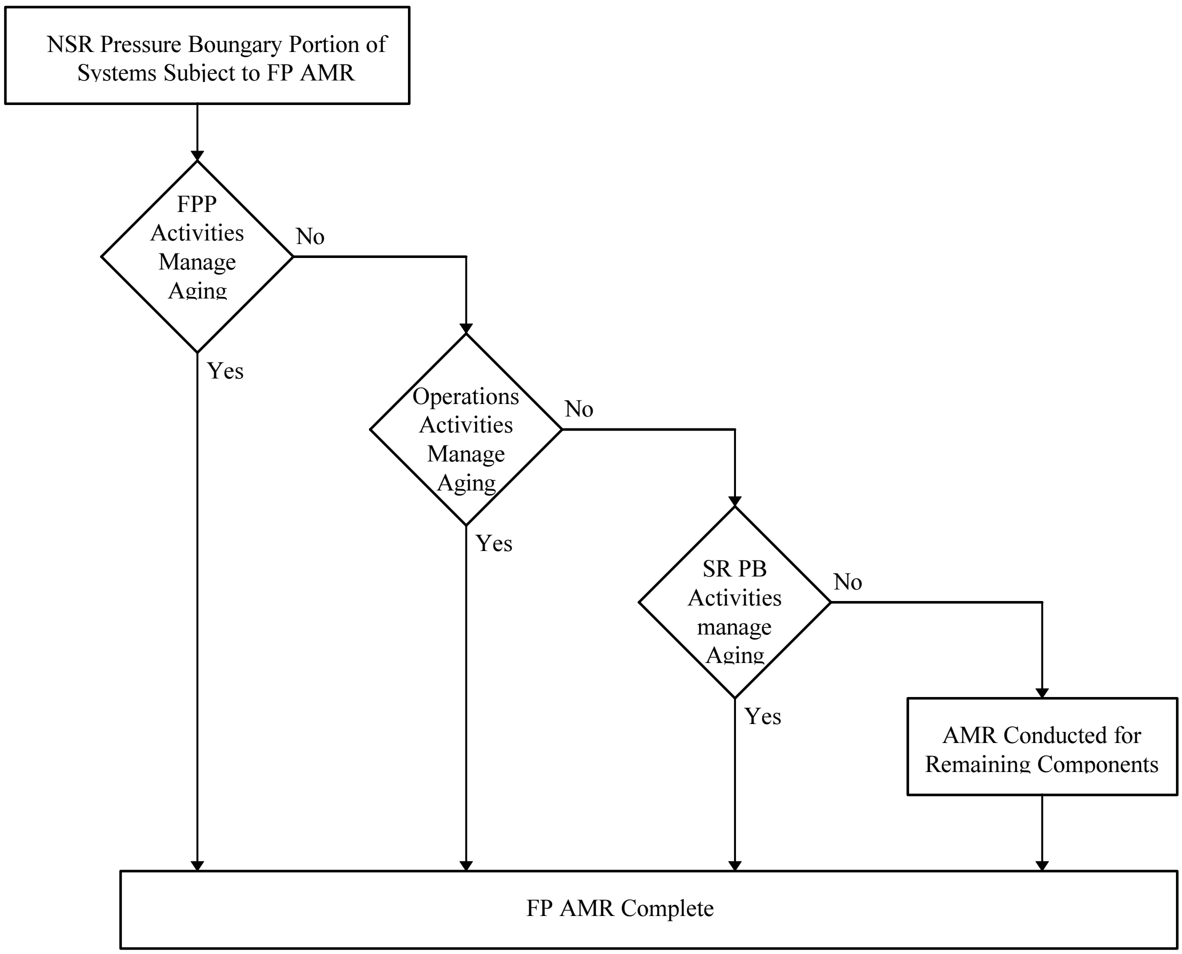


TABLE 5.10-2

FP AMR SUMMARY OF RESULTS

System	System No.	FP Program Activities Manage Aging	Performance and Condition Monitoring Activities Manage Aging	SR PB AMR Manages Aging	AMR Conducted	BGE LRA Section
Well and Pretreated Water	008	No	Yes	N/A	N/A	5.10.3.1
SRW	011	No	Yes	N/A	N/A	5.10.3.2
FP	013	Yes	N/A	N/A	N/A	5.10.3.3
CC	015	No	Yes	N/A	N/A	5.10.3.4
Compressed Air	019	No	Yes	N/A	N/A	5.10.3.5
Diesel Fuel Oil	023	Yes	N/A	N/A	N/A	5.10.3.6
Plant Heating	029	No	Yes	N/A	N/A	5.10.3.7
AFW	036	Yes (Partial)	Yes (Partial)	N/A	N/A	5.10.3.8
Demineralized Water & Condensate Storage	037	No	Yes	N/A	N/A	5.10.3.9
Chemical and Volume Control	041	No	No	Yes	N/A	5.10.3.10
Condensate	044	No	Yes (Partial)	No	Yes (Partial)	5.10.3.11
Plant Drains	053	Yes (Partial)	Yes (Partial)	N/A	N/A	5.10.3.12
Reactor Coolant	064	No	No	Yes	N/A	5.10.3.13
Liquid Waste	071	No	Yes	N/A	N/A	5.10.3.14
Nitrogen & Hydrogen Gas	074	Yes	N/A	N/A	N/A	5.10.3.15
Main Steam	083	No	Yes	N/A	N/A	5.10.3.16

5.10.2.1 FP Program Activities Manage Aging

This is the first step in the sequential process described above. This method demonstrates that the aging effects on a system's NSR pressure-retaining components are adequately managed by specific performance and/or condition monitoring activities required by the plant's FP Program. The Nuclear Program Directive SA-1, "Fire Protection Program," establishes requirements and assigns responsibilities for the FP Program at CCNPP. The FP Program is the integrated effort involving components, procedures, and personnel used to carry out all activities of FP Program and prevention. It contains maintenance, testing, and inspection criteria to provide reasonable assurance that various NSR systems are capable of performing their FP intended functions. Any abnormal condition would be detected and investigated to ensure that it does not have the ability to impact safety or adversely affect operation of the system. Any such condition would be repaired prior to impacting the passive FP intended function of the system in question. The site's FP Program is part of the plant's CLB. [Reference 2, Section 6.1; Reference 50]

In order to demonstrate adequate aging management for each system's components through various FP Program performance and/or condition monitoring activities, the following tasks were performed: [Reference 2, Section 6.1]

- The system's intended functions were identified.
- The applicable performance and/or condition monitoring activities (e.g., maintenance, testing, and inspection activities) required by the FP Program for the system were identified.
- The performance and/or condition monitoring activities applicable to the system's passive FP intended functions were identified.
- The NSR pressure-retaining components within the portion of the system tested by the FP Program performance and/or condition monitoring activities were identified.

For systems and components to which it applies, this method shows that the effects of aging will not impact FP intended functions during the period of extended operations. Where this type of demonstration was successful, the FP Program is credited as the appropriate aging management program. [Reference 2, Section 6.1]

The FP Program provides the necessary controls to protect the health and safety of CCNPP workers and the general public, satisfy NRC and Insurer requirements, meet applicable State of Maryland codes and standards, and safeguard BGE assets by preventing fires and minimizing the consequences of any fire that may occur. A discussion of the CCNPP FP Program is presented in Section 9.9 of the UFSAR. [Reference 51] The program addresses: [Reference 50, Section 1.2]

- Fire protection aspects of structure system, and component design;
- Inspection and testing of FP systems and equipment;
- Procurement of FP equipment and material;
- Controls for the prevention of fires;
- Fire fighting;
- Fire prevention and response training;
- Monitoring and continuous assessment of the FP Program; and
- Auditing of the FP Program.

Fire protection equipment and systems are inspected and tested upon initial installation and periodically thereafter. [Reference 51] Inspections ensure that the installation, maintenance, and modification of FP equipment conform to design requirements. [Reference 50] The inspection and testing is conducted following the guidance of applicable National Fire Protection Association Codes and Standards, as well as recommendations and requirements of the insurance carrier and the NRC. Plant procedures mandate test frequencies and the testing process. Applicability, compensatory actions, testing requirements, and testing frequencies for those FP systems that protect safe shutdown and SR equipment are contained in the CCNPP Technical Specifications. [Reference 52] Plant procedures also identify compensatory actions to be taken when equipment required for 10 CFR Part 50, Appendix R, safe shutdown actions becomes inoperable. [Reference 51]

Activities related to FP are performed within the applicable provisions of the BGE's Quality Assurance Program based on 10 CFR Part 50, Appendix B, and in accordance with the quality assurance guidance in Branch Technical Position 9.5-1, Appendix A, and the NRC's guidance document, "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance." [Reference 51] Internal assessments of the FP Program are conducted through periodic audits in accordance with Quality Assurance Policy requirements. [Reference 50]

5.10.2.2 Performance and Condition Monitoring Activities During Normal Operation Manage Aging

This is the second step in the sequential process and is applied if the FP Program method above is not completely successful in demonstrating aging management of a system's NSR components. As was noted previously, the demands placed on most NSR systems and components during normal operation are the same as, or greater than, the demands placed on them during mitigation of fires. Therefore, satisfactory performance of periodic functional tests can be used to demonstrate that aging is adequately managed for the passive FP functions of NSR components. A system that is in continuous operation during normal operation can be characterized as undergoing a continuous FP functional test if the system parameters (pressure, temperature, flow, etc.) encountered during performance of FP intended functions are bounded by the normal operating parameters of the system. The performance and condition monitoring activities conducted in accordance with procedures such as MN-1-319, Structure and System Walkdowns, and NO-1-100, Conduct of Operations, ensure detection of abnormal conditions. MN-1-319 stipulates in part that the intent of the walkdowns is to identify and record any new or existing condition that could prevent a system or component from performing its intended function. Conditions adverse to functionality, indications of system or equipment stress or abuse, safety or fire hazards and housekeeping deficiencies are identified. Walkdowns are scheduled for plant conditions that provide good indications of system functionality. NO-1-100 requires that operators be accountable for their immediate areas of responsibility. This includes performing general inspections and checking the condition of areas and equipment. Operators assess degraded equipment conditions to ensure personnel and affected equipment safety while completing corrective actions. [References 53 and 54] It should be noted that many of the systems are required to deliver water for their FP function, whether for fire fighting or for safe shutdown. For those systems, absolute leak tightness is not required.

Where the above type of demonstration is successful, performance and condition monitoring activities during normal operation are credited for identifying the effects of system aging. Specific aging management programs are not necessary, and no further evaluation is required. [Reference 2, Section 6.2] A more detailed description of MN-1-319 and NO-1-100 are provided below.

System Walkdowns

The Structure and System Walkdown Program has been established to standardize the general intent and method of conducting walkdowns and of reporting the walkdown results. This procedure meets the requirements for evaluating structure and system material condition in accordance with the (NRC) Maintenance Rule at CCNPP. Walkdown activities provide for discovery of many ARDMs by performing periodic visual inspections for evidence of aging. When degraded conditions are identified, more detailed inspections are performed and/or corrective actions are taken to repair the deficiency. [Reference 53]

Under this program, personnel with assigned responsibility for specific structures and systems perform periodic walkdowns. Walkdowns may also be performed as required for reasons such as material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when a system is pressurized, re-energized, or placed into normal service); and as required for plant modifications. Inspection items typically related to aging management include identifying unusual noises, leaks, corrosion, or degraded paint and identifying system and equipment stress or abuse, such as excessive vibrations, bent or broken component supports, loosened fasteners, etc. [Reference 53, Sections 5.1 and 5.2]

One of the objectives of the program is to assess the condition of the CCNPP structures, systems, and components such that any degraded condition will be identified, documented, and corrective actions taken before the degradation proceeds to failure of any structure, system, and component to perform its intended functions. Conditions adverse to quality are documented and resolved by the Calvert Cliffs Corrective Actions Program. [Reference 53, Sections 5.1.C, 5.2.A.1, and 5.2.A.5; Reference 55]

The program provides guidance for specific types of degradation or conditions to inspect for when performing the walkdowns. General inspection items related to aging management include the following: [Reference 53, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion;
- Effects that may have been caused by ARDMs such as damaged supports, concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, excessive vibration, or inadequate support of components (e.g., missing, detached, or loose fasteners and clamps).

This program promotes familiarity of the systems by the responsible personnel and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance alone. The program has been improved over time, based on past experience, to provide guidance on specific activities to be included in the scope of the walkdowns.

Conduct of Operations

Administrative procedure NO-1-100 addresses the controls and basic standards for conduct of daily shift operations, Control Room access and conduct, special evolutions and tests, and briefings. This procedure requires that operators assess degraded equipment conditions to ensure personnel and affected equipment safety while completing corrective actions. [Reference 54] For those system(s) and component(s) where the system parameters during performance of FP intended functions are bounded by the normal system operating parameters, performance and condition monitoring activities during normal operation provide for discovery of unspecified aging effects by visual inspection and assessment of degraded conditions.

Administrative procedure NO-1-100 establishes the responsibilities and authority of operating shift personnel for the daily conduct of plant operations. It serves as a governing procedure for a wide range of performance and condition monitoring activities during normal operation. Some of the performance and condition monitoring activities that are controlled by this procedure include the following: [Reference 54]

Operator Rounds - visual inspections of operating spaces each shift during plant operator rounds;

Plant Logs - collect selected data for operating equipment and analyze it to detect abnormal or degraded equipment performance;

Operations Section Performance Evaluations - periodic checks to determine equipment performance, as determined by manufacturers' recommendations, System Engineers' recommendations, and operating needs;

Surveillance Testing - surveillance requirements specified by CCNPP Technical Specifications to verify that SR structures, systems, and components continue to function or are in a state of readiness to perform their functions; and

Troubleshooting - diagnosing plant/equipment symptoms for the purpose of identifying/quantifying a degraded parameter/component or verifying the operability of a component.

Operator rounds have historically been effective in identifying plant deficiencies. The documented guidance and expectations have been improved over the years as a result of lessons learned and the site emphasis on continual quality improvement. Plant operating practices are also periodically evaluated by the NRC as part of their Systematic Assessment of Licensee Performance efforts.

5.10.2.3 AMR of SR PB Components Manages Aging

The third step in the sequential process is applied if the FP Program and normal operating condition methods above are not completely successful in addressing a system's aging management. This method applies to the NSR portion of SR systems for which there is an AMR that determined plausible ARDMs and addressed management of the aging effects. This method recognizes that similar materials subjected to similar process fluids and environmental service conditions can reasonably be expected to have the same plausible aging effects, and can be managed in the same manner regardless of whether a system's components are classified as SR or NSR. [Reference 2, Section 6.3]

This method involves the following tasks: [Reference 2, Section 6.3]

- Review the results of a system's SR PB AMR with specific focus on the plausible ARDMs identified and the aging management programs.
- Determine if the plausible ARDMs are equally applicable to NSR PB components of the FP AMR through similarities in equipment types, device types, materials of construction, process fluids, exterior environments, operating conditions and other service conditions.
- Determine if the programs credited for the SR PB components are applicable to the NSR PB components subject to the same ARDMs. If the Age-Related Degradation Inspection (ARDI) Program is used to manage aging, add the NSR PB components to the scope of the ARDI.

In completing the above steps, component make, model and other component-specific information was not always identified for components subject to the FP AMR solely for the purpose of determining the applicability of the SR review results. Rather, the similarities between the two portions of the system were characterized based on a review of design specifications (e.g., the pipe class and valve type specification sheets) supplemented with a review of the system descriptions, other available design documents, and any other appropriate information. [Reference 2, Section 6.3]

This method demonstrates that aging of NSR PB components with passive FP intended functions is adequately managed when they are subject to the same aging management activities as similar SR PB components.

5.10.2.4 AMR Conducted for Remaining Components

One system, the Condensate System, was found to have components not addressed by the three methods discussed above. For portions of the Condensate System, it was necessary to use the fourth method. This method utilizes the normal IPA process used for most systems and structures, which includes identifying system intended functions, plausible ARDMs, and methods to manage aging effects.

5.10.2.5 Summary of FP AMR Results

- Aging of all components in scope for three systems is fully managed by the FP Program (Systems 013, 023 and 074).
- Aging of all components in scope for eight systems is fully managed by performance and condition monitoring activities during normal operation. (Systems 008, 011, 015, 019, 029, 037, 071 and 083)
- Aging of all components in scope for two systems is fully managed by a combination of the activities associated with the FP Program and performance and condition monitoring activities during normal operation. (Systems 036 and 053)
- Aging of all components in scope for two systems is fully managed by programs identified for similar SR PB components. (Systems 041 and 064)
- Aging of all components in scope for one system is fully managed by a combination of the performance and condition monitoring activities during normal operation and the ARDI Program as determined by identification of plausible ARDMs. (System 044)

5.10.3 Systems

The remainder of this report provides the results of the review for the 16 systems listed in Table 5.10-2. For each, a brief discussion of the scoping is provided along with the aging management demonstration.

5.10.3.1 Well and Pretreated Water System [Reference 2, Appendix A, System 008]

The Well and Pretreated Water System consists of three ground wells, three submersible pumps, two activated carbon filters, two pretreated water storage tanks (PWSTs), and two pretreated water booster pumps. Each of the storage tanks is equipped with a heat exchanger and a circulating pump. The system interfaces with the Domestic Water System, Demineralized Water and Condensate Storage System, the warehouse and switchyard control house domestic water subsystem, the FP System, and the Plant Heating System.

The fire pumps take suction from two 500,000 gallon capacity (each) PWSTs. The layout of the pump suction piping from the tanks is such that a minimum of 300,000 gallons (each tank) is always available to the FP System. The remaining 200,000 gallons (each tank) may be used for other services and also is available for FP System supply backup.

During normal operation, the Well and Pretreated Water System is the source of all makeup water for power production, fire fighting and potable water systems. The system pumps operate intermittently to provide makeup water to the PWSTs on an automatic basis to ensure minimum capacity requirements are maintained. The level of the PWSTs is monitored to provide continuous verification of the required capacity. There are two separate alarm annunciators (Control Room and fire pump house) to indicate if the level in either tank drops below 303,000 gallons.

The tanks are supplied by three well water pumps with a nominal combined capacity of 966 gallons per minute to ensure replenishment of the 300,000 gallons within eight hours. The valve in the interconnection piping between the tanks is maintained locked closed to preclude inadvertent draining of both tanks should a leak develop in one tank or its piping. Any of the well water pumps can be aligned to either or both tanks, the FP header and ultimately to the fixed fire suppression system, hoses, and hydrants.

5.10.3.1.1 Operating Experience

In 1997, the No. 13 well water header developed leaks due to corrosion. This one portion of the system was particularly susceptible to corrosion due to it being a carbon steel pipe without a protective wrap, lack of a cathodic protection system, and its location in an area with groundwater flow. Other portions of the system that have been uncovered and inspected have been in excellent condition primarily due to adequate coating and wrapping. The corroded portion is currently being replaced.

Heavy corrosion has been discovered on selected penetrations on the PWSTs from failed coatings due to heat from installed heat tracing. Some penetrations have been replaced as required, additional penetrations were inspected and sandblasted, and then all penetrations were coated with a high temperature coating.

5.10.3.1.2 Scoping Summary

The FP function of this system is to provide water to the FP System for suppression of fires in the plant. There is also a safe shutdown-related FP function to support RCS heat removal by providing an alternate source of water to the steam generators via the FP and AFW Systems. At reduced steam generator pressure, the diesel-driven fire pump can be used to supply steam generator inventory via a fire hose and spool piece connected to direct fire main water to the AFW System. Also, a well water pump can be used to supply makeup water from a PWST to a condensate storage tank (CST), which is a water supply source for the AFW System. The line-up is accomplished by connecting a fire hose between the fire pump house test manifold and a CST emergency hose connection.

The portion of the Well and Pretreated Water System within scope for FP includes components in the flow path from the well water pumps to the PWSTs and the associated pretreated water booster pumps. The following passive FP intended function (not addressed in other evaluations) applies:

- Maintain pressure-retention capability of the system (liquid and/or gas).

5.10.3.1.3 Aging Management Demonstration

As it relates to the requirement to retain system pressure, the parameters of the system while performing the required FP functions are no different than the normal operating parameters. Under certain fire scenarios, the system may have to provide water at a higher flow rate than that required for normal plant makeup requirements. In some cases water would have to be provided directly from the wells to refill tanks or to keep the supply header pressurized. The quantity or rate of water usage under fire suppression or safe shutdown scenarios, however, is not an issue since these are clearly active functions of the system. At issue is the assurance of system pressure-retaining capability. The fire suppression or safe shutdown functions supported by the system do not challenge the system pressure-retaining capability any more than normal operating conditions. Thus, system parameters during performance of FP intended functions are bounded by the normal operating parameters, and aging of all components in scope for this system is fully managed by performance and condition monitoring activities during normal operation.

5.10.3.2 SRW System [Reference 2, Appendix A, System 011]

The SRW System is a closed loop system and uses plant demineralized water with a corrosion inhibitor. The system removes heat from turbine plant components, blowdown recovery heat exchangers, containment cooling units, spent fuel pool cooling heat exchangers, and emergency diesel generator heat exchangers. The system is divided into two subsystems in the Auxiliary Building to meet single failure criteria. Each subsystem has a head tank to maintain the subsystem's pressure and to allow for thermal expansion. The SRW additive tank is connected to both subsystems to allow chemical addition to control and minimize corrosion.

5.10.3.2.1 Operating Experience

Representative historical operating experience pertinent to aging is included in the AMR discussion for the SRW System in Section 5.17 of the BGE LRA.

5.10.3.2.2 Scoping Summary

For nearly all fires, the required SRW flow path is the normal system line-up. The FP function of the SRW System is to provide cooling water to emergency diesel generators, containment air coolers, instrument air compressors, and plant air compressors to ensure safe shutdown in the event of a fire. Diesel Generators 1B, 2A, and 2B receive cooling water from SRW Headers 12, 21, and 22, respectively. Diesel Generators 0C and 1A have self-contained cooling systems and are not supplied by the SRW System. The containment air coolers maintain the containment temperature less than 120°F. Depending on the location of a fire, alternate SRW valve line-ups, including cross-connecting unit headers, may be required to provide a heat sink for the containment coolers. The system also supplies cooling water to the instrument air compressors and plant air compressors that are required to support various loads during shutdown following a fire. Normally, one of the instrument air compressors is used for supplying the control air for air-operated valves.

The portions of the system that provide cooling to the diesels and to the containment air coolers are all SR and are addressed in Section 5.17 of the BGE LRA. The NSR portion of the system in scope for the FP AMR includes the components that retain pressure in the cooling process flow paths to the instrument air and plant air compressors. Since most of the NSR loads are serviced by a common header, most of the NSR portions of the system must maintain pressure to allow cooling water to be supplied to the air compressors. This includes open line connections to other NSR equipment that form the boundaries of the system subject to the FP AMR. The following passive FP intended function (not addressed in other evaluations) applies: [Reference 56]

- Maintain the PB of the system liquid.

5.10.3.2.3 Aging Management Demonstration

The operation of the NSR portion of the SRW System during a fire is the same as normal operation with respect to providing cooling to the air compressors. The parameters of the system while performing the required FP functions are no different than the normal operating parameters. The use of the system during a fire will not challenge the pressure-retention ability of the system more than normal. Thus, system parameters during performance of FP intended functions are bounded by the normal operating parameters, and aging of all NSR components in scope for this system is fully managed by performance and condition monitoring activities during normal operation.

5.10.3.3 FP System [Reference 2, Appendix A, System 013]

The FP System is designed using the guidance of National Fire Protection Association codes and in accordance with insurance requirements, NRC requirements, and applicable Maryland State codes. The FP System is made up of several subsystems: deluge water spray, preaction sprinklers, automatic sprinklers, indoor and outdoor hose stations, Halon, foam, and portable extinguishers.

The deluge water spray systems protect the steam generator feed pumps, hydrogen seal oil unit, unit transformers, and service transformers. The preaction sprinkler systems protect the Diesel Generator Rooms, and manually-actuated systems protect the turbine generator bearings. The automatic sprinkler systems protect many areas/rooms containing redundant trains of safe shutdown equipment located within the Auxiliary Building, as well as the following areas: Lube Oil Room, Warehouses, Service Buildings, Paint Shop, Baling and Drumming Room, Turbine Building under the operating floor and intermediate floor, and the Auxiliary Boiler Room. Dry pipe automatic sprinkler systems protect the equipment hatch access buildings. Hose stations provide protection for the Auxiliary Building, Intake Structure, Containment Structures, Turbine Building, and Service Buildings. The Halon system protects the Cable Spreading Rooms and contiguous cable chases, Switchgear and Electrical Equipment Rooms, and under the Computer Room floor. The foam system is manually released to protect the outdoor fuel storage tanks. The foam storage tank is located outdoors. Portable fire extinguishers are provided at convenient and readily accessible locations throughout the plant.

Fire protection water is supplied by two full-capacity fire pumps from the PWSTs. One is electrically-driven, the other is diesel-driven. A jockey pump is provided to maintain the FP water system full and pressurized. A booster pump takes suction from plant SRW and discharges to the system to meet intermittent water usage requirements other than FP. All systems are enunciated in the Control Room.

5.10.3.3.1 Operating Experience

Over the years, generally favorable system performance has been attributed in part to the use of well water stored in a closed tank. The use of such water results in low levels of organic materials in the piping, which helps to minimize microbiologically-induced corrosion. During the recent installation of the new diesel generators, there was a need to tie into the existing main loop in the protected area. This loop is important to safety in that it supplies fire fighting water to SR structures, systems, and components. Opening of the water main allowed an inspection of the interior and exterior surfaces, which showed no evidence of corrosion, even though it was installed in the early 1970s.

Cases of unacceptable leakage have occurred in a portion of the system that supplies water to the warehouses. The leaks were promptly isolated from the main header and repaired so as not to impact plant operation. The warehouse portion of the system was originally considered temporary, so it was installed underground without cathodic protection. Now that the warehouses have remained in use, leaks in this section of the system have occurred. Some leaks were attributed to corrosion of the piping that lacks cathodic protection, and some were attributed to damage from heavy loads (vehicles) passing over the buried pipes. Leaks are detected by the amount of time the jockey pump runs to maintain system pressure and from physical changes of the ground around the leak. Monitoring the jockey pump run time provides for a continuous test of system leakage. An increase in jockey pump run time would lead to initiation of corrective actions to identify and repair unacceptable system leakage.

5.10.3.3.2 Scoping Summary

The FP functions of the FP System are:

- Protect personnel, structures, and equipment from fire utilizing fixed fire suppression equipment, including:
  - Fire pumps, piping systems, and water supply;
  - Automatic water suppression systems;
  - Manual water and foam suppression equipment and systems; and
  - Automatic Halon suppression systems.
- Provide water curtains as rated fire barriers for unrated hatches and doors.
- Provide pressurized fire fighting water to hose stations inside containment.
- Provide isolation for ventilation duct penetrations to limit the spread of fire (automatic fire dampers).

The safe shutdown functions of the FP System are:

- Provide alternate makeup water via fire hose connections to the CSTs to support RCS heat removal.
- Provide an alternate source of head tank makeup water for the CC and SRW Systems, via fire hose connection, to support RCS heat removal.
- Provide an alternate water source to the steam generators via the AFW System through a spool piece and fire hose for decay heat removal, at reduced steam generator pressure.
- Provide an alternate source of cooling water to the instrument air and plant air compressors via fire main hose connections.

The portion of the system in scope for the FP AMR includes the pressure-retaining fire fighting equipment that performs one or more of the intended functions listed above. This includes the AFW spool piece and hose stations in the protected area. The containment isolation intended function of the fire suppression water main is addressed in Containment Isolation, Section 5.5 of the BGE LRA. The following passive FP intended function (not addressed in other evaluations) applies:

- Maintain the pressure-retaining capability of the system (liquid and/or gas).

5.10.3.3.3 Aging Management Demonstration

Fire Protection Program activities are credited with maintaining/verifying the ability of the FP System to perform active and passive FP intended functions. Aging effects on the NSR pressure-retaining components are adequately managed by the following specific performance and/or condition monitoring activities required by the plant's FP Program:

- STP-M-021-0 Fire Pump Diesel Inspection (every 549 days)
- STP-F-076-0 Staggered Test of Electric Fire Pump (every 31 days)
- STP-F-077-0 Staggered Test of Diesel Fire Pump (every 31 days)
- STP-M-190-0 Diesel Fire Pump Battery Weekly Check (every 7 days)
- STP-F-290-0 Hose Station and Hydrant House Inspection (every 31 days)
- STP-F-291-0 Halon System Valve Position Verification (every 31 days)
- STP-M-390-0 Fire Pump Battery Quarterly Check (every 92 days)
- STP-F-489-0 Halon System Nozzle and Piping Inspection (every 366 days)
- STP-F-492-0 Halon System Tank Level and Pressure Verification (every 184 days)
- STP-F-493-0 Fire Suppression Water System Flush Test (every 366 days)
- STP-F-495-0 Visual Inspection of Yard Fire Hydrants (every 184 days)
- STP-F-496-0 Yard Fire Hydrant Hose Hydrostatic Test and Gasket Inspection (every 366 days)
- STP-F-497-0 Yard Fire Hydrant Flow Check (every 366 days)
- STP-F-690-0 Sprinkler System Inspection (every 549 days)
- STP-F-691-0 Fire Suppression System Flow Test (every 730 days)
- STP-F-692-0 Hose Station Operability Test (every 1095 days)
- STP-F-693-0 Fire Suppression System Valve Cycling Test (every 366 days)
- STP-F-694-0 Inspection & Hydrostatic Test of Fire Hoses Outside Containment (every 1095 days)
- STP-F-695-0 Inspection & Rerack of Fire Hoses Outside Cont. (every 549 days)
- STP-F-696-0 Fire Pump Flow Test (every 549 days)
- STP-F-697-0 Fire Suppression System Functional Test (every 549 days)
- STP-F-690-1 Hose Station Inspection (Shutdown) (every 31 days)
- STP-F-690-2 Hose Station Inspection (Shutdown) (every 31 days)
- STP-F-693-1 Removal & Replacement of Fire Hoses in Containment (every 730 days)
- STP-F-693-2 Removal & Replacement of Fire Hoses in Containment (every 730 days)
- STP-M-699-1 Switchgear Rooms Halon System Functional Test (every 184 days)
- STP-M-699-2 Switchgear Rooms Halon System Functional Test (every 184 days)

This extensive set of periodic performance and condition monitoring activities ensures the system can perform the passive intended PB function. Performance of these activities will provide opportunities for degradation to be detected before a loss of intended function can occur. Thus, aging of all NSR components in scope for this system is fully managed by the FP Program.

5.10.3.4 CC System [Reference 2, Appendix A, System 015]

Component cooling is a closed system consisting of three motor-driven circulating pumps, two heat exchangers, a head tank, associated valves, piping, instrumentation, and controls for each unit. During normal plant operation, one of the pumps and one of the heat exchangers are required for cooling service.

Items cooled by the system include:

- Letdown heat exchanger;
- Shutdown cooling heat exchangers;
- Miscellaneous waste processing heat exchanger;
- Waste gas compressor aftercoolers and jacket coolers;
- Control element drive mechanism coolers;
- Reactor coolant pump mechanical seals and lube oil coolers;
- Low pressure safety injection seals and coolers;
- High pressure safety injection seals and coolers;
- Containment penetration cooling;
- Reactor support cooling;
- Steam generator lateral support cooling;
- Coolant waste evaporators;
- Reactor Coolant and Miscellaneous Waste Sampling System;
- Degasifier vacuum pump cooler;
- Post-Accident Sample System; and
- Reactor coolant drain tank heat exchanger.

5.10.3.4.1 Operating Experience

Representative historical operating experience pertinent to aging is included in the AMR discussion for the CC System in Section 5.3 of the BGE LRA.

5.10.3.4.2 Scoping Summary

The safe shutdown FP functions of the CC System are:

- Provide a heat sink for essential shutdown cooling loads to ensure safe shutdown in the event of a severe fire.
- Provide a heat sink for essential shutdown cooling loads of the alternate unit in the event it experiences a severe fire that debilitates its own CC System.

In order to provide cooling to the shutdown cooling heat exchanger, one of three pumps and either of the two CC heat exchangers with attendant flow path must be operable. Should the CC System in the affected unit be disabled by a fire, cooling can be supplied from the unaffected unit through existing piping. This requires backflow through the affected unit's reactor coolant waste evaporator supply and return lines. Also, if normal CC head tank makeup flow paths become unavailable due to a fire, makeup can be supplied from the fire main via a hose connection to the Condensate System.

The portion of the system in scope for the FP AMR includes the NSR components in the head tank make up flow paths and the flow paths to and from the reactor coolant waste evaporator. The following passive FP intended function (not addressed in other evaluations) applies: [References 57]

- Maintain the PB of the system liquid.

5.10.3.4.3 Aging Management Demonstration

The CC System is in continuous operation during power production. All of the normally operating heat loads are critical to the production of power. The greatest heat loads on the system are the shutdown cooling heat exchangers when the RCS is cooled down to cold shutdown. The operation of the system during a fire is the same as normal or shutdown cooling modes of operations with respect to providing cooling to the essential heat loads. The parameters of the NSR portion of the system in scope while performing the required FP functions are no different than the normal operating parameters. The use of the system during a fire will not challenge the pressure-retention ability of the system more than normal. Thus, system parameters during performance of FP intended functions are bounded by the normal operating parameters, and aging of all NSR components in scope for this system is fully managed by performance and condition monitoring activities during normal operation.

5.10.3.5 Compressed Air System [Reference 2, Appendix A, System 019]

The Compressed Air System consists of the instrument air and plant air subsystems with a SR backup supply of air from the saltwater air compressors. The instrument air subsystem is designed to provide a reliable supply of oil-free dry air for the pneumatic instruments and controls and pneumatically-operated containment isolation valves. The plant air subsystem is designed to meet necessary service air requirements for plant maintenance and operation.

The instrument air subsystem incorporates two full-capacity, non-lubricated compressors, each having a separate inlet filter aftercooler and moisture separator. The instrument air compressors discharge to a single header that is connected to two air receivers. Both air receivers discharge to a common outlet header that supplies instrument air to the dryer and filter assemblies. The header then divides into branch lines supplying various plant areas. An emergency back-up tie from the plant air header automatically supplies air to the instrument air subsystem if the pressure to the instrument filter and dryer assembly falls below a pre-determined setpoint. Local controls prevent plant air use when this occurs. For the transition from normal to emergency service, strategically-located air storage tanks provide an approximate 20-minute supply.

The plant air subsystem incorporates one full-capacity plant air compressor with an inlet filter, aftercooler, and moisture separator that discharges to the plant air receiver. The receiver outlet header is connected to the prefilter assembly, which is followed by an outlet header branching into two separate air headers, one to the instrument air dryers and filter assembly, and the other to various plant areas. A system cross-tie between Units 1 and 2 has been provided for the plant air headers.

The Compressed Air System operates continuously during all plant operating modes. Normally, only one of the two instrument air compressors are sufficient for maintaining adequate pressure on the instrument air header of each unit. [Reference 51, Section 9.10.4] Instrumentation and controls are provided to automatically maintain system operating pressure by initiating actions at predetermined pressure setpoints. The automatic actions include starting the standby instrument air compressor, cross-connecting the plant air subsystem to the instrument air header, isolation of plant air header loads, and isolation of containment loads. [References 58 through 63] Because of its importance to plant operations, the compressor load time is routinely tracked in order to discover any increase in system leakage so appropriate corrective actions can be taken. The design of the system and installed equipment redundancy assure a reliable source of compressed air to loads being supplied by the instrument air header. [Reference 51, Section 9.10.5]

The power supply for the instrument air compressors is the normal distribution system backed up by the emergency diesel generator. Additional emergency air compressors, known as the saltwater air compressors, provide redundant air supply to most SR components if the normal air compressors are lost. The saltwater air compressors are seismically-qualified, air-cooled, and oil-free. The instrument air portion of the Compressed Air System is primarily used for valve actuation and is not used in any reactor indication, control, or protective circuitry. These valve actuators are designed to fail in the safe position after loss of the instrument air supply.

5.10.3.5.1 Operating Experience

Representative historical operating experience pertinent to aging is included in the AMR discussion for the Compressed Air System in Section 5.4 of the BGE LRA.

5.10.3.5.2 Scoping Summary

The safe shutdown FP functions of the Compressed Air System are:

- Provide compressed air to the instrument air header from an instrument air compressor;
- Provide compressed air to selected SR equipment from a saltwater air compressor;
- Provide compressed air to the instrument air header from the plant air compressor via the back-up tie from the plant air header; or
- Provide compressed air to the instrument air header from the unaffected unit's plant air compressor via the back-up tie from the plant air header and the Unit 1/2 plant air cross-connect.

The Compressed Air System provides control air for essential loads to support safe shutdown. The components include the instrument air, plant air, and saltwater air compressors, along with the associated system valves, piping and controls. This function also includes manual isolation of non-essential air loads. Only one air compressor is required to achieve safe shutdown. The portion of the system in scope for the FP AMR includes all NSR components of the system. The following passive FP intended function (not addressed in other evaluations) applies: [Reference 64]

- Maintain the PB of the system (liquid and/or gas).

5.10.3.5.3 Aging Management Demonstration

Pneumatically-operated equipment can be found in every system that is crucial for power production. Thus, the system is relied on daily. Normally, the plant air compressor and one instrument air compressor will cycle to maintain the desired pressure. The other instrument air compressor and the saltwater air compressors are on standby. [Reference 51, Section 9.10.4] The demands placed on the Compressed Air System during a fire are the same as, or less than, the normal operating requirements. Only a single air compressor is required to supply necessary loads following a fire. The parameters of the NSR portion of the system while performing the required FP functions are no different than the normal operating parameters. The use of the system during a fire will not challenge the pressure-retention ability of the system more than normal. Thus, system parameters during performance of FP intended functions are bounded by the normal operating parameters, and aging of all NSR components in scope for this system is fully managed by performance and condition monitoring activities during normal operation.

5.10.3.6 Diesel Fuel Oil System [Reference 2, Appendix A, System 023]

The Diesel Fuel Oil System supplies fuel to the emergency diesel generators, auxiliary boilers, and the diesel-driven fire pumps. Major components of the system are: two fuel oil storage tanks, a fuel oil unloading pump, an auxiliary boiler supply header, and two diesel generator supply headers.

5.10.3.6.1 Operating Experience

Representative historical operating experience pertinent to aging is included in the AMR discussion for the Diesel Fuel Oil System in Section 5.7 of the BGE LRA.

5.10.3.6.2 Scoping Summary

The Diesel Fuel Oil System provides the following FP support functions in the event of a fire:

- Provide diesel fuel to the emergency diesel generators; and
- Provide diesel fuel to the diesel-driven fire pump.

Most of the system is SR. The only NSR portion of the system in scope for the FP AMR includes the piping and components related to the diesel-driven fire pump. The following passive FP intended function (not addressed in other evaluations) applies: [Reference 65]

- Maintain the PB of the system liquid.

5.10.3.6.3 Aging Management Demonstration

Fire Protection Program activities are credited with maintaining/verifying the ability of the Diesel Fuel Oil System to perform active and passive FP intended functions. Aging effects on the NSR pressure-retaining components are adequately managed by the following specific performance and condition monitoring activities required by the plant's FP Program:

- STP-F-77-0 - Staggered Test of Diesel Fire Pump; and
- STP-F-696-0 - Fire Pump Flow Test.

The diesel-driven fire pump is periodically tested to verify operability/availability through valve lineups, flow and discharge pressure testing, sequential starting capabilities, and controller functions. The pump is under observation during performance of the above tests, and degradation of the fuel oil supply lines would be immediately evident. Additionally, the day tank is refilled as required following each test to maintain a minimum quantity of fuel oil in the tank. [References 66 and 67] Thus, the integrity of the fuel oil supply piping to the tank is verified each time it is refilled. These periodic performance monitoring activities ensure the system can perform the passive FP intended function. Performance of these activities will provide opportunities for degradation to be detected before a loss of intended function can occur. Thus, aging of all NSR components in scope for this system is fully managed by the FP Program.

5.10.3.7 Plant Heating System [Reference 2, Appendix A, System 029]

The Plant Heating System consists of two main hot water pumps, two main hot water generators, a main circulating loop, an air removal subsystem, and various branch loops and booster pumps. It is a closed system with provision for automatic makeup from the pretreated water systems. The system is set up for balanced flow conditions, thus maintaining steady flow conditions even if unit heaters or branch loops are isolated.

5.10.3.7.1 Operating Experience

In 1994, BGE discovered leakage of some plant heating piping due to corrosion. There was some corrosion adjacent to the penetration through the concrete wall of the pipe tunnel, but the worst corroded area was in the range of 5-10 feet from the wall. The leak was located approximately 5 feet from the wall. There was evidence of past excavation in the area where digging equipment struck the outside of the pipes in the same area. Furthermore, cathodic protection levels were noted to be weak in this area. The piping has been replaced and wrapped, and new anodes were installed for the cathodic protection system.

5.10.3.7.2 Scoping Summary

The Plant Heating System provides heating (freeze protection) to the PWSTs. The PWSTs are the source of water for the FP System. These tanks are provided with a recirculating-type heating system to maintain a minimum temperature of 45°F as protection against freezing. The portion of the system in scope for the FP AMR includes the components in the main process flow paths shown as normally open on the system drawings. The containment isolation intended function of the system is addressed in Containment Isolation, Section 5.5 of the BGE LRA. The following passive FP intended function (not addressed in other evaluations) applies:

- Maintain the PB of the system (liquid and/or gas).

5.10.3.7.3 Aging Management Demonstration

The PWST heat exchangers are constructed of a tube bundle mounted in an enclosed shell. Hot water from the Plant Heating System circulates through the tubes during cold weather to keep the water in the PWST from freezing. The shell is physically located within the tank from which the PWST circulating pump takes suction. The circulating pump discharges near the top of the tank and ensures adequate mixing of the contents. All components of the heat exchanger not visible from the outside of the tank are constructed of monel, which is highly resistant to corrosion in this environment. Thus, corrosion of the heat exchanger in a location not normally visible is extremely unlikely. The carbon steel components are plainly visible from the outside of the tank, and any corrosion would be easily identified. [References 68 and 69]

During periods of cold weather, the Plant Heating System is in continual use and is crucial to heating plant areas and selected plant equipment. The demands placed on the system during a fire are the same as the normal operating requirements. The parameters of the system while performing the required FP functions are no different than the normal operating parameters. The use of the system during a fire will not challenge the pressure-retention ability of the system more than normal. Thus, system parameters during performance of FP intended functions are bounded by the normal operating parameters, and aging of all NSR components in scope for this system is fully managed by performance and condition monitoring activities during normal operation.

5.10.3.8 AFW System [Reference 2, Appendix A, System 036]

The AFW System is designed to provide feedwater to the steam generators for the removal of sensible and decay heat, and to cool the primary system to 300°F in case the main condensate pumps or the main feed pumps are inoperable. The turbine-driven AFW trains may also be used for normal system cooldown to 300°F. The motor-driven portion of the system is designated for emergency use only (i.e., not for use during normal plant startup or shutdown - except testing is allowed).

Three AFW pumps are installed in each unit, consisting of one motor-driven and two non-condensing steam turbine-driven pumps. For a shutdown, only one pump is required to be operating, the others are in standby. The steam generator's AFW System is initiated by remote manual control or on low level in either steam generator. Upon automatic initiation of AFW, one motor-driven and one turbine-driven pump automatically start. These pumps take suction from a 350,000 gallon CST that is protected against tornadoes and tornado-generated missiles.

The turbine driver is supplied with steam from the steam generator as long as the pressure is above 50 psig. Each turbine has a manually-set governor for controlling turbine speed. Once set for a certain speed, the governor is designed to maintain approximately constant speed with a minimum of 50 psig steam pressure. The steam supply can also be provided from the Auxiliary Boiler Steam System. In addition, in an emergency, the steam-driven train can operate independent of offsite power and the diesels for up to two hours. The AFW air accumulators provide a sufficient control air source until operators can manually regulate the system.

5.10.3.8.1 Operating Experience

Representative historical operating experience pertinent to aging is included in the AMR discussion for the AFW System in Section 5.1 of the BGE LRA.

5.10.3.8.2 Scoping Summary

The safe shutdown FP functions for the AFW System are as follows:

- Monitor essential AFW parameters to ensure safe shutdown in the event of a fire (CST level, steam generator level, steam generator pressure, and AFW pump discharge pressure);
- Provide control of the AFW System from the Control Room or the auxiliary shutdown panel to ensure safe shutdown in the event of a fire;
- Provide heat removal to support hot standby and cold shutdown functions from either turbine-driven train of the affected unit;
- Provide heat removal to support hot standby and cold shutdown functions from the motor-driven train of either unit; and
- Provide heat removal to support hot standby and cold shutdown functions at low pressure situations via the motor-driven train using water from the diesel-driven fire pump.

Alternate sources of water to support the AFW heat removal functions include CSTs 11 and 12, which can be aligned to the AFW System through manipulation of manual valves as required. Another source of water is the FP System. Specifically, when steam generator pressure has been reduced to less than 100 psig, the diesel-driven fire pump can be used to provide steam generator inventory using FP System water sources. The procedure requires the motor-driven AFW pump on the affected unit to be isolated and drained. An AFW spool piece is installed at the discharge of the pump and connected to two fire hoses supplied from hose stations that are aligned to the diesel-driven fire pump. The NSR portion of the system in scope for the FP AMR includes: the AFW spool piece for the fire hose connections, AFW isolation valves from CSTs 11 and 21 and the piping between the isolation valves and the CSTs. The CSTs are included within the scope of the Demineralized Water and Condensate Storage System discussed below in Section 5.10.3.9. The following passive FP intended function (not addressed in other evaluations) applies: [Reference 70]

- Maintain the PB of the system (liquid and/or gas).

5.10.3.8.3 Aging Management Demonstration

Per the FP Program, the AFW spool piece and associated hardware is prestaged equipment that is inventoried and inspected each quarter. This activity ensures that the spool piece can perform the passive FP intended function, and it will provide opportunities for degradation to be detected before a loss of intended function can occur. Thus, aging of the spool piece is fully managed by the FP Program.

The CSTs are used to store makeup water for the Condensate System during normal operation. The NSR section of piping and valves in scope are open to the CSTs and pressurized by the height of water in the tanks. The parameters of this portion of the system while performing the required FP functions are no different than the normal operating parameters. The use of the system during a fire will not challenge the pressure-retention ability of the system more than normal. Thus, system parameters during performance of FP intended functions are bounded by the normal operating parameters, and aging of this portion of the system is fully managed by performance and condition monitoring activities during normal operation.

5.10.3.9 Demineralized Water & Condensate Storage System [Reference 2, Appendix A, System 037]

The Demineralized Water and Condensate Storage System stores demineralized water from the Makeup Demineralizer System for normal plant operations and emergency conditions. The system consists of a demineralized water storage tank, two demineralized water transfer pumps, two CSTs, and the associated valves, piping, and controls. The system interfaces with the:

- Auxiliary Boilers;
- AFW System;
- Chemical and Volume Control System (CVCS);
- CC System;
- Condensate Demineralizer;
- Condenser Air Removal System;
- Miscellaneous Waste System;
- Post Accident Sampling System;
- Reactor Coolant and Waste Processing Sampling System;
- RCS;
- Reactor Coolant Waste Processing System;
- SRW System;

- Stator Winding Cooling System;
- Steam Generator Blowdown System;
- Various Lab Stations and Faucets; and
- Waterbox Priming System.

5.10.3.9.1 Operating Experience

Leaks have been discovered on penetrations on CSTs 11 and 21 due to galvanic corrosion. The penetrations have a carbon steel nipple that is welded to a stainless steel half coupling. The lines are insulated, and over time, were brought into electrical contact by wet insulation. No other damage was observed on the pipe or tank walls. The penetrations will be replaced and protectively coated and/or wrapped before being reinsulated.

5.10.3.9.2 Scoping Summary

The safe shutdown FP function of the Demineralized Water and Condensate Storage System is to provide a backup source of water to the AFW System from CSTs 11 and 21. The AFW System is normally aligned to CST 12. At a predetermined low level in the tank, an alternate CST (11 or 21) is placed in service. The CSTs are normally provided makeup water from the demineralized water storage tank. As a last resort, the CSTs can be filled with water from the PWSTs. The line up is accomplished by connecting a fire hose between the fire pump house test manifold and emergency hose connections on the tanks. The portion of the system in scope for the FP AMR is limited to CSTs 11 and 21, associated level instruments, emergency hose connections, and all pressure-retaining piping and components up to the first isolation valve on all headers to and from the tanks. The containment isolation intended function of the system is addressed in Containment Isolation, Section 5.5 of the BGE LRA. The following passive FP intended function (not addressed in other evaluations) applies: [Reference 71]

- Maintain the PB of the system (liquid and/or gas).

5.10.3.9.3 Aging Management Demonstration

The CSTs are used to store makeup water for the Condensate System during normal operation. The NSR components in scope are pressurized by the height of water in the tanks. The parameters of this portion of the system while performing the required FP functions are no different than the normal operating parameters. The use of the system during a fire will not challenge the pressure-retention ability of the system more than normal. Thus, system parameters during performance of FP intended functions are bounded by the normal operating parameters, and aging of this portion of the system is fully managed by performance and condition monitoring activities during normal operation.

5.10.3.10 CVCS [Reference 2, Appendix A, System 041]

The CVCS is composed of two subsystems: letdown and charging, and makeup. The system performs the following functions:

- Maintain reactor coolant activity at the desired level by removing corrosion and fission products;
- Inject chemicals into the RCS to control coolant chemistry and minimize corrosion;
- Control the reactor coolant volume by compensating for coolant contraction or expansion resulting from changes in reactor coolant temperature and other coolant losses or additions;
- Provide means for transferring fluids to the Radioactive Waste Processing System;

- Inject concentrated boric acid into the RCS upon a safety injection actuation signal;
- Control the reactor coolant boric acid concentration;
- Provide auxiliary pressurizer spray for operator control of RCS pressure during shutdown;
- Provide a means for functionally testing the check valves that isolate the Safety Injection System from the RCS, and for hydrostatic and leak testing of the RCS; and
- Provide continuous on-line measurement of reactor coolant boron concentration and fission product activity.

5.10.3.10.1 Operating Experience

Representative historical operating experience pertinent to aging is included in the AMR discussion for the CVCS System in Section 5.2 of the BGE LRA.

5.10.3.10.2 Scoping Summary

The safe shutdown FP function for the CVCS is to provide primary makeup in support of RCS pressure and inventory control. If it becomes necessary to conserve RCS inventory during a fire, all letdown, including NSR controlled reactor coolant pump bleedoff flow, is isolated. The pressure-retaining capability of these components must be maintained intact if the RCS inventory control strategy is to be successful. Thus, the portion of the system in scope for the FP AMR is limited to the NSR piping and valves comprising the flow path from the reactor coolant pump controlled bleedoff lines to the letdown subsystem. The following passive FP intended function (not addressed in other evaluations) applies: [Reference 72]

- Maintain the PB of the system (liquid and/or gas).

5.10.3.10.3 Aging Management Demonstration

Under certain fire conditions, RCS inventory control requirements may lead to the isolation of the controlled bleedoff flow to the volume control tank. Depending on the RCS pressure and the condition of the reactor coolant pump seals, the pressure in the isolated lines could rise high enough to cause a relief valve to lift for short periods of time. The end result is that the temperature and pressure in this portion of the system is likely to be slightly higher than during normal operation.

The AMR for the SR PB components of the system includes an evaluation of the letdown line from the RCS, the charging line into the RCS, and associated components in these flow paths. The materials of construction are predominately stainless steel with alloy and carbon steel fasteners at mechanical joints. The chemistry in this part of the system is the same as RCS chemistry, including hydrogen overpressure. The NSR piping and components from the controlled bleedoff lines are constructed of the same materials and exposed to the same environmental conditions as these SR portions of the system. Thus, the same conclusions apply to the NSR components in scope for FP. The only plausible ARDM is general corrosion of the alloy and carbon steel fasteners due to boric acid leakage. Aging of those NSR subcomponents for the period of extended operation will be managed by the Boric Acid Corrosion Inspection Program.

5.10.3.11 Condensate System [Reference 2, Appendix A, System 044]

The exhaust steam from the low pressure turbines is discharged into the main condenser shells where the latent heat of vaporization is removed and condensate is formed. Condensate from the hotwells is pumped by two electric, motor-driven condensate pumps through the gland steam condenser, the Condensate Demineralizer and Precoat Filtering System, the lowest feedwater heating stage drain coolers, and the two lowest pressure feedwater heating stages (three heaters per stage), to the suction of the three condensate booster pumps. These pumps deliver the condensate to the two turbine-driven feed pumps through two parallel sets of three feedwater heaters.

5.10.3.11.1 Operating Experience

No significant age-related degradation has been identified that would affect the pressure-retaining portions of the Condensate System. The water chemistry controls used to minimize steam generator corrosion are generally effective in controlling corrosion of components in the Condensate System.

5.10.3.11.2 Scoping Summary

The safe shutdown function of the Condensate System is to provide an alternate flow path for makeup water to the SRW and CC head tanks from the fire main. This is accomplished via a condensate system fire hose connection to a Turbine Building hose station. The portion of the Condensate System in scope for the FP AMR includes the NSR components in the makeup flow path to the SRW and CC head tanks from the fire hose connection. It is comprised of the following two parts:

1. The piping tapping off the condensate pump discharge header that is normally pressurized, up to and including the normally closed manual isolation valves of the makeup lines going to the SRW and CC Systems; and
2. The makeup lines downstream of the normally closed manual isolation valves to the SRW and CC Systems, up to the check valves of the head tank demineralized water makeup lines. This includes a section of piping only; the check valves and downstream piping to the head tanks are evaluated with the SRW and CC Systems in Sections 5.10.3.2 and 5.10.3.4, respectively.

The following passive FP intended function (not addressed in other evaluations) applies:

- Maintain the pressure-retaining capability of the system (liquid and/or gas).

5.10.3.11.3 Aging Management Demonstration

The part of the system identified in Item 1 above is pressurized by condensate pump discharge pressure during normal operation. The demands placed on this part of the system during a fire are the same as, or less than, the normal operating requirements. Therefore, use of this part of the system during a fire will not challenge its pressure-retention ability more than normal. Thus, for this part of the system, parameters during performance of FP intended functions are bounded by the normal operating parameters, and aging of this part of the system is fully managed by performance and condition monitoring activities during normal operation.

The system piping identified in Item 2 above is isolated under normal operating conditions and, therefore, it is not managed by performance and condition monitoring activities during normal operation. Thus, an AMR was conducted for this device type. The list of potential ARDMs identified is provided in Table 5.10-3. The plausible ARDMs are identified by a check mark (✓) in the device type column. [Reference 2, System 044, Attachment 5]

TABLE 5.10-3

POTENTIAL AND PLAUSIBLE ARDMs

Potential ARDMs	Device Type
	Piping
Cavitation Erosion	
Corrosion Fatigue	
Crevice Corrosion	✓
Erosion Corrosion	
Fatigue	
Fouling	
Galvanic Corrosion	
General Corrosion	✓
Hydrogen Damage	
Intergranular Attack	
Microbiologically-Induced Corrosion	
Particulate Wear Erosion	
Pitting	✓
Radiation Damage	
Rubber Degradation	
Saltwater Attack	
Selective Leaching	
Stress Corrosion Cracking	
Stress Relaxation	
Thermal Damage	
Thermal Embrittlement	
Wear	

The following paragraphs contain a discussion of the AMR for the piping. It includes a discussion on materials and environment, aging effects, methods to manage aging, aging management programs, and aging management demonstration.

Crevice corrosion, general corrosion, and pitting for piping - Materials and Environment

The material of the device type is carbon steel with subcomponents consisting of the pipe, fittings, flanges, studs, and nuts. [Reference 2, System 044, Attachment 3, Attachment 4]

The internal environment for the device type during power generation is stagnant condensate at a temperature less than 200°F. [Reference 2, System 044, Attachment 3] The stagnant conditions result because the piping is downstream of normally shut valves up to the check valves on the head tank makeup lines. [Reference 2, System 044, Section 5.0]

Crevice corrosion, general corrosion, and pitting for piping - Aging Mechanism Effects

This section describes each ARDM and the effects on the susceptible subcomponents. [Reference 2, System 044, Attachments 6 and 7]

General corrosion is a thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The consequences of the damage are loss of load-carrying cross-sectional area. General corrosion requires an aggressive environment and materials susceptible to that environment.

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, surface deposits, and integral weld backing rings or back-up bars. The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. In an oxidizing environment, a crevice can set up a differential aeration cell to concentrate an acid solution within the crevice. Crevice corrosion is closely related to pitting corrosion and can initiate pits in many cases.

Pitting is a form of localized attack with greater corrosion rates at some locations than at others. This form of corrosion essentially produces "holes" of varying depth-to-diameter ratios in the steel. These pits are, in many cases, filled with oxide debris, especially for ferrous materials such as carbon steel. Deep pitting is more common with passive metals, such as austenitic stainless steels, than with non-passive metals. Pits are generally elongated in the direction of gravity.

These forms of corrosion are plausible for the pipe, fittings, and flanges of this device type since they have geometry that allows process fluids (condensate) to stagnate and environmentally-produced impurities to concentrate causing localized corrosion of these components. Since this piping is not exposed to the main flow stream, local fluid chemistry conditions may deviate substantially from bulk fluid chemistry of the Condensate System. The direct effect of these three corrosion mechanisms is a localized loss of material that, if left unmitigated, could result in degradation of the pressure-retaining ability either by through-wall leakage or loss of mechanical joint fasteners.

General, crevice, and pitting corrosion mechanisms are also plausible for the nuts and bolts of this device type since corrosion of the mechanical joint sealing surfaces and leakage onto the surrounding fasteners can occur. The fasteners are susceptible to these corrosion mechanisms when the internal fluid (condensate) escapes onto them. Corrosion of the fasteners could lead to their failure and breech of the mechanical joint and loss of pressure-retaining ability.

Crevice corrosion, general corrosion, and pitting for piping - 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 material to an aggressive chemical environment. Although CCNPP has a Secondary Chemistry Program, the line is not normally filled, so proper water chemistry cannot be relied on.

Discovery: The effects of corrosion on system components can be discovered and monitored through non-destructive examination techniques such as visual inspections. Inspections at susceptible locations can be used to assess the need for additional inspections at less susceptible locations. Based on piping and component geometry and fluid flow conditions, areas most likely to experience corrosion can be determined and evaluated.

Crevice corrosion, general corrosion, and pitting for piping - Aging Management Programs

Mitigation: The occurrence of corrosion is expected to be limited and not likely to affect the intended function due to the relatively benign environmental operating conditions. No additional mitigation programs are needed at this time.

Discovery: Corrosion can be readily detected through non-destructive examination techniques. As such, an inspection program to identify occurrence of localized corrosion is an effective means of determining if corrective actions are required for managing this aging mechanism.

The subject piping will be included within a new plant program to accomplish the needed inspections for general corrosion, crevice corrosion, and pitting. This program is 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 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 Actions Program and will ensure that the components will remain capable of performing the PB integrity function under all CLB conditions.

Crevice corrosion, general corrosion, and pitting for piping - 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 the subject piping:

- The piping provides a pressure-retaining boundary and the integrity must be maintained under CLB design conditions.
- Crevice corrosion, general corrosion, and pitting are plausible for this piping, and result in material loss which, if left unmanaged, can lead to loss of pressure-retaining boundary integrity.
- Due to the relatively benign environmental operating conditions, significant degradation of this piping is not expected. However, to provide assurance that these ARDMs are being managed in this portion of piping, these 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 of this piping will be managed in such a way as to maintain the components' PB integrity, consistent with the CLB, during the period of extended operation.

5.10.3.12 Plant Drains System [Reference 2, Appendix A, System 053]

The Plant Drains System is commonly referred to as the plant sump system. It includes the floor and equipment drain piping, sump piping, sump pumps, and instrumentation associated with all areas of the plant. Plant drains include the Turbine Building clean and oily waste sumps, the Service Buildings clean and oily waste sumps, the Auxiliary Building sumps, the Intake Structure sumps, the yard area sumps, and the Fuel Oil System drainage. The yard area sumps include the lube oil storage tank area sump, the yard manhole sump, the fire pump house sumps, the acid storage tank area sump, the yard sump, the yard waste oil collection tank, and the yard oil interceptor. Fuel oil system drainage includes the Diesel Generator Room oil drainage subsystem, Fuel Oil Storage Tank 11 area dike, and valve pit drainage subsystem. Containment sumps are treated separately in other sections of the BGE LRA.

5.10.3.12.1 Operating Experience

No pertinent operating experience was discovered for this system.

5.10.3.12.2 Scoping Summary

Sumps and floor drains collect and remove fire fighting water from areas containing SR equipment where fixed fire suppression systems are installed or where fire hoses may be used. Drains discharging to a common header from SR areas containing five or more gallons of combustible liquids were designed with check valves to prevent backflow of combustible liquids. The drains provided with such check valves are from the Charging Pump Rooms, ECCS Pump Rooms, Diesel Generating Rooms, and Auxiliary Feed Pump Rooms. The portion of the system in scope for the FP AMR includes the NSR piping and valves in the floor drain lines from rooms containing SR equipment. The containment isolation intended function of the system is addressed in Containment Isolation, Section 5.5 of the BGE LRA. The following passive FP intended functions (not addressed in other evaluations) apply:

- Provide drainage of fire fighting water in rooms containing SR equipment, and
- Maintain the pressure-retaining capability of the system (liquid and/or gas).

5.10.3.12.3 Aging Management Demonstration

The drain system piping (and associated components) from rooms containing SR equipment must maintain pressure to ensure drainage of fire fighting water. The demands placed on the system to drain water during a fire are the same as those during normal drain system operation. Use of the drains during a fire will not challenge this pressure-retention ability more than normal. Thus, system parameters during performance of FP intended functions are bounded by the normal operating parameters of the system, and aging of this part of the system, with the exception of the backflow prevention check valve disks, is fully managed by performance and condition monitoring activities during normal operation.

Aging management of the disks of the backflow prevention check valves from the Charging Pump Rooms, ECCS Pump Rooms, Diesel Generator Rooms, and AFW Pump Rooms will be accomplished through the FP Program. Baltimore Gas and Electric Company is currently evaluating the most appropriate method of accomplishing this aging management. The activity selected will ensure the valves can perform their FP intended function, and it will provide opportunities for degradation to be detected before a loss of intended function can occur. Thus, aging management of the check valves will be fully managed by the FP Program and performance and condition monitoring activities during normal operation.

5.10.3.13 RCS [Reference 2, Appendix A, System 064]

The RCS is the primary coolant loop, located entirely within the containment, consisting of two heat transfer loops connected in parallel across the reactor pressure vessel. Each loop contains one steam generator, two circulating pumps, connecting piping, and flow and temperature instrumentation. Coolant system pressure is maintained by a pressurizer connected to one of the loop hot legs. During operation, the four pumps circulate water through the reactor vessel where the water serves as both coolant and moderator for the core. The heated water enters the two steam generators, transferring heat to the secondary (steam) system, and then returns to the pumps to repeat the cycle. A lube oil collection system for the reactor coolant pump motors is considered a subsystem of the RCS. The lube oil collection tanks are sized for the entire oil contents of two reactor coolant pumps. There are four tanks to handle the eight reactor coolant pumps (four reactor coolant pumps per unit).

5.10.3.13.1 Operating Experience

Representative historical operating experience pertinent to aging is included in the AMR discussion for the RCS in Section 4.1 of the BGE LRA..

5.10.3.13.2 Scoping Summary

The FP function for the RCS is:

- Provide a lube oil collection system for reactor coolant pump motors, sized to accommodate the largest potential oil leak.

The safe shutdown functions for the RCS are:

- Provide monitoring of essential parameters;
- Provide a means for removal of decay heat;
- Serve as a fission product barrier; and
- Control inventory loss.

Parameters monitored include pressurizer pressure and level indication and hot/cold leg temperature indication. Monitoring is included in the Control Room and at the alternate shutdown panel. All monitoring components in scope are SR PB and have been addressed by the SR PB AMR for the RCS or other commodity evaluations. Also, the reactor coolant pump motor lube oil collection system is SR and is addressed in the SR PB AMR as well.

Decay heat removal, fission product boundary, and controlling inventory loss are all related to the PB of the RCS. Decay heat removal and fission product boundary functions are entirely accomplished within the SR PB portion of the system. However, if it becomes necessary to conserve RCS inventory during a fire, all letdown, including NSR controlled reactor coolant pump bleedoff flow, is isolated. [Reference 2, Appendix A, System 041, Section 5.0] The pressure-retaining capability of these components must be maintained intact if the RCS inventory control strategy is to be successful. Thus, the portion of the system in scope for the FP AMR is limited to the NSR piping and associated components in the controlled bleedoff lines from the reactor coolant pumps to the CVCS. The following passive FP intended function (not addressed in other evaluations) applies: [Reference 73]

- Maintain the PB of the system (liquid and/or gas).

5.10.3.13.3 Aging Management Demonstration

Under certain fire conditions, RCS inventory control requirements may lead to the isolation of the controlled bleedoff flow to the volume control tank. Depending on the RCS pressure and the condition of the reactor coolant pump seals, the pressure in the isolated lines could rise high enough to cause a relief valve to lift for short periods of time. The end result is that the temperature and pressure in this portion of the system is likely to be slightly higher than during normal operation.

The AMR for the SR PB components of the CVCS includes an evaluation of the letdown line from the RCS, the charging line into the RCS, and associated components in these flow paths. The materials of construction are predominately stainless steel with alloy and carbon steel fasteners at mechanical joints. The chemistry in this part of the system is the same as RCS chemistry including hydrogen overpressure. The NSR piping and components of the controlled bleedoff lines are constructed of the same materials and exposed to the same environmental conditions as these SR portions of the CVCS. Thus, the same conclusions apply to the NSR components of the RCS in scope for FP. The only plausible ARDM is general corrosion of the alloy and carbon steel fasteners due to boric acid leakage, and aging for the period of extended operation will be managed by the Boric Acid Corrosion Inspection Program.

5.10.3.14 Liquid Waste System [Reference 2, Appendix A, System 071]

The Liquid Waste System consists of two subsystems - miscellaneous waste processing and reactor coolant waste processing. The miscellaneous waste processing subsystem provides controlled handling and disposal of various liquid wastes from both units. The subsystem consists of:

- Miscellaneous waste receiver tank;
- Miscellaneous waste monitor tank;
- Miscellaneous waste receiver tank pump;
- Miscellaneous waste monitor tank pump;
- Miscellaneous waste filters;
- Miscellaneous waste ion exchanger;
- Miscellaneous waste metering pump; and
- Associated strainers, piping, valves, and instrumentation.

The miscellaneous waste processing subsystem receives liquid waste from three major sources:

- Auxiliary building gravity drains;
- Hot laboratory and soapy drains; and
- Containment normal sump and pumped sumps.

Additional sources are:

- SRW System;
- CC System;
- Blowdown Recovery System;
- Refueling water tanks;
- Refueling water tank room sump pump; and
- Spent fuel pool.

The reactor coolant waste processing subsystem provides controlled handling and disposal of radioactive liquid wastes from both reactor units. The subsystem provides temporary storage for reactor coolant wastes and processes wastes prior to disposal. The reactor coolant waste processing subsystem consists of:

- Two reactor coolant drain tanks;
- Three cartridge filters;
- Two degasifiers;
- Four reactor coolant waste ion exchangers;
- Two reactor coolant waste receiver tanks;
- Two evaporators;
- Two reactor coolant waste monitoring tanks;
- Reactor coolant drain tank pumps;
- Degasifier vacuum pumps;
- Reactor coolant waste receiver tank pumps;
- Reactor coolant waste receiver tank metering pumps; and
- Associated piping, valves, controls, and instrumentation.

5.10.3.14.1 Operating Experience

No significant age-related degradation has been identified that would affect the pressure-retaining portions of the Plant Drains System. The system is comprised of components constructed of stainless steel thereby minimizing any corrosion related concerns.

5.10.3.14.2 Scoping Summary

The Liquid Waste System supports the Plant Drains system by ensuring fire suppression water is drained from rooms containing SR equipment. The portion of the system in scope for the FP AMR is limited to the NSR components in the flow paths from the sump pump discharge check valves serving areas containing SR equipment to the waste processing subsystems. The containment isolation intended function of the system is addressed in Containment Isolation, Section 5.5 of the BGE LRA. The following passive FP intended functions (not addressed in other evaluations) apply:

- Provide drainage of fire suppression water in rooms containing SR equipment; and
- Maintain the pressure-retaining capability of the system (liquid and/or gas).

5.10.3.14.3 Aging Management Demonstration

The Liquid Waste System receives and processes the drains from the rooms containing SR equipment through the interface with the Plant Drains System. Piping (and associated valves) located within rooms containing SR equipment must maintain pressure-retaining capability to ensure drainage from the rooms. The demands placed on the system to drain water during a fire are the same as those during normal system operation. Use of the system during a fire will not challenge the pressure-retention ability more than normal. Thus, system parameters during performance of FP intended functions are bounded by the normal operating parameters of the system, and aging of this part of the system is fully managed by performance and condition monitoring activities during normal operation.

5.10.3.15 Nitrogen and Hydrogen System

The Nitrogen and Hydrogen System consists of two independent subsystems supplying gasses for normal operation. Portions of the nitrogen gas subsystem provide containment isolation so they are SR and are addressed in Section 5.5 of the BGE LRA. A portion of the hydrogen gas subsystem is important for FP and is included herein. The hydrogen gas subsystem is common to both units and provides hydrogen gas to the following equipment:

- Two main generators (cooling medium);
- Two volume control tanks (RCS chemistry control); and
- Radiation-chemistry chemical cabinet (gas standard and burn gas).

The hydrogen gas subsystem consists of hydrogen gas bottles, a truck fill connection, pressure control unit, distribution header, and the associated piping, valves, and controls. [Reference 1]

5.10.3.15.1 Operating Experience

No significant age-related degradation has been identified that would affect the pressure-retaining portions of the hydrogen supply lines for the Nitrogen and Hydrogen System. Cracks were discovered where a hydrogen supply line enters the main generator. However, this failure was due to high vibration on the main generator and is not considered an age-related concern. To prevent this from recurring, a new support was added for the hydrogen supply line to the main generator. Periodic pressure testing of the main generators has identified only minor system leakage due to valve packing and other mechanical joint leakage.

5.10.3.15.2 Scoping Summary

The FP function of the hydrogen gas subsystem is to isolate hydrogen flow to the Auxiliary Building in the event of a downstream piping rupture. Excess flow check valves are installed upstream of the Auxiliary Building supply lines to each unit (one per unit). The two valves were designed to close if flow exceeds 75 cfm or if the differential pressure across the valves exceeds 75 psi. The portion of the system in scope for the FP AMR is limited to the NSR excess flow check valves. The following passive FP intended functions (not addressed in other evaluations) apply:

- Maintain the pressure-retaining capability of the system gas.

5.10.3.15.3 Aging Management Demonstration

Aging management of the excess flow check valves will be accomplished through the FP Program. Baltimore Gas and Electric Company is currently evaluating the most appropriate method of accomplishing this aging management The activity selected will ensure the valves can perform their FP intended function, and it will provide opportunities for degradation to be detected before a loss of intended function can occur. Thus, aging management of the check valves will be fully managed by the FP Program.

5.10.3.16 Main Steam System [Reference 2, Appendix A, System 083]

The Main Steam System is designed to transfer steam from the steam generators to the turbine throttle stop valves, the reheaters, and the turbine-driven pumps. The Main Steam System also controls steam generator pressure by means of steam bypass, dump, or safety valves (high pressure) and main steam isolation valves (MSIVs) (low pressure).

Major components of the system are: flow restrictors, safety valves, MSIVs, turbine throttle stop valves, steam dump valves, turbine bypass valves, MSIV-bypass valves, AFW pump turbine steam supply isolation valves and bypass valves, moisture separator reheater isolation valves, moisture separator reheaters, and associated piping and controls.

Overpressure protection for the shell side of the steam generators and the main steam line piping up to the inlet of the turbine stop valve is provided by 16 spring-loaded American Society of Mechanical Engineers Code main steam safety valves that discharge to the atmosphere. Eight of these safety valves are mounted on each of the main steam lines upstream of the MSIVs and outside of the containment.

The Steam Dump and Bypass System is used to rapidly remove RCS stored energy and to limit secondary steam pressure following a turbine-reactor trip. The Atmospheric Steam Dump System consists of two automatically-actuated atmospheric dump valves (ADVs) that exhaust to the atmosphere. The Turbine Bypass System consists of four turbine bypass valves that exhaust to the main condenser. The power-operated steam dump valves and steam bypass valves minimize the need for opening of the main steam safety valves following turbine and reactor trips from full power.

The Main Steam System also provides a means of heat removal during hot standby and during a plant cooldown. The ADVs are capable of removing reactor decay heat when the condenser is not available.

5.10.3.16.1 Operating Experience

Representative historical operating experience pertinent to aging is included in the AMR discussion for the Main Steam System in Section 5.12 of the BGE LRA.

5.10.3.16.2 Scoping Summary

The safe shutdown functions for the Main Steam System in the event of a fire are:

- Provide controlled RCS heat removal to maintain the affected unit at hot standby and to cool the affected unit down to cold shutdown conditions if required.
- Provide monitoring of steam generator pressure in support of RCS heat removal function.

Heat removal is accomplished using the ADVs or main steam safety valves. Due to the limited capacity of the ADVs at low steam generator pressures, use of both steam generators is required to reach cold shutdown within 72 hours. If the room where the fire is located meets 10 CFR Part 50, Appendix R, Paragraph III.G.2 requirements, then the affected unit does not need to be in cold shutdown within 72 hours. In this case, only one steam generator is necessary. If the ADVs are disabled by a fire, they are manually isolated, and RCS heat is removed through the main steam safety valves until manual operation of the ADVs can be established. If main steam isolation is required to control the RCS heat removal rate, it can be accomplished by closure of the MSIVs and associated bypass valves and isolating the Steam Generator Blowdown System. If the MSIVs are inoperable due to fire, an alternate method of isolating the main steam header is to manually isolate the turbine bypass valves, gland seal steam, and second stage steam to the moisture separator reheaters. Steam generator pressure is monitored using SR pressure instrument loops.

The portion of the system in scope for the FP AMR is limited to the NSR pressure-retaining piping and components located downstream of the MSIVs up to the next isolation valves, i.e., turbine bypass valves, moisture separator reheater isolation valves, main turbine stop valves, main feed pump turbine stop valves, and steam seal isolation valve. All other portions of the system used for FP intended functions are SR and included in the AMR in Section 5.12 of the BGE LRA. The following passive FP intended function (not addressed in other evaluations) applies: [Reference 74]

- Maintain the PB of the system (liquid and/or gas).

5.10.3.16.3 Aging Management Demonstration

This portion of the Main Steam System is subjected to normal system conditions during operation since it is part of the main steam flow path to the high pressure turbines. The demands placed on the system during a fire are the same as, or less than, those during normal system operation. Use of the system during a fire will not challenge the pressure-retention ability more than normal. Thus, system parameters during performance of FP intended functions are bounded by the normal operating parameters of the system, and aging of this part of the system is fully managed by performance and condition monitoring activities during normal operation.

5.10.4 Conclusion

Table 5.10-4 lists the programs credited in this section of the BGE LRA. These programs will be administratively controlled by a formal review and approval process. As has been demonstrated in the above sections, these programs will manage the aging mechanisms and their effects such that the intended function of the components of these systems 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 5.10-4

LIST OF AGING MANAGEMENT PROGRAMS FOR FIRE PROTECTION

	Program	Credited As
Existing	FP Program, Nuclear Program Directive SA-1	Managing the effects of aging for the following systems; FP, Diesel Fuel Oil, Auxiliary Feedwater (partial), Plant Drains (partial), and Nitrogen and Hydrogen Gas.
Existing	Structure and System Walkdown Program, CCNPP Administrative Procedure MN-1-319	Managing the effects of aging for the following systems; Well and Pretreated Water, SRW, CC, Compressed Air, Plant Heating, Auxiliary Feedwater (partial), Demineralized Water and Condensate Storage, Condensate (partial), Plant Drains (partial), Liquid Waste, and Main Steam.
Existing	Conduct of Operations, CCNPP Administrative Procedure NO-1-100	Managing the effects of aging for the following systems; Well and Pretreated Water, SRW, CC, Compressed Air, Plant Heating, Auxiliary Feedwater (partial), Demineralized Water and Condensate Storage, Condensate (partial), Plant Drains (partial), Liquid Waste, and Main Steam.
Existing	Boric Acid Corrosion Inspection Program (Refer to the discussions in Sections 5.2, CVCS, and 4.1, RCS, of the BGE LRA for detailed information regarding this program)	Mitigation, detection, and management of the effects of general corrosion in a portion of the CVCS, i.e., the fasteners in the NSR piping and associated components in the controlled bleedoff lines for the reactor coolant pumps. Mitigation, detection, and management of the effects of general corrosion in a portion of the RCS, i.e., the fasteners in the NSR piping and associated components in the controlled bleedoff lines for the reactor coolant pumps.
New	ARDI Program	Detection and management of the effects of crevice corrosion, general corrosion, and pitting on a portion of the piping in the Condensate System (as identified in Section 5.10.3.11).

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4. CCNPP Component Level Scoping Results for the Primary Containment System (059), Revision 0, February 23, 1993
5. CCNPP Pre-Evaluation Results for the Containment System (059), Revision 1, May 9, 1996
6. CCNPP Component Level Scoping Results for the Primary Containment Structure (SYS 059), Revision 1, March 25, 1996
7. CCNPP Component Level Scoping Results for the Auxiliary Building, Revision 2, February 14, 1997
8. CCNPP Component Level Scoping Results for the Turbine Building, Revision 2, February 12, 1997
9. CCNPP Component Level Scoping Results for the Salt Water Cooling System, Revision 3, July 15, 1996
10. CCNPP Component Pre-evaluation for the Salt Water System (012), Revision 4, December 30, 1996
11. CCNPP Component Level Scoping Results for the Emergency Diesel Generators, Revision 1, January 5, 1993
12. CCNPP Pre-evaluation Results for the Emergency Diesel Generator System (024), Revision 0, January 30, 1995
13. CCNPP Component Level Scoping Results for the Feedwater System (045), Revision 2, December 16, 1996
14. CCNPP Pre-evaluation Results for the Main Feedwater System (045), Revision 1, March 11, 1996
15. CCNPP Component Level Scoping Results for System 052 Safety Injection System, Revision 2, April 8, 1996
16. CCNPP Pre-evaluation Results for the Safety Injection System (052), Revision 1, December 1, 1995
17. CCNPP Component Level Scoping Results for System 061 - Containment Spray System, Revision 1, April 17, 1996
18. CCNPP Component Pre-evaluation Results for the Containment Spray System (061), Revision 2, March 6, 1997
19. CCNPP Component Level Scoping Results for the Control Room HVAC System, Revision 1, July 17, 1996

20. CCNPP Component Pre-evaluation for the Control Room HVAC System (030), Revision 1, April 2, 1997
21. CCNPP Component Level Scoping Results for the Auxiliary Building and Radwaste H&V System, Revision 2, July 17, 1996
22. CCNPP Pre-evaluation Results for the Auxiliary Building and Radwaste H&V System 032, Revision 0, June 2, 1995
23. CCNPP Component Level Scoping Results for the Primary Containment H&V System, Revision 1, August 15, 1996
24. CCNPP Pre-evaluation Results for the Primary Containment Heating & Ventilating System (060), Revision 0, May 1, 1995
25. CCNPP Component Level Scoping Results for the Electrical 125 Volt DC Distribution System, Revision 3, August 8, 1995
26. CCNPP Pre-evaluation Results for the 125 VDC System (002), Revision 0, September 7, 1994
27. CCNPP Component Level Scoping Results for the Electrical 4 kV Transformers and Buses System, Revision 1, August 5, 1995
28. CCNPP Pre-evaluation Results for the Electrical 4kV Transformers and Buses System (004), Revision 1, October 13, 1994
29. CCNPP Component Level Scoping Results for the Electrical 480V Transformers and Buses System, Revision 1, August 5, 1995
30. CCNPP Pre-evaluation Results for the Electrical 480V Transformers and Buses System (005), Revision 1, October 15, 1994
31. CCNPP Component Level Scoping Results for the Electrical 480V Motor Control Centers System, Revision 1, August 5, 1995
32. CCNPP Pre-evaluation Results for the Electrical 480V Motor Control Centers System (006), Revision 0, September 12, 1994
33. CCNPP Component Level Scoping Results for the Instrument AC System, Revision 1, June 30, 1995
34. CCNPP Pre-evaluation Results for the Instrument AC System (017), Revision 0, September 12, 1994
35. CCNPP Component Level Scoping Results for the Vital Instrument AC System, Revision 1, August 5, 1995
36. CCNPP Pre-evaluation Results for the Vital Instrument AC System (018), Revision 0, September 12, 1994
37. CCNPP Component Level Scoping Results for the Annunciation System, Revision 1, August 4, 1995
38. CCNPP Pre-evaluation Results for the Annunciation System (026), Revision 0, October 12, 1994
39. CCNPP Component Level Scoping Results for the Control Rod Drive Mechanism and Electrical System, Revision 2, May 22, 1995

40. CCNPP Pre-evaluation Results for the Control Rod Drive Mechanism and Electrical System (055), Revision 0, September 28, 1994
41. CCNPP Component Level Scoping Results for the Nuclear Instrumentation System, Revision 1, January 14, 1997
42. CCNPP Pre-evaluation Results for the Nuclear Instrumentation System (078), Revision 0, February 2, 1995
43. CCNPP Component Level Scoping Results for the Main Turbine System, Revision 0, October 11, 1994
44. CCNPP Pre-evaluation Results for the Main Turbine System (093), Revision 0, October 14, 1994
45. CCNPP Component Level Scoping Results for the Lighting and Power Receptacle System, Revision 1, August 5, 1995
46. CCNPP Pre-evaluation Results for the Lighting and Power Receptacle System (097), Revision 0, October 27, 1994
47. CCNPP Component Level Scoping Results for the Plant Communications System, Revision 0, October 14, 1995
48. CCNPP Pre-evaluation Results for the Plant Communications System (100), Revision 0, October 27, 1994
49. Memorandum from Mr. J. P. Moulton (NRC) to Baltimore Gas and Electric Company, dated November 20, 1996, “Summary of Meeting with Baltimore Gas and Electric Company (BGE) on BGE License Renewal Activities”
50. CCNPP Nuclear Program Directive SA-1, “Fire Protection Program,” Revision 2, January 20, 1998
51. CCNPP Updated Final Safety Analysis Report, Revision 21
52. CCNPP Technical Specifications, Units 1 and 2
53. CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns,” Revision 0, September 16, 1997
54. CCNPP Administrative Procedure NO-1-100, “Conduct of Operations,” Revision 10, January 9, 1998
55. CCNPP Administrative Procedure QL-2-100, “Issue Reporting and Assessment,” Revision 10, March 9, 1998
56. CCNPP Component Pre-evaluation for the Service Water System (011), Revision 1, October 7, 1996
57. CCNPP Component Pre-evaluation for the Component Cooling Water System (015), Revision 1, November 4, 1996.
58. CCNPP Operations Drawing No. 60712SH0001, “Compressed Air System, Instrument Air and Plant Air, Unit 1” Revision 46, December 5, 1996
59. CCNPP Operations Drawing No. 62712SH0001, “Compressed Air System, Instrument Air and Plant Air, Unit 2” Revision 33, February 10, 1998

60. CCNPP Electrical Logic Diagram No. 62622SH0001, “Instrument Air Compressor, Units 1 and 2” Revision 7, January 14, 1991

61. CCNPP Electrical Logic Diagram No. 62622SH0002, “Plant Air Compressor, Units 1 and 2” Revision 8, December 18, 1996

62. CCNPP Electrical Logic Diagram No. 62622SH0006, “Containment Instrument Air Header Control Valve, Units 1 and 2” Revision 4, December 21, 1990

63. CCNPP Electrical Logic Diagram No. 62622SH0004, “Instrument/Plant Cross Connect Plant Air Header Isolation, Units 1 and 2” Revision 3, December 21, 1990

64. CCNPP Pre-evaluation Results in Compliance with BGE Procedure LCM-10 for Compressed Air System (019), Revision 0, November 30, 1995

65. CCNPP Pre-evaluation Results for the Diesel Fuel Oil System (023), Revision 1, March 11, 1996

66. CCNPP Surveillance Test Procedure STP-F-77-0, “Staggered Test of Diesel Fire Pump,” Revision 3, December 1, 1997

67. CCNPP Surveillance Test Procedure STP-F-696-0, “Fire Pump Flow Test,” Revision 3, January 1, 1997

68. CCNPP Drawing No. 12352-0001, “Eight Inch Heat Exchanger for Pretreated Water Storage Tank,” Revision 0, July 10, 1970

69. CCNPP Specification No. M-0024, “Pretreated Water Storage tanks Heat Exchangers and Miscellaneous Waste Processing System Heat Exchanger, Units 1 and 2,” Revision 3, October 4, 1973

70. CCNPP Pre-evaluation Results for the Auxiliary Feedwater System (036), Revision 1, April 3, 1996.

71. CCNPP Pre-evaluation Results for the Demineralized Water & Condensate Storage System (037), Revision 0, October 11, 1994

72. CCNPP Pre-evaluation Results for the Chemical and Volume Control System 041, Revision 2, October 17, 1996

73. CCNPP Component Pre-evaluation for the Reactor Coolant System (064), Revision 1, December 20, 1996.

74. CCNPP Pre-evaluation Results for the Main Steam System (083), Revision 1, July 11, 1996

5.11A Auxiliary Building Heating and Ventilation System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing the Auxiliary Building Heating and Ventilation (H&V) System. The Auxiliary Building H&V 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.

5.11A.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 device types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Representative historical operating experience pertinent to aging 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.

Section 5.11A.1.1 presents the results of the system level scoping, 5.11A.1.2 the results of the component level scoping, and 5.11A.1.3 the results of scoping to determine components subject to an AMR.

5.11A.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.

<u>System Description/Conceptual Boundaries</u>

The Auxiliary Building H&V System is comprised of fans, air handling units, dampers, filters, coolers, controls, and ductwork, which provide air, in some cases filtered and tempered, to various rooms in the auxiliary and radwaste buildings. A negative pressure, with respect to ambient and surrounding areas of the building, is normally maintained in the Auxiliary Building to ensure that clean areas do not become contaminated through the ventilation system. Areas serviced by the system include the Switchgear Rooms (each unit), Diesel Generator Rooms (three total), Auxiliary Feedwater (AFW) Pump Room (each unit), Service Water (SRW) Heat Exchanger Room (each unit), main steam line penetration area (each unit), waste processing area (each unit), Emergency Core Cooling System (ECCS) Pump Rooms (each unit), the fuel handling areas (shared between units), and general areas of the Auxiliary Building. Exhaust air from the waste processing areas, ECCS Pump Rooms, and the fuel handling areas is passed through a roughing filter and a high efficiency particulate (HEPA) filter to remove potentially radioactive particulate contamination prior to discharge through the plant vent. Exhaust air from the ECCS Pump Room and the fuel handling area can also be routed through separate charcoal filters to remove radioactive iodine in the event of a loss-of-coolant accident or fuel handling incident, respectively. [References 1 through 5]

The Switchgear Rooms are cooled the year round by redundant heating, ventilating, and air conditioning (HVAC) units and refrigeration systems. The air conditioning system provides conditioned air for cooling and ventilation. A set of mixing dampers automatically proportion the amount of fresh air and recirculated air as needed to maintain room temperature within design limits. The HVAC units and refrigeration components are redundant, but the supply and return ducts to the Switchgear Room are not. [References 1, 4, and 5]

The Fairbanks Morse diesel generators are housed in three separate rooms in the Auxiliary Building. Heat output from each generator is sufficiently high that cooling must be provided for both summer and winter. The ventilation system for this area is designed to limit room temperature to a maximum of 120°F in summer and a minimum of 60°F in winter. Outside air is used as the cooling medium. An air-handling unit and mixing box-damper arrangement proportion the flow of outside air and recirculated air according to room temperature. When the emergency diesel generator (EDG) is running, its room is pressurized and the excess air is forced out through a weatherproof exhaust opening over the outside door. Hot water unit heaters maintain a minimum temperature of 60°F when the diesel is shut down. [References 1 and 4] Heating and ventilation for the additional EDGs, which are located in a separate building outside, are discussed in the Control Room HVAC System Evaluation in Section 5.11C of this application.

There are "normal" and "emergency" air cooling systems for the AFW Pump Room. During normal plant operation, one self-contained HVAC unit maintains the temperature in this room at 90°F or below. During the emergency mode of operation, which would exist if the normal HVAC unit fails for any reason, redundant fans circulate air between these two rooms through a system of connecting ductwork. The heat sink effect of the equipment room supplies all of the cooling required to prevent the room air temperature from rising above 130°F, provided administrative operational restrictions are followed, to prevent failure of the air-cooled bearings of the pumps while they are operating. [References 1, 4, and 5]

The SRW Heat Exchanger Room is provided with forced air ventilation by separate supply and exhaust fans and dampers. The ventilation is required to remove equipment heat and maintain the room temperature low enough for equipment operability in post-accident situations. Relatively cool air is drawn from the Turbine Building and the warmer exhaust air is returned there, as well. The dampers automatically shut upon high pressure to isolate the room from temperature rises due to a high energy line break inside of the Turbine Building. [References 6 and 7]

Heat released by the main steam and feedwater pipes requires that cooling be provided in the main steam line penetration area all year round. This system uses outside air as the cooling medium. Fresh air is mixed with recirculated air as required and supplied through ducting from an air-handling unit. The main steam line penetration area is pressurized and the excess air flows out through the open safety vent to the roof. A room thermostat controls the position of the mixing dampers, which are located upstream of dust-stop filters. [References 1, 4, and 5]

A negative pressure with respect to ambient and surrounding areas of the building is normally maintained in the waste processing area. A common air supply system consisting of three 50% capacity air handling units supplies outdoor air for ventilation of the common waste processing area and general areas in the Auxiliary Building. A system of ductwork ensures a uniform distribution throughout this area. The exhaust system draws air from the waste processing areas by means of ductwork and forces it through

HEPA filters, after which it is discharged into the main exhaust plenums. From here, the main plant exhaust fans force the air past the radioactivity monitors and out through the exhaust stacks. These exhaust fans are 100% redundant, but the filters are not. [References 1 and 3]

The ECCS Pump Rooms require ventilation to limit room temperature and provide proper cooling of the safety injection and containment spray pumps. The subsystem consists of one cooling unit for each ECCS Pump Room, cooling unit fans, and an ECCS Pump Room exhaust system that includes a roughing filter, a HEPA filter, charcoal filter, and dampers. The Saltwater System provides cooling to the cooling unit. [References 1 and 3]

Two 50% capacity air handling units provide filtered air to the fuel handling area, which includes the spent fuel pool area, New Fuel Storage Room, and the Miscellaneous Waste Evaporator Room. A separate exhaust system draws air through a manifold and HEPA filters and feeds it into the main plant vent of Unit 1. During load handling evolutions over the spent fuel pool that includes moving fuel, this air is diverted through charcoal filters after it leaves the HEPA filters for removal of radioactive iodines prior to discharge to minimize radioactive material release in the event of a fuel handling accident. The exhaust fans are capable of maintaining a negative pressure with respect to ambient and surrounding areas of the building. Unit heaters are provided to maintain a minimum temperature of 60°F in the winter. [References 1 and 3]

System Interfaces

The Auxiliary Building H&V System has an interface with the following systems and components: [References 2 through 5; Reference 8]

System/Component	Within the Scope of License Renewal at the Interface?
Main Plant Vent	No
Control Room HVAC System	Yes, See Section 5.11C of the BGE LRA
Radiation Monitoring System	No
Saltwater Cooling System	Yes, See Section 5.16 of the BGE LRA
Service Water System	No

System Scoping Results

The Auxiliary Building H&V System is within the scope of license renewal based on 10 CFR 54.4(a). The following intended functions of the Auxiliary Building H&V 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 9, Table 1]

- To supply air to the battery ventilation system in response to a Design Basis Event (DBE);
- To initiate letdown line isolation to provide radiological release control during a loss-of-coolant accident;
- To provide ventilation for, and remove potentially radioactive contamination from, the ECCS Pump Room in response to a DBE;
- To provide HVAC for, and remove potentially radioactive contamination from, the Fuel Handling area in response to a DBE;

- To provide HVAC to the Electrical Switchgear Room in response to a DBE;
- To provide ventilation to the Diesel Generator Rooms in response to a DBE;
- To provide ventilation to the AFW Pump Room in response to a DBE;
- To provide ventilation to the SRW Heat Exchanger Room in response to a DBE;
- To maintain electrical continuity and/or provide protection of the electrical system;
- To maintain the pressure boundary of the system (liquid and/or gas); and
- To maintain structural integrity to support proper operation of other Auxiliary Building H&V System components.

The following Auxiliary Building H&V System intended functions were determined based on the requirements of §54.4(a)(3): [Reference 9, Table 1]

- For fire protection (§50.48)- To provide alternate ventilation to the AFW Pump Room during a fire; and
- For environmental qualification (§50.49)- To maintain functionality of electrical equipment as addressed by the Environmental Qualification Program and to provide information used to assess the plant and environs condition during and following an accident.

All components of the Auxiliary Building H&V System that meet the fire protection or environmental qualification criteria of 54.4(a)(3) are also safety-related. No components were scoped that only meet a 54.4(a)(3) criteria.

Components of the Auxiliary Building H&V System that support the above functions are safety-related and Seismic Category 1 and are subject to the applicable loading conditions identified in the Updated Final Safety Analysis Report Section 5A.3.2 for Seismic Category 1 systems and equipment design. [References 3 through 6; Reference 10] The ductwork was constructed of galvanized copper bearing sheet steel, which conformed to the latest Guide from the American Society of Heating, Refrigeration, and Air Conditioning Engineers. It was installed in accordance with high velocity and low velocity duct construction standards from the Sheet Metal and A/C Contractors National Association. [Reference 11]

Operating Experience

Over 20 years of operating experience has shown the H&V systems at CCNPP to be highly reliable in maintaining their passive functions. Some cracking has been discovered in HVAC ducting due to vibration-induced fatigue. However, these isolated failures were due to a combination of design and installation deficiencies. In one case, additional supports were added to the ducting to prevent recurrence. In another case, the fans were balanced to minimize the vibration. Some loosening of fasteners has been experienced due to dynamic loading. Vibration-related aging concerns are minimized through system design and existing maintenance practices, which are further described below in the discussion for Group 3. Vibration isolators, i.e., flexible collars or cloth boots, are installed around the fans to minimize the vibration being transferred to other equipment. [Reference 2, Attachments 6] Furthermore, fans are monitored for vibration whenever the fan belts are retensioned or replaced.

In 1980, a Control Room air conditioning unit was placed out-of-service to repair broken damper linkages. This failure was caused by excessive wear due to inadequate lubrication of the damper linkage. The existing preventive maintenance (PM) procedure was modified to include lubrication along with the periodic visual inspection. [Reference 12] During performance of these periodic inspections, elastomer degradation of the seals has also been identified. If the seals on jambs or blade edging lose their resiliency or are deteriorated, corrective actions are taken to have the seals replaced. [Reference 13]

Corrosion has been discovered in the housing below the cooling coils in some of the HVAC units. These areas have been inspected to assess the corrosion rates and adequacy of the system pressure boundary. Other than the limited amount of degradation experienced due to vibration, wear, and corrosion, no other significant aging concerns have been identified that could affect the ability of the Auxiliary Building H&V System components to perform their passive intended functions.

5.11A.1.2 Component Level Scoping

Based on the intended system functions listed above, the portions of the Auxiliary Building H&V System that are within the scope of license renewal include all safety-related components in the system (electrical, mechanical, and instrumentation), and their supports. Safety-related portions of the Auxiliary Building H&V System include the following: [References 3 through 5; Reference 10]

Plant Area	Portion Within Scope
Switchgear Room	Entire subsystem including HVAC units, refrigeration system, and supply and return duct and dampers
Diesel Generator Rooms	Entire subsystem including supply duct, dampers and fans, and the exhaust dampers
AFW Pump Rooms	Supply duct and dampers and exhaust fans, duct and dampers (the normal A/C unit, and associated duct and damper is not)
SRW Heat Exchanger Rooms	Entire subsystem including supply fan, dampers and duct, and exhaust fan and dampers
Main steam line penetration area	None
Waste processing area	None
ECCS Pump Room	Exhaust path including fans, HEPA filters, charcoal filters, duct, and dampers (exhaust duct from the downstream side of the exhaust fan discharge damper to the plant vent is not)
Fuel handling area	Exhaust fans, HEPA filters, charcoal filters, duct, and dampers (all supply fans, HVAC units, filters, duct, and dampers are not, exhaust duct from the wall of the fuel handling area Exhaust Fan Equipment Room to the plant vent is also not)

APPENDIX A - TECHNICAL INFORMATION
5.11A - AUXILIARY BUILDING HEATING AND VENTILATION SYSTEM

The following 46 device types in the Auxiliary Building H&V System were designated as within the scope of license renewal because they have at least one intended function [Reference 2, Section 3.2 and Table 3-2]:

Device Type	Device Description	Device Type	Device Description
ACC	Accumulator	MD	125/250VDC Motor
CKV	Check Valve	MO	Motor Operator
COIL	Coil	PDI	Pressure Diff Indicator
COMP	Compressor	PDIS	Pressure Diff Indicator Switch
CV	Control Valve	PI	Pressure Indicator
DAMP	Damper	PNL	Panel
DISC	Disconnect Switch/Link	PO	Piston Operator
DRY	Air Dryer	PS	Pressure Switch
DUCT	HVAC Duct	PT	Pressure Transmitter
FAN	Fan	PY	Pressure Converter (Relay)
FL	Filter	RV	Relief Valve
FU	Fuse	RY	Relay
GD	Gravity Damper	SV	Solenoid Valve
HD	Manual Damper	TC	Temperature Controller
HS	Handswitch	TCV	Temperature Control Valve
HV	Hand Valve	TE	Temperature Element
HX	Heat Exchanger	TIC	Temperature Indicating Controller
HY	Converter/Relay	TS	Temperature Switch
JD	Tubing with Piping Code of “JD”	TT	Temperature Transmitter
JL	Power Lamp Indicator	TY	Temperature Device (Relay)
LY	Level Device (Relay)	ZC	Position Controller
M	480V Motor (Feed from MCC)	ZL	Position Indicating Lamp
MB	480V Motor	ZS	Position Switch

Some components in the Auxiliary Building H&V System are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 2, Section 3.2]

- Structural supports for ducting, piping, cables, and components are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of this application.
- Electrical control and power cabling are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of this application. This commodity evaluation completely addresses the passive intended function entitled “maintain electrical continuity and/or provide protection of the electrical system” for the Auxiliary Building H&V 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.

5.11A.1.3 Components Subject to AMR

This section describes the components within the Auxiliary Building H&V System that are subject to 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 CCNPP IPA Methodology Section 5.1, the following Auxiliary Building H&V System functions were determined to be passive: [Reference 2, Table 3-1]

- Maintain the pressure boundary of the system (liquid and/or gas);
- Maintain electrical continuity and/or provide protection of the electrical system; and
- Maintain structural integrity to support proper operation of other Auxiliary Building H&V System components.

Device Types Subject to AMR

Of the 46 device types within the scope of license renewal; [Reference 2, Table 3-2 and Appendix B; Reference 14]

- Twenty-five device types have only active functions and do not require AMR; coil, control valve, disconnect switch/link, fuse, hand switch, converter/relay, power lamp indicator, level device (relay), 480V motor (feed from MCC), 480V motor, 125/250VDC motor, motor operator, piston operator, pressure transmitter, pressure converter (relay), relay, temperature controller, temperature element, temperature indicating controller, temperature switch, temperature transmitter, temperature device (relay), position controller, position indicating lamp, and position switch.
- Ten device types do not require a detailed evaluation of specific aging mechanisms because they are considered part of a complex assembly whose only passive function is closely linked to active performance as discussed below; accumulator, air dryer, compressor, tubing with piping Code of "JD," pressure indicator, pressure switch, check valve, relief valve, solenoid valve, and temperature control valve.

  In accordance with the provisions of Section 6.1.1 of the CCNPP IPA Methodology, components that comprise the refrigeration units do not require a specific evaluation of ARDMs because the detrimental effects of aging mechanisms can be observed by detrimental changes in the performance characteristics or condition of refrigeration unit components if they are properly monitored. Therefore, by adequately monitoring these performance or condition characteristics, the effects of aging on the passive intended function are also adequately managed. The active functions are monitored by: (1) operational requirements that must be satisfied for continued plant operation; (2) Maintenance Rule system performance monitoring; and (3) component-specific condition monitoring addressed under the CCNPP Maintenance Program. [Reference 2, Appendix B]

  The ten device types listed above are entirely included in these complex assemblies. Three other device types, i.e., hand valves, heat exchangers, and fans, include some components that are part of these complex assemblies and some that are included in the AMR presented herein.

- Two devices types are evaluated in another section of this application;
  - ‘Panel’ is evaluated for the effects of aging in the Electrical Commodities Evaluation in Section 6.2 of this application. This commodity evaluation completely addresses the passive intended function entitled “maintain structural integrity to support proper operation of other Auxiliary Building H&V System components”
  - ‘Pressure differential indicator switch’ is evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of this application.

The remaining nine device types listed in Table 5.11A-1 are subject to a detailed evaluation of aging mechanisms as part of the AMR and are included in this section. For AMR, some device types have a number of groups associated with them because of the diversity of materials used in their fabrication or differences in the environments to which they are subjected.

Maintenance of the pressure boundary of the system is the only passive intended function associated with the Auxiliary Building H&V System not addressed by one of the commodity evaluations referred to above. Therefore, only the pressure-retaining function for the nine device types listed in Table 5.11A-1 is considered in the AMR for the Auxiliary Building H&V System. Unless otherwise annotated, all components of each listed device type are subject to AMR.

TABLE 5.11A-1

AUXILIARY BUILDING H&V SYSTEM DEVICE TYPES REQUIRING AMR

Damper
HVAC Duct
Fan (1)
Filter
Gravity Damper
Manual Damper
Hand Valve (1, 2)
Heat Exchanger (1)
Pressure Differential Indicator (2)

(1) The fans (condenser fans), heat exchangers (condenser and cooling coils of the HVAC unit), and hand valves that are part of the Switchgear Room refrigeration unit are not evaluated herein because they are part of a complex assembly whose only passive function is closely linked to active performance as permitted in Section 6.1.1 of the CCNPP IPA Methodology.

(2) The equalization valve (hand valve) and pressure differential indicator switch for the ECCS Pump Room exhaust HEPA filters are evaluated in the Instrument Line Commodity Evaluation in Section 6.4 of this application. [Reference 9, Attachment 4A]

5.11A.2 Aging Management

A list of potential age-related degradation mechanisms (ARDMs) identified for the Auxiliary Building H&V System components is given in Table 5.11A-2. The plausible ARDMs are identified in the Table by a check mark (✓) in the appropriate device type column. A check mark indicates that the ARDM applies to at least one group for the device type listed. For efficiency in presenting the results of the evaluations in this section, 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 5.11A-2 identifies the group in which each ARDM/device type combination belongs.

The following groups have been selected for the Auxiliary Building H&V System:

Group 1 - Includes crevice corrosion, general corrosion, and pitting for duct and heat exchangers.

Group 2 - Includes elastomer degradation and wear for non-metallic duct and damper parts.

Group 3 - Includes dynamic loading for fans.

TABLE 5.11A-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE AUXILIARY BUILDING H&V SYSTEM

	Auxiliary Building H&V System Device Types								
Potential ARDMs	DAMP	DUCT	FAN	FL	GD	HD	HV	HX	PDI
Cavitation Erosion									
Corrosion Fatigue									
Crevice Corrosion		√ (1)						√ (1)	
Dynamic Loading			√ (3)						
Erosion Corrosion									
Fatigue									
Fouling									
Galvanic Corrosion									
General Corrosion		√ (1)						√ (1)	
Hydrogen Damage									
Intergranular Attack									
Microbiologically-Induced Corrosion									
Particulate Wear Erosion									
Pitting		√ (1)						√ (1)	
Radiation Damage									
Elastomer degradation		√ (2)			√ (2)	√ (2)			
Selective Leaching									
Stress Corrosion Cracking									
Stress Relaxation									
Thermal Embrittlement									
Wear		√ (2)			√ (2)	√ (2)			

√ - indicates that the ARDM is plausible for component(s) within the device type
(#) - Indicates the Group in which this device type/ARDM combination is evaluated

Note: Not every component within the device types listed here may be susceptible to a given ARDM. This is because components within a device type are not always fabricated from the same materials or subjected to the same environments. Exceptions for each device type will be indicated in the aging management section for each ARDM discussed in this report.

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.

Group 1 (crevice corrosion, general corrosion, and pitting for duct and heat exchangers) - Materials and Environment

Group 1 is comprised of components that are potentially exposed to moist air and condensation. These include the ducting where the steel materials are exposed to the potentially moist air. The duct, fittings, doors, and door hinges/latches are constructed of galvanized carbon steel. The joint angles are constructed of carbon steel, and the bolts and rivets are plated carbon steel. The supply and exhaust registers are constructed of either enameled carbon steel or aluminum. Group 1 ducting includes all of the Auxiliary Building H&V System duct that is within the scope of license renewal. Some of the components' surfaces are painted or galvanized. [Reference 2, Attachments 4 and 6]

Also included in Group 1 is the galvanized carbon steel housing for the Switchgear Room cooling coils that may be exposed to moist air and condensate from the coils. If the drains become plugged, there may also be standing water in the drain pan that could spill over onto other sections of the equipment base. The coils themselves have the system pressure boundary intended function; however, they do not require AMR because they are part of the refrigeration units and considered a complex assembly, as discussed in Section 5.11A.1.2. [Reference 2, Attachments 4 and 6]

The Auxiliary Building H&V System is designed to maintain the temperatures inside each of the ventilated areas, assuming the outdoor air temperature is 95°F, below the design temperature as follows: [Reference 1, Table 9-18]

Subsystem	Design Temperature (°F)
Switchgear Room	104
EDG Rooms	120
AFW Pump Room	90
Main steam penetration area	160
Waste processing	110
Fuel handling area	110
ECCS Pump Room	110

The internal environment for the Auxiliary Building H&V System consists of outside air or of air drawn from ventilated areas. No design requirements exist for maintaining humidity below a specified value in the Auxiliary Building. However, the maximum normal relative humidity inside the Auxiliary Building areas is 70%. [Reference 15] Outdoor air could reach a relative humidity of up to 100%. All of these components are located in ventilated areas indoors and, therefore, not exposed to the outside weather or sun.

Group 1 (crevice corrosion, general corrosion, and pitting for duct and heat exchangers) - Aging Mechanism Effects

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. Crevice corrosion is closely related to pitting corrosion and can initiate pits in many cases, as well as leading to stress corrosion cracking. [Reference 2, Attachments 6 and 7]

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. General corrosion requires an aggressive environment and materials susceptible to that environment. The consequences of the damage are loss of load carrying cross-sectional area. [Reference 2, Attachments 6 and 7]

Pitting is another form of localized attack with greater corrosion rates at some locations than at others. Pitting can be very insidious and destructive, with sudden failures in high pressure applications (especially in tubes) occurring by perforation. This form of corrosion essentially produces holes of varying depth to diameter ratios in the steel. Deep pitting is more common with passive metals, such as austenitic stainless steels, than with non passive metals. Pits are generally elongated in the direction of gravity. In many cases, erosion corrosion, fretting corrosion, and crevice corrosion can also lead to pitting. [Reference 2, Attachments 6 and 7]

For Group 1 components, there are two possible effects from long-term exposure to the moist environment; a uniform corrosion of the exposed steel surfaces causing material thinning, and localized attack resulting in pits and cracks. Those items that are painted or galvanized are protected from the effects of corrosion; however, where the coating is damaged, the corrosion may take place. The most likely locations for corrosion is in crevices at duct joints and between support angles and sheet metal. These corrosion ARDMs are not plausible for the registers constructed of aluminum because that material is resistant to corrosion in this mild environment. If corrosion were left unmanaged, it could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. [Reference 2, Attachment 6]

Group 1 (crevice corrosion, general corrosion, and pitting for duct and heat exchangers) - Methods to Manage Aging

Mitigation: Since there are no design features for control of humidity, the only feasible method of preventing exposure of these components to a corrosive environment is to apply a protective coating to them. Those subcomponents without a protective coating, or where the coating has degraded, will potentially be exposed to moisture from condensation. The subcomponents constructed of carbon steel materials could be replaced with subcomponents constructed of more corrosion resistant materials. [Reference 2, Attachment 8]

Discovery: The effects of corrosion (crevice corrosion, general corrosion, and pitting) on Group 1 components can be discovered and monitored through non-destructive examination techniques, such as visual inspections or pressure tests. [Reference 2, Attachment 8] Representative samples of susceptible locations can be used to assess the need for additional inspections at less susceptible locations.

Group 1 (crevice corrosion, general corrosion, and pitting for duct and heat exchangers) - Aging Management Program(s)

Mitigation: Maintaining the protective coatings, as discussed below in Discovery, will help to mitigate corrosion of these components. No other mitigation techniques are deemed necessary at this time, so there are no mitigation programs credited for managing corrosion of Group 1 components.

Discovery: For Group 1 components, crevice corrosion, general corrosion, and pitting can be readily detected through visual examination. Additionally, degraded protective coatings, which help mitigate corrosion, can also be visually detected so that corrective actions can be taken to restore the coatings. As such, an inspection program can provide the assurance needed to conclude that the effects of plausible aging are being effectively managed for the period of extended operation. Routine system walkdowns would discover corrosion of the external surfaces of the Group 1 components. To assure that corrosion is discovered if it exists on the internal surfaces of these components, they will be included in a new ARDI Program to accomplish the necessary inspections. [Reference 2, Attachment 8]

System Walkdowns

Calvert Cliffs Administrative Procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of general corrosion, and conditions that could allow corrosion to occur (e.g. degraded paint), of the Auxiliary Building H&V System by performance of visual inspections during plant walkdowns. The purpose of the procedure is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. [Reference 16, Sections 1.1 and 1.2]

In accordance with MN-1-319, personnel with assigned responsibility for specific structures and systems perform periodic walkdowns. Walkdowns may also be performed as required for reasons such as material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when a system is re-energized or placed in service); and as required for plant modifications. [Reference 16, Section 5.1]

One of the objectives of the walkdowns is to assess the condition of the CCNPP structures, systems, and components such that any degraded condition will be identified, documented, and corrective actions taken before the degradation proceeds to failure of the structures, systems, and components to perform their intended functions. [Reference 16, Sections 5.1.C, 5.2.A.1, and 5.2.A.5] Conditions adverse to quality are documented and resolved by the Calvert Cliffs Corrective Actions Program. The existing procedure will be modified to include specific inspection items with respect to discovery of these ARDMs to help ensure they are being adequately managed.

The procedure provides guidance for specific types of degradation or conditions to inspect for when performing the walkdowns. Inspection items related to aging management include the following: [Reference 16, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion or vibration;
- Effects that may have been caused by ARDMs such as damaged supports; concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, or inadequate support of components (e.g., missing, detached , or loose fasteners and clamps).

The walkdowns promote familiarity of the systems by the responsible personnel and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance alone. The procedure has been improved over time, based on past experience, to provide guidance on specific activities to be included in the scope of the walkdowns.

The corrective actions taken as a result of system walkdowns will ensure that the Group 1 duct and heat exchangers remain capable of performing their passive intended function under all CLB conditions.

Age-Related Degradation Inspection Program

To monitor the effects of corrosion for internal surfaces of Group 1 components, they will be included within a new plant program to accomplish the needed inspections. 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 current licensing basis (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.

Corrective actions will be taken, as necessary, in accordance with the CCNPP Corrective Actions 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 duct and heat exchangers) - 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 duct and heat exchangers:

- The Group 1 components provide system pressure-retaining boundary and their integrity must be maintained under all CLB 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.
- Existing visual inspections will continue to be performed in accordance with modified Administrative Procedure MN-1-319 to help ensure that these ARDMs are being adequately managed. Signs of degraded paint or galvanized surfaces, of external corrosion, or of internal corrosion that resulted in holes in the duct or cooler housing would be detected during these walkdowns. If unsatisfactory conditions are detected, corrective actions are taken in accordance with the CCNPP Corrective Actions Program.
- To provide the needed inspection for the internal surfaces of Group 1 components, they 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 Group 1 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 (elastomer degradation and wear for non-metallic duct and damper parts) - Materials and Environment

The Auxiliary Building H&V System galvanized carbon steel ducting was installed with flexible collars in connections between fans and ducts or casings to prevent excessive movements of long ducts. These flexible collars are constructed of elastomers and are installed with sufficient slack to prevent transmission of vibration. Collars are secured to fans and ducts with galvanized steel bars fastened with bolts for an air-tight construction. Some of the Auxiliary Building H&V System dampers are required to maintain system pressure boundary while in the closed position, and they are provided with compressible seals for leak tightness. These seals are constructed of neoprene material, which is an elastomer. [Reference 2, Attachment 4s; Reference 11]

The internal and external environments for the Auxiliary Building H&V System components are discussed above in the Materials and Environment Section for Group 1.

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Aging Mechanism Effects

An elastomer is a material that can be stretched to significantly greater than original length and, upon release of the stress, will return with force to approximately its original length. When an elastomer ages, there are three mechanism primarily involved:

- Scission - The process of breaking molecular bonds, typically due to ozone attack, UV light, or radiation;
- Crosslinking - The process of creating molecular bonds between adjacent long-chain molecules, typically due to oxygen attack, heat, or curing; and
- Compound ingredient evaporation, leaching, mutation, etc.

Natural aging tests indicate that where there is a significant property change in a elastomer, it appears to occurs within the first five to ten years after initial formulation/curing. Measurable properties that change include hardness, modulus, elongation, tensile strength, and compression strength. Elastomers generally harden as they age making sealing more difficult. [Reference 2, Attachment 7s]

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard, abrasive particles (abrasive wear) or fluid stream (erosion), and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). Motions may be linear, circular, or vibratory in inert or corrosive environments. Fretting is a wear phenomenon that occurs between tight-fitting surfaces subjected to a cyclic, relative motion of extremely small amplitude. Common sites for fretting are in joints that are bolted, keyed, pinned, press fit or riveted; in oscillating bearings, couplings, spindles, and seals; in press fits on shafts; and in universal joints. [Reference 2, Attachment 7s]

Elastomer degradation and wear are plausible for the flexible collars since the elastomers will degrade at the joints in the HVAC equipment due to relative motion between vibrating equipment, pressure variations and turbulence, and exposure to temperature changes and oxygen. These stressors will result in eventual tearing of the boot. Elastomer degradation and wear are plausible for damper seals because the neoprene will degrade due to relative motion between the blade and sleeve during damper operation and exposure to temperature changes and oxygen. These stressors will result in eventual breakdown of the seal. [Reference 2, Attachment 6s] If left unmanaged, elastomer degradation and wear could eventually result in the loss of pressure boundary integrity of the duct flexible collars and damper seals under CLB design loading conditions.

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Methods to Manage Aging

Mitigation: Elastomer degradation can be mitigated by utilizing materials that are less susceptible to heat and oxygen. Wear can be mitigated by minimizing operation of the dampers to slow degradation of the seating surfaces, which leads to a loss of leak tightness. [Reference 2, Attachment 7s]

Discovery: Periodic visual inspections can be performed for the Group 2 equipment to detect the effects of elastomer degradation and wear. Degradation of the flexible collars can be detected through periodic system walkdowns because the collars are readily accessible. Degradation of damper seals can be detected through continued inspections and walkdowns. If significant degradation is discovered, the flexible collars or damper seals can be repaired or replaced as appropriate. [Reference 2, Attachment 8]

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Aging Management Program(s)

Mitigation: The system was designed to minimize vibration by using equipment support isolators and equipment-to-duct isolators, such as the flexible collars. Changes to materials or to system operating practices are not deemed necessary to mitigate the effects of these ARDMs. Implementing the discovery methods discussed below are adequate methods to manage these ARDMs. Since there are no additional methods beyond these design features for mitigating elastomer degradation and wear, there are no programs credited with mitigating the aging effects due to these ARDMs. [Reference 2, Attachment 6s and 8]

Discovery:

Routine system walkdowns would discover elastomer degradation and wear of the duct flexible collars and possibly of the damper seals. To assure that degradation of the damper seals is not threatening the capability of the dampers to provide the pressure boundary function they will be included in a new ARDI Program.

System Walkdowns

Procedure MN-1-319 provides for discovery of the effects of elastomer degradation and wear by providing for system walkdowns that include visual inspections, 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 excessive vibrations, bent or broken component supports, etc.). Signs of cracking or tearing of duct flexible collars would be detected during these walkdowns. In some cases, these walkdowns can detect degradation in the dampers, such as if a non-operating fan is rotating backward due to a leaking damper. All the accessible external surfaces of the subject equipment are monitored and conditions identified as adverse to quality are corrected in accordance with the CCNPP Corrective Actions Program. [Reference 16] The existing procedure will be modified to include specific inspection items with respect to discovery of these ARDMs to help ensure they are being adequately managed. Refer to the discussion on Aging Management Programs for Group 1 for a detailed description of procedure MN-1-319.

ARDI Program

The system walkdowns can identify degradation evident externally from the components, which is adequate for the duct flexible collars and, in some cases, the damper seals. An inspection of the internals of the dampers would provide additional assurance that the effects of elastomer degradation and wear are being adequately managed. This inspection will be accomplished as part of an ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program.

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

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to elastomer degradation and wear for duct flexible collars and damper seals:

- Auxiliary Building H&V System ducts and dampers provide system pressure-retaining boundary and their integrity must be maintained under CLB design conditions.
- Elastomer degradation and wear are plausible for the flexible collars due to the relative motion between vibrating equipment, pressure variations, and turbulence, and exposure to temperature changes and oxygen. Elastomer degradation and wear are plausible for the damper seals due to relative motion between the blade and sleeve during damper operation and exposure to temperature changes and oxygen.
- If left unmanaged, elastomer degradation and wear can result in material loss, tearing, or cracking, which could lead to loss of pressure-retaining boundary integrity.
- Existing visual inspections will continue to be performed in accordance with modified Administrative Procedure MN-1-319 to help ensure that these ARDMs are being adequately managed. Signs of cracking or tearing of duct collars would be detected during these walkdowns, as well as such conditions as identifying unusual noises, leaks, or vibration. If unsatisfactory conditions are detected, corrective actions are taken in accordance with the CCNPP Corrective Actions Program.
- To provide the needed internal inspection for the dampers, 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 of the damper seals is discovered.

Therefore, there is reasonable assurance that the effects of elastomer degradation and wear for duct flexible collars and damper seals 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 3 (dynamic loading for fans) - Materials and Environment

Group 3 is comprised of fans because the rotating equipment can cause vibration that causes dynamic loading of the fasteners. Normal bearing wear and dirt buildup cause imbalances in the rotating parts of the fans, thereby creating vibrations. Flexible collars are installed on the fans to provide dynamic isolation for adjacent components, which minimizes the dynamic loading for those components. The fans have air for their internal and external environments. [Reference 2, Attachment 7]

Fan housings and fasteners for the ECCS Pump Room exhaust fans, AFW Pump Room supply fans, EDG Room supply fans, Switchgear Room supply fans, and fuel handling area exhaust fans are constructed of carbon steel. The SRW Heat Exchanger Room supply and exhaust fan housings and supports are constructed of aluminum and the fasteners of carbon steel. The fan blades and motors do not perform a passive intended function. Therefore, they are not subject to AMR. [Reference 2, Attachment 4s]

Group 3 (dynamic loading for fans) - Aging Mechanism Effects

Dynamic loadings (vibrations) are created at blowers by rotating parts with imbalances due to dirt buildup and normal bearing wear. There is a history of loosened mechanical fasteners due to vibration in fans at CCNPP. This mechanism is plausible for the fans, but is not considered plausible for adjacent HVAC equipment due to the dynamic isolation provided by flexible collars. If dynamic loading was left unmanaged, it could eventually result in the loss of pressure boundary integrity of the Auxiliary Building H&V fans under CLB design loading conditions. [Reference 2, Attachments 5 and 6]

Group 3 (dynamic loading for fans) - Methods to Manage Aging

Mitigation: Dynamic loading can be mitigated by minimizing the mechanical loading due to vibration. The system is designed to minimize vibration by using equipment support isolators and equipment-to-duct isolators, such as flexible collars. Visual inspections during system walkdowns would provide for detection of vibration so that corrective actions could be taken to minimize vibration and, thereby, mitigate the effects of dynamic loading. [Reference 2, Attachment 8]

Discovery : The effects of dynamic loading, e.g., loosened fasteners, can be detected through visual inspections. Periodic visual inspections during system walkdowns would provide for detection of the effects of dynamic loading, as well as vibration problems that can cause this ARDM to occur. [Reference 2, Attachment 8]

Group 3 (dynamic loading for fans) - Aging Management Program(s)

Mitigation: System walkdowns provide for periodic visual inspections of the external surfaces of Auxiliary Building H&V System components. During these walkdowns any vibration problems would be detected so that corrective actions can be taken to minimize the vibration. [Reference 2, Attachment 8] Refer to the discussions below in Discovery for a description of the system walkdowns.

Discovery: Routine inspections are performed on system components in accordance with Administrative Procedure MN-1-319. System walkdowns are credited for discovery of the effects of dynamic loading, as well as abnormal or excessive vibration, which can cause dynamic loading to occur. Procedure MN-1-319 requires routine system walkdowns that include visual inspections, reporting the walkdown results, and initiating corrective action. Under this procedure, inspection items typically related to aging management include identifying unusual noises and identifying system and equipment stress or abuse, such as excessive vibrations, bent or broken component supports, etc. Conditions identified as adverse to quality are corrected in accordance with the CCNPP Corrective Actions Program. [Reference 16] The existing procedure will be modified to include specific inspection items with respect to discovery of these ARDMs to help ensure they are being adequately managed. Refer to the discussion above in Group 1 under Aging Management Programs for a detailed discussion of procedure MN-1-319.

Group 3 (dynamic loading for fans) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to dynamic loading for all Auxiliary Building H&V fans:

- Auxiliary Building H&V System fans provide the system pressure-retaining boundary and their integrity must be maintained under CLB design conditions.
- Dynamic loading is a plausible ARDM for the fans due to excessive vibration resulting from fan operation.
- If left unmanaged, dynamic loading can result in loosened fasteners, which could lead to loss of pressure-retaining boundary integrity.
- Existing visual inspections will continue to be performed in accordance with modified CCNPP Administrative Procedure MN-1-319 to help ensure that these ARDMs are being adequately managed. Signs of loosened fasteners would be detected during these walkdowns, as well as such conditions as identifying unusual noises or vibration, so that corrective actions can be taken to mitigate this ARDM.

Therefore, there is reasonable assurance that the effects of dynamic loading for fans 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.

5.11A.3 Conclusion

The programs discussed for the Auxiliary Building H&V System are listed in Table 5.11A-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 Auxiliary Building H&V System 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 5.11A-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE AUXILIARY BUILDING H&V SYSTEM

	Program	Credited As
Modified	CCNPP System Walkdowns Administrative Procedure MN-1-319, "Structure and System Walkdowns" Existing procedure will be modified to include specific items with respect to discovery of these ARDMs to help ensure each plausible ARDM is being adequately managed.	• Discovery and management of the effects of crevice corrosion, general corrosion, and pitting for the external surfaces of duct and heat exchangers (Group 1) • Discovery and management of the effects of elastomer degradation and wear for the duct flexible collars (Group 2) • Mitigation of vibration and discovery and management of the effects of dynamic loading for the fans (Group 3)
New	ARDI Program	• Discovery and management of the effects of crevice corrosion, general corrosion, and pitting for the internal surfaces of duct and heat exchangers (Group 1) • Discovery and management of the effects of elastomer degradation and wear for the surfaces of damper seals (Group 2)

5.11A.3 References

1. "CCNPP Updated Final Safety Analysis Report," Revision 20
2. "CCNPP Auxiliary Building and Radwaste H&V System Aging Management Review Report," Revision 1, March 21, 1997
3. CCNPP Drawing No. 60722SH0001, "Auxiliary Building Ventilation Systems," Revision 40, January 16, 1997
4. CCNPP Drawing No. 60722SH0002, "Auxiliary Building Ventilation Systems," Revision 36, December 2, 1996
5. CCNPP Drawing No. 60722SH0003, "Auxiliary Building Ventilation Systems," Revision 3, August 29, 1996
6. CCNPP Drawing No. 60723SH0001, "Ventilation Systems: Containment, Turbine, and Penetration Rooms," Revision 38, July 12, 1996
7. CCNPP Drawing No. 60625SH0015, Service Water Heat Exchanger Room Ventilation," Revision 2, November 21, 1990
8. CCNPP Drawing No. 60708SH0002, "Circulating Saltwater Cooling System," Revision 78, November 28, 1996
9. CCNPP Report, "Component Level Screening Results for the Auxiliary Building and Radwaste H&V System, System No. 032," Revision 2, July 10, 1996
10. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 4, August 27, 1996
11. CCNPP Specification No. 6750-M-196, "Specification for Heating, Ventilating, and Air Conditioning Ducts," Revision 4, June 14, 1974
12. Letter from Mr. L. B. Russell (BGE) to Mr. B. H. Grier (NRC), dated July 18, 1980, "Thirty-day Report for Licensee Event Report 80-29/3L"
13. CCNPP Preventive Maintenance Checklist MPM09021, "Auxiliary Building H&V Damper Inspection"
14. CCNPP Report, "Component Pre-Evaluation for the Auxiliary Building and Radwaste H&V System (032)," Revision 1, February 14, 1997
15. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions", Revision 0, November 8, 1995
16. CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns," Revision 0, September 16, 1997

5.11B Primary Containment Heating and Ventilation System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing the Primary Containment Heating and Ventilating (H&V) System. The Primary Containment H&V System was evaluated in accordance with the Calvert Cliff 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.

5.11B.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 device types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Representative historical operating experience pertinent to aging 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.

Section 5.11B.1.1 presents the results of the system level scoping, 5.11B.1.2 the results of the component level scoping, and 5.11B.1.3 the results of scoping to determine components subject to an AMR.

5.11B.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.

<u>System Description/Conceptual Boundaries</u>

The Primary Containment H&V System consists of the six subsystems described below. Also included within the system boundaries is pressure monitoring equipment for the containment and penetration room atmospheres. The pressure for the containment atmosphere is measured to provide signals for the Engineered Safety Features Actuation System (ESFAS) protective actuation and for post-accident monitoring. Penetration room pressure is monitored to provide signals upon high pressure to isolate letdown during a loss-of-coolant accident or a letdown line rupture (high energy line break). Containment dome temperature, containment cooler fan status, and containment hydrogen purge inside and outside containment isolation valve positions are monitored for post-accident monitoring. Other monitoring equipment is provided to support operations and testing. [References 1 and 2]

The containment air recirculation and cooling subsystem removes heat from the containment atmosphere during normal plant operations and accident conditions. The subsystem is independent of the Containment Spray and Safety Injection Systems. The system consists of four cooling units, an air mixing plenum, and the distributing ductwork and piping, all located inside of containment. Service water (SRW) is circulated through the air cooling coils to remove heat. Engineered Safety Features Actuation Signal provides startup signals for accidents that require containment heat removal. [References 2 through 5]

The containment penetration room ventilation subsystem processes air passing through the hydrogen purge subsystem following a Design Basis Event while that subsystem is in operation. The penetration room exhaust fans draw air through the hydrogen purge lines and through a prefilter, a high efficiency particulate air (HEPA) filter, and an activated charcoal filter to remove radioactive particulates and iodines before discharging the air to the environs. The containment penetration room ventilation subsystem can also collect and process containment penetration leakage during the post-accident period by drawing air from the containment penetration rooms. No credit is taken for the latter method of post-accident dose reduction. [References 2, 4, and 6]

The containment iodine removal subsystem removes iodine from the containment following a loss-of-coolant accident. The subsystem consists of three banks of filters made up of moisture separators, HEPA filters, and activated charcoal filters. An electric-driven induced-draft fan is used to pull the containment atmosphere through the filters and to discharge back into the containment. [References 2 and 3]

The hydrogen purge subsystem is designed to control hydrogen concentrations inside containment below 4.0 % by volume should both hydrogen recombiners fail to function properly. During power operations, the exhaust portion of this system is used to vent the containment to control containment pressure and airborne radioactivity levels. The containment atmosphere is drawn from containment through a moisture separator by the penetration room exhaust blowers. The purged atmosphere is carried to the containment penetration room ventilation subsystem's HEPA and charcoal filters before being discharged to the environs. A separate blower is provided to supply purge replacement air to the containment through a separate penetration. This blower is not used during normal operations. Motor-operated valves (MOVs) are located in the supply and exhaust penetration piping on the outboard side of the containment penetration to provide containment isolation when necessary. [References 4 and 6]

The containment purge subsystem supplies filtered air to the containment via a supply fan and penetration piping. One exhaust fan for each containment draws air from the containment through penetration piping and HEPA filters, and discharges the air into the respective main plant exhaust plenum and ultimately to the plant vent. Air-operated butterfly valves are located in the supply and exhaust penetration piping on each side of the containment penetration to provide containment isolation when the system is in operation. During normal operation, the Unit 2 containment penetrations are sealed with blind flanges on the outboard side of the penetration. [References 2, 3, and 5] The outboard side butterfly valves for Unit 1 will be replaced with sealed blind flanges during normal operation following the next refueling outage.

The control element drive mechanism cooling subsystem draws air from the containment atmosphere and through the reactor head cooling shroud and into two cooling coils of the control element drive mechanism cooler, which is located on the missile shield above the reactor. From there, 100% redundant fans discharge the cooled air upward and back into the containment atmosphere. Four ducts connect the shroud to the cooler coil house. One pair of ducts directs air to one cooling coil and the other pair supplies air to the opposite coil. Component cooling water is pumped through the water-air coils. A motor-operated damper, located between each fan and the coil house, prevents short-circuiting of air around the cooler when only one fan is operating. [References 2, 3, and 5]

System Interfaces

The Primary Containment H&V System has an interface with the following systems and components: [References 2, 7, and 8]

- Containment Spray Actuation System;
- Containment Isolation Actuation System;
- Main Plant Vent;
- Radiation Monitoring System;
- Reactor Protective System;
- Safety Injection Actuation System;
- Service Water System; and
- Component Cooling Water System.

System Scoping Results

The Primary Containment H&V System is within the scope of license renewal based on 10 CFR 54.4(a). The following intended functions of the Primary Containment H&V 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 9, Table 1]

- To control containment temperature and pressure;
- To provide containment atmosphere filtration and radiation control;
- To collect and process containment penetration leakage into the penetration rooms;
- To filter hydrogen purge air for radiation control following Design Basis Events;
- To measure pressure in the containment penetration rooms;
- To provide containment atmosphere pressure source to ESFAS instrumentation for protective actuation;
- To isolate the containment;
- To maintain electrical continuity and/or provide protection of the electrical system;
- To maintain the pressure boundary of the system (liquid and/or gas); and
- To provide seismic integrity and/or protection of safety-related components.

The following Primary Containment H&V System intended function was determined based on the requirements of §54.4(a)(3): [Reference 9, Table 1]

- For environmental qualification (§50.49) - To maintain functionality of electrical equipment as addressed by the Environmental Qualification Program, and to provide information used to assess the plant and environs condition during and following an accident.

All components of the Primary Containment H&V System that support the above functions are considered safety-related and Seismic Category I and are subject to the applicable loading conditions identified in Calvert Cliff's UFSAR Section 5A.3.2 for Seismic Category I systems and equipment design. [References 1 and 6]

Operating Experience

Over 20 years of operating experience has shown the H&V systems at CCNPP to be highly reliable in maintaining their passive functions. Some fasteners have become loose due to dynamic loading. Vibration-related aging concerns are minimized through system design and maintenance practices. Vibration isolators, i.e., flexible collars or rubber boots, are installed to minimize fan vibration being transferred to other equipment. [Reference 1, Attachments 6] Furthermore, fans are monitored for vibration whenever the fan belts are retensioned or replaced. [Reference 10]

Corrosion has been discovered below the cooling coils in some coolers. These areas are routinely inspected to assess the corrosion rates and adequacy of the system pressure boundary. Other than the limited amount of degradation experienced due to vibration, wear, and corrosion, no other significant aging concerns have been identified that could affect the ability of the Primary Containment H&V System components to perform their passive functions.

The CCNPP Containment Leakage Rate Testing Program has been inspected by the NRC on numerous occasions through routine inspections and during reviews of Technical Specification amendment requests. These inspections have not identified any aging-related concerns that need to be addressed in the AMR of Primary Containment H&V System components. Overall, the Containment Leakage Rate Testing Program has maintained the containment isolation portions of the system within the requirements of 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." Baltimore Gas and Electric Company has requested and received Technical Specification amendments for revising the containment Type C testing schedule required under 10 CFR Part 50, Appendix J; e.g., to adopt the performance-based requirements of Option B to Appendix J. During the reviews of these requests, significant analysis of past operating experience was performed for CCNPP and the industry as a whole. The NRC has indicated, based on their reviews of Type C performance history, that the wear-out portion of the component life has not been reached, and may not be reached provided good maintenance practices continue to be followed. [References 11 through 18] Additional information on operating experience is provided in the Group 1 discussion of aging management programs.

5.11B.1.2 Component Level Scoping

Based on the intended system functions listed above, the portions of the Primary Containment H&V System that are within the scope of license renewal include all safety-related components in the system (electrical, mechanical, and instrument), and their supports. Safety-related portions of the Primary Containment H&V System include the following: [References 1, 3, 4, and 5]

Subsystem	Portion Within Scope
Containment Air Recirculation and Cooling	Cooling units, fans, and connecting ductwork up to and including the fusible dropout plates
Containment Penetration Room Ventilation	Entire subsystem
Containment Iodine Removal	Entire subsystem

Subsystem	Portion Within Scope
Hydrogen Purge	All components from the inboard containment isolation valve to the connection with the containment penetration exhaust subsystem
Containment Purge	Containment penetrations only
Control Element Drive Mechanism Cooling	None
Pressurizer Compartment Cooling	None
Instrumentation and Controls	Containment pressure instrumentation and integrated leak rate testing containment penetrations

The following 38 device types in the Primary Containment H&V System were designated as within the scope of license renewal because they have at least 1 intended function [Reference 1, Table 2-1]:

Device Type	Device Description	Device Type	Device Description
CKV	Check valve	MB	480V motor
COIL	Coil	MD	125/250VDC motor
CV	Control valve	MOVOP	Motor-operated valve operator
DAMP	Damper	MOV	Motor-operated valve
DISC	Disconnect switch/link	NB	480V local control station
DUCT	Heating, ventilation and air conditioning duct	PDI	Pressure differential indicator
		PDIS	Pressure differential indicator switch
E/I	Voltage/current device	PI	Pressure Indicator
FAN	Fan	PIA	Pressure Indicating alarm
FL	Filter	PO	Piston operator
FT	Flow transmitter	PT	Pressure transmitter
FU	Fuse	RCMB	Hydrogen recombiner
GD	Gravity damper	RY	Relay
HB	Piping (Code HB)	SV	Solenoid valve
HS	Handswitch	TE	Temperature element
HV	Hand valve	TI	Temperature indicator
HX	Heat exchanger	YX	Power supply
II	Ammeter	ZL	Position indicating lamp
JL	Power lamp indicator	ZS	Position switch
M	480V motor (feed from MCC)		

Some components in the Primary Containment H&V System are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 1, Section 3.2]

- 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 this application.
- Electrical control and power cabling are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of this application. This commodity evaluation completely

addresses the passive intended function entitled "maintain electrical continuity and/or provide protection of the electrical system" for the Primary Containment H&V System.

- Process and instrument tubing and tubing supports are evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of this application.

5.11B.1.3 Components Subject to AMR

This section describes the components within the Primary Containment H&V System that 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 CCNPP IPA Methodology Section 5.1, the following Primary Containment H&V System intended functions were determined to be passive. [Reference 1, Table 3-1]

- To isolate the containment;
- Maintain the pressure boundary of the system;
- Maintain electrical continuity and/or provide protection of the electrical system; and
- Provide seismic integrity and/or protection of safety-related components.

Device Types Subject to AMR

Of the 38 device types within the scope of license renewal: [Reference 1, Table 3-2; Reference 19]

- 21 Device types have only active functions and do not require AMR; coil, voltage/current device, fuse, handswitch, ammeter, power lamp indicator, 480V motor (feed from MCC), 480V motor, 125/250VDC motor, motor-operated valve operator, pressure differential indicator, pressure indicator, pressure indicating alarm, piston operator, hydrogen recombiner, relay, temperature element, temperature indicator, power supply, position indicating lamp, position switch.
- 5 Devices types are evaluated in another section of this application.

  Disconnect switches/links and 480V local control stations, i.e., cabinets, panels, and enclosures, are evaluated for the effects of aging in the Electrical Commodities Evaluation in Section 6.2 of this application. The disconnect switches/links and 480V local control stations are the only device types in the system that have the passive intended function entitled "provide seismic integrity and/or protection of safety-related components" Therefore, this commodity evaluation completely addresses that passive intended function for the Primary Containment H&V System.

  Pressure differential indicator switch, pressure transmitter, and flow transmitter are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of this application.

The remaining 12 device types listed in Table 5.11B-1 are subject to AMR and are included in this section. For AMR, some device types have a number of subgroups associated with them because of the diversity of materials used in their fabrication or differences in the environments to which they are subjected.

Containment and system pressure boundary integrity are the only passive intended functions associated with the Primary Containment H&V System not addressed by one of the commodity evaluations referred to above. Therefore, only the pressure-retaining function for the 12 device types listed in Table 5.11B-1 is considered in the AMR for the Primary Containment H&V System. Unless otherwise annotated, all components of each listed device type are subject to AMR and included in this section.

TABLE 5.11B-1

PRIMARY CONTAINMENT H&V SYSTEM DEVICE TYPES REQUIRING AMR

Check valve	Gravity damper
Control valve	Piping (Code HB)
Damper	Hand Valve(1)
Duct	Heat exchanger
Fan	MOV
Filter	Solenoid valve

(1) Instrument line manual drain, equalization, and isolation valves in the Primary Containment H&V System that are subject to AMR are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of this application. Instrument line manual root valves are evaluated in this report. [Reference 19, Attachment 3]

5.11B.2 Aging Management

A list of potential age-related degradation mechanisms (ARDMs) identified for the Primary Containment H&V System components is given in Table 5.11B-2. The plausible ARDMs are identified in the Table by a check mark (✓) in the appropriate device type column. A check mark indicates that the ARDM applies to at least one group for the device type listed. For efficiency in presenting the results of the evaluations in this section, 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 5.11B-2 identifies the group in which each ARDM/device type combination belongs. [Reference 1, Table 4-2]

TABLE 5.11B-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE PRIMARY CONTAINMENT H&V SYSTEM

Potential ARDMs	**Primary Containment H&V System Device Types**											
	HB	CKV	CV	DAMP	DUCT	FAN	FL	GD	HV	HX	MOV	SV
Cavitation Erosion												
Corrosion Fatigue												
Creep/Shrinkage												
Crevice Corrosion	✓(2)								✓(2)	✓(2,5)	✓(2)	
Dynamic Loading						✓(3)						
Erosion Corrosion												
Fatigue												
Fouling												
Galvanic Corrosion												
General Corrosion	✓(2)								✓(2)	✓(2)	✓(2)	
Hydrogen Damage												
Intergranular Attack												
Irradiation Embrittlement												
Microbiologically-Induced Corrosion (MIC)										✓(2)		
Oxidation												
Particulate Wear Erosion												
Pitting	✓(2)								✓(2)	✓(2,5)	✓(2)	
Radiation Damage										✓(4)		
Elastomer Degradation					✓(4)			✓(4)		✓(4)		
Saline Water Attack												
Selective Leaching												
Stress Corrosion Cracking												
Stress Relaxation												
Thermal Damage												
Thermal Embrittlement												
Wear		✓(1)	✓(1)		✓(4)			✓(4)	✓(1)	✓(4)	✓(1)	

✓ - indicates that the ARDM is plausible for component(s) within the Device Type

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

Note: Not every component within the device types listed here may be susceptible to a given ARDM. This is because components within a device type are not always fabricated from the same materials or subjected to the same environments. Exceptions for each device type will be indicated in the aging management section for each ARDM discussed in this report.

The following groups have been selected for the Primary Containment H&V System:

Group 1 - Includes wear for check valves, control valves, hand valves and MOVs;

Group 2 - Includes crevice corrosion, general corrosion, MIC, and pitting for all components exposed to moisture;

Group 3 - Includes dynamic loading for fans;

Group 4 - Includes radiation damage, elastomer degradation, and wear for non-metallic subcomponent parts; and

Group 5 - Includes crevice corrosion and pitting for heat exchanger cooling coils.

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.

Group 1 (wear for check valves, control valves, hand valves, and MOVs) - Materials and Environment

The Primary Containment H&V System contains several types of valves that form part of the containment pressure boundary and whose disks/balls and seats are subject to wear. Check valves, control valves, hand valves, and MOVs provide containment pressure boundary for the containment penetrations in the containment purge subsystem (Unit 1 only, blank flanges are installed in Unit 2), hydrogen purge subsystem, and integrated leak rate testing lines. Hand valves also provide containment pressure boundary (some are required to be open and some closed) for the containment pressure instrumentation lines used for ESFAS. Solenoid valves are also used for containment isolation of the containment pressure instrumentation lines, but are discussed in Group 2 below. [Reference 1, Attachments 3 and 5]

The disks/balls and seats of the check valves, hand valves and MOVs are constructed of alloy steel, stainless steel, or stellited carbon steel. The control valves have a disk constructed of carbon steel and a seat of ethylene propylene. [Reference 1, Attachment 4]

The internal environment for the Primary Containment H&V System containment pressure boundary valves is containment air. The ambient air pressure variation is limited to -1.0 to +1.8 psig during normal plant operation. The maximum design service conditions regarding relative humidity and ambient air temperature for normal plant operation are 70% and 120°F, respectively. [Reference 20, Attachment 1, Table 1]

Group 1 (wear for check valves, control valves, hand valves, and MOVs) - Aging Mechanism Effects

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard, abrasive particles (abrasive wear) or fluid stream (erosion), and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). Motions may be linear, circular, or vibratory in inert or corrosive environments. Wear rates may accelerate as expanded clearances result in higher contact stresses. [Reference 1, Attachment 7]

The internals of Group 1 valves subject to wear are relied on to maintain containment pressure boundary integrity. These valves are periodically cycled during testing and outages and the valve internals and seating surfaces may experience wear. Wear is considered plausible for the disk/ball and seat of check valves, control valves, hand valves, and MOVs because they may experience cyclic relative motion at the tight fitting surfaces. Movement of the disk against the seat can result in a gradual loss of material, which could result in a small amount of leakage. If left unmanaged, wear could lead to a loss of pressure boundary integrity. [Reference 1, Attachment 6]

Calvert Cliffs has experienced some wear of the containment purge supply and exhaust containment isolation valves (control valves). Check valves have also experienced pressure boundary failures with several valves failing back-leakage tests, including those tests performed in response to Generic Letter 88-14. However, the root cause of these failures is due to a combination of wear and misapplication of the valve for its intended function. [Reference 1, Attachments 4 and 6; Reference 21]

Group 1 (wear for check valves, control valves, hand valves, and MOVs) - Methods to Manage Aging

Mitigation: Since the wear of valve disk/balls and seats is due to valve operation, decreased operation of the valves would slow the degradation of the valves seating surfaces. This is not a feasible mitigation technique because it would place unnecessary restrictions on plant operation. The restrictions are unnecessary because limited leakage through the valves will not significantly impact the intended function. Furthermore, the discovery methods discussed below are deemed adequate for verifying that significant degradation is not occurring. [Reference 1, Attachment 6]

Discovery: Wear for valve disks/balls and seats can be detected by performing visual inspections or through leak rate testing. Since wear occurs gradually over time, periodic testing can be used to discover minor leakage of the valve seating surfaces so that corrective actions can be taken prior to the loss of the intended function. [Reference 1, Attachment 6]

Group 1 (wear for check valves, control valves, hand valves, and MOVs) - Aging Management Program(s)

Mitigation: There are no feasible methods of mitigating wear of the valve disks/balls and seats; therefore, there are no programs credited with mitigating the aging effects due to this ARDM.

Discovery: The containment isolation valves are subject to local leak rate testing under the CCNPP Containment Leakage Rate Testing Program. Hand valves are not subject to periodic leakage testing. They will be included in the scope of an Age-Related Degradation Inspection (ARDI) Program.

Containment Leakage Rate Testing Program

The valves performing the containment pressure boundary function are subject to local leak rate testing under the CCNPP Containment Leakage Rate Testing Program as required by 10 CFR Part 50, Appendix J. This testing is implemented through CCNPP Surveillance Test Procedures in accordance with the plant Technical Specifications and CCNPP Administrative Procedure EN-4-105, "Containment Leakage Rate Testing Program." [Reference 1, Attachment 6; References 22 through 26]

The CCNPP Containment Leakage Rate Testing 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 - "Performance-Based Requirements." It follows the guidance provided in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," September 1985. 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 local leak rate tests (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. [References 22, 26, 27, and 28]

The CCNPP Containment Leakage Rate Testing Program is based on 10 CFR Part 50, Appendix J, Option B, requirements and implements the requirements in 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. [Reference 1, Attachment 6; References 22 through 26] Per References 22 through 26, 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 the LLRT pressure, which is conservative with respect to the 10 CFR Part 50, Appendix J, Option B, test pressure requirements.
- 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 that 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, plant personnel 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 containment isolation valve that changes the closing characteristic of the valve, an "as left" test must be performed on the penetration to ensure leakage rates are acceptable.

The CCNPP Containment Leakage Rate Testing Program has been inspected by the NRC on numerous occasions through routine inspections and during reviews of Technical Specification amendment requests. Routine inspections at the site included procedure reviews, leakage test witnessing, test reviews, and results evaluation of both integrated leakage rate tests and LLRTs. Inspectors noted when individual containment isolation valves failed their leakage tests and reviewed the repair and resetting actions taken by BGE. With some specific exceptions, the inspections typically noted acceptable conditions. No aging-related deficiencies were identified. [References 11 through 14]

Baltimore Gas and Electric Company has requested, and received Technical Specification amendments for revising the containment Type C testing schedule required under 10 CFR Part 50, Appendix J. The requests were initiated to accommodate extending the fuel cycle to 24 months, and to recognize the added Option B under Appendix J. Currently CCNPP follows the schedule of Option B, which is a performance-based scheduling process. During the reviews of these requests, significant analysis of past operating experience was performed for CCNPP and the industry as a whole. The NRC has indicated, based on their reviews of Type C performance history, that the wear-out portion of the component life has not been reached, and may not be reached provided good maintenance practices continue to be followed. Furthermore, reviews of site-specific data indicate that the leakage rate data at the end of the CCNPP Unit 1 operating cycles falls within a typical range. [References 15 through 18]

These reviews demonstrate that CCNPP has normal and acceptable operating experience with respect to component aging of components relied on the containment isolation. The corrective actions taken as part of the Containment Leakage Rate Testing Program will ensure that the containment isolation check valves, control valves, and MOVs remain capable of performing their containment pressure boundary integrity function under all current licensing basis (CLB) conditions.

ARDI Program

The Group 1 hand valves will be included within a new plant program to accomplish the needed inspections for wear. This program is considered an ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0.

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 Actions Program and will ensure that the components will remain capable of performing the system pressure boundary integrity function under all CLB conditions.

Group 1 (wear for check valves, control valves, hand valves, and MOVs) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to wear of check valves, control valves, hand valves and MOVs for the Primary Containment H&V System.

- The valve internals maintain containment pressure boundary and their integrity must be maintained under all CLB conditions.
- Wear is plausible for valve disks/seats and results in material loss which, if left unmanaged, could lead to leakage.
- The containment isolation valves are subject to local leak rate testing in accordance with the CCNPP Containment Leakage Rate Testing Program.
- Leak rate testing activities will provide reasonable assurance that significant leakage that could be the result of wear of the seating surfaces is discovered and appropriate corrective actions taken.
- The hand valves are not subject to periodic leak rate testing so they will be included within a new ARDI program to accomplish the needed inspections.

Therefore, there is reasonable assurance that the effects of wear for Primary Containment H&V System valves 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 (crevice corrosion, general corrosion, MIC, and pitting for all components exposed to moisture) - Materials and Environment

Group 2 is comprised of components that are potentially exposed to moist air and condensation. These include the piping, hand valves, and MOVs in the hydrogen purge subsystem exhaust path. This portion of the system is potentially exposed to warm humid air from containment. The moisture in the air could condense upon contact with the cooler pipe and valves, particularly outside of containment. Also included in Group 2 are the containment coolers that may be exposed to condensed moisture from the cooling coils. If the drains become plugged, there may also be standing water in the drain pan that could spill over onto other sections of the equipment base. Surfaces that are painted or galvanized are protected from corrosion by keeping the component surfaces from being exposed to the moisture. However, where the coating is damaged, corrosion may take place. [Reference 1, Attachment 6s and Attachment 8]

The subject piping, fittings, flanges, and welds are all constructed of carbon steel. The body/bonnet of the hand valves is constructed of carbon steel and the stems, disks, and seats are either alloy steel, stellited carbon steel, or stainless steel. The body/bonnet of the MOVs are constructed of carbon steel, the stems of stainless steel, the wedge/disk of stellited carbon steel or stainless steel, and the seat of stellite stainless steel or ethylene propylene. All of the studs and nuts are external and are not exposed to the moisture. The valve disks/seats of the containment isolation valves are relied upon for containment pressure boundary. The disk seat of the flow control MOV does not serve the pressure boundary function. [Reference 1, Attachments 4, 5, and 6]

The containment cooler housing is constructed of carbon steel. The boot between the cooler and the fan is constructed of rubber. The cooling coils are addressed below in Group 5. [Reference 1, Attachments 4, 5, and 6]

Group 2 (crevice corrosion, general corrosion, MIC, and pitting for all components exposed to moisture) - Aging Mechanism Effects

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. Crevice corrosion is closely related to pitting corrosion and can initiate pits in many cases, as well as lead to stress corrosion cracking. [Reference 1, Attachments 6 and 7]

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. General corrosion requires an aggressive environment and materials susceptible to that environment. Wastage is not a concern for austenitic stainless steel alloys. The consequences of the damage are loss of load carrying cross-sectional area. [Reference 1, Attachments 6 and 7]

Microbiologically-induced corrosion is accelerated corrosion of materials resulting from surface microbiological activity. Sulfate reducing bacteria, sulfur oxidizers, and iron oxidizing bacteria are most commonly associated with corrosion effects. Microbiologically-induced corrosion often results in pitting followed by excessive deposition of corrosion products. Stagnant or low flow areas are most susceptible. Essentially all systems using untreated water and most commonly used materials are susceptible. Consequences range from leakage to excessive differential pressure and flow blockage. Microbiologically-induced corrosion is generally observed in SRW applications utilizing raw, untreated water. [Reference 1, Attachments 6 and 7]

Pitting is another form of localized attack with greater corrosion rates at some locations than at others. Pitting can be very insidious and destructive, with sudden failures in high pressure applications (especially in tubes) occurring by perforation. This form of corrosion essentially produces holes of varying depth-to-diameter ratios in the steel. Deep pitting is more common with passive metals, such as austenitic stainless steels, than with non passive metals. Pits are generally elongated in the direction of gravity. In many cases, erosion corrosion, fretting corrosion, and crevice corrosion can also lead to pitting. [Reference 1, Attachments 6 and 7]

For Group 2 components, long-term exposure to the moist environment may result in localized and/or general area material loss of the internal surfaces of the components and, if unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. The areas where there are crevices and/or stagnant conditions, e.g., body/bonnet joint, stem to bonnet/packing area, valve seat area, low points in the pipe, etc., are the locations most susceptible to these corrosion mechanisms. Crevice corrosion, general corrosion, and pitting are plausible for the subcomponents constructed of carbon steel or alloy steel. Crevice corrosion, general corrosion, and pitting are not plausible for subcomponents constructed of stainless steel or for the stellited surfaces of carbon steel components due to the inherent corrosion resistance of the materials and the non-aggressiveness of the environment. The containment cooler housing is also subject to MIC due to the potential existence of standing stagnant water. Since the valves are required to maintain pressure boundary while in the closed position, degradation of the internal surfaces of all subcomponents required for the pressure-retaining function must be managed. [Reference 1, Attachments 4, 5, and 6]

Group 2 (crevice corrosion, general corrosion, MIC, and pitting for all components exposed to moisture) - Methods to Manage Aging

Mitigation: Since there is no design feature to control the humidity of the air the Group 2 components are exposed to, the only feasible method of mitigating the effects of corrosion is to replace the components with components constructed of more corrosion resistant materials. However, this mitigation technique is not necessary because the discovery techniques discussed below are deemed adequate to manage aging due to crevice corrosion, general corrosion, MIC, and pitting. [Reference 1, Attachment 8]

Discovery: The effects of corrosion (crevice corrosion, general corrosion, MIC, and pitting) on Group 2 components can be discovered and monitored through non-destructive examination techniques such as visual inspections. Representative samples at susceptible locations can be used to assess the need for additional inspections at less susceptible locations. Periodic preventive maintenance would lead to the discovery of corrosion of components that are readily observable during the activity. If corrosion is occurring on valve seating surfaces, the degradation can be detected through pressure tests of the valves in the closed position. Corrosion would cause loss of material that can lead to valve leakage. [Reference 1, Attachment 8]

Group 2 (crevice corrosion, general corrosion, MIC, and pitting for all components exposed to moisture) - Aging Management Program(s)

Mitigation: Since there are no mitigation techniques deemed necessary at this time, there are no mitigation programs credited for managing corrosion of Group 2 components.

Discovery: For Group 2 components, crevice corrosion, general corrosion, MIC, and pitting can be readily detected through non-destructive examination techniques. Periodic preventive maintenance will provide assurance that the effects of corrosion are not threatening the pressure-retaining capability of the heat exchangers. The remaining Group 2 components will be included in the scope of an ARDI Program. In addition, the containment isolation valves are periodically leak tested. This will provide an early indication of degradation of the valve seating surfaces. [Reference 1, Attachment 8]

Preventive Maintenance Program

The CCNPP Preventive Maintenance Program has been established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimization of equipment failure, and extension of equipment and plant life. The program covers all preventive maintenance activities for nuclear power plant structures and equipment within the plant, including the Primary Containment H&V System components within the scope of license renewal. [Reference 29] Guidelines drawn from industry experience and utility best practices were used in the development and enhancement of this program.

Calvert Cliffs currently has preventive maintenance activities scheduled for every two years (i.e., every refueling outage) to perform inspections and cleaning of the containment air coolers. These activities specifically include a complete inspection of the coolers for cleanliness, corrosion, and leaks. [References 30 and 31] This inspection would discover significant corrosion of the containment air cooler housings if it were occurring. Corrective actions are taken in accordance with the CCNPP Corrective Actions Program.

The plant maintenance program has numerous levels of management review, all the way down to the specific implementation procedures. For example, there are specific responsibilities assigned to BGE personnel for evaluating and upgrading the Preventive Maintenance Program. [Reference 29] The Preventive Maintenance Program has also undergone evaluation by the NRC as part of their routine licensee assessment activities. These assessments and controls provide reasonable assurance that the Preventive Maintenance Program will continue to be an effective method of managing the effects of corrosion for the heat exchangers.

ARDI Program

The Group 2 piping, hand valves, and MOVs will be included within a new plant program designed to provide the needed inspections for corrosion. This program is considered an ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0. The corrective actions will be taken in accordance with the CCNPP Corrective Actions Program and will ensure that the components will remain capable of performing the system pressure boundary integrity function under all CLB conditions. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program.

Containment Leakage Rate Testing Program

In addition to the ARDI Program, the containment isolation valves are subject to periodic pressure testing for valve leakage at the seating surface. These components are subject to local leak rate testing under the CCNPP Surveillance Test Procedures in accordance with 10 CFR Part 50, Appendix J. [Reference 1, Attachment 8; References 23 and 24] Continued local leak rate testing on a periodic basis will assure acceptable leak tightness of the seating surfaces of these valves and will also ensure that any leakage remains within the guidelines of the Technical Specifications.

The LLRT is part of the overall CCNPP Containment Leakage Rate Testing Program, which is implemented through Surveillance Test Procedures. The CCNPP Containment Leakage Rate Testing Program is discussed in detail above for Group 1. The corrective actions taken as part of the Containment Leakage Rate Testing Program will ensure that the containment isolation valves are capable of performing their containment pressure boundary integrity function under all CLB conditions.

Group 2 (crevice corrosion, general corrosion, MIC, and pitting for all components exposed to moisture) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to crevice corrosion, general corrosion, MIC, and pitting of Group 2 components:

- The Group 2 components provide the system pressure boundary and their integrity must be maintained under all CLB conditions.

- Crevice corrosion, general corrosion, MIC, and pitting are plausible for the components, and result in material loss which, if left unmanaged, can lead to loss of pressure boundary integrity.
- Cleaning and inspection activities performed in accordance with the Preventive Maintenance Program will provide reasonable assurance that the effects of corrosion are discovered prior to threatening the pressure retention capability of the containment air coolers. Inspections will be performed, and appropriate corrective action will be taken if significant corrosion is discovered.
- To provide the assurance needed to conclude that the effects of corrosion are not threatening the pressure retention capability of the piping, hand valves, and MOVs, they 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.
- In addition to the ARDI Program, the containment isolation valves are subject to periodic pressure testing for valve leakage as part of the CCNPP Containment Leakage Rate Testing Program. Pressure testing for valve leakage would provide an early indication of degradation of the valve seating surfaces.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, MIC, and pitting on Group 2 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 3 (dynamic loading for fans) - Materials and Environment

Group 3 is comprised of fans because dynamic loading is a concern for the fasteners. Normal bearing wear and dirt buildup can cause imbalances in the rotating parts of the fans, thereby inducing vibration. Flexible collars are installed on the fans to provide dynamic isolation for adjacent components, which minimizes the dynamic loading for those components. The fan casings and fasteners are constructed of carbon steel. The fans are located indoors and have an internal environment of air with minimal humidity/moisture. [Reference 1, Attachments 3, 4, and 7]

Group 3 (dynamic loading for fans) - Aging Mechanism Effects

Dynamic loading (vibration) is created in blowers by rotating parts with imbalances due to dirt buildup and normal bearing wear. There is a history of loosened mechanical fasteners due to vibration in fans at CCNPP. This mechanism is plausible for the fans, but is not considered plausible for adjacent heating, ventilation and air conditioning equipment due to the dynamic isolation provided by flexible collars. If dynamic loading was left unmanaged, it could result in the loss of pressure boundary integrity of the Group 3 components under CLB design loading conditions. [Reference 1, Attachments 5 and 6]

Group 3 (dynamic loading for fans) - Methods to Manage Aging

Mitigation: Dynamic loading can be mitigated by minimizing the mechanical loading due to vibration. The system is designed to minimize vibration by using equipment support isolators and equipment-to-duct isolators, such as flexible collars and boots. Visual inspections during routine walkdowns would provide for detection of vibration so that corrective actions could be taken to minimize vibration and, thereby, mitigate the effects of dynamic loading. [Reference 1, Attachment 8]

Discovery: The effects of dynamic loading, e.g., loosened fasteners, can be detected through visual inspections. Periodic visual inspections and system walkdowns would provide for detection of the effects of dynamic loading, as well as vibration problems, which can cause this ARDM to occur. [Reference 1, Attachment 8]

Group 3 (dynamic loading for fans) - Aging Management Program(s)

Mitigation: The CCNPP Structure and System Walkdown Program provides for periodic visual inspections of the external surfaces of Primary Containment H&V System components. During these walkdowns, any vibration problems would be detected so that corrective actions could be taken to minimize the vibration. [Reference 1, Attachment 8] Refer to the discussions below in Discovery for a description of the CCNPP Structure and System Walkdown Program.

Discovery: The effects of dynamic loading can be detected through visual inspections and walkdowns. Loosened fasteners may be detected by visual observation or by hearing unusual noise and vibration. For the equipment located outside containment, routine system walkdowns are adequate for detection of the effects of dynamic loading. For the equipment located inside containment, routine preventive maintenance activities are adequate for detection of the effects of dynamic loading.

System Walkdowns

Visual inspections are performed on system fans located outside containment as part of the routine system walkdowns in accordance with CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns." MN-1-319 provides for discovery of the effects of dynamic loading, as well as abnormal or excessive vibration, which can cause this ARDM to occur. This procedure requires routine system walkdowns that include visual inspections, reporting the walkdown results, and initiating corrective action. [Reference 32]

Under this program, BGE personnel, with assigned responsibility for specific structures and systems, perform periodic walkdowns. Walkdowns may also be performed as required for reasons such as material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when a system is re-energized or placed in service); and as required for plant modifications. Inspection items typically related to aging management include identifying unusual noises and identifying system and equipment stress or abuse, such as excessive vibrations, bent or broken component supports, loosened fasteners, etc. [Reference 32, Section 5.1]

One of the objectives of the program is to assess the condition of the CCNPP structures, systems, and components such that any degraded condition will be identified, documented, and corrective actions taken before the degradation proceeds to failure of any structure, system, and component to perform its intended functions. Conditions adverse to quality are documented and resolved by the Calvert Cliffs Corrective Actions Program. [Reference 32, Sections 5.1.C, 5.2.A.1, and 5.2.A.5]

The program provides guidance for specific types of degradation or conditions to inspect for when performing the walkdowns. General inspection items related to aging management include the following: [Reference 32, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion;

- Effects that may have been caused by ARDMs such as damaged supports, concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, excessive vibration, or inadequate support of components (e.g., missing, detached, or loose fasteners and clamps).

This program promotes familiarity of the systems by the responsible personnel and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance alone. The program has been improved over time, based on past experience, to provide guidance on specific activities to be included in the scope of the walkdowns.

Preventive Maintenance

Calvert Cliffs currently has preventive maintenance activities that help keep the subsystems operating reliably. These routine activities will allow for early detection of vibration problems for equipment located inside containment that can then be fixed prior to loss of fastener tightness. If dynamic loading does affect the fans, it will also be discovered during the performance of those activities. Preventive maintenance tasks are currently in place for performing inspections of the containment air coolers every two years (i.e., every refueling outage). These activities specifically include an inspection of the fasteners to ensure they are installed and not loose. [References 30 and 31] Preventive maintenance tasks are also in place for lubricating the containment iodine removal fan motor every two years (i.e., each refueling outage). This activity typically includes running the fan after lubrication to verify operability. [References 33 and 34] Refer to the discussion above in Group 2 under Aging Management Programs for a detailed discussion of the Preventive Maintenance Program.

The corrective actions required as a result of the system walkdowns and preventive maintenance activities will be taken in accordance with the CCNPP Corrective Actions Program, and will ensure that the fans will remain capable of performing the system pressure boundary integrity function under all CLB conditions.

Group 3 (dynamic loading for fans) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to dynamic loading for fans:

- Primary Containment H&V System fan housing provide a system pressure boundary function and the integrity of their fasteners must be maintained under CLB design conditions.
- Dynamic loading is a plausible ARDM for the fans due to potentially excessive vibration resulting from fan operation. Dynamic loading is considered plausible only for the fans due to the use of vibration isolators for each of the fans, which prevents excessive vibration from being transmitted to other components.
- If left unmanaged, dynamic loading can result in loosened fasteners, which could lead to loss of pressure boundary integrity.
- Existing visual inspections provide reasonable assurance that signs of loosened fasteners, as well as such conditions as unusual noises or vibration on fans located outside containment, would be detected as part of routine system walkdowns

- Existing activities performed as part of the Preventive Maintenance Program for equipment located inside containment provide reasonable assurance that the effects of dynamic loading will be detected. These activities include specific inspections of fasteners for the containment air cooler fans.

Therefore, there is reasonable assurance that the effects of dynamic loading for fans 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 4 (radiation damage, elastomer degradation, and wear for non-metallic subcomponent parts) - Materials and Environment

The Primary Containment H&V System galvanized carbon steel ducting was installed with flexible collars in connections between fans and ducts or casings to prevent excessive movement of long ducts. These flexible collars are made of elastomers and are installed with sufficient slack to prevent transmission of vibration. Collars are secured to fans and ducts with galvanized steel bars fastened with bolts for an air-tight construction. There are no flexible collars located inside containment that are within the scope of license renewal. [Reference 1, Attachment 4; Reference 35]

The penetration room exhaust dampers are required to maintain system pressure boundary while in the closed position, and are constructed with compressible seals to provide leak tightness. These seals are constructed of neoprene sponge material, which is an elastomer. The dampers are located outside of containment where exposure to low radiation levels is not sufficient to cause degradation of the material. [Reference 1, Attachment 4s and 6s]

Each containment air cooler has a rubber boot installed between it and the fan to prevent the transfer of vibration to the cooler. Normal bearing wear and dirt buildup cause imbalances in the rotating parts of the fans, thereby inducing vibration. The containment air coolers and associated rubber boots are exposed to radiation because they are located inside containment. [Reference 1, Attachment 6s]

The design service conditions for ducting and equipment located inside containment are discussed above in the Materials and Environment section of Group 1. The penetration room exhaust dampers have an internal environment of air from the penetration rooms or containment. The maximum environmental service conditions regarding relative humidity and ambient air temperature for the penetration rooms during normal plant operation are 70% and 140°F, respectively. [Reference 20, Attachment 1, Table 1]

Group 4 (radiation damage, elastomer degradation, and wear for non-metallic subcomponent parts) - Aging Mechanism Effects

Radiation can cause ionization and excitation of atoms in organic materials, which leads to damage through chemical reaction of the excited ions and/or free radicals. For elastomers, exposure to radiation can result in degradation of material properties, such as tensile strength, elongation, and compressibility. Material susceptibility is dependent upon the strength and type of the radiation field, and upon the specific material composition. Most materials exhibit a threshold level below which significant degradation of mechanical properties of the material does not occur. [Reference 5, Attachment 7; Reference 36]

An elastomer is a material that can be stretched to significantly greater than original length and, upon release of the stress, will return with force to approximately its original length. When an elastomer ages, there are three mechanisms primarily involved:

- Scission - the process of breaking molecular bonds, typically due to ozone attack, UV light, or radiation;
- Crosslinking - the process of creating molecular bonds between adjacent long-chain molecules, typically due to oxygen attack, heat or curing; and
- Compound ingredient evaporation, leaching, mutation, etc.

Natural aging tests indicate that where there is a significant property change in an elastomer, it appears that it occurs within the first five to ten years after initial formulation/curing. Elastomers generally harden as they age, making sealing more difficult. [Reference 1, Attachment 7s]

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard, abrasive particles (abrasive wear), or fluid stream (erosion), and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). Motions may be linear, circular, or vibratory in inert or corrosive environments. Fretting is a wear phenomenon that occurs between tight-fitting surfaces subjected to a cyclic, relative motion of extremely small amplitude. Common sites for fretting are in joints that are bolted, keyed, pinned, press fit, or riveted. [Reference 1, Attachment 7s]

Elastomer degradation and wear are plausible for the flexible collars in the duct, and rubber boots on the heat exchangers, since the elastomers will degrade due to the relative motion caused by vibrating equipment, pressure variations and turbulence, and exposure to moderate heat, oxygen, and ozone. These stressors could result in eventual tearing of the collars and boot. Elastomer degradation and wear are plausible for the damper seals because the neoprene will degrade due to relative motion between the blade and sleeve during damper operation and exposure to moderate heat, oxygen, and ozone. These stressors will result in eventual breakdown of the seal. Radiation damage is plausible for the rubber boots on the containment air coolers because they are located inside containment and are exposed to radiation. Radiation damage is not plausible for the duct flexible collars or damper seals because they are located outside of containment where the radiation levels are relatively low. [Reference 1, Attachment 6s and 7s] If left unmanaged, these ARDMs could eventually result in the loss of pressure boundary integrity of the duct flexible collars, damper seals, and heat exchanger rubber boots under CLB design loading conditions.

Group 4 (radiation damage, elastomer degradation, and wear for non-metallic subcomponent parts) - Methods to Manage Aging

Mitigation: Radiation damage can be mitigated by reducing the component's exposure to radiation through shielding. Elastomer degradation can be mitigated by utilizing materials that are less susceptible to heat and oxygen. Wear can be mitigated by minimizing vibration of the duct and heat exchangers and by minimizing operation of the dampers to slow degradation of the seating surfaces, which lead to a loss of leak tightness.

Discovery: Periodic visual inspections can be performed for the equipment in Group 4 to detect the effects of radiation damage, elastomer degradation, and wear. Degradation of the flexible collars and rubber boots located outside containment can be detected through periodic system walkdowns because the collars and boots are readily accessible. Degradation of rubber boots for the containment air coolers can be detected during routine preventive maintenance activities. Degradation of damper seals can be detected through periodic inspections. Periodic walkdowns and preventive maintenance activities may also detect loss of the damper seal because leakage would become apparent by the backward rotation of the opposite non-operating fan. If significant degradation is discovered, the flexible collars, damper seals, or rubber boots can be repaired or replaced as appropriate. [Reference 1, Attachment 8]

Group 4 (radiation damage, elastomer degradation, and wear for non-metallic subcomponent parts) - Aging Management Program(s)

Mitigation: The system was designed to minimize vibrations by using equipment support isolators and equipment-to-duct isolators, such as the flexible collars and rubber boots. Changes to materials or to system operating practices are not deemed necessary to mitigate the effects of these ARDMs. Implementing the discovery methods discussed below will be adequate to manage these ARDMs. Since there are no additional methods of mitigating radiation damage, elastomer degradation, and wear, there are no programs credited with mitigating the aging effects due to these ARDMs. [Reference 1, Attachment 6s and 8]

Discovery: Radiation damage, elastomer degradation, and wear can be readily detected for Group 4 components through visual examination. Routine system walkdowns would discover the effects of these ARDMs on the external surfaces of the Group 4 components located outside containment. Periodic preventive maintenance would lead to the discovery of the effects of these ARDMs on the internal surfaces of components and for components located inside containment where routine walkdowns are not feasible. [Reference 1, Attachment 8]

System Walkdowns

Calvert Cliffs Administrative Procedure MN-1-319 provides for discovery of the effects of elastomer degradation and wear of the Primary Containment H&V System components located outside of containment by performance of visual inspections during plant walkdowns. The purpose of the procedure is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. Under this program, inspection items typically related to aging management include identifying unusual noises and identifying system and equipment stress or abuse, such as excessive vibrations, bent or broken component supports, etc. Specifically, signs of cracking or tearing of duct flexible collars would be detected during these walkdowns. In addition, loss of the damper seal may be detected due to the leakage becoming apparent by the backward rotation of the opposite non-operating fan. [Reference 32] Refer to the discussion above in Group 3 under Aging Management Programs for a detailed discussion of MN-1-319.

Preventive Maintenance Program

The CCNPP Preventive Maintenance Program has been established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimization of equipment failure, and extension of equipment and plant life. Preventive maintenance activities are scheduled every 48 weeks to perform lubrication and fan belt inspections of the penetration room exhaust fans and lubrication of the penetration room exhaust dampers. Following maintenance activities, the fans are test run to assure proper operation. [Reference 10] Personnel responsible for the maintenance activities would discover if significant elastomer degradation or wear to the penetration room exhaust damper seals is occurring. In addition, loss of damper seal may be detected during the test run by the backward rotation of the opposite non-operating fan due to leakage past the failed seal.

Preventive maintenance activities currently in place will also provide for visual inspection of the containment air cooler boots. Inspections and cleaning of the containment air coolers and their associated fans are performed every two years (i.e., every refueling outage). These activities specifically include an inspection of the rubber boot for tears, holes, or deterioration. [References 30 and 31] Corrective actions are taken in accordance with the CCNPP Corrective Actions Program. Refer to the discussion of aging management programs for Group 2 for a detailed description of the Preventive Maintenance Program.

Group 4 (radiation damage, elastomer degradation, and wear for non-metallic subcomponent parts) - Demonstration of Aging Management

Based on the above discussions, the following conclusions can be reached with respect to radiation damage, elastomer degradation, and wear for duct flexible collars, damper seals, and rubber boots:

- Primary Containment H&V System ducts, dampers and heat exchangers provide a system pressure boundary function and their integrity must be maintained under CLB design conditions.
- Radiation damage, elastomer degradation, and wear are plausible for the flexible collars and rubber boots. Elastomer degradation and wear are plausible for the damper seals.
- If left unmanaged, radiation damage, elastomer degradation, and wear can result in material loss, tearing, or cracking which could lead to loss of pressure boundary integrity.
- Visual inspections conducted in accordance with CCNPP Administrative Procedure MN-1-319 provide reasonable assurance that the effects of these ARDMs would be discovered for components located outside containment. Signs of cracking or tearing of duct collars would be detected during these walkdowns, as well as such conditions as excessive vibrations and leakage of dampers, which would become apparent by the opposite non-operating fan rotating backwards.
- Existing routine preventive maintenance activities to periodically lubricate and inspect the fan belts on the penetration room exhaust fans and to lubricate the penetration room exhaust dampers provide reasonable assurance that the effects of these ARDMs on the damper seals would be detected.
- Existing routine preventive maintenance activities to periodically inspect the containment air coolers and associated fans provide reasonable assurance that the effects of these ARDMs on the rubber boots would be detected.

Therefore, there is reasonable assurance that the effects of radiation damage, elastomer degradation, and wear for duct flexible collars, damper seals, and heat exchanger rubber boots 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 5 (crevice corrosion and pitting of heat exchanger cooling coils) - Materials and Environment

The cooling coils in the containment air coolers provide a system pressure boundary for a safety-related portion of the SRW System. The cooling coils are constructed of 90/10 copper-nickel. The internal environment is SRW that is chemically-treated water. The external environment is air with some humidity. Since the purpose of this component is to cool the air, condensation occurs on the outside surface of the coil. [Reference 1, Attachments 4 and 6]

Group 5 (crevice corrosion and pitting of heat exchanger cooling coils) - Aging Mechanism Effects

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It may occur in areas presenting a crevice geometry that allows the process fluid to stagnate and/or environmentally-produced impurities to concentrate. The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. Crevice corrosion is closely related to pitting corrosion and can initiate pits in many cases, as well as lead to stress corrosion cracking. [Reference 1, Attachments 6 and 7]

Pitting is another form of localized attack with greater corrosion rates at some locations than at others. Pitting can be very insidious and destructive, with sudden failures in high pressure applications (especially in tubes) occurring by perforation. This form of corrosion essentially produces holes of varying depth to diameter ratios in the steel. Deep pitting is more common with passive metals, such as austenitic stainless steels, than with non passive metals. Pits are generally elongated in the direction of gravity. In many cases, erosion corrosion, fretting corrosion, and crevice corrosion can also lead to pitting. [Reference 1, Attachments 6 and 7]

For the containment air cooler cooling coils, long-term exposure to the moist environment may result in localized material loss of the internal and/or external surfaces of the coils and, if unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. Crevice corrosion and pitting are plausible for the cooling coils particularly in areas where there are crevices and/or stagnant conditions. [Reference 1, Attachments 5 and 6]

Group 5 (crevice corrosion and pitting of heat exchanger cooling coils) - Methods to Manage Aging

Mitigation: The effects of corrosion on the internal surface cannot be completely prevented, but they can be mitigated by minimizing the exposure of the cooling coils to an aggressive environment. Maintaining an environment of purified water with controls on pH, oxygen, suspended solids, and chlorides during normal plant operation can mitigate these ARDMs. Since there is no design feature to control the humidity of the air the cooling coils are exposed to, the only feasible methods of mitigating the effects of corrosion of the external surface is to replace the coils with coils constructed of a more corrosion resistant material and to periodically clean the coils to remove corrosive impurities. [Reference 1, Attachment 8]

Discovery: The effects of corrosion (crevice corrosion and pitting) on the containment air cooler cooling coils can be discovered and monitored through non-destructive examination techniques such as visual inspections. Periodic inspections/cleaning would lead to discovery of corrosion of components that are readily observable during the activity. [Reference 1, Attachment 8] If corrosion is occurring on the internal surfaces, the degradation can be detected through planned visual inspections or testing (e.g., ultrasonic testing, eddy current testing, pressure testing).

Group 5 (crevice corrosion and pitting of heat exchanger cooling coils) - Aging Management Program(s)

Mitigation: The CCNPP Chemistry Program is relied upon for monitoring and maintaining SRW chemistry to control the concentrations of oxygen, chlorides, other chemicals and contaminants. For example, the water is chemically treated to minimize the amount of oxygen in the water, which aids in the prevention and control of most corrosion mechanisms. Continued maintenance of system water quality will ensure minimal degradation of the cooling coil internals. Routine cleaning of the coils to remove corrosive impurities will continue to be done in conjunction with the preventive maintenance inspections discussed below in Discovery. [Reference 1, Attachment 8; Reference 37]

Calvert Cliffs Chemistry Procedure CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems," describes the surveillance and specifications for monitoring the SRW System fluid. CP-206 lists the parameters to monitor, the frequency of monitoring these parameters, and the target and action levels for the SRW System fluid parameters. These chemistry parameters are currently monitored on a frequency ranging from three times per week to once a month. All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter. [Reference 37, Attachment 1]

The CCNPP Chemistry Program has been subject to periodic internal assessment activities. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their strength of performance and safety significance, and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. [Reference 38, Section 1B.18] These activities, as well as other external assessments, help to maintain highly effective chemistry control. Continuous improvement is also achieved through monitoring industry initiatives and trends in the area of corrosion control. For example, in 1996, CP-206 was revised to include dissolved iron as a chemistry parameter. Dissolved iron was added to CP-206 to act as a method to discover any abnormal corrosion of carbon steel components.

Discovery: For the containment air cooler cooling coils, crevice corrosion and pitting can be readily detected through non-destructive examination techniques. Periodic inspections as part of the Preventive Maintenance Program will provide assurance that the effects of corrosion of the external surface are not threatening the pressure-retaining capability of the cooling coils. The internal surface of the cooling coils will be included in the scope of an ARDI Program. [Reference 1, Attachment 8]

Preventive Maintenance Program

The CCNPP Preventive Maintenance Program has been established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimization of equipment failure, and extension of equipment and plant life. Calvert Cliffs currently has preventive maintenance activities for performing inspections and spray washing the containment air coolers every four years (i.e., every other refueling outage). These activities specifically include an inspection of the cooling coils for leaks, which would lead to the discovery of any crevice corrosion or pitting on the external surface of the coils. [References 39] Corrective actions are taken in accordance with the CCNPP

Corrective Actions Program. Refer to the discussion of aging management programs for Group 2 for a detailed description of the Preventive Maintenance Program.

ARDI Program

The containment air cooler cooling coils will be included within a new plant program to accomplish the needed inspections for corrosion of the internal surfaces. This program is the ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0. Corrective actions will be taken in accordance with the CCNPP Corrective Actions Program and will ensure that the components will remain capable of performing their pressure boundary integrity function under all CLB conditions. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program.

Group 5 (crevice corrosion and pitting of heat exchanger cooling coils) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to crevice corrosion and pitting of the containment air cooler cooling coils:

- The cooling coils provide a system pressure boundary for the SRW System and their integrity must be maintained under all CLB conditions.
- Crevice corrosion and pitting are plausible for the cooling coils, and result in material loss which, if left unmanaged, can lead to loss of pressure boundary integrity.
- The CCNPP Chemistry Program controls fluid chemistry of the SRW System to minimize the corrosiveness of the environment for components exposed to SRW.
- The containment air coolers will be included in a new ARDI Program to complete the necessary inspection for the effects of corrosion on the internal surfaces.
- Existing preventive maintenance activities to clean and inspect the containment air coolers provide reasonable assurance that the effects of corrosion on the external surfaces will be discovered.

Therefore, there is reasonable assurance that the effects of crevice corrosion and pitting on the containment air cooler cooling coils 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.

5.11B.3 Conclusion

The programs discussed for the Primary Containment H&V System are listed in Table 5.11B-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 Primary Containment H&V System 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 5.11B-3

AGING MANAGEMENT PROGRAMS FOR THE PRIMARY CONTAINMENT H&V SYSTEM

	Program	Credited For
Existing	CCNPP Containment Leakage Rate Testing Program Surveillance Test Procedures STP M-571I-1, STP M-571I-2, and STP M-671-1	• Discovery and management of leakage that could be an effect of seating surface wear of the check valves, control valves, and MOVs that provide containment pressure boundary (Group 1) • Discovery and management of leakage that could be an effect of crevice corrosion, general corrosion, MIC, and pitting on the seating surfaces of containment isolation valves that are potentially exposed to moisture (Group 2)
Existing	CCNPP Preventive Maintenance Program	
	• Preventive Maintenance Checklists MPM09150 and MPM09151	• Discovery and management of the effects of crevice corrosion, general corrosion, MIC, and pitting for the containment air cooler housings (Group 2)
	• Preventive Maintenance Checklists MPM09150 and MPM09151	• Mitigation, discovery, and management of the effects of dynamic loading of the containment air cooler fans (Group 3)
	• Preventive Maintenance Checklists MPM04112 and MPM04197	• Mitigation, discovery, and management of the effects of dynamic loading of the containment iodine removal fans (Group 3)
	• Preventive Maintenance Checklist MPM04111	• Discovery and management of the effects of radiation damage, elastomer degradation, and wear of damper seals (Group 4)
	• Preventive Maintenance Checklists MPM09150, and MPM09151	• Discovery and management of the effects of radiation damage, elastomer degradation, and wear of rubber boots for the containment air coolers (Group 4)
	• Preventive Maintenance Checklists MPM09007	• Mitigation, discovery, and management of the effects of crevice corrosion and pitting for the external surface of the containment air cooler cooling coils (Group 5)

	Program	Credited For
Existing	CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns"	• Mitigation, discovery, and management of the effects of dynamic loading of fans located outside containment (Group 3) • Discovery and management of the effects of elastomer degradation and wear of duct flexible collars and damper seals located outside containment (Group 4)
Existing	CCNPP Chemistry Program Procedure CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems"	• Mitigation of the effects of crevice corrosion and pitting for the internal surface of the containment air cooler cooling coils (Group 5)
New	ARDI Program	• Discovery and management of the effects of seating surface wear of the hand valves (Group 1) • Discovery and management of the effects of crevice corrosion, general corrosion, MIC, and pitting for piping, hand valves, and MOVs that are potentially exposed to moisture (Group 2) • Discovery and management of the effects of crevice corrosion and pitting for the internal surfaces of the containment air cooler cooling coils (Group 5)

5.11B.4 References

1. "CCNPP Primary Containment H&V System Aging Management Review Report," Revision 1, February 7, 1997
2. CCNPP Report "System Level Screening Results,", Revision 4, April 6, 1995
3. CCNPP Drawing No. 60723SH001, "Ventilation Systems: Containment, Turbine, and Penetration Rooms," Revision 39, April 25, 1997
4. CCNPP Drawing No. 60723SH002, "Ventilation Systems: Containment, Turbine, and Penetration Rooms," Revision 29, September 8, 1997
5. CCNPP Drawing No. 60723SH003, "Ventilation Systems: Containment," Revision 17, September 8, 1997
6. "CCNPP Updated Final Safety Analysis Report," Revision 21
7. CCNPP Drawing No. 60710SH0002, "Component Cooling System, Unit 1," Revision 31, January 17, 1996
8. CCNPP Drawing No. 62710SH0002, "Component Cooling System, Unit 2," Revision 19, January 17, 1996
9. "Component Level Screening Results for the Containment H&V System, System No. 060, CCNPP," Revision 1, July 23, 1996
10. CCNPP Preventive Maintenance Checklist MPM04111, "Lubricate Containment Penetration Room Exhaust Fans"
11. Letter from Mr. T. T. Martin (NRC) to Mr. A. E. Lundvall, Jr. (BGE) dated June 30, 1982, Inspection No. 50-317/82-15 (Routine, Unannounced Inspection of the Containment Penetration Leakage Testing Program, the Containment Integrated Leakage Rate Test, Tours of Facility, and Follow-up on Previous Inspection Findings, June 16, 17, 18, 21, 22, 1982)
12. Letter from Mr. T. T. Martin (NRC) to Mr. A. E. Lundvall, Jr. (BGE) dated January 20, 1983, "Inspection No. 50-318/82-26" (Routine, Unannounced Inspection of Procedure Review, Witnessing and Results Evaluation of Local Leak Rate Test and Integrated Leak Rate Test, December 15 through 18, 1982)
13. Letter from Mr. S. D. Ebneter (NRC) to Mr. A. E. Lundvall, Jr. (BGE), dated June 25, 1985, "Inspection No. 50-317/85-10" (Routine, Announced Inspection of the Containment Leakage Testing Program including Procedure Review of Containment Integrated Leakage Rate Test [CILRT] and Local Leak Rate Test [LLRT] Procedures, CILRT and LLRT Witnessing, CILRT and LLRT Test Review, On-Line Primary Containment Leakage Monitoring, and General Tours of the Facility, April 29 - May 2, and May 17 - 21, 1985)
14. Letter from Mr. S. D. Ebneter (NRC) to Mr. A. E. Lundvall, Jr. (BGE), dated December 24, 1985, "Combined Inspection Nos. 50-317/85-33 and 50-318/85-33" (November 18 through 25, 1985)
15. Letter from Mr. S. A. McNeil (NRC) to Mr. G. C. Creel (BGE), dated March 15, 1989, "Issuance of Technical Specification Amendment and Temporary Exemption Concerning Retest

Schedular Requirements of Appendix J to 10 CFR Part 50 for Types B and C Local Leak Rate Tests (TAC No. 71589)" [Amendment No. 118, Unit 2]

16. Letter from Mr. D. G. McDonald, Jr. (NRC) Mr. Mr. G. C. Creel (BGE), dated February 19, 1992, "Issuance of Amendments for CCNPP Unit No. 1 (TAC No. M82213) and Unit No. 2 (TAC No. M82212)" [Amendment Nos. 168/147]
17. Letter from Mr. A. W. Dromerick (NRC) Mr. C. H. Cruse (BGE), dated February 11, 1997, "Issuance of Amendments for CCNPP Unit No. 1 (TAC No. M97341) and Unit No. 2 (TAC No. M97342)" [Amendment Nos. 219/196]
18. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated November 26, 1996, "License Amendment Request; Adoption of 10 CFR Part 50, Appendix J, Option B for Types B and C Testing"
19. CCNPP Report "Component Pre-Evaluation for the Primary Containment H&V System," Revision 1, January 24, 1997
20. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0, November 8, 1995
21. Letter from Mr. G. C. Creel (BGE) to NRC Document Control Desk, dated May 25, 1989, "Response to Request for Additional Information Generic Letter 88-14, Instrument Air Supply System Problems Affecting Safety-Related Equipment"
22. Letter from Mr. A. W. Dromerick (NRC) to Mr. C. H. Cruse (BGE), "Issuance of Amendments for Calvert Cliffs Nuclear Power Plant, Unit 1(TAC No. M92549) and Unit 2 (TAC No. M92550)," dated December 10, 1996 [Amendment Nos. 217/194]
23. Surveillance Test Procedure STP-M-571I-1, "Local Leak Rate Test, Penetrations 1D (Oxygen Sampling), 47A, 47B, 47C, 47D, 48A, 48B, 49A, 49B, 49C (Hydrogen Sampling)," (Unit 1), Revision 0, May 16, 1991
24. Surveillance Test Procedure STP-M-571I-2, "Local Leak Rate Test, Penetrations 1D (Oxygen Sampling), 47A, 47B, 47C, 47D, 48A, 48B, 49A, 49B, 49C (Hydrogen Sampling)," (Unit 2), Revision 1, March 18, 1997
25. Surveillance Test Procedure STP-M-671-1, "Containment Purge Isolation Valve Leak Rate Test, Penetrations 13 and 14," (Unit 1), Revision 4, July 30, 1991
26. CCNPP Administrative Procedure EN-4-105, "Containment Leakage Rate Testing Program," Revision 1, March 14, 1997
27. 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors"
28. 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
29. CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," Revision 5, September 27, 1996
30. CCNPP Preventive Maintenance Checklist MPM09150, "Inspect Containment Air Coolers"

31. CCNPP Preventive Maintenance Checklist MPM09151, "Inspect Containment Air Coolers"
32. CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns," Revision 0, September 16, 1997
33. CCNPP Preventive Maintenance Checklist MPM04197, "Lubricate Containment Iodine Removal Fan Motor"
34. CCNPP Preventive Maintenance Checklist MPM04112, "Lubricate Containment Iodine Removal Fan Motor"
35. CCNPP Specification No. 6750-M-196, "Specification for Heating, Ventilating, and Air Conditioning Ducts," Revision 4, June 14, 1974
36. EPRI Report NP-2129, "Radiation Effects on Organic Materials in Nuclear Plants," Final Report, November 1981
37. CCNPP CP-206, "Specifications and Surveillance Component Cooling/Service Water System," Revision 3, November 4, 1996
38. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48
39. CCNPP Preventive Maintenance Checklist MPM09007, "Inspect/Clean Containment Air Cooler Coils"

5.11C Control Room and Diesel Generator Buildings' Heating, Ventilation, and Air Conditioning Systems

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing the Control Room Heating, Ventilation, and Air Conditioning (HVAC) System. This section also addresses the Diesel Generator Buildings' HVAC System, which has similar equipment. The Control Room and Diesel Generator Buildings' HVAC Systems were evaluated in accordance with the Calvert Cliff 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.

5.11C.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 device types as either only associated with active functions, part of a complex assembly, or subject to AMR either in this report or another report.

Representative historical operating experience pertinent to aging 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.

Section 5.11C.1.1 presents the results of the system level scoping; 5.11C.1.2 the results of the component level scoping; and 5.11C.1.3 the results of scoping to determine components subject to an AMR for the Control Room HVAC System. Section 5.11C.1.4 summarizes the results of the scoping and AMR process for the Diesel Generator Buildings' HVAC System.

5.11C.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.

<u>System Description/Conceptual Boundaries</u>

Although it is named for the Control Room, the Control Room HVAC System provides ventilation to the Control Room, the Units 1 and 2 Cable Spreading Rooms, and the Units 1 and 2 Battery Rooms. The Control Room and Cable Spreading Rooms are supplied by a single, year-round air-conditioning system serving both Units 1 and 2. Air handling equipment and refrigeration units are redundant, but the ductwork is not. The Control Room and Cable Spreading Room areas have a third source of cooling, which is not safety-related, in the form of a water chiller supplying a second set of coils in the safety-related air handling systems. If airborne contamination occurs at the fresh air intake, a self-contained recirculation system is automatically initiated through a post-loss-of-coolant accident filter system. The Control Room air is then processed through high efficiency particulate air and charcoal filters. [Reference 1]

The air conditioning system is divided into three supply and return duct systems: one for each of the two Cable Spreading Rooms, and one for the Control Room. Each branch contains isolation dampers that are automatically closed if smoke is detected within the branch. The remaining branches continue to serve the other two zones without interruption. Smoke can be evacuated from the isolated zone by means of an auxiliary fan, motorized dampers, and an outside air intake. [Reference 2]

The Battery Rooms are separately ventilated. Heated and filtered air is supplied to the four Battery Rooms and the reserve 125V DC Battery Room on the 27-foot and 45-foot levels of the Auxiliary Building, using one supply fan, one exhaust fan, a heating coil, roughing filter, and motor-operated dampers. Separate supply and exhaust fans are utilized to maintain a negative pressure in these rooms, with respect to the surrounding areas, to preclude the hydrogen concentration in the air from reaching the explosive limit. Upon loss of either fan, sufficient ventilation is provided by the remaining fan to preclude the possibility of hydrogen accumulation within the Battery Rooms. [References 1 and 3]

System Interfaces

The Control Room HVAC System has an interface with the following systems and components: [Reference 2]

- Main Exhaust Equipment Room;
- Auxiliary Building Heating and Ventilation System; and
- Radiation Monitoring System

System Scoping Results

The Control Room HVAC System is within the scope of license renewal based on 10 CFR 54.4(a). The following intended functions of the Control Room HVAC 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 4, Table 1]

- To provide HVAC to the Control Room, Cable Spreading Rooms, and Battery Rooms to ensure habitability during design basis events, limit Reactor Protective System/Engineered Safety Features Actuation System temperatures, and minimize hydrogen accumulation;
- To provide seismic integrity and/or protection of safety-related components;
- To maintain the pressure boundary of the system (liquid and/or gas); and
- To maintain electrical continuity and/or provide protection of the electrical system.

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

For fire protection (§50.48):

- To provide Technical Support Center supply and exhaust ventilation duct isolation to confine or retard a fire from spreading to adjacent areas; and

- To detect smoke, maintain ventilation in unaffected zones, and remove smoke/supply fresh air to affected zones in the event of a fire in the Control Room or Cable Spreading Rooms.

All components of the Control Room HVAC System that support the above functions, with the exception of the fire protection functions, are safety-related and Seismic Category 1 and are subject to the applicable loading conditions identified in the Updated Final Safety Analysis Report Section 5A.3.2 for Seismic Category 1 systems and equipment design. Portions of the system that are within the scope of license renewal only because of the fire protection functions are non-safety-related and non-seismic. [References 5 and 6] The ductwork is constructed of galvanized carbon steel, which conformed to the then current guide from the American Society of Heating, Refrigeration, and Air Conditioning Engineers. It was installed in accordance with high velocity and low velocity duct construction standards from the Sheet Metal and Air Conditioning Contractors National Association. [Reference 2, Attachments 4; Reference 7]

Operating Experience

Over 20 years of operating experience has shown that the heating and ventilation systems at CCNPP are highly reliable in maintaining their passive functions. Some cracking has been discovered in plant HVAC ducting due to vibration-induced fatigue. However, these isolated failures were due to a combination of design and installation deficiencies. In one case, additional supports were added to the ducting to prevent recurrence. In another case, the fans were balanced to minimize the vibration. Some loosening of fasteners has been experienced due to dynamic loading. Vibration-related aging concerns are minimized through system design and existing maintenance practices, which are further described below in the discussions on aging management. Vibration isolators, i.e., flexible collars, are installed around the fans to minimize the vibration being transferred to other equipment. [Reference 2, Attachments 6] Furthermore, fans are monitored for vibration whenever the fan belts are retensioned or replaced. [References 8 and 9]

In 1980, a Control Room Air conditioning unit was placed out-of-service to repair broken damper linkages. This failure was caused by excessive wear due to inadequate lubrication of the damper linkages. The existing preventive maintenance procedure was modified to include lubrication along with periodic visual inspection. [Reference 10] During performance of these periodic inspections, elastomer degradation of the seals has also been identified. If the seals on jambs or blade edging lose their resiliency or are deteriorated, corrective actions are taken to have the seals replaced. [Reference 11]

Corrosion has been discovered below the cooling coils in several of the plant HVAC units. These areas have been reinspected in order to assess the corrosion rates and the adequacy of the system pressure boundary. Other than the limited amount of degradation experienced due to vibration, wear, and corrosion, no other significant aging concerns have been identified that could affect the ability of the Control Room HVAC System components to perform their passive functions.

5.11C.1.2 Component Level Scoping

Based on the intended system functions listed above, the portions of the Control Room HVAC System that are within the scope of license renewal include all safety-related components in the system (electrical, mechanical, and instrument) and their supports. This includes the Control Room HVAC units; the supply, exhaust, and recirculation portions of the Control Room HVAC ducting, dampers, and filters; the safety-related refrigeration units; and the Battery Room supply and exhaust fan, ducting, filter, and dampers. It does not include the non-safety-related Control Room chillers and associated piping, pumps, valves and instrumentation. [References 4, 5, and 6]

Portions of the Control Room HVAC System that are non-safety-related and have only fire protection-related intended functions are also within the scope of license renewal. This includes the exhaust fan, supply and exhaust ducting, and dampers associated with the smoke removal function and the smoke detectors for the Technical Support Center. [References 4, 5, and 6]

The following 44 device types in the Control Room HVAC System were designated as within the scope of license renewal because they have at least 1 intended function: [Reference 2, Section 2.2 and Table 2-1]

Device Type	Device Description	Device Type	Device Description
ACC	Accumulator	LG	Level Gauge
AE	Analyzer Element	M	480V Motor (Feed from Motor Control Center)
CKV	Check Valve	MB	480V Motor
COIL	Coil	MD	125/250VDC Motor
COMP	Compressor	MO	Motor Operator
CV	Control Valve	PCV	Pressure Control Valve
DAMP	Damper	PDI	Pressure Differential Indicator
DISC	Disconnect Switch/Link	PI	Pressure Indicator
DRY	Air Dryer	PNL	Panel
DUCT	HVAC Duct	PO	Piston Operator
FAN	Fan	PS	Pressure Switch
FG	Flow Gauge	PY	Pressure Converter (Relay)
FL	Filter	RV	Relief Valve
FS	Flow Switch	RY	Relay
FU	Fuse	SV	Solenoid Valve
GD	Gravity Damper	TC	Temperature Controller
HS	Handswitch	TCV	Temperature Control Valve
HV	Hand Valve	TS	Temperature Switch
HX	Heat Exchanger	TT	Temperature Transmitter
HY	Converter/Relay	XL	Miscellaneous Indicating Lamp
JD	Tubing with Piping Code of "JD"	ZL	Position Indicator Lamp
JL	Power Lamp Indicator	ZS	Position Switch

Some components in the Control Room HVAC System are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 2, Section 3.2]

- 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 BGE's LRA.
- Electrical control and power cabling are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of BGE's LRA.
- Process and instrument tubing and tubing supports are evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of BGE's LRA.

5.11C.1.3 Components Subject to AMR

This section describes the components within the Control Room HVAC System that 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, part of a complex assembly, 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 CCNPP IPA Methodology Section 5.1, the following Control Room HVAC System functions were determined to be passive: [Reference 2, Table 3-1]

- Maintain the pressure boundary of the system (liquid and/or gas);
- Detect smoke, maintain ventilation in unaffected zones, and remove smoke/supply fresh air to affected zones in the event of a fire in the Control Room or Cable Spreading Rooms (includes only those device types that perform the function by requiring no motion or change of properties or configuration);
- Maintain electrical continuity and/or provide protection of the electrical system; and
- Provide seismic integrity and/or protection of safety-related components.

Device Types Subject to AMR

Of the 44 device types within the scope of license renewal: [Reference 2, Table 3-2; Reference 12]

- 17 device types have only active functions and do not require AMR: Coil, Control Valve, Fuse, Hand Switch, Converter/Relay, Power Lamp Indicator, 480V Motor (Feed from Motor Control Center), 480V Motor, 125/250VDC Motor, Motor Operator, Piston Operator, Pressure Converter (Relay), Relay, Temperature Controller, Miscellaneous Indicating Lamp, Position Indicator Lamp, and Position Switch.
- 4 devices types are evaluated in another section of this application:
  - Panel and Disconnect Switch/Link are evaluated for the effects of aging in the Electrical Commodities Evaluation in Section 6.2 of BGE's LRA.
  - Flow Switch and Pressure Differential Indicator are evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of BGE's LRA.

- 14 device types do not require a detailed evaluation of specific aging mechanisms because they are considered part of a complex assembly whose only passive function is closely linked to active performance, as discussed below: Accumulator, Air Dryer, Compressor, Flow Gauge, Level Gauge, Pressure Indicator, Tubing with Piping Code of JD, Pressure Switch, Temperature Switch, Check Valve, Pressure Control Valve, Relief Valve, Solenoid Valve, and Temperature Control Valve.

In accordance with the provisions of Section 6.1.1 of the CCNPP IPA Methodology, components that comprise the refrigeration units do not require a specific evaluation of age-related degradation mechanism (ARDM), because the detrimental effects of aging mechanisms can be observed by detrimental changes in the performance characteristics or condition of refrigeration unit components if they are properly monitored. Therefore, by adequately monitoring these performance or condition characteristics, the effects of aging on the passive intended function are also adequately managed. The active functions are monitored by: (1) operational requirements that must be satisfied for continued plant operation; (2) Maintenance Rule system performance monitoring; and (3) component-specific condition monitoring addressed under the CCNPP Maintenance Program. [Reference 2, Appendix B]

The 14 device types listed above are entirely included in these complex assemblies. One other device type, i.e., fan, includes the air conditioning condenser fan that is part of these complex assemblies. Other fans in the system are included in the AMR presented herein.

Maintenance of the pressure boundary of the system is the only passive intended function associated with the Control Room HVAC System not addressed by one of the commodity evaluations referred to above. Therefore, only the pressure retaining function for the nine device types listed in Table 5.11C-1 is considered in this section of the BGE LRA. Unless otherwise annotated, all components of each listed device type are subject to AMR.

TABLE 5.11C-1
CONTROL ROOM HVAC SYSTEM DEVICE TYPES REQUIRING AMR

Analyzer Element	Gravity Damper
Damper	Heat Exchanger
HVAC Duct	Hand Valve (1)
Fan	Temperature Transmitter
Filter	

(1) The hand valves that are part of the Control Room HVAC System's refrigeration units are not evaluated herein because the aging is being adequately managed as specified in Section 6.1.1 of the CCNPP IPA Methodology.

5.11C.1.4 Diesel Generator Buildings' HVAC System Scoping

In 1995, two new diesel generators were placed into operation at CCNPP. These diesel generators are located in two separate buildings that are dedicated to housing these diesels. The Diesel Generator Buildings' HVAC System provides ventilation, heating, and cooling for these building spaces. Due to the unique circumstances pertaining to these HVAC systems (i.e., they have been placed into service approximately 20 years after other similar HVAC systems at CCNPP, and they have a design life of

45 years), an AMR process separate and unique from that used for other plant systems and structures was used. Since aging of the existing Control Room HVAC System equipment is some 20 years ahead of the aging of the Diesel Generator Buildings' HVAC System equipment, and since this equipment is just at the beginning of its design life, aging management of the new equipment can be deferred and then be based on future results of aging management from similar equipment groups associated with the Control Room HVAC System. [Reference 13]

All passive intended functions of the Diesel Generator Buildings' HVAC System are equivalent to the Control Room HVAC System's passive intended functions. Common attributes, like intended functions, component configuration, material, and service conditions, result in the conclusion that the effects of aging for these components will be very similar between systems. The aging management programs for the Control Room HVAC System will provide 20 years experience for application to the Diesel Generator Buildings' HVAC System. Therefore, there are no new programs or modifications to existing programs needed to manage the aging of the Diesel Generator Buildings' HVAC System.

5.11C.2 Aging Management

A list of potential ARDMs identified for the Control Room HVAC System components is given in Table 5.11C-2. The plausible ARDMs are identified in the Table by a check mark (✓) in the appropriate device type column. A check mark indicates that the ARDM applies to at least one component for the device type listed. [Reference 2, Table 4-2] For efficiency in presenting the results of the evaluations in this section, ARDM/device type combinations are grouped together where there are similar characteristics and the discussion is applicable to all components within that group with exceptions noted, where appropriate. Table 5.11C-2 identifies the group in which each ARDM/device type combination belongs. The following groups have been selected for the Control Room HVAC System:

Group 1 - Includes crevice corrosion, general corrosion, microbiologically-induced corrosion (MIC), and pitting for components potentially exposed to moisture.

Group 2 - Includes elastomer degradation and wear for non-metallic duct and damper parts.

Group 3 - Includes dynamic loading for fans.

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 5.11C-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE CONTROL ROOM HVAC SYSTEM

Plausible ARDMs	Control Room HVAC System Device Types								
	AE	DAMP	DUCT	FAN	FL	GD	HX	HV	TT
Cavitation Erosion									
Corrosion Fatigue									
Creep/Shrinkage									
Crevice Corrosion		√ (1)	√ (1)	√ (1)	√ (1)		√ (1)		
Dynamic Loading				√ (3)					
Elastomer Degradation		√ (2)	√ (2)						
Erosion Corrosion									
Fatigue									
Fouling									
Galvanic Corrosion									
General Corrosion		√ (1)	√ (1)	√ (1)	√ (1)		√ (1)		
Hydrogen Damage									
Intergranular Attack									
Irradiation Embrittlement									
MIC				√ (1)			√ (1)		
Oxidation									
Particulate Wear Erosion									
Pitting		√ (1)	√ (1)	√ (1)	√ (1)		√ (1)		
Radiation Damage									
Saline Water Attack									
Selective Leaching									
Stress Corrosion Cracking									
Stress Relaxation									
Thermal Damage									
Thermal Embrittlement									
Wear		√ (2)	√ (2)						

√ - Indicates that the ARDM is plausible for component(s) within the device type
(#) - Indicates the group in which this device type/ARDM combination is evaluated

Note: Not every component within the device types listed here may be susceptible to a given ARDM. This is because components within a device type are not always fabricated from the same materials or subjected to the same environments. Exceptions for each device type will be indicated in the aging management section for each ARDM discussed in this report.

APPENDIX A - TECHNICAL INFORMATION
5.11C - CONTROL ROOM AND DIESEL GENERATOR BUILDINGS' HEATING, VENTILATION, AND AIR CONDITIONING SYSTEMS

Group 1 (crevice corrosion, general corrosion, MIC, and pitting for components potentially exposed to moisture) - Materials and Environment

Group 1 is comprised of components that are potentially exposed to moist air and condensation. The flow paths of concern include the outside air intakes for the Control Room, the outside air intake and exhaust for the Battery Rooms, and the outside air intake and exhaust for smoke removal. The ducts, dampers, fans, filters, and heat exchangers that are located in these flow paths are exposed to potentially moist air, which can cause corrosion of the steel materials. The Battery Room exhaust fan and heat exchangers are subject to even wetter conditions since the fan is exposed to the weather and the Control Room coolers are exposed to condensation from the cooling coils. Both the Battery Room exhaust fan and the heat exchangers have drains to remove this moisture. However, the drains could become clogged and allow water to remain standing in the lower portions of the housings. If there is stagnant water, MIC may develop and contribute to local corrosive effects. [Reference 2, Attachments 6]

The materials of construction for each device type are as follows:

- damper - The Control Room outside air dampers and the Battery Room inlet air dampers have frames, shutters, and internals constructed of galvanized steel, axles of carbon steel, bearings of bronze, and seals of neoprene sponge material. The Control Room fresh air dampers and the smoke removal supply and exhaust dampers have their sleeve, flange, stuffing box, axle, and blade constructed of carbon steel and the seals of a neoprene sponge material. [Reference 2, Attachments 4]
- duct - The duct, fittings, doors, and door hinges/latches are constructed of galvanized carbon steel. The joint angles are constructed of carbon steel, and the bolts and rivets are plated carbon steel. The ducting includes flexible collars that are constructed of elastomer materials and secured to fans and ducts with galvanized steel bars. The supply and exhaust registers are constructed of either painted carbon steel or aluminum. [Reference 2, Attachments 4]
- fan - The Battery Room exhaust fan housing and supports are constructed of aluminum. The Battery Room supply fan and the Control Room supply fan housings and supports are constructed of carbon steel and are painted. All fan fasteners are constructed of carbon steel. The motors/fans do not perform a passive intended function. [Reference 2, Attachments 4]
- filter - The Battery Room supply fan filter cabinets are constructed of galvanized carbon steel. The Control Room cooling coil filter housing is constructed of carbon steel and painted. The filters and internals do not perform a passive intended function. [Reference 2, Attachments 4]
- heat exchanger - The Control Room cooling evaporator housing and supports are constructed of carbon steel and painted. The coils themselves have the system pressure boundary intended function; however, they do not require AMR because they are part of the refrigeration units and are considered a complex assembly, as discussed in Section 5.11C.1.3. [Reference 2, Attachments 4]

The internal environment for the Control Room HVAC System can be conditioned air, outside air, or air drawn from ventilated areas. The Control Room HVAC System is designed to maintain the temperatures inside the Control Room and Cable Spreading Room at 75°F and 90°F, respectively, assuming the outdoor air temperature is 95°F. [Reference 1, Table 9-18] The maximum normal relative humidity inside the Auxiliary Building areas is 70%. [Reference 14] Outdoor air reaches a relative humidity of up to 100%.

Most of the Control Room HVAC equipment is located in ventilated areas indoors and, therefore, the external surfaces are not exposed to the outside weather or sunlight. The Auxiliary Building maximum area temperatures for normal operating conditions are 110°F with a maximum relative humidity of 70%. [Reference 14] The Battery Room exhaust fan and the exhaust register for the duct are located outdoors and, therefore, are exposed to the weather.

Group 1 (crevice corrosion, general corrosion, MIC, and pitting for components potentially exposed to moisture) - Aging Mechanism Effects

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. Crevice corrosion is closely related to pitting corrosion and in many cases can initiate pits. [Reference 2, Attachment 7s]

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. General corrosion requires an aggressive environment and materials susceptible to that environment. The consequences of the damage are loss of load carrying cross-sectional area. [Reference 2, Attachment 7s]

Microbiologically-induced corrosion is accelerated corrosion of materials resulting from surface microbiological activity. Sulfate reducing bacteria, sulfur oxidizers, and iron oxidizing bacteria are most commonly associated with the corrosion effects. Microbiologically-induced corrosion most often results in pitting, followed by excessive deposition of corrosion products. Stagnant or low flow areas are most susceptible. Essentially all systems using untreated water and most commonly used materials are susceptible. Consequences range from leakage to excessive differential pressure and flow blockage. Microbiologically-induced corrosion is generally observed in service water applications utilizing raw, untreated water. [Reference 2, Attachment 7s]

Pitting is another form of localized attack with greater corrosion rates at some locations than at others. Pitting can be very insidious and destructive, with sudden failures in high pressure applications (especially in tubes) occurring by perforation. This form of corrosion essentially produces holes of varying depth-to-diameter ratios in the steel. Deep pitting is more common with passive metals, such as austenitic stainless steels, than with non passive metals. Pits are generally elongated in the direction of gravity. In many cases, erosion corrosion, fretting corrosion, and crevice corrosion can also lead to pitting. [Reference 2, Attachment 7s]

For Group 1 components, there are two possible effects from long-term exposure to the moist environment: a uniform corrosion of the exposed steel surfaces causing material thinning, and localized attack resulting in pits and cracks. Crevice corrosion, general corrosion, and pitting are plausible for the subcomponents constructed of carbon steel or galvanized carbon steel. Those items that are painted or galvanized are generally protected from the effects of corrosion; however, where the coating is damaged, corrosion may take place. The most likely locations for corrosion is in crevices at duct joints and between support angles and sheet metal. Corrosion is not plausible for subcomponents constructed of aluminum, bronze, or neoprene sponge material because these materials are generally resistant to corrosion. The Battery Room exhaust fan and the Control Room cooling evaporator housing are also subject to MIC due to the potential for stagnant water. If corrosion, i.e., crevice corrosion, general corrosion, MIC, and pitting, were left unmanaged, it could eventually result in loss of the pressure-retaining capability under current licensing basis (CLB) design loading conditions. [Reference 2, Attachment 6]

Group 1 (crevice corrosion, general corrosion, MIC, and pitting for components potentially exposed to moisture) - Methods to Manage Aging

Mitigation: Since there are no design features for control of humidity, the only feasible method of preventing exposure of these components to a corrosive environment is to apply a protective coating to them. Those subcomponents without a protective coating, or where the coating has degraded, will potentially be exposed to moisture from condensation. The subcomponents constructed of carbon steel materials could be replaced with subcomponents constructed of more corrosion-resistant materials.

Discovery: The effects of crevice corrosion, general corrosion, MIC, and pitting on Group 1 components can be discovered and monitored through non-destructive examination techniques, such as visual inspections. [Reference 2, Attachment 8] Representative samples at susceptible locations can be used to assess the need for additional inspections at less susceptible locations.

Group 1 (crevice corrosion, general corrosion, MIC, and pitting for components potentially exposed to moisture) - Aging Management Program(s)

Mitigation: Maintaining the protective coatings, as discussed below in Discovery, will help to mitigate corrosion of these components. No other mitigation techniques are deemed necessary at this time, so there are no mitigation programs credited for managing corrosion of Group 1 components.

Discovery: For Group 1 components, crevice corrosion, general corrosion, and pitting can be readily detected through visual examination. Additionally, degradation of protective coatings, which help mitigate corrosion, can also be visually detected so that corrective actions can be taken to restore the coatings. An inspection program can provide the assurance needed to conclude that the effects of corrosion are being effectively managed for the period of extended operation. Routine system walkdowns would discover corrosion of the external surfaces of the Group 1 components. Periodic preventive maintenance would lead to the discovery of corrosion on the internal surfaces of components that are readily observable during the activity, including the adjacent ductwork. Components not covered by periodic preventive maintenance will be included in a new Age-Related Degradation Inspection (ARDI) Program to accomplish the necessary inspections. The components to be included in the ARDI Program for corrosion include the battery room inlet dampers, fresh air intake dampers, battery room supply fans, and ducting. [Reference 2, Attachment 8]

System Walkdowns

Calvert Cliffs Administrative Procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of general corrosion, and conditions that could allow corrosion to occur (e.g., degraded paint), of the Control Room HVAC System components by performance of visual inspections during plant walkdowns. The purpose of the procedure is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. [Reference 15, Sections 1.1 and 1.2]

Under procedure MN-1-319, personnel with assigned responsibility for specific structures and systems perform periodic walkdowns. Walkdowns may also be performed as required for reasons such as material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when a system is re-energized or placed in service); and as required for plant modifications. [Reference 15, Section 5.1]

One of the objectives of system walkdowns is to assess the condition of the CCNPP structures, systems, and components such that any degraded condition will be identified, documented, and corrective actions taken before the degradation proceeds to failure of the structures, systems, and components to perform their intended functions. [Reference 15, Sections 5.1.C, 5.2.A.1, and 5.2.A.5] The existing procedure will be modified to include specific inspection items with respect to discovery of these ARDMs to help ensure they are being adequately managed. Conditions adverse to quality are documented and resolved by the Calvert Cliffs Corrective Actions Program.

Procedure MN-1-319 provides guidance for specific types of degradation or conditions to inspect for when performing the walkdowns. Inspection items related to aging management include the following: [Reference 15, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion or vibration;
- Effects that may have been caused by ARDMs such as damaged supports, concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, or inadequate support of components (e.g., missing, detached, or loose fasteners and clamps).

System walkdowns promote familiarity with the systems by the responsible personnel and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance alone. The structure and system walkdown procedure has been improved over time based on past experience to provide guidance on specific activities to be included in the scope of the walkdowns.

Preventive Maintenance Program

The CCNPP 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 Control Room HVAC System components within the scope of license renewal. Guidelines drawn from industry experience and utility best practices were used in the development and enhancement of this program. [Reference 16]

Calvert Cliffs currently has a number of Preventive Maintenance Tasks to periodically perform maintenance and inspections on many of the Group 1 components. These activities include damper inspections, fan lubrications, and fan belt inspections, which are all currently scheduled to be performed every 24 weeks (the Control Room and Cable Spreading Room smoke removal damper inspections are currently scheduled to be performed every 44 months). It also includes fan refurbishment and inspection/cleaning of cooling coils, which are currently scheduled every 48 weeks, and filter inspections, which are currently scheduled every 12 weeks. Each of these activities would lead to the discovery of corrosion for those components that are readily observable during the activity, including the adjacent ductwork. If unsatisfactory conditions are detected, corrective actions will be taken in accordance with the CCNPP Corrective Actions Program. [References 8, 9, and 11; References 17 through 22]

The specific PM activities credited are listed in Table 5.11C-3. During past performance of these maintenance activities, corrosion has been discovered below the cooling coils in several of the HVAC units. These areas have been reinspected in order to assess the corrosion rates and adequacy of the system pressure boundary. Baltimore Gas and Electric Company is currently evaluating alternatives for addressing corrosion in the cooling coil housings.

Specific responsibilities are assigned to BGE personnel for evaluating and upgrading the PM Program and for initiating program improvements based on system performance. Issue Reports are initiated according to CCNPP Procedure QL-2-100 to request changes to the program that could improve or correct plant reliability and performance. Changes to the PM Program that require Issue Reports included changes to the PM task scope, frequency, process changes, results from operating experience reviews, as well as other types of changes. [Reference 16, Section 5.1.A and 5.4]

The PM Program is subject to periodic internal assessment. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their strength of performance and safety significance, and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. An audit performed in 1997 of the CCNPP Maintenance Program (which includes the PM Program) concluded that the program is effectively implemented at CCNPP. No age-related degradation issues were identified. [Reference 23, Section 1B.18]

ARDI Program

To monitor the effects of corrosion for internal surfaces of Group 1 components where periodic preventive maintenance is not performed, these components will be included within a new plant program to accomplish the needed inspections. The components to be included in the ARDI Program for corrosion include the battery room inlet dampers, fresh air intake dampers, battery room supply fans, and ducting. This program is 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 unacceptable examination findings, including consideration of all design loads required by the current licensing basis (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.

Corrective actions will be taken, as necessary, in accordance with the CCNPP Corrective Actions 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, MIC, and pitting for components potentially exposed to moisture) - Demonstration of Aging Management

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

- The Group 1 components provide a system pressure-retaining boundary function and their integrity must be maintained under all CLB conditions.
- Crevice corrosion, general corrosion, and pitting are plausible for the components that are potentially exposed to moist air. Microbiologically-induced corrosion is plausible for the Battery Room exhaust fan and the Control Room HVAC cooling coils due to the potential for stagnant water to collect in the housings. These corrosion mechanisms result in material loss which, if left unmanaged, can lead to loss of pressure-retaining boundary integrity.
- Visual inspections will continue to be performed in accordance with a modified MN-1-319 to help ensure that these ARDMs are being adequately managed. Signs of degraded paint on galvanized surfaces, of external corrosion, or of internal corrosion that resulted in holes in a duct or cooler housing would be detected during these walkdowns. If unsatisfactory conditions are detected, corrective actions will be taken in accordance with the CCNPP Corrective Actions Program.
- Existing routine preventive maintenance activities will continue to be performed on many of the Group 1 components. Performance of these activities will allow for discovery of corrosion in accessible internal surfaces, including the adjacent ductwork.
- Components that do not have routine maintenance will be included in the scope of an ARDI Program to provide the needed inspections of the internal surfaces. 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, MIC, and pitting on Group 1 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 (elastomer degradation and wear for non-metallic duct and damper parts) - Materials and Environment

The Control Room HVAC System galvanized carbon steel ducting was installed with flexible collars in connections between fans and ducts or casings to prevent excessive movements of long ducts. These flexible collars are constructed of elastomers and are installed with sufficient slack to prevent transmission of vibration. Collars are secured to fans and ducts with galvanized steel bars fastened with bolts for an air-tight construction. Some of the Control Room HVAC System dampers are required to maintain system pressure boundary while in the closed position, and they are constructed with compressible seals to provide leak tightness. These seals are constructed of neoprene sponge material, which is an elastomer. [Reference 2, Attachment 4s; Reference 7]

Refer to the Group 1 discussion on Materials and Environment for a discussion of the internal and external environments for the Control Room HVAC System Group 2 components.

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Aging Mechanism Effects

An elastomer is a material that can be stretched to significantly greater than original length and, upon release of the stress, will return with force to approximately its original length. When an elastomer ages, there are three mechanisms primarily involved:

- Scission - the process of breaking molecular bonds, typically due to ozone attack, ultraviolet light, or radiation;
- Crosslinking - the process of creating molecular bonds between adjacent long-chain molecules, typically due to oxygen attack, heat, or curing; and
- Compound ingredient evaporation, leaching, mutation, etc.

Measurable properties that change include hardness, modulus, elongation, tensile strength, and compression strength. Elastomers generally harden as they age, making sealing more difficult. [Reference 2, Attachment 7s]

Wear results from relative motion between two surfaces (adhesive wear); from the influence of hard, abrasive particles (abrasive wear), or fluid stream (erosion); and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). Motions may be linear, circular, or vibratory in inert or corrosive environments. Fretting is a wear phenomenon that occurs between tight-fitting surfaces subjected to a cyclic, relative motion of extremely small amplitude. Common sites for fretting are in joints that are bolted, keyed, pinned, press fit, or riveted; in oscillating bearings, couplings, spindles, and seals; in press fits on shafts; and in universal joints. [Reference 2, Attachment 7s]

Elastomer degradation and wear are plausible for the flexible collars since the elastomers will degrade at the joints in the HVAC equipment due to the relative motion caused by vibrating equipment, pressure variations, and turbulence; and exposure to temperature changes and oxygen. These stressors will result in eventual tearing of the collars. Elastomer degradation and wear are plausible for the damper seals due to relative motion between the blade and sleeve during damper operation, and exposure to temperature changes and oxygen. These stressors will result in eventual breakdown of the seal. [Reference 2, Attachment 6s] If left unmanaged, elastomer degradation and wear could eventually result in the loss of pressure boundary integrity of the duct flexible collars and damper seals under CLB design loading conditions.

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Methods to Manage Aging

Mitigation: Elastomer degradation can be mitigated by utilizing materials that are less susceptible to heat and oxygen. Wear can be mitigated by minimizing vibration of the duct and dampers and by minimizing operation of the dampers to slow degradation of the seating surfaces, which leads to a loss of leak tightness.

Discovery: Periodic visual inspections can be performed for the equipment in Group 2 to detect the effects of elastomer degradation and wear. Degradation of the flexible collars can be detected through periodic system walkdowns because the collars are readily accessible. Degradation of damper seals can be detected through periodic inspections and walkdowns. If significant degradation is discovered, the flexible collars or damper seals can be repaired or replaced as appropriate. [Reference 2, Attachment 8] Another method to discover the effects of elastomer degradation and wear would be to perform periodic inleakage testing of the system. An increase in system inleakage may be caused by worn damper seals or torn flexible collars and would be an alert condition that would trigger investigations as to the location and cause of the increased inleakage.

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Aging Management Program(s)

Mitigation: The system was designed to minimize vibrations by using equipment support isolators and equipment-to-duct isolators, such as the flexible collars. Changes to materials or to system operating practices are not deemed necessary to mitigate the effects of this ARDM because the discovery methods discussed below are adequate methods to manage aging. Since there are no additional methods of mitigating elastomer degradation and wear, there are no programs credited with mitigating the aging effects due to these ARDMs. [Reference 2, Attachment 6s and 8]

Discovery: Elastomer degradation and wear can be readily detected for Group 2 components through visual examination. An inspection program can provide the assurance needed to conclude that the effects of plausible aging are being effectively managed for the period of extended operation. Routine system walkdowns would discover the effects of these ARDMs on the external surfaces of the Group 2 components. Periodic preventive maintenance would lead to the discovery of the effects of these ARDMs on the internal surfaces of components that are readily observable during the activity. Components not covered by periodic preventive maintenance will be included in a new ARDI Program to accomplish the necessary inspections. The components currently included in the ARDI Program for elastomer degradation and wear include the return air exhaust dampers, battery room inlet dampers, and the fresh air intake dampers. [Reference 2, Attachment 8]

System Walkdowns

Routine inspections are performed on system components in accordance with CCNPP Administrative Procedure MN-1-319. These walkdowns provide for discovery and management of the effects of elastomer degradation and wear through visual inspections, reporting the walkdown results, and initiating corrective action. Under this procedure, 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 excessive vibrations, bent or broken component supports, etc. Signs of cracking or tearing of duct flexible collars would be detected during these walkdowns. The accessible external surfaces of the subject equipment are monitored and conditions identified as adverse to quality are corrected in accordance with the CCNPP Corrective Actions Program. [Reference 15] The existing procedure will be modified to include specific inspection items with respect to discovery of these ARDMs to help ensure they are being adequately managed. Refer to the discussion on Aging Management Programs for Group 1 for a detailed description of MN-1-319.

Preventive Maintenance Program

The CCNPP 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. Calvert Cliffs currently has a Preventive Maintenance Task to periodically perform inspections of the outside air supply dampers for the Control Room and Battery Rooms. This task, which is scheduled to be performed every 24 weeks, requires that the accessible damper, operator, and attachments be visually inspected and that the damper be stroked and visually inspected again. Damper linkage pivot points are also lubricated. The visual inspection specifically includes verification that seals on jambs and blade edging is resilient and not deteriorated. [Reference 11] This inspection would discover if significant elastomer degradation and wear is occurring to the damper seals. During past performance of these periodic inspections, degradation of the seals had been identified. Corrective actions were taken to have the seals replaced. Refer to the discussion on Aging Management Programs for Group 1 for a detailed description of the Preventive Maintenance Program.

ARDI Program

To provide the needed inspections for the internals of Group 2 dampers that are not subject to routine maintenance, an inspection of the internals of those dampers will be accomplished as part of an ARDI Program, as defined in the CCNPP IPA Methodology presented in Section 2.0. The components currently included in the ARDI Program for elastomer degradation and wear include the return air exhaust dampers, battery room inlet dampers, and the fresh air intake dampers. Corrective actions will be taken in accordance with the CCNPP Corrective Actions Program and will ensure that the components will remain capable of performing their pressure boundary integrity function under all CLB conditions. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program.

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to elastomer degradation and wear for duct flexible collars and damper seals:

- Control Room HVAC System ducts and dampers provide a system pressure-retaining boundary function and their integrity must be maintained under CLB design conditions.
- Elastomer degradation and wear are plausible for the flexible collars due to the relative motion between vibrating equipment, pressure variations, and turbulence; and exposure to temperature changes and oxygen. Elastomer degradation and wear are plausible for the seals due to relative motion between the blade and sleeve during damper operation and exposure to temperature changes and oxygen.

- If left unmanaged, elastomer degradation and wear can result in material loss, tearing, or cracking, which could lead to loss of pressure-retaining boundary integrity.
- Visual inspections will continue to be performed in accordance with a modified MN-1-319 to help ensure that these ARDMs are being adequately managed. Signs of cracking or tearing of duct collars would be detected during these walkdowns, as well as such conditions as unusual noises, leaks, or vibrations. If unsatisfactory conditions are detected, corrective actions are taken in accordance with the CCNPP Corrective Actions Program.
- An existing routine preventive maintenance activity to periodically inspect the outside air supply damper seals will continue to be conducted as part of the Preventive Maintenance Program. If unsatisfactory conditions are detected, corrective actions will be taken in accordance with the CCNPP Corrective Actions Program.
- To provide the needed inspections for the internals of Group 2 dampers that are not subject to routine maintenance, 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 of the damper seals is discovered.

Therefore, there is reasonable assurance that the effects of elastomer degradation and wear for duct flexible collars and damper seals 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 3 (dynamic loading for fans) - Materials and Environment

Group 3 is comprised of fans because the rotating equipment can cause vibrations that can lead to dynamic loading concerns for fasteners. Normal bearing wear and dirt buildup cause imbalances in the rotating parts of the fans, thereby creating vibrations. Flexible collars are installed on the fans to provide dynamic isolation for adjacent components, which minimizes the dynamic loading for those components. The internal and external environments of the fans are discussed above in the Materials and Environment section for Group 1. [Reference 2, Attachment 7s]

The Battery Room exhaust fan housing and supports are constructed of aluminum. The Battery Room supply fan, Control Room supply fan, Control Room return fan, and the post-loss-of-coolant accident filter fan housings and supports are constructed of carbon steel, and some are painted. All fan fasteners are constructed of carbon steel. The motors/fans do not perform a passive intended function. [Reference 2, Attachments 4]

Group 3 (dynamic loading for fans) - Aging Mechanism Effects

Dynamic loadings (vibrations) are created at blowers by rotating parts with imbalances due to dirt buildup and normal bearing wear. There is a history of loosened mechanical fasteners due to vibration in fans at CCNPP. This mechanism is plausible for the fans, but is not considered plausible for adjacent HVAC equipment due to the dynamic isolation provided by flexible collars. If dynamic loading was left unmanaged, it could result in the loss of pressure boundary integrity of the Group 3 components under CLB design loading conditions. [Reference 2, Attachments 5 and 6]

Group 3 (dynamic loading for fans) - Methods to Manage Aging

Mitigation: Dynamic loading can be mitigated by minimizing the mechanical loading due to vibration. The system is designed to minimize vibration by using equipment support isolators and equipment-to-duct isolators, such as flexible colors. Visual inspections through system walkdowns would provide for detection of vibration so that corrective actions could be taken to minimize vibration and, thereby, mitigate the effects of dynamic loading. [Reference 2, Attachment 8]

Discovery: The effects of dynamic loading, e.g., loosened fasteners, can be detected through visual inspections. Periodic visual inspections through system walkdowns would provide for detection of the effects of dynamic loading, as well as vibration problems, which can cause this ARDM to occur. [Reference 2, Attachment 8]

Group 3 (dynamic loading for fans) - Aging Management Program(s)

Mitigation: Routine system walkdowns provide for periodic visual inspections of the external surfaces of Control Room HVAC System components. During these walkdowns, any vibration problems would be detected so that corrective actions can be taken to minimize the vibration. [Reference 2, Attachment 8] Refer to the discussions below in Discovery for a description of the walkdown activities relied on for managing dynamic loading.

Discovery: Routine inspections are performed on system components in accordance with MN-1-319. The walkdowns provide for discovery of the effects of dynamic loading, e.g., loosened fasteners, as well as abnormal or excessive vibration, which can cause this ARDM to occur. Administrative Procedure MN-1-319 requires routine system walkdowns that include visual inspections, reporting the walkdown results, and initiating corrective action. Under this program, inspection items typically related to aging management include identifying unusual noises and identifying system and equipment stress or abuse, such as excessive vibrations, bent or broken component supports, etc. Signs of loosened fasteners would be discovered during these walkdowns. The corrective actions required as a result of the system walkdowns will be taken in accordance with the CCNPP Corrective Actions Program, and will ensure that the fans will remain capable of performing the system pressure boundary integrity function under all CLB conditions. [Reference 15] The existing procedure will be modified to include specific inspection items with respect to discovery of these ARDMs to help ensure they are being adequately managed. Refer to the discussion above in Group 1 under Aging Management Programs for a detailed discussion of MN-1-319.

Group 3 (dynamic loading for fans) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to dynamic loading for fans:

- Control Room HVAC System fans provide a system pressure-retaining boundary function and their integrity must be maintained under CLB design conditions.
- Dynamic loading is a plausible ARDM for the fans due to excessive vibration resulting from fan operation.

- If left unmanaged, dynamic loading can result in loosened fasteners, which could lead to loss of pressure-retaining boundary integrity.
- Visual inspections will continue to be performed in accordance with a modified MN-1-319 to help ensure that these ARDMs are being adequately managed. Signs of loosened fasteners on the fans would be detected during these walkdowns, as well as such conditions as unusual noises or vibrations, so that corrective actions can be taken to mitigate this ARDM.

Therefore, there is reasonable assurance that the effects of dynamic loading for fans 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.

5.11C.3 Conclusion

The programs discussed for the Control Room HVAC System are listed in Table 5.11C-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 Control Room HVAC System will be maintained, consistent with the CLB, during the period of extended operation.

For the Diesel Generator Buildings' HVAC System equipment, aging management of the new equipment can be deferred and then be based on future results of aging management from similar equipment groups associated with the Control Room HVAC System, since aging of the existing Control Room HVAC System equipment is some 20 years ahead of this equipment, and since this equipment is just at the beginning of its design life. Therefore, there are no new programs or modifications to existing programs needed to manage the aging of the Diesel Generator Buildings' HVAC System.

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 5.11C-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE CONTROL ROOM HVAC SYSTEM

	Program	Credited As
Existing	CCNPP Maintenance Program	
	• Preventive Maintenance Checklists MPM09109, MPM09000, MPM04169, MPM09021, MPM09115, MPM09132, MPM07111, MPM09022, and EPM30700	• Discovery and management of the effects of crevice corrosion, general corrosion, MIC, and pitting for internal surfaces of components potentially exposed to moisture. (Group 1)
	• Preventive Maintenance Checklist MPM09021	• Discovery and management of the effects of elastomer degradation and wear for damper seals. (Group 2)
Modified	CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns" Existing procedure will be modified to include specific items with respect to discovery of these ARDMs to help ensure each plausible ARDM is being adequately managed.	• Discovery and management of the effects of crevice corrosion, general corrosion, MIC, and pitting for external surfaces of components potentially exposed to moisture. (Group 1) • Discovery and management of the effects of elastomer degradation and wear for duct flexible collars. (Group 2) • Discovery and management of the effects of dynamic loading for fans. (Group 3)
New	ARDI Program (new)	• Discovery and management of the effects of crevice corrosion, general corrosion, MIC, and pitting for internal surfaces of components potentially exposed to moisture and that are not subject to routine maintenance. (Group 1) • Discovery and management of the effects of elastomer degradation and wear for the seals of dampers that are not subject to routine maintenance. (Group 2)

5.11C.4 References

1. "CCNPP Updated Final Safety Analysis Report," Revision 21
2. "CCNPP Control Room HVAC System Aging Management Review Report," Revision 1, March 1997
3. CCNPP "System Level Screening Results," Revision 4, April 6, 1995
4. CCNPP Report, "Component Level Screening Results for the Control Room HVAC System, System No. 030," Revision 1, July 1, 1996
5. BGE Drawing No. 60723SH004, "Ventilation Systems: Control Room and Cable Spreading Room HVAC," Revision 34, August 14, 1996
6. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 4, August 27, 1996
7. CCNPP Specification No. 6750-M-196-A, "Specification for Heating, Ventilating, and Air Conditioning Ducts," Revision 2, May 29, 1974
8. CCNPP Preventive Maintenance Checklist MPM09109, "Inspect/Replace Belts for Control Room HVAC Unit Fan Coil"
9. CCNPP Preventive Maintenance Checklist MPM09000, "Inspect Belt(s) and Sheaves"
10. Letter from Mr. L. B. Russell (BGE) to Mr. B. H. Grier (NRC), dated July 18, 1980, "Thirty-Day Report for Licensee Event Report 80-29/3L"
11. CCNPP Preventive Maintenance Checklist MPM09021, "Control Room HVAC Damper Inspection"
12. CCNPP Report, "Component Pre-Evaluation for the Control Room HVAC System (030)," Revision 1, January 31, 1997
13. "CCNPP Diesel Generator Buildings HVAC System Aging Management Review Report," Revision 0, April 4, 1997
14. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0, November 8, 1995
15. CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns," Revision 0, September 16, 1997
16. CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," Revision 5, September 27, 1996
17. CCNPP Preventive Maintenance Checklist MPM04169, "Inspect Filter/Lubricate Battery Room Supply Fan/Motor"
18. CCNPP Preventive Maintenance Checklist MPM09115, "Lubricate Control Room HVAC Unit Fan and Motor Bearings"
19. CCNPP Preventive Maintenance Checklist MPM09132, "Inspect/Clean Control Room HVAC Evaporator Coils"

20. CCNPP Preventive Maintenance Checklist MPM07111, "Inspect/Replace Filters for Control Room HVAC Unit Fan Coil"

21. CCNPP Preventive Maintenance Checklist EPM30700, "Control Room and Cable Spreading Room Smoke Removal Damper and MCC Breaker Inspection"

22. CCNPP Preventive Maintenance Checklist MPM09022, "Air Handling Unit Refurbishment of No. 11 and No. 12 Control Room Air Conditioning Unit"

23. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48, March 28, 1997

5.12 Main Steam System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing the Main Steam, Extraction Steam, and Nitrogen and Hydrogen Systems. The Main Steam, Extraction Steam, and Nitrogen and Hydrogen Systems have been evaluated in accordance with 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.

5.12.1 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 device types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Operating Experience

Representative historical operating experience pertinent to aging 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.

The Main Steam System operating experience relative to the scope of this section of the BGE LRA has resulted in several changes to improve its reliability and functionality. Several system valves have been replaced. The main steam isolation valves (MSIVs) have been replaced due to reliability concerns and to ensure their ability to consistently close within the required time limits. They were initially hydraulically actuated valves. They are now nitrogen closed, pilot actuated valves that still utilize hydraulics, but do so much more reliably. To assure their reliability, they are scheduled to be examined every four years under the Preventive Maintenance (PM) Program, at which time their actuators are sent back to the vendor for inspection/refurbishment. The check valves in the steam supply lines to the auxiliary feedwater (AFW) pumps have also been replaced due to operating problems in the past.

The nature of the periodic operation (testing) of the AFW pump also resulted in problems with the pump turbine governor (not within the scope of this report) during startup. System condensation that occurred while the system was idle resulted in water impingement of the governor during the required periodic system automatic start testing mandated by NUREG 0737, “Clarification of TMI *[Three Mile Island]* Action Plan Requirements.” To remedy this, the drains from the system have been enhanced with the installation of tanks to direct and collect the amount of condensation that accumulates during idle periods and automatic starts. This modification has eliminated the problem.

The failure of some extraction steam piping, not within the scope of license renewal, several years in the past resulted in the creation of the plant’s Erosion Corrosion Program. This program is credited for the mitigation of several components that are within the scope of license renewal and included in this section of the BGE LRA. The portion of the Extraction Steam System that is within the scope of license renewal is no longer used. It was piping used for reactor vessel head washdown. It, therefore, no longer sees an extraction steam environment. It is included in this section of the BGE LRA due to its containment penetration.

There have been problems with system drains associated with portions of the system not within the scope of license renewal. Excessive cycling of non-scope drain motor-operated valves (MOVs) has resulted in burnt out fuses and failed wiring, as well as problems with the valve bodies, couplings, and valve body connections. Due to these problems, the frequency of inspection of all system drains, including those within the scope of license renewal, has been increased, and many portions of the main steam drain piping inside and outside the scope of license renewal have been included in the plant's Erosion Corrosion Program. Drain system piping, where leaks or thinning have been discovered, is being replaced with piping that is more resistant to erosion corrosion.

The portions of the Steam Generator (SG) Blowdown System that are inside containment are included in the scope of this section of the BGE LRA. This piping has been replaced with all new carbon steel piping and with bent carbon steel piping sections instead of elbow fittings. This was done to reduce the erosion corrosion of fittings. The only exception to this is the connection of the blowdown piping to the SGs themselves. The elbows at this connection were replaced with chrome-moly socket-welded elbows. All SG blowdown piping is covered by the Erosion Corrosion Program. Many portions of the blowdown piping outside of containment, and not within the scope of license renewal, have already been replaced with chrome-moly piping. As piping inside of containment is found to meet the requirements for replacement, as defined by the Erosion Corrosion Program, it is planned to replace it with piping that is more resistant to erosion corrosion.

Section 5.12.1.1 presents the results of the system level scoping, 5.12.1.2 the results of the component level scoping, and 5.12.1.3 the results of scoping to determine components subject to an AMR.

5.12.1.1 System Level Scoping

The Main Steam System AMR Report [Reference 1] includes the Extraction Steam and Nitrogen and Hydrogen Systems in its scope. This section begins with descriptions of these systems, which includes the boundaries of the systems as they were scoped. The intended functions of the systems are listed and are used to define what portions of the systems are within the scope of license renewal.

System Description/Conceptual Boundaries

The Main Steam System has the following functional requirements: [Reference 1, Section 1.1.1]

- To provide the flow path for SG output steam that flows to the main high pressure turbines, the moisture separator reheaters, main feedwater pump turbines, the AFW pump turbines, and the steam seal regulator;
- To provide overpressure protection for the SGs;
- To provide for automatic removal of Nuclear Steam Supply System stored energy and sensible heat following a turbine and reactor trip;

- To provide for operator control of SG pressure and Reactor Coolant System temperature during plant cooldown and heatup;
- To provide a means of heat removal during hot standby and plant cooldown; and
- To remove excessive moisture from the high pressure turbine exhaust (dry the steam by heating it further) prior to entering the low pressure turbines via the reheat steam subsystem.

During normal plant operations, steam is generated in the SGs. This steam flows through a main steam header from each SG (two per unit) to the main turbine high pressure stop valves. Located in each main steam header, at the exit of each SG inside containment, is a flow restrictor. The MSIV in each header, outside containment, represents the downstream terminus of the safety-related main steam piping (and the portion of the system within scope of license renewal). The two main steam headers are cross-connected downstream of the MSIVs. Main steam also flows from each of the main steam headers, downstream of the containment penetration, and upstream of the MSIVs, through air-operated valves, to the AFW pump turbines when the AFW System is operated. Downstream of the MSIVs, a branch header provides a steam flow path from each main steam header to the moisture separator reheaters and to the steam seal regulator (from Nos. 11/21 Headers only). Another branch header connects to the SG feedwater pump turbines.

One atmospheric steam dump valve and eight safety valves are connected to each main steam header between the containment penetration and the MSIV. These valves are normally shut and, when opened, exhaust main steam to the atmosphere. Four turbine bypass valves are connected to the branch header, downstream of the MSIVs, that supplies main steam to the SG feedwater pump turbines. These valves are normally shut and, when operated, exhaust main steam to the main condenser.

The Extraction Steam System's functional requirements are: [Reference 1, Section 1.1.4]

- To increase the temperature of the feedwater prior to its entering the SG, which results in an increase in overall plant efficiency;
- To minimize thermal shock in the SGs; and
- To assist in removing moisture from the high pressure turbine third stage by supplying steam to the first stage of the moisture separator reheater.

During normal plant operations, the extraction steam is used to increase the temperature of the feedwater prior to its entering the SGs. Wet steam is directed from the three highest stage pressure feedwater heaters in the condensate and feedwater systems en route to the heater drain tanks. Wet steam from the three lowest stage pressure feedwater heaters is cascaded to the previous stage feedwater heater and eventually recovered in the condenser.

The functional requirements of the Nitrogen and Hydrogen System are: [Reference 1, Section 1.1.7]

- To store and distribute the required amounts of nitrogen for normal plant operations;
- To provide nitrogen for backup to the instrument air system (however, this is not currently in service); and

- To supply hydrogen to the main generators, the volume control tanks, and the Radiological Chemistry Explosive Gas Storage Room.

The Nitrogen and Hydrogen System consists of two independent systems supplying gases for normal plant operations.

The nitrogen subsystem can itself be divided into two subsystems, the storage system and distribution header. The storage system includes an insulated storage tank that is kept pressurized by a combination of ambient and electric vaporizers.

The hydrogen subsystem is a common subsystem consisting of hydrogen gas bottles, a truck fill connection, pressure control unit, distribution header, and the associated piping valves and controls.

System Interfaces

The interfaces discussed in this section that serve a safety-related function are within the scope of license renewal and addressed in this section of the BGE LRA. The non-safety-related portions of the Main Steam System that are within the scope of license renewal for fire protection considerations are addressed in Section 5.10, Fire Protection, of the BGE LRA.

The Main Steam System has interfaces with the SG, main turbine, SG feedwater pump turbines, AFW, Steam Seal and Exhaust System, Reactor Regulating System, Main Turbine Control System, Engineered Safety Features Actuation System, Circulating Water System, the main condensers, and instrument air. [Reference 1, Section 1.1.2; Reference 2, Section 10.1; Reference 3]

The following interfaces with or portions of the Main Steam System are within the scope of license renewal and included in this section of the BGE LRA:

- Main steam lines from the SGs to the MSIVs. The SGs are within the scope of license renewal for the Reactor Coolant System, which is addressed in Section 4.1 of the LRA.
- The Engineered Safety Features Actuation System supplies a signal to the MSIV Hydraulic Actuator and Control System to rapidly shut the MSIVs when a SG Isolation Signal or Containment Spray Actuation Signal has been generated.
- Main steam line drains transfer moisture from the main steam piping to the auxiliary blowdown tanks during plant startup. The contents of these tanks are transferred to the Chesapeake Bay via the Circulating Water System discharge piping. These Main Steam System drains are partially within the scope of license renewal. The lines up to the drain line orifices that act as the specification break between Class EB and Class GB piping are within the scope of license renewal.
- The main steam line drains transfer moisture from the main steam piping to the main condensers during normal plant operation. As above, the main steam drains up to the drain line orifices that act as the specification break between Class EB and Class GB piping are within the scope of license renewal.

- The Instrument Air System provides operating air for the main steam atmospheric dump valves and the AFW pump turbine steam isolation valves. A portion of the air system relative to these valves is included within the scope of license renewal and is also included in this section of the BGE LRA.

The SG Blowdown System piping that is included in this section of the BGE LRA has four interfaces that are within the scope of license renewal as follows: [Reference 1, Section 1.1.2; Reference 2, Section 10.1; Reference 3]

- The nitrogen portion of the Nitrogen and Hydrogen System taps into the surface blowdown lines inside of containment to provide for dry layup of the SG. The SG is filled with nitrogen to ensure that no oxygen is present during layup. This piping (blowdown and nitrogen) penetrates containment.
- The isolation valves from the SG Lay-up Chemical Addition System interface with the SG bottom blowdown lines.
- The second in the series of two blowdown heat exchangers in each unit is cooled by the safety-related Service Water (SRW) System.
- Similarly, the SG blowdown radiation monitor coolers in each unit are cooled by the safety-related Component Cooling Water (CCW) System.

The Extraction Steam System interfaces with the Feedwater Heaters, Drains and Vents System, Reheat Steam System, scavenging steam, Reactor Coolant Waste Evaporator System, Miscellaneous Waste Processing System, and the Main Steam System; however, none of these interfaces are within the scope of license renewal. The only portion of the system that is in scope is the system containment penetration. This penetration was provided to make low pressure steam available for reactor vessel head washdown. This function has since been abandoned, but the containment penetration still exists and that small section of safety-related piping at the penetrations in each unit is within the scope of license renewal. [Reference 1, Section 1.1.5; Reference 2, Section 10.1; Reference 4]

The nitrogen distribution header runs throughout the plant, going to a variety of components ranging from the MSIVs to the auxiliary boilers. Nitrogen is used in the safety injection tanks, virtually all storage tanks, and water bearing vessels such as the volume control tanks and the SGs. Only its interface with the SG blowdown system, addressed above, and the containment penetrations for the nitrogen supply to the SGs and pressurizer quench tanks, the safety injection tanks, and the reactor coolant drain tanks are within the scope of license renewal. [Reference 1, Section 1.1.8; Reference 5]

The hydrogen subsystem is a common subsystem consisting of hydrogen gas bottles, a truck fill connection, pressure control unit, distribution header, and the associated piping valves and controls. The hydrogen subsystem interfaces with the Main Generator and the Chemical and Volume Control System. None of these interfacing functions are within the scope of license renewal. [Reference 1, Section 1.1.8; Reference 5]

Because only the nitrogen portion of the Nitrogen and Hydrogen System is applicable to the scope of this report, the system will be referred to as the Nitrogen System for the balance of this report.

System Scoping Results

The Main Steam System, Extraction Steam, and Nitrogen Systems are in scope for license renewal based on 10 CFR 54.4(a).

The following intended functions of the Main Steam System (and SG Blowdown, as applicable) 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]

- Maintain the pressure boundary of the system (liquid and/or gas);
- Provide closure of the SG blowdown isolation valves on receipt of a Containment Spray Actuation Signal to reduce the heat load on the SRW System;
- Provide SG overpressure protection/decay heat removal;
- Provide SG steam line isolation;
- Provide motive steam to AFW pump turbines on receipt of an Auxiliary Feedwater Actuation System actuation signal;
- Maintain electrical continuity and/or provide protection of the electrical system;
- Maintain mechanical operability and/or provide protection of the mechanical system; and
- Restrict flow to a specified value in support of a design basis event response.

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

- For fire protection (§50.48) - Provide Reactor Coolant System heat removal in the event of a postulated severe fire (addressed in Section 5.10, Fire Protection, of the BGE LRA);
- For environmental qualification (§50.49) - Maintain the functionality of electrical components as addressed by the Environmental Qualification Program;
- For station blackout (§50.63) - Provide SG overpressure protection/decay heat removal;
- For station blackout (§50.63) - Provide SG steam line isolation;
- For station blackout (§50.63) - Provide motive steam to AFW pump turbines on receipt of an Auxiliary Feedwater Actuation System actuation signal; and
- For station blackout (§50.63) - Provide valve position indication and manual closure of MSIV bypass isolation valves following a loss of AC power.

All components of the Main Steam System evaluated in this section of the BGE LRA are Seismic Category 1 and are subject to the applicable loading conditions identified in the Updated Final Safety Analysis Report Section 5A.3.2 for Seismic Category 1 systems and equipment design. The main steam piping from the SG to the containment penetration is designed in accordance with American Nuclear Standards Institute (ANSI) B31.1, Power Piping Code. From the penetration to the MSIVs, the piping meets the design requirements of ANSI B31.7, Class II, Nuclear Power Piping Code. The steam supply piping to the AFW pumps is designed in accordance with ANSI B31.1, Power Piping Code. The piping is considered Class II piping for the purposes of the American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection Program. The above main steam piping is designated as Classes EB-1, EB-12, and EB-8, respectively, which have a rating of 1000 psig/580°F. Steam generator blowdown piping is designated as Classes EB-6 and EB-14, which have a rating of 1000 psig/525°F. The Class EB-6 piping is non-penetration piping that is designed in accordance with ANSI B31.1. The penetration piping, Class EB-14, is designed in accordance with ANSI B31.7, Class II. Both classes are Class II piping for the purposes of the Section XI Inservice Inspection Program. See Figure 5-12.1. [References 2, 6, 7, and 8]

Additionally, the instrument air piping to the AFW steam supply isolation control valves is included in the scope of this section of the BGE LRA. This piping is designated as Class HB-35, is rated at 125 psig/100°F, and is designed in accordance with ANSI B31.1. It is non-class for the purposes of the ASME Section XI Inservice Inspection Program. [References 2, 9, 10, and 11]

The following intended functions of the Extraction Steam 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 4, Table 1]

- To provide containment isolation, and
- To maintain electrical continuity and/or provide protection of the electrical system.

The extraction steam piping within scope for license renewal is the containment penetration piping for reactor vessel head washdown. This piping is designated as Class GB-24, is rated at 250 psig/425°F, is designed in accordance with ANSI B31.7, Class II, and is not included in the ASME Section XI Inservice Inspection Program. See Figure 5-12.2. [References 12 and 13]

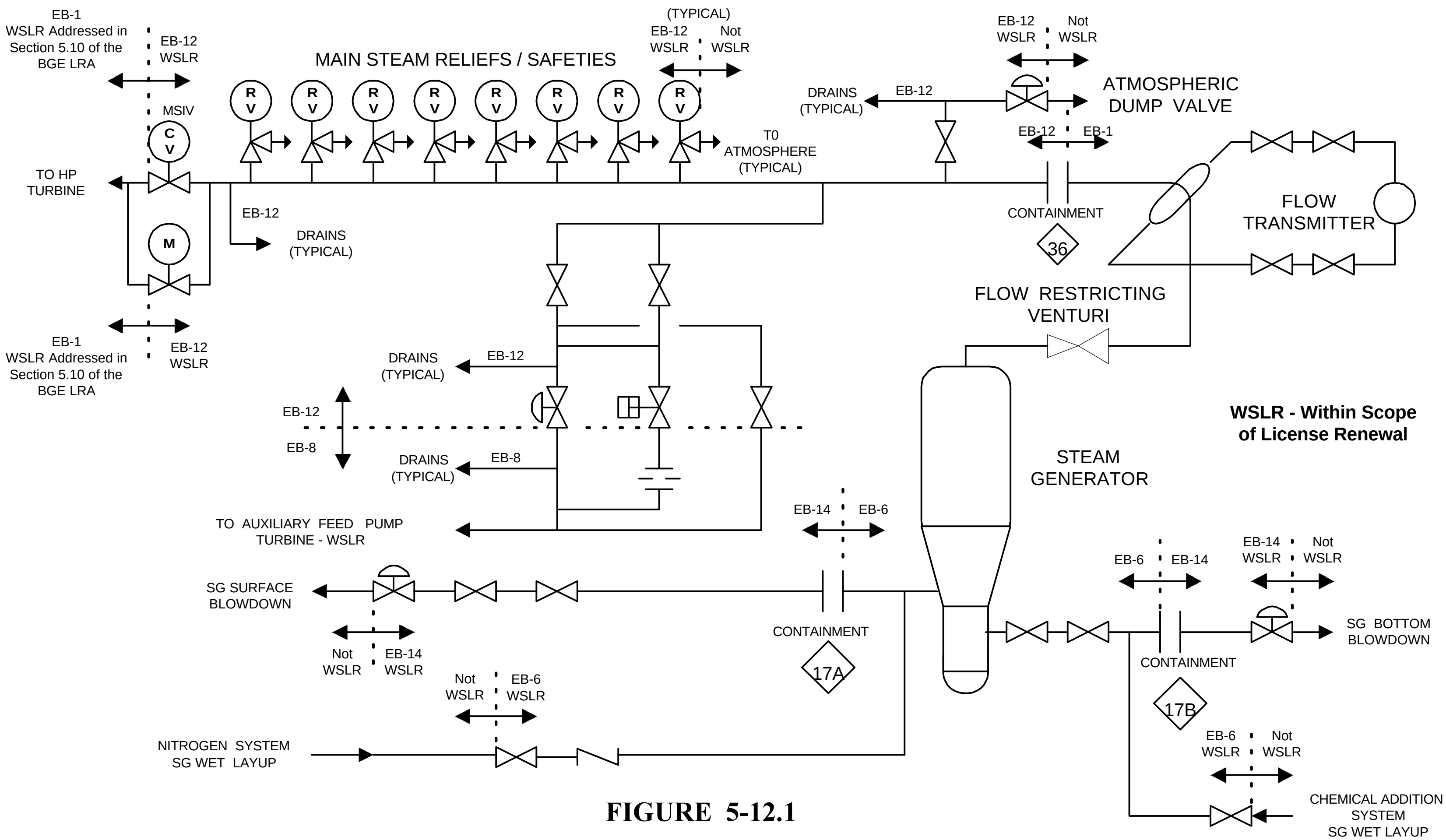

FIGURE 5-12.1

MAIN STEAM AND INTERFACING SYSTEMS
(TYPICAL FOR EACH STEAM GENERATOR)
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

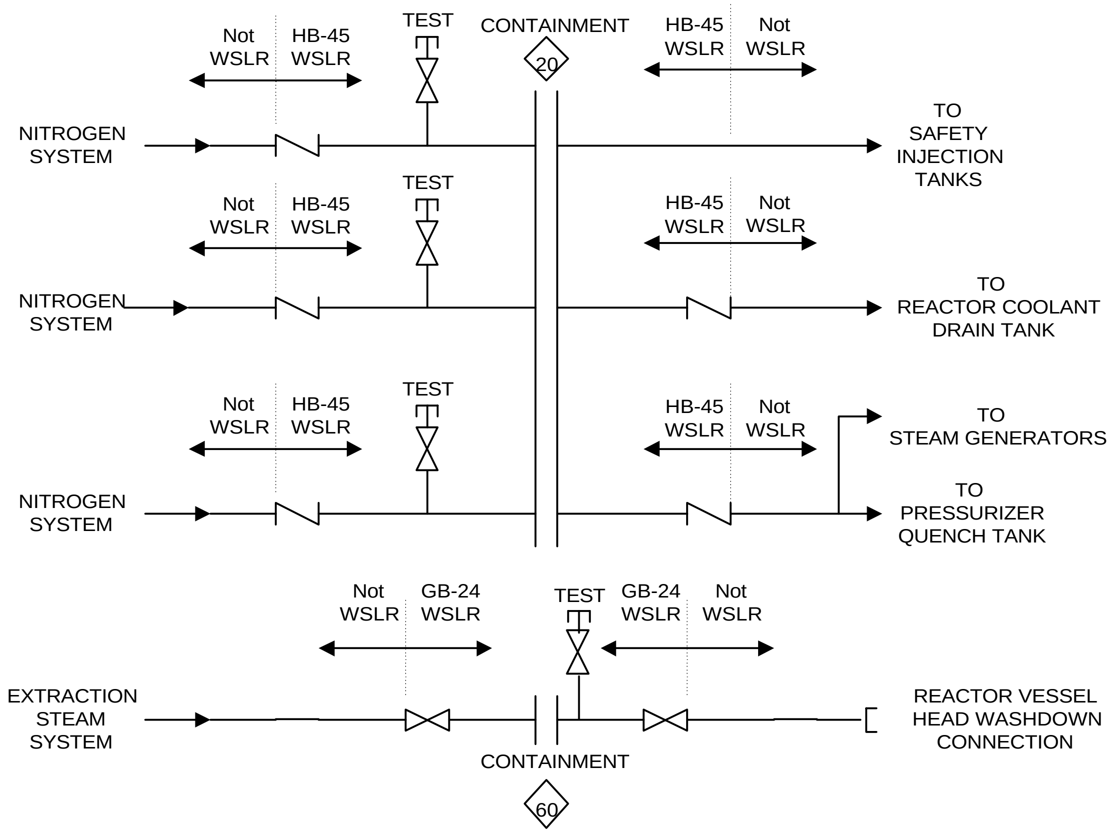

FIGURE 5.12-2

NITROGEN AND EXTRACTION STEAM PENETRATIONS
(TYPICAL FOR EACH UNIT)
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

The following intended functions of the Nitrogen 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 5, Table 1]

- To provide containment isolation; and
- To maintain the pressure boundary of the system.

The Nitrogen System piping in scope for license renewal is the nitrogen penetration piping and the nitrogen piping to the SGs via the surface blowdown piping. The penetration piping is designated as Class HB-45, is rated at 300 psig/150°F, is designed in accordance with ANSI B31.7, Class II, and is not included in the ASME Section XI Inservice Inspection Program. The nitrogen piping to the SG is designated as Class EB-6, is rated at 1000 psig/525°F, is designed in accordance with ANSI B31.1, and is Class II for the purposes of the ASME Section XI Inservice Inspection Program. See Figure 5-12.2. [References 8, 11, and 14]

5.12.1.2 Component Level Scoping

Based on the intended system functions listed above, the portions of the Main Steam System that are within the scope of license renewal, and addressed in this section of the BGE LRA, include all piping, components, component supports, instrumentation, and cables for the sections of the system from the SG outlet to MSIVs, AFW branch header to AFW stop control valves, surface and bottom blowdown to containment isolation control valves, the safety-related main steam system drains up to the flow restrictors or the MOVs, and the air supply piping to the AFW stop control valves. [Reference 3, Tables 1 and 2; References 6, 7, 9, 10, 12, and 15 through 19]

The following 34 device types in the Main Steam System were designated as within the scope of license renewal because they have at least one intended function: [Reference 1, Table 2-1]

Class EB Piping (EB)	Hand Indicator Controller (HIC)	Pressure Switch (PS)
Class HB Piping (HB)	Hand Switch (HS)	Pressure Transmitter (PT)
Accumulator (ACC)	Hand Valve (HV)	Relief Valve (RV)
Check Valve (CKV)	Heat Exchanger (HX)	Relay (RY)
Control Valve (CV)	Current/Current Device (I/I)	Solenoid Valve (SV)
Encapsulation (ENC)	Current/Pneumatic Device (I/P)	Temperature Element (TE)
Flow Control Valve (FCV)	Power Lamp Indicators (JL)	Tank (TK)
Flow Element (FE)	Level Switch (LS)	Miscellaneous Indicating Lamp (XL)
Flow Orifice (FO)	Motor-Operated Valve (MOV)	Position Indicating Lamp (ZL)
Flow Transmitter (FT)	Pressure Control Valve (PCV)	Position Switch (ZS)
Fuse (FU)	Pressure Indicator (PI)	Pressure Indicator Control (PIC)
Hand Controller (HC)		

Five device types in the Main Steam System are common to many other plant systems and have been included in the Instrument Line Commodity Evaluation in Section 6.4 of the BGE LRA. These device types are: [Reference 1, Table 3-2]

- Flow Transmitters;
- Level Switches;
- Pressure Indicators;
- Pressure Switches; and
- Pressure Transmitters.

One additional device type, hand valves, has also been evaluated in the BGE LRA Section 6.4 for those hand valves that have a specific function associated with an instrument.

The portions of the Extraction Steam System within the scope of license renewal consist of piping, component supports, and hand valves associated with the extraction steam containment penetrations and two 1E fuses and their associated cables, panels, and supports. [Reference 1, Table 2-1; Reference 4, Tables 1 and 2; Reference 12]

The following three device types in the Extraction Steam System were determined to be within the scope of license renewal because they have at least one intended function: [Reference 1, Table 2-1]

Class GB Piping

Fuse

Hand Valve

There are no Extraction Steam System device types that are included in separate commodity AMR reports.

The portions of the Nitrogen System within the scope of license renewal consist of piping, component supports, and check and hand valves associated with SG blowdown and containment penetrations 20A, 20B, and 20C. [Reference 1, Table 2-1; Reference 5, Tables 1 and 2; Reference 14]

The following four device types in the Nitrogen System were designated as within the scope of license renewal because they have at least one intended function: [Reference 1, Table 2-1]

Class HB Piping

Class EB Piping

Check Valve

Hand Valve

There are no Nitrogen System device types that are included in separate commodity AMR reports.

For all systems addressed in this section of the BGE LRA, applicable component supports, cables, and electrical components are discussed in the Commodity Evaluations for those commodities, i.e., Sections 3.1, 6.1, and 6.2 of the BGE LRA for Component Supports, Cables, and Electrical Panels, respectively.

5.12.1.3 Components Subject to AMR

This section describes the components within the Main Steam, Extraction Steam, and Nitrogen Systems that are subject to an AMR. It begins with a listing of passive intended functions and then dispositions the component 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 Main Steam System functions were determined to be passive. [Reference 1, Table 3-1]

- Maintain the pressure boundary of the system (liquid and/or gas);
- Maintain electrical continuity and/or provide protection of the electrical system; and

- Restrict flow to a specified value in support of a design basis event response.

For the second of these functions, only the system electrical cables perform a passive function. All other electrical system components perform an active function only. System cables are evaluated in Section 6.1 of the BGE LRA.

The following Extraction Steam System functions were determined to be passive: [Reference 1, Table 3-1]

- Provide containment isolation; and
- Maintain electrical continuity and/or provide protection of the electrical system.

As for main steam above, only electrical cables perform a passive electrical function and they are also addressed in Section 6.1 of the BGE LRA.

The following Nitrogen System functions were determined to be passive: [Reference 1, Table 3-1]

- Provide containment isolation; and
- Maintain the pressure boundary of the system (liquid and/or gas).

Component Types Subject to AMR

Of the 34 device types in the Main Steam System that are within the scope of license renewal:

- 11 device types have only active functions -- fuses, hand controllers, hand indicator controllers, hand switches, current/current devices, power lamp indicators, pressure indicator controls, relays, miscellaneous indicating lamps, position switch indicating lamps, and position switches; [Reference 1, Table 3-2]
- 5 device types are subject to (or partially subject to) the MSIV-13 Refurbishment Program; therefore, these specific devices are not evaluated for plausible age-related degradation mechanisms (ARDMs). These devices are: one of the two AMR report accumulator groups, one of the six AMR report check valve groups, one of the eight AMR report control valve groups; all flow control valves; and one of the fourteen AMR report hand valve groups. [Reference 1, Attachment 1; Reference 20]
- 5 device types are evaluated in the Instrument Line Commodity Evaluation section of the BGE LRA. Flow transmitters, level switches, pressure indicators, pressure switches, and pressure transmitters are the device types included in these other evaluations. Hand valves within the scope of license renewal associated with instruments, not evaluated in this report, are evaluated in the same BGE LRA section; and [Reference 1, Table 3-2]
- 1 device type, solenoid valves is partially evaluated in the Environmentally Qualified Equipment Commodity Evaluation (Section 6.3 of the BGE LRA). This applies to one of the two AMR report solenoid valve groups. There were other system solenoid valves that were dispositioned in the system pre-evaluation as being short-lived environmentally qualified devices. As such, they are included in a replacement program for short-lived environmentally qualified devices and not subject to AMR. [Reference 1, Attachment 3s]

The 18 device types listed in Table 5.12-1 are subject to AMR and included in this report. [Reference 1, Table 3-2]

TABLE 5.12-1

MAIN STEAM SYSTEM DEVICE TYPES REQUIRING AMR

Class EB Piping (EB)	Flow Control Valves (FCV)	Motor Operated Valves (MOV)
Class HB Piping (HB)	Flow Elements (FE)	Relief Valves (RV)
Accumulators (ACC)	Flow Orifices (FO)	Pressure Control Valves (PCV)
Check Valves (CKV)	Hand Valves (HV)	Solenoid Valves (SV)
Control Valves (CV)	Heat Exchangers (HX)	Temperature Elements (TE)
Encapsulation (ENC)	Current/Pneumatic Devices (I/P)	Tanks (TK)

The MSIV-13 Refurbishment Program [Reference 20] is a PM Program through which the MSIV actuators and their associated subcomponents are scheduled to be removed from the valve every four years for shipment to the manufacturer (Edwards) to be inspected and rebuilt as necessary. The current practice is to perform this task every two years. Because of the frequency and scope of this activity, these actuator subcomponents are not evaluated for plausible ARDMs in accordance with Section 6.1.2 of the IPA Methodology. This program, therefore, provides for the aging management of the actuators and their associated subcomponents.

Of the three device types in the Extraction Steam System that are within the scope of license renewal, the fuses do not support a passive function, so the two device types listed in Table 5.12-2 are included in this AMR. [Reference 1, Table 3-3]

TABLE 5.12-2

EXTRACTION STEAM SYSTEM DEVICE TYPES REQUIRING AMR

Class GB Piping (GB)	Hand Valves (HV)

All four of the device types in the Nitrogen System that are within the scope of license renewal are included in this AMR. They are listed in Table 5.12-3. [Reference 1, Table 3-4]

TABLE 5.12-3

NITROGEN SYSTEM DEVICE TYPES REQUIRING AMR

Class EB Piping (EB)	Check Valves (CKV)
Class HB Piping (HB)	Hand Valves (HV)

In addition to these device types, there are device types from three other systems that have been included in the Main Steam System AMR report, as discussed earlier in this report. These are the encapsulations for the Feedwater and Chemical and Volume Control Systems, per the Auxiliary Building AMR report [Reference 21], and hand valves from the Chemical Addition System [Reference 1]. The latter were not able to be covered elsewhere and interface with the SG blowdown piping, so they have been included in this section of the BGE LRA.

5.12.2 Aging Management

A list of potential ARDMs for the Main Steam, Extraction Steam, and Nitrogen System device types presented in Tables 5.12-1 through 5.12-3 is given in Table 5.12-4. Once the potential ARDMs are identified, they are evaluated for each of the device types to which they apply. Based on the evaluation of the device types' operating environment and design, a number of these potential ARDMs are determined to be non-plausible and will not require further evaluation. These mechanisms are identified by an (×) in the "Not Plausible for System" column of Table 5.12-4. The plausible ARDMs are identified in the table by a check mark (✓) in the appropriate device type column. For efficiency in presenting the results of these evaluations in this report, device type/ARDM combinations were grouped together where there are similar characteristics and the discussion is applicable to all equipment types within that group. Exceptions are noted where appropriate. Five groups have been selected for the Main Steam, Extraction Steam, and Nitrogen Systems. Table 5.12-4 identifies the group in which each device type/ARDM combination belongs and defines the group scope. [Reference 1, Table 4-1, Table 4-2] Flow elements are not included in the table because they are covered by the evaluations for main steam piping. [Reference 1, Tables 4-1 and 4-2, 083-FE-01 Attachment 3]

TABLE 5.12-4

POTENTIAL AND PLAUSIBLE ARDMs FOR MAIN STEAM, EXTRACTION STEAM, AND NITROGEN

POTENTIAL ARDMs	MAIN STEAM, EXTRACTION STEAM, AND NITROGEN DEVICE TYPES						MAIN STEAM DEVICE TYPES												NOT PLAUSIBLE
	-EB	-GB	-HB	CKV	CV	HV	ACC	ENC[1]	FO	HX	I/P	MOV	FCV[2]	PCV	RV	SV	TE	TK	
Cavitation Erosion	✓(2)																		
Corrosion Fatigue																			×
Crevice Corrosion	✓(1)			✓(1)	✓(1)	✓(1)			✓(1)	✓(1)		✓(1)					✓(1)	✓(1)	
Dynamic Loading																			×
Electrical Stressors																			×
Erosion Corrosion	✓(2)			✓(2)	✓(2)	✓(2)			✓(2)	✓(2)		✓(2)							
Fatigue																			×
Fouling																			×
Galvanic Corrosion																			×
General Corrosion	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)		✓(1)					✓(1)	✓(1)	
Hydrogen Damage																			×
Intergranular Attack																			×
MIC																			×
Particle Wear Erosion																			×
Pitting	✓(1)			✓(1)	✓(1)	✓(1)			✓(1)	✓(1)		✓(1)					✓(1)	✓(1)	
Radiation Damage																			×
Rubber Degradation																			×

TABLE 5.12-4

POTENTIAL AND PLAUSIBLE ARDMS FOR MAIN STEAM, EXTRACTION STEAM, AND NITROGEN

POTENTIAL ARDMS	MAIN STEAM, EXTRACTION STEAM, AND NITROGEN DEVICE TYPES						MAIN STEAM DEVICE TYPES												NOT PLAUSIBLE
	-EB	-GB	-HB	CKV	CV	HV	ACC	ENC[1]	FO	HX	I/P	MOV	FCV[2]	PCV	RV	SV	TE	TK	
Saltwater Attack																			×
Selective Leaching										✓(3)									
Stress Corrosion Cracking																			×
Stress Relaxation																			×
Thermal Damage																			×
Thermal Embrittlement																			×
Wear					✓(4)														

✓ - indicates plausible ARDM determination
× - indicates non-plausible ARDM determination
(#) - indicates the group in which this SC/ARDM combination is evaluated
Note 1 - Encapsulations evaluated are from the Main Steam, Main Feedwater, and Chemical and Volume Control Systems (see page 5.12-14).
Note 2 - Flow control valves are not evaluated for plausible ARDMs, all flow control valves are in the MSIV-13 Refurbishment Program.
MIC = Microbiologically-Induced Corrosion

Group 1 covers crevice corrosion, general corrosion, and pitting for all device types.

Group 2 includes erosion corrosion and cavitation erosion of piping and erosion corrosion of check valves, control valves, flow orifices, hand valves, heat exchangers, and MOVs.

Group 3 covers the selective leaching of the SG blowdown radiation monitor cooler.

Group 4 covers the wear within control valves.

APPENDIX A - TECHNICAL INFORMATION
5.12 - MAIN STEAM, STEAM GENERATOR BLOWDOWN, EXTRACTION STEAM, AND NITROGEN AND HYDROGEN SYSTEMS

The following is a discussion of the aging management demonstration process for each group identified in Table 5.12-4. It is presented by group and includes discussion sections on materials and environment, aging mechanism effects, methods to manage aging, aging management program(s), and aging management demonstration.

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

All of the applicable piping in the Main Steam, Extraction Steam, and Nitrogen Systems is seamless carbon steel. Piping joints are butt-welded for large bore piping (main steam lines from the SGs to the MSIVs and the AFW pump turbine supply piping) and socket-welded for small bore piping (all steam drain piping, SG blowdown piping, nitrogen piping, extraction steam piping, and instrument air piping within the scope of license renewal). [Reference 1, Attachment 3s for Pipe; References 8, 11, and 13]

All other device types or device type subcomponents that are subject to all three ARDMs are also carbon or alloy steel. The following other device types or device type subcomponents are subject to crevice corrosion and pitting only:

- The Type 316 stainless steel Main Steam System flow orifices;
- The stellite or stainless steel A351 CF-8M in some Main Steam System check valve seats/discs (main steam to AFW pumps);
- The Type 316 stainless steel in the bodies/bonnets and/or stems/seats/plugs in some Main Steam System control valves (steam atmospheric dump valves and SG blowdown valves);
- The stellite or stainless steel A351 CF-8M internals of some Main Steam System, Extraction Steam System, and Nitrogen System hand valves (SG layup interface valves via bottom blowdown lines; extraction steam containment isolation, reactor head washdown, and test connection valves; SG nitrogen inlet valves; and main steam drain valves);
- The stainless steel A182 F316, A351 CF-8M, Type 316 or Type 630 body/bonnet/stem in some Main Steam System hand valves (SG blowdown valves); and
- The stellite, Hastelloy X, or A567 disc/seat in some Main Steam System MOVs (main steam drain valves). [Reference 1, Attachment 3s for Element, Check Valve, Control Valve, Motor-Operated Valve, and Pipe]

The internal environment for the Main Steam System and its components during power generation is saturated steam at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. [Reference 2, Chapter 10.1; Reference 8] During normal operation, between test actuations of the AFW System, the main steam lines to the AFW pumps will experience significant condensation of residual steam from those test actuations such that reactuation of the system will result in two-phase flow through the main steam drains from the system which have been redesigned post-Three Mile Island to accommodate this.

The portion of the Extraction Steam System that is within the scope of license renewal is the piping that penetrates containment to provide a reactor head washdown function. This function is not used; therefore, this piping is usually empty except when subjected to the presence of testing air. [Reference 1, Attachment 3s for 046-GB-01 and 046-HV-01; Reference 4, Table 2]

The Nitrogen System has design conditions of 300 psig/150°F, although it can also contain testing air. [Reference 1, Attachment 3s for 074-HB-01 and 074-HV-01; Reference 5, Table 2]

The internal environment for the SG blowdown piping is one of a saturated mixture of steam and feedwater that is subcooled to water via the blowdown heat exchangers. The blowdown heat exchangers within scope contain SG blowdown on the shell side and SRW or CCW on the tube side for the non-regenerative SG blowdown heat exchanger and the SG blowdown radiation monitor cooler, respectively.

The internal environment for the instrument air piping is air that has been dried to a dewpoint of -40°F with design operating conditions of 125 psig/100°F. [Reference 1, Attachment 6s; References 2, 9, 10, and 11].

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

Carbon steel is susceptible to general and localized (crevice and pitting) corrosion mechanisms, whereas stainless steel is generally considered to be susceptible only to localized corrosion. Carbon steel piping containing steam or steam/water environments is particularly susceptible to general corrosion over a period of time, particularly when the system is subjected to intermittent periods of operation and shutdown. The rate of general corrosion of carbon steel is reduced after the initial buildup of the magnetite protective corrosion film. Exposure to higher oxygen concentrations during shutdown results in the removal or partial removal and then recreation of this film. The effect of this process is component wall thinning over a relatively large area, which could result in pressure boundary failure if extensive. [Reference 1, Attachment 6s, 7s, and 8]

In the saturated steam environment of the Main Steam System, the internal environment (high velocity steam during operating/testing and condensation/dampness during standby) perpetuate general corrosion of the piping and carbon steel components. The periodic exposure to condensation may result in uniform thinning of the pressure boundary material. The areas of primary concern for general corrosion are piping low spots. [Reference 1, Attachment 6s, 7s, and 8]

The extraction steam piping within the scope of license renewal is piping that penetrates containment to provide a containment washdown function. This function is no longer used so that the piping is normally empty and occasionally subject to the presence of testing air. Since the air can contain moisture, the piping and components are subject to general corrosion. [Reference 1, Attachment 3s for 046-GB-01 and 046-HV-01; Reference 4, Table 2]

The SG blowdown piping and components are subject to general corrosion due to the exposure of the piping to a corrosive medium (i.e., a high velocity, two-phase mixture of steam and water) during normal operation and, to a lesser extent, during shutdown periods. The fact that the system is operated in an intermittent manner exposes it to higher general corrosion rates than the other piping within the scope of this section of the BGE LRA. For this reason, the system piping is being replaced with piping made from a more corrosion-resistant material as it is warranted. [Reference 1, Attachment 6s, 7s, and 8]

For the Nitrogen System piping and components, the periodic exposure of this piping to testing air may result in general corrosion. [Reference 1, Attachment 6s, 7s, and 8]

For the Instrument Air System piping and instrument air containing components (e.g., the accumulators) included in this scope, general corrosion is considered to be plausible; however, it is also considered to be unlikely since the dewpoint of the air is controlled to minus 40°F. At this value, there is insufficient moisture to cause significant occurrences of this mechanism. [Reference 1, Attachment 6s, 7s, and 8]

For the alloy steel temperature element thermowells, the corrosive environment during shutdown and, to a lesser extent, the normal operation environment, can cause general corrosion, albeit at low rates, due to the chromium content of the steel. During shutdown, in particular, the higher oxygen concentrations in the system present the opportunity for general corrosion. [Reference 1, Attachment 7 for Element, Attachment 6 for 083-TE-01]

The Main Steam, Main Feedwater, and Chemical and Volume Control Systems' encapsulations are also susceptible to general corrosion during shutdown conditions, when the carbon steel, of which they are made, could be exposed to potentially moist air if their protective coatings are damaged. [Reference 1, Attachment 7 and Attachment 6s for Encapsulation]

Crevice corrosion and pitting can occur in areas of piping that are not exposed to the general flow stream, such as areas with a lack of complete penetration of butt welds, clearances at socket weld fit-ups, holes, gasket surfaces, lap joints, crevices under bolt heads, integral welding backing rings, etc. The crevice must be wide enough to permit liquid entry and narrow enough to maintain static conditions, typically a few thousandths of an inch or less. These areas may comprise small, localized volumes of stagnant solution for which fluid chemistry may deviate from bulk system chemistry. Higher concentrations of impurities may exist in these crevices due to out-of-specification system chemistry during shutdown conditions and due to stagnant flow conditions in the crevice. In an oxidizing environment, a crevice can set up a differential aeration cell to concentrate an acid solution within the crevice. Even in a reducing environment, alternate wetting and drying can concentrate aggressive ionic species to cause pitting and crevice corrosion. The resulting degradation is highly localized pits or cracks. Controls over piping fit-up and welding quality during construction limit the locations of potential crevices in the large bore piping. Most susceptible locations for crevices are the small bore piping (including drains and instrument taps from the large bore piping) where socket welding creates potential crevices due to the design of the joint. The effects of crevice corrosion and pitting are expected to be more severe in areas of the main steam system (e.g., SG blowdown) where there exists a two-phase fluid. [Reference 1, Attachment 6s, 7s, and 8]

For the alloy steel temperature element thermowell assemblies, areas not exposed to the general flowstream that could be subject to crevice corrosion and pitting are the half couplings that attach them to the main piping. In the heat exchangers, areas such as locations where internal parts interface with the shell are susceptible to these ARDMs. In the Main Steam System flow orifices, the accumulation of condensation can occur at the orifice junctions with the piping and flanges making them susceptible to crevice corrosion and pitting at those locations. In any of the system valves, crevice corrosion in the gaps between valve subcomponents is possible (including those valves with non-carbon steel subcomponents); however, a lack of dissolved oxygen and chloride ions in solution and, in some cases, a protective oxide passive layer will delay the corrosive process. Valves can also have stagnant condensation conditions that are conducive to pitting; however, the rate of pitting is proportional to the concentration of chlorides present. [Reference 1, Attachment 6s and 7s for Element]

For the nitrogen piping that is within scope, the crevice corrosion and pitting ARDMs are not considered to be plausible due to the normal no-flow condition of the piping at the containment penetrations and the normal presence of nitrogen. Local stagnant flow conditions and/or the presence of moisture are required for these mechanisms. The same is true for the extraction steam piping that is within scope. This portion of the system is no longer used and does not see flow conditions. [Reference 1, Attachment 6s and 7s]

For the instrument air system piping and components within scope, these ARDMs are not plausible because of the controlled system dewpoint of minus 40°F. There is insufficient moisture present for either mechanism to occur. [Reference 1, Attachment 6s, 7s, and 8]

The Main Steam System accumulators (carbon steel), pressure control valves (aluminum), current/pneumatic devices (aluminum and brass), some relief valves (stainless steel), and the solenoid valves (brass) are also subjected to the dry, instrument air environment such that these ARDMs are not plausible for them either, particularly the aluminum, brass, and stainless steel devices. [Reference 1, Attachment 6s and 7s]

The encapsulations are not subject to these ARDMs since the normal operating temperatures of these devices (550°F for the Chemical and Volume Control System, 435°F for feedwater, and 520°F for main steam) are such that condensation due to local environmental conditions is not possible and the encapsulations are insulated. Even if condensation could develop during shutdown, the water would quickly evaporate during startup. Since the encapsulations are insulated, the possibility for condensation on the cooler encapsulation metal due to the relative humidity and ambient temperature of the surrounding air is eliminated. [Reference 1, Attachment 6s and 7 for Encapsulation]

For the Main Steam System relief valves, the process fluid is very high quality steam due to chemistry control and maintenance. This is not a corrosive environment, particularly for the stainless steel material from which they are fabricated; therefore, pitting and crevice corrosion are not plausible. [Reference 1, Attachment 6 for 083-RV-01]

Corrosion (general, crevice, or pitting) is also not plausible for any device bolting, since it is not exposed to any process fluids. [Reference 1, Attachment 4s, 5s, and 6s]

Long-term repeated exposure to the described environments may result in localized pitting and/or general area material loss which, 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 systems included within the scope of this section of the BGE LRA. [Reference 1, Attachment 6s and 7s]

Group 1 (crevice corrosion, general corrosion, and pitting for all device 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 piping to an aggressive environment. [Reference 1, Attachment 6s and 7s]

Maintaining a main steam environment of high quality steam via the secondary chemistry control program results in limited corrosion reactions. The initial formation of the passive magnetite oxide layer also protects the pipe interior surface by minimizing the exposure of bare metal to water. [Reference 1, Attachment 6s and 7s]

Maintaining the Instrument Air System air quality at a dewpoint of minus 40°F or less, by maintaining proper dryer alignment and operation, results in limited corrosion reactions due to the lack of the moisture required to cause the reactions. The use of stainless steel and non-ferrous materials in some of the system components also prevents system corrosion. [Reference 1, Attachment 6s and 7s]

The portions of the Extraction Steam System that are within the scope of license renewal are abandoned in place because the reactor vessel head washdown function is no longer used. The containment penetration piping between the containment isolation valves is not subjected to the steam environment. The system is ambient beyond the outside isolation valve. [Reference 1, Attachment 6s and 7s]

The normal operation of the Nitrogen System is such that system corrosion is not a problem since the system normally contains dry nitrogen. The potential for corrosion is introduced only for a short duration in each refueling cycle during testing of the system when testing air is used. [Reference 1, Attachment 6s and 7s]

Discovery: The effects of corrosion on system components can be discovered and monitored through non-destructive examination techniques such as visual inspections. 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 (e.g., as part of periodic erosion corrosion inspections or normal PM). [Reference 1, Attachment 8]

Group 1 (crevice corrosion, general corrosion, and pitting for all device 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 22, Section 6.1.A] The scope of the Secondary Chemistry Program procedure, CP-217, "Specifications and Surveillance for Secondary Chemistry," [Reference 23], which controls Feedwater System chemistry, includes the SGs, condensate storage tanks, feedwater, condensate, the Main Steam System, heater drain tanks, condensate demineralizer effluent, SG blowdown ion exchanger effluent, and condensate precoat filters. [Reference 23, Section 2.C] The program is based on References 24 through 30.

The Secondary Chemistry Program controls fluid chemistry in order to minimize the concentration of corrosive impurities (chlorides, sulfates, oxygen) and optimizes fluid pH. Control of secondary fluid chemistry minimizes the corrosive environment for Main Steam System components, and limits the rate and effects of corrosion. [Reference 1, Attachment 8] The rate of corrosion is also reduced by the initial buildup of the passive magnetite oxide layer that minimizes bare metal exposure to water. [Reference 1, Attachment 6s]

Secondary chemistry parameters are measured at procedurally specified frequencies. The measured parameter values are compared against “target” values which represent a goal or predetermined warning limit. If a measured value is outside of its required range, corrective actions are taken (e.g., power reduction, plant shutdown) in accordance with CP-217. Remedial actions are specified to minimize corrosion degradation of components and to ensure that secondary system integrity is maintained. [Reference 23, Sec. 6.0 and 2.C]

In conformance with the plant Technical Specifications, the plant is expected to be operated in a manner such that the secondary coolant chemistry parameters will be maintained within those limits that result in negligible 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 Electric Power Research Institute (EPRI), Institute for Nuclear Power Operations (INPO), and the CCNPP Nuclear Steam Supply System vendor. These values ensure a timely response to chemical and radiochemical excursions with appropriate corrective actions. [Reference 23]

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

The operating experience review for the CCNPP Chemistry Program identified no site specific problems or events related to these aging mechanisms that required significant changes or adjustments to the program. It has been effective in its function of minimizing corrosion and 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 other secondary systems are also successfully controlled. CCNPP 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.

For the non-regenerative SG blowdown heat exchangers and the SG blowdown radiation monitor coolers, credit is also taken for CCNPP Technical Procedure CP-206, “Specifications and Surveillance for Component Cooling/Service Water Systems.” [Reference 31] This procedure provides for monitoring and maintaining SRW System chemistry (non-regenerative SG blowdown heat exchangers) and CCW System (SG blowdown radiation monitor coolers) chemistry to control the concentrations of oxygen, chlorides, other chemicals, and contaminants. The water is treated with hydrazine to minimize the amount of oxygen in the water which aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal piping or component degradation. [Reference 32, Attachment 8]

Calvert Cliffs procedure CP-206 describes the surveillance and specifications for monitoring the SRW System fluid. CP-206 lists the parameters to monitor, the frequency of monitoring these parameters, and the target and action levels for the SRW System fluid parameters. [Reference 31, Attachment 1]

These chemistry parameters are currently monitored on a frequency ranging from three times per week to once a month. All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter. Two of the parameters, pH and hydrazine, have action levels associated with them. For pH, the current action level is less than 9.0 or greater than 9.8, for hydrazine the current action level is less than 5 or greater than 25 parts per million (ppm). [Reference 31, Attachment 1]

Operational experience related to CP-206 has shown no problems related to the use of this procedure with respect to the CCW System. In 1996, CP-206 was revised to include dissolved iron as a chemistry parameter to act as a method for the discovery of any unusual corrosion of CCW components.

An internal BGE chemistry summary report for 1996 described the CCNPP Units 1 and 2 CCW/SRW System chemistry as excellent. Action levels for all four systems were only exceeded on eight occasions, or approximately 0.7% of the time during the year. Over 70% of the action levels entered were due to major system changes during the 1996 refueling outage. Recommendations to correct this condition have been made to determine outage evolutions that can affect the CCW/SRW chemistry and take action to prevent chemistry targets being exceeded. [Reference 33]

The SRW System usually operates within normal parameters except when the system is restarted after an outage lay-up. During an outage lay-up, the SRW System experiences some minor corrosion when the internal component surfaces are exposed to air. After the SRW System is returned to service and flow is once again established, some of this minor corrosion is removed from the pipe inner surface and released into the system where it is detected. It was discovered that suspended solids spike when one SRW header is taken out-of-service for heat exchanger cleaning and total system flow is then directed through the in-service heat exchanger. One or two days after the SRW System is aligned to normal, the suspended solids levels drop to the normal value of less than 10 parts per billion. [Reference 33]

Calvert Cliffs procedure CP-206 provides for a prompt review of SRW System chemistry parameters so that steps can be taken to return chemistry parameters to normal levels, and thus minimize the effects of crevice corrosion/pitting.

For the hand valves in the Chemical Addition System (035-HV-02), credit has been taken for CP-202, Specifications and Surveillance - Demineralized Water, Safety Related Battery Water, Well Water Systems, and Acceptance Criteria for On-Line Monitors. CP-202, has been established to:

- Minimize impurity ingress to plant systems;
- Reduce corrosion product generation, transport, and deposition;

- Improve integrity and availability of plant systems; and
- Extend component and plant life. [Reference 22, Section 6.1.A]

The Demineralized Water Chemistry Program is applicable to the Demineralized Water and Well Water Systems for use in primary, auxiliary, and secondary plant systems. It also specifies the requirements for dedicating demineralized water for the use in safety-related batteries and acceptance criteria for on-line monitors. [Reference 34, Section 2] The program is based on the following:

- CCNPP Procedure CP-410, Make-Up Demineralized Water System;
- EPRI NP-6377-SL, Volume 2, Guidelines for the Design and Operation of Make-up Water Treatment Systems, Final Report, June 1989;
- INPO 88-021, Guidelines for Chemistry of Nuclear Power Stations, Revision 1, September 1989;
- EPRI TR-105714, Primary Water Chemistry Guidelines, Revision 3, November 1995;
- Combustion Engineering Manual CENPD-28, “Combustion Engineering Chemistry Manual,” Revision 3, September 1982; and
- State Water Appropriation Permit No. CA69G010.

The Demineralized Water Chemistry Program controls fluid chemistry in order to minimize the concentration of corrosive impurities and optimizes specific conductivity. Control of fluid chemistry prevents a corrosive environment for the Chemical Addition System hand valves and limits the rate and effects of crevice corrosion, general corrosion, and pitting corrosion. [Reference 1, Attachment 8]

The demineralized water chemistry parameters are measured at procedurally-specified frequencies. The measured parameter values are compared against target values that represent a goal or predetermined warning limit. If a measured value is outside the specified range, special, and/or general corrective actions (such as resampling, increased surveillance frequency, and/or technical evaluation) are taken as prescribed by CP-202. [Reference 34, Section 6.0] The corrective actions taken will ensure that Chemical Addition System hand valves subject to crevice corrosion, general corrosion, and pitting remain capable of performing their intended functions under all CLB conditions.

The Demineralized Water Chemistry Program is subject to internal assessment activity both within the CCNPP Chemistry Section and through the site performance assessment group. The program is recognized through these assessments as maintaining highly effective secondary chemistry controls, and aggressively pursuing 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, NRC, and others.

The CP-202 program, since its inception, has essentially remained unchanged and has performed well. The changes in the limits of chemistry parameters are reflective of upgrades in the capability of measuring instruments and experience gained over the years.

Operating experience, relative to the CP-202 Program at CCNPP, has been such that no site-specific problems or events are known to have occurred that required significant changes or adjustments to the program. It has been effective in its function of preventing corrosion and corrosion-related failures and problems. [Reference 35]

The quality of the air to Instrument Air System components that are within scope is periodically verified, in accordance with Checklists IPM10000 and IPM10001, per system repetitive tasks under the Plant PM Program discussed in the following Discovery section. These checklists assure that the system is being maintained in accordance with industry standards for moisture (dewpoint) and particulate contamination. [Reference 1, Attachment 8]

Discovery: For non-stagnant areas where local fluid chemistry will not differ significantly from the system bulk fluid chemistry, general corrosion will result in wall thinning over a relatively large area. The wall thickness of all main steam piping, where this applies, is monitored as part of the Erosion Corrosion Program, and is thereby managed for the effects of general corrosion. Erosion corrosion is discussed in detail later in the section on Group 3. The effects of general corrosion in the main steam and blowdown valves can be evaluated through the erosion corrosion inspections of a representative sample of components to determine the extent of corrosion. [Reference 1]

For Main Steam or Extraction Steam components in stagnant or crevice areas, localized corrosion, i.e., crevice corrosion and pitting, can be readily detected through non-destructive examination techniques. This type of corrosion occurs over a long period of time prior to any threat of minimum wall thickness reaching an unacceptable value. As such, an inspection program to identify occurrence of localized corrosion is an effective means of determining if corrective actions are required for managing this aging mechanism. [Reference 1]

All components susceptible to general, crevice, and pitting corrosion within the scope of this section of the BGE LRA, with the exception of the MSIVs, will be included in a 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.

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.

Main steam isolation valves are periodically inspected as part of the plant's PM Program. There are specific PM activities (Repetitive Tasks 10832098 and 99 and 20832089 and 90, for the Units 1 and 2 MSIVs, respectively) for each of the MSIVs that require the periodic disassembly and inspection of these valves, per the requirements of procedure MSIV-04. These regularly scheduled inspections would result in the detection of the effects of degradation such that corrective action would be taken. [Reference 1, Attachment 8; References 36 and 37]

The PM 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 PM activities for nuclear power plant structures and equipment within the plant. [Reference 38] It is based on INPO documents. [References 39 through 41]

The PM Program undergoes periodic evaluation by the NRC during Plant Performance Reviews which serve as inputs to the NRC Systematic Assessment of Licensee Performance and senior management meeting reviews. The plant Maintenance Program itself has numerous levels of management review, all the way down to the specific implementation procedures. Preventive Maintenance Program evaluation and any resultant upgrades are primarily based on equipment trends. [Reference 42] These controls provide reasonable assurance that the PM Program will continue to be an effective method of managing the effects of general corrosion, erosion corrosion, and wear, as applicable, for the MSIVs and Instrument Air System components included in the scope of this section of the BGE LRA.

Group 1 (crevice corrosion, general corrosion, and pitting for all device 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 Feedwater System components:

- The Main Steam, Extraction Steam, and Nitrogen System components, as well as the other Feedwater, Chemical and Volume Control System, and Chemical Addition System components included in the scope of this section of the BGE LRA, provide a system pressure-retaining boundary function 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 (and SRW System Program for the non-regenerative SG blowdown heat exchangers and radiation monitor coolers, as well as the Demineralized Water System Program for the Chemical Addition System hand valves) 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.

- Wall thickness inspections for erosion corrosion, discussed in the erosion corrosion section of this report, will monitor general and localized corrosion mechanisms in areas subject to high flow for the applicable piping and components. Predictions of wall thickness based on erosion corrosion may not be conservative for localized corrosion in stagnant and low flow areas and should not be relied upon solely for detection.
- Elements of the PM Program provide for the periodic inspection and maintenance of the MSIVs and for the maintenance of the applicable portions of the Instrument Air System in accordance with industry standards.
- To provide additional assurance that localized corrosion is not significant in stagnant and low-flow areas, the in-scope components will be included in an ARDI Program. Inspections will be performed and appropriate corrective action will be taken if significant corrosion is discovered.

There is, therefore, reasonable assurance that the effects of crevice corrosion, general corrosion, and pitting of Main Steam, Extraction Steam, and Nitrogen System components, as well as the other Feedwater, Chemical and Volume Control System, and Chemical Addition System components, within the scope of this section of the BGE LRA, 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 (erosion corrosion and cavitation erosion of piping and erosion corrosion of check valves, control valves, flow orifices, hand valves, heat exchangers, and MOVs) - Materials and Environment:

The components and materials affected by erosion corrosion are: the main steam piping; the main steam drains piping; the SG blowdown piping; the non-regenerative SG Blowdown heat exchanger tubesheets and tubesheet nozzle necks, heads, and flanges; the inlet and safe ends of the SG flow venturis; main steam drain check valves; main steam to AFW pump check valves; main steam to AFW pump isolation control valves; hand valves for the main steam atmospheric dump valves and the steam supply to the AFW pumps; and the main steam drain MOVs. All of these components are fabricated of carbon steel. [Reference 1, Attachment 4s, 6s, and 7s]

In addition to these components, the following additional components are affected: the Main Steam System atmospheric dump valves, which are carbon steel with stainless steel stems, seats, and plugs; and the MSIVs, which are carbon steel with stellited seating surfaces. These valves and the indicated non-carbon steel subcomponents are potentially affected by erosion corrosion. [Reference 1, Attachment 4s, 6s, and 7s]

The SG blowdown piping, in addition to being affected by erosion corrosion, is also affected by cavitation erosion. The SG blowdown valves have been evaluated for this mechanism with the erosion corrosion mechanism. [Reference 1, Attachment 6s, 7s, and 8]

The environment discussion for Group 1 also applies to the systems/components included for this group.

Group 2 (erosion corrosion and cavitation erosion of piping and erosion corrosion of check valves, control valves, flow orifices, hand valves, heat exchangers, and MOVs) - Aging Mechanism Effects

Erosion corrosion is an increase in the rate of attack of a metal because of the relative movement between a corrosive fluid and a metal surface. Mechanical wear or abrasion can result. The fluid movement or turbulence accelerates corrosion by continually eroding the protective surface film as it forms, resulting in chemical attack or dissolution of the underlying metal. The occurrence of erosion corrosion is highly dependent on construction material and fluid flow conditions. Carbon and low alloy steels are particularly susceptible when subjected to a high-velocity, turbulent flow (single or two-phase) of water with low oxygen content and a pH less than 9.3.

Erosion corrosion can result in material loss in areas that are subject to disturbances in the flowstream, such as those caused by bends, tees, valves, thermowells, pumps, and localized internal surface irregularities. This process can result in significant wall thickness reduction in a period of time much shorter than the period of extended operation, especially for carbon steel. Erosion corrosion can reduce the component wall thickness and result in grooves, gullies, waves, holes, and valleys on the metal surface. [Reference 1, Attachment 6s and 7s] If left unmanaged, it could result in the loss of the pressure boundary function under CLB design loading conditions.

Cavitation erosion is similar to erosion corrosion; however, the attack on the protective passive layer is caused by the formation and collapse of vapor bubbles located in close proximity to the material surface. This mechanism requires fluid flow and pressure variations that temporarily drop the liquid pressure below its vapor pressure. [Reference 1, Attachment 6s and 7s]

Group 2 (erosion corrosion and cavitation erosion of piping and erosion corrosion of check valves, control valves, flow orifices, hand valves, heat exchangers, and MOVs) - Methods to Manage Aging

Mitigation: The effects of erosion corrosion can be mitigated by selecting erosion corrosion resistant materials and 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 oxygen levels are so low that there is insufficient oxygen present to reform the passive magnetite layer once it is stripped away. The original piping design took materials of construction and erosion and corrosion allowances into consideration. 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 1, Attachment 7s and 8]

The effects of cavitation erosion can be managed through material selection and inspections of the piping/components. [Reference 1, Attachment 7s and 8]

Discovery: The effects of erosion corrosion or cavitation erosion 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 1, Attachment 8; Reference 35]

Group 2 (erosion corrosion and cavitation erosion of piping and erosion corrosion of check valves, control valves, flow orifices, hand valves, heat exchangers, and MOVs) - Aging Management Programs

Mitigation: The CCNPP Secondary Chemistry Program, discussed in Group 1 for general and local corrosion, specifically considers erosion corrosion. The limits for impurity concentration and fluid pH are set to minimize erosion corrosion while also minimizing other forms of corrosion in the secondary system. This program is credited for the mitigation of all components subject to erosion corrosion included under this group discussion.

The SRW System Chemistry Program, discussed under Group 1, also provides mitigation for the SRW side of the non-regenerative SG blowdown heat exchangers.

Discovery: The CCNPP Erosion Corrosion Program was implemented formally in 1984 after the failure of extraction steam piping at CCNPP. The 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 main steam-related piping addressed in the system AMR (main steam headers, main steam to the AFW pumps, main steam drains, and SG blowdown) is included in this program. The program is based on EPRI and NRC documents, References 43 through 45. [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 primarily based on the results of the previous inspections and the erosion trends that are discovered as the data collected grows. The CHECKWORK software developed by EPRI is used as a backup for identifying inspection points and supplements CCNPP site-specific information where appropriate. 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 repair or replace components. [Reference 35]

Class II piping has predetermined minimum wall thickness values that are based on the allowable stresses as addressed in the original design code ANSI B31.7. ANSI 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. [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 or 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 and the Corrective Action Program. [Reference 35]

Baltimore Gas and Electric Company has been proactive in the management of erosion corrosion at CCNPP. The Erosion Corrosion Program was started formally in 1984 after the failure of non-safety related extraction steam piping, prior to the 1986 feedwater break incident at Surry Power Station. Prior to initiation of the formal program, periodic ultrasonic testing 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 CHECKWORK Users group, which is an industry organization that shares industry information and provides training on methods and technology. CHECKWORK software provides a systematic method for identifying locations that theoretically are 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 Program personnel. The inspections are followed by a formal report of the results. In the past, the NRC has made recommendations that CCNPP has incorporated to improve the program. [Reference 46]

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 47] Internal reviews have been performed by the CCNPP 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 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 that were documented in Licensee Event Reports 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.

The ARDI Program, discussed under Group 1, is also credited for all of the components affected by erosion corrosion (and the SG blowdown piping/valves affected by cavitation erosion), with the exception of the piping included under the Erosion Corrosion Program and the main steam MSIVs. [Reference 1, Attachment 8]

The MSIV specific repetitive tasks of the PM Program, also discussed under Group 1, are credited for the discovery of the effects of erosion corrosion for these valves. [References 36 and 37]

Group 2 (erosion corrosion and cavitation erosion of piping and erosion corrosion of check valves, control valves, flow orifices, hand valves, heat exchangers, and MOVs) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to erosion corrosion of the applicable Main Steam System piping and components:

- The Main Steam System components and related 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 (as well as cavitation erosion for the SG blowdown 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 erosion corrosion (via both the Secondary Chemistry Program for all components and the SRW System Chemistry Program for the SRW side of the non-regenerative SG blowdown heat exchangers). 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 specific Main Steam System piping through measurement of pipe wall thickness on a frequency dependent upon the 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 MSIVs are performed in accordance with Repetitive Tasks 10832098, 10832099, 20832089, and 20832090 of the PM Program, and procedure MSIV-04 [Reference 37] to monitor valve degradation.
- To ensure that all components not covered by the Erosion Corrosion Program or the PM Program 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.

There is, therefore, reasonable assurance that the effects of erosion corrosion and cavitation erosion will be managed to maintain the Main Steam System components' pressure boundary integrity under all design loadings, required by the CLB, during the period of extended operation.

Group 3 (selective leaching of the SG blowdown radiation monitor cooler) - Materials and Environment

The only component affected by this ARDM is the SG Blowdown radiation monitor cooler, which has:

- A yellow brass, ASTM B135, shell;
- A red brass, ASTM B36, tube sheet and baffles;
- A forged brass, ASTM B283, hub; and

- A gray cast iron, ASTM A278, bonnet.

The shell, hub, and bonnet of the cooler are susceptible to selective leaching. Red brass is only 15% zinc and is significantly less susceptible than the other materials. The shell side environment is SG blowdown, which could be a two-phase mixture of steam and water upon entry into the cooler. The tube side environment is CCW System water. [Reference 48]

Group 3 (selective leaching of the SG blowdown radiation monitor cooler) - Aging Mechanism Effects:

Selective leaching is the removal of one element from a solid alloy by corrosion processes. The environmental conditions that are normally required for this ARDM are high temperature, stagnant aqueous solution, and porous inorganic scale. Acidic solutions and oxygen aggravate the mechanism. With this mechanism, the overall dimensions of the component do not change. The voids left by the leaching of the vulnerable element, which are often obstructed from view by debris or surface deposits, can lead to sudden unexpected failure due to the poor strength of the remaining material.

The most common example of selective leaching is "dezincification," or the removal of zinc, from brass alloys. There are the "layer-type" and "plug-type" submechanisms of dezincification. The layer-type mechanism is a uniform attack, whereas the plug-type is extremely localized and leads to pitting.

Cast iron is also susceptible to a selective leaching process called "graphitic corrosion" by which the iron or steel matrix is stripped from the graphite network leaving a matrix of graphite, voids and rust. [Reference 1, Attachment 7 for Heat Exchangers; Reference 48]

Group 3 (selective leaching of the SG blowdown radiation monitor cooler) - Methods to Manage Aging:

Mitigation: Since oxygen content, pH, and the production of scale are significant contributors to the selective leaching process, it can be mitigated for the materials in this cooler through chemistry control of the fluids flowing through it. All three of these fluid properties can be managed through chemical addition to the fluid systems.

Discovery: The presence of damage from selective leaching can be detected via visual inspection of the potentially affected subcomponents. The removal of any surface scale on the material will reveal the effects of the selective leaching process if it is occurring. [Reference 48]

Group 3 (selective leaching of the SG blowdown radiation monitor cooler) - Aging Management Programs:

Mitigation: The selective leaching process will be effectively mitigated by the Component Cooling/SRW System Chemistry Program (CP-206) and the Secondary Chemistry Program (CP-217) that have been previously described under the Group 1 Aging Management Program discussions.

Discovery: These coolers will be added to the ARDI Program for the performance of visual inspections. This program is also described under the Group 1 Aging Management Program discussions.

Group 3 (selective leaching of the SG blowdown radiation monitor cooler) - Demonstration of Aging Management:

Based on the factors presented above, the following conclusions can be reached with respect to the selective leaching of SG blowdown radiation monitor cooler subcomponents:

- The cooler subcomponents provide a system pressure-retaining boundary for the safety-related CCW System and their integrity must be maintained under all CLB design conditions.
- Selective leaching of the cooler subcomponent surfaces is plausible for the coolers such that surface deterioration may result which, if left unmanaged, could lead to loss of the coolers' pressure-retaining integrity.
- Maintenance of CCW chemistry (CP-206) and secondary system chemistry (CP-217) provides a means of mitigation of the selecting leaching ARDM for the SG blowdown radiation monitor coolers.
- To ensure that all subcomponent surfaces of the coolers are being managed for selective leaching, they will be included in the scope of an ARDI Program. Inspections will be performed, and appropriate corrective action will be taken if significant subcomponent surface degradation is encountered.

There is, therefore, reasonable assurance that the effects of selective leaching will be managed to maintain the safety-related CCW System pressure boundary integrity within the SG blowdown radiation monitor coolers under, all design loadings required by the CLB, during the period of extended operation.

Group 4 (wear of control valves) - Materials and Environment:

The only components affected by this ARDM are the stainless steel seats and plugs of the steam atmospheric dump valves and the stellited carbon steel bodies and disc assemblies of the MSIVs. The environment for these valves is the Main Steam System, as described under Group 1 above. [Reference 1, Attachment 6s, 7s, and 8]

Group 4 (wear of control valves) - Aging Mechanism Effects:

Wear of the seating surfaces of the main steam atmospheric dump valves is plausible due to their contact under heavy load and their relative motion resulting from valve cycling. The valve stem is resistant to wear and is not subject to relative motion that would cause wear. In the MSIVs, wear may occur between the piston assembly and the body in the bore area; but, since this is not the major pressure-retaining section of the valve (i.e., not the disc and seat), this wear is insufficient to affect the pressure boundary function. Wear of the seating surfaces between the body (the seat) and disc assembly is plausible due to contact under heavy load and relative motion. The aging effect for these valves as a result of wear is the loss of the pressure-retaining capability of the mating surfaces within the valves. [Reference 1, Attachment 6s, 7s, and 8]

Group 4 (wear of control valves) - Methods to Manage Aging:

Mitigation: There is no available mitigation methodology for this mechanism. The use of stellited surfaces in the MSIVs minimizes the effects of seating surface wear. [Reference 1, Attachment 6s, 7s, and 8]

Discovery: This mechanism can be detected via the periodic inspection of the valves for degraded seating surface conditions. [Reference 1, Attachment 5s, 7s, and 8]

Group 4 (wear of control valves) - Aging Management Programs:

Mitigation: There is no mitigation program credited for this ARDM. [Reference 1, Attachment 6s, 7s, and 8]

Discovery: The atmospheric dump valves and their internals are to be included in the ARDI Program described under Group 1 above. The MSIVs and their internals are periodically inspected as a function of specific repetitive tasks within the PM Program. These are also described under Group 1 above. [Reference 1, Attachment 6s, 7s, and 8]

Group 4 (wear of control valves) - Demonstration of Aging Management:

Based on the factors presented above, the following conclusions can be reached with respect to the wear of the seating surfaces within the applicable control valves:

- The valve seating surfaces provide a system pressure-retaining boundary and their integrity must be maintained under all CLB design conditions.
- Wear of the seating surfaces is plausible for the subject valves that may result in surface deterioration which, if left unmanaged, could lead to loss of the valves' pressure-retaining integrity.
- To ensure that all the seating surfaces of the atmospheric dump valves are being managed for wear, they will be included in the scope of an ARDI Program. Inspections will be performed, and appropriate corrective action will be taken if significant seating surface degradation is encountered.
- The seating surfaces of the MSIVs are managed for wear as a result of the repetitive tasks under the plant's PM Program that require the periodic disassembly of these valves for inspection of the valve internals (MSIV-04).

There is, therefore, reasonable assurance that the effects of control valve wear will be managed to maintain the Main Steam System components pressure boundary integrity under all design loadings required by the CLB during the period of extended operation.

5.12. Conclusion

The programs discussed for the Main Steam, Extraction Steam, and Nitrogen Systems are listed in Table 5.12-5. 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 applicable systems 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 5.12-5

LIST OF AGING MANAGEMENT PROGRAMS FOR THE MAIN STEAM, EXTRACTION STEAM, AND NITROGEN SYSTEMS

STATUS	PROGRAM	CREDITED AS
Existing	CCNPP Chemistry Program Procedure CP-202, "Specifications and Surveillance for Demineralized Water, Safety Related Battery Water, Well Water Systems, and Acceptance Criteria for On-Line Monitors"	Mitigating the effects of crevice corrosion, general corrosion, and pitting of the Chemical Addition System components that interface with the SGs (Group 1).
Existing	CCNPP Erosion Corrosion Program Procedure MN-3-202, "Erosion/Corrosion Monitoring of Secondary Piping"	Detecting and managing the effects of erosion corrosion of Main Steam and SG Blowdown System components as well as the general corrosion, crevice corrosion, and pitting of the same piping inspected as part of this program (Groups 1 and 2).
Existing	CCNPP Chemistry Program Procedure CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems"	Mitigating the effects of crevice corrosion, general corrosion, and pitting on the SRW side of the non-regenerative SG blowdown heat exchanger and the SG blowdown radiation monitor cooler (Groups 1 and 2), as well as the selective leaching of the subcomponents in the SG blowdown radiation monitor cooler (Group 3).
Existing	CCNPP Chemistry Program Procedure CP-217, "Specifications and Surveillance for Secondary Systems"	Mitigating the effects of crevice corrosion, general corrosion, pitting (Group 1), erosion corrosion (Group 2), and wear (Group 4) of Main Steam and SG Blowdown System components, and the general corrosion of Nitrogen System piping and components that interface with the SGs via the blowdown lines (Group 1).
Existing	MSIV-4; PM Repetitive Tasks 10832098, 10832099, 20832089, and 20832090; IPM10000 and IPM10001	Detecting and managing the effects of corrosion and wear within the MSIVs, and managing the effects of corrosion within the applicable portions of the Instrument Air System that interface with the Main Steam System (Groups 1, 2, and 4).
Existing	MSIV-13, "MSIV Actuator Removal and Installation"	Managing the effects of aging of the MSIV actuators and their related subcomponents (N/A to any group).
New	ARDI Program	Detecting and managing the effects of all types of corrosion of applicable Main Steam, Extraction Steam, Nitrogen, SG Blowdown, Instrument Air, Chemical and Volume Control, Main Feedwater, and Chemical Addition Systems' components, as well as wear of the atmospheric steam dump valves (Groups 1, 2, 3, and 4).

5.12.4 References

1. CCNPP "Aging Management Review Report for the Main Steam System (083)," Revision 1, February 1997
2. "CCNPP Updated Final Safety Analysis Report," Revision 20
3. "Component Level ITLR Screening Results for the Main Steam System, System No. 083," Revision 1, June 19, 1996
4. CCNPP "Component Level ITLR Screening Results for the Extraction Steam System (#046)," Revision 0, April 6, 1993
5. CCNPP "ITLR Screening Results for the Nitrogen System (#074)," Revision 0, November 12, 1993
6. 60700SH0001, "Main Steam and Reheat System Operations Drawing," Revision 37, December 3, 1996
7. CCNPP Drawing 62-700-E SH. 1, "Main Steam and Reheat System Operations Drawing," Revision 40, January 26, 1996
8. CCNPP Drawing 92767SH-EB-1, "M-600 Piping Class Sheets," Revision 49, November 12, 1996
9. CCNPP Drawing 60712SH0005, "Compressed Air System Instrument Air and Plant Air Operating Drawing," Revision 6, November 11, 1996
10. CCNPP Drawing 62712SH0003, "Compressed Air System Instrument Air and Plant Air Operating Drawing," Revision 84, April 16, 1997
11. CCNPP Drawing 92767SH-HB-1, "M-600 Piping Class Sheets," Revision 57, July 31, 1996
12. CCNPP Drawing 60734SH0003, "Reactor Coolant Waste Processing System Operating Drawing," Revision 31, January 16, 1997
13. CCNPP Drawing 92767SH-GB-1, "M-600 Piping Class Sheets," Revision 52, November 12, 1996
14. CCNPP Drawing 60726, "Nitrogen Generating and Blanket System Operating Drawing," Revision 48, October 8, 1996
15. CCNPP Drawing 60740SH0001, "Miscellaneous Steam Line Drainage Systems Operation Drawing," Revision 32, November 4, 1996
16. CCNPP Drawing 62740SH0001, "Miscellaneous Steam Line Drainage Systems Operation Drawing," Revision 35, October 8, 1996
17. CCNPP Drawing 60583, "Auxiliary Feedwater System Operating Drawing," Revision 46, December 10, 1996
18. CCNPP Drawing 62583, "Auxiliary Feedwater System Operating Drawing," Revision 45, April 20, 1995

19. CCNPP Drawing 60761, "Steam Generator Blowdown Recovery System Operating Drawing," Revision 40, November 4, 1996

20. CCNPP Procedure MSIV-13, "MSIV Actuator Removal and Installation," Revision 2, February 17, 1997

21. CCNPP "Aging Management Review Report for Auxiliary Building," Revision 3, February 21, 1997

22. CCNPP Administrative Procedure CH-1, "Chemistry Program," Revision 1, December 13, 1995

23. CCNPP Technical Procedure CP-217, "Specifications and Surveillance - Secondary Chemistry," Revision 5, December 18, 1995

24. INPO 88-021, "Guidelines for Chemistry at Nuclear Power Stations," Revision 1, September 1991

25. INPO 85-021, "Control of Chemicals in Nuclear Power Plants," June 1985

26. EPRI NP-6239, 5405-2, "PWR Secondary Water Chemistry Guidelines," Final Report, Revision 2, December 1988

27. EPRI TR-102134, Projects 2493, 5401, "PWR Secondary Water Chemistry Guidelines," Final Report, Revision 3, May 1993

28. CENPD-28, "Combustion Engineering Chemistry Manual," Revision 3, September 1982

29. ANSI N45.2.1, "Cleaning of Fluid Systems and Associated Components During the Construction Phase of Nuclear Power Plants," February 26, 1973

30. 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

31. CCNPP Technical Procedure CP-206, "Specifications and Surveillance Component Cooling/Service Water Systems," Revision 3, November 4, 1996

32. CCNPP 1996 Component Cooling and Service Water Assessment, February 26, 1997

33. "Component Cooling System Aging Management Review," Revision 1, November 7, 1996

34. CCNPP Technical Procedure CP-202, "Specifications and Surveillance - Demineralized Water, Safety Related Battery Water, Well Water Systems, and Acceptance Criteria for On-Line Monitors," Revision 3, November 14, 1995

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

36. Repetitive Tasks 10832098, 10832099, 20832089, and 20832090, "MSIV Inspections," Preventive Maintenance Program

37. CCNPP Procedure MSIV-4, "Disassembly and Assembly of MSIV," Revision 9, August 27, 1991

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

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

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

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

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

43. "Metal Fatigue in Engineering," H. O. Fuchs and R. I. Stephens, John Wiley and Sons, Copyright 1980

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

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

46. 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"

47. Letter from Mr. M. V. Hodges (NRC) to Mr. G. C. Creel (BGE), dated April 9, 1990, "Inspection Reports 50-317/90-01 and 50-318/90-01," Inspection of Activities Related to Modification, Erosion Corrosion, and Inservice Activities

48. "Corrosion Engineering," Mars G. Fontana and Norbert D. Greene, McGraw-Hill, Inc., Copyright 1967

5.13 Nuclear Steam Supply System Sampling System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Nuclear Steam Supply System (NSSS) Sampling System. The NSSS Sampling 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.

5.13.1 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.

Representative historical operating experience pertinent to aging 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.

Section 5.13.1.1 presents the results of the system level scoping; 5.13.1.2 the results of the component level scoping; and 5.13.1.3 the results of scoping to determine components subject to an AMR.

5.13.1.1 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.

<u>System Description/Conceptual Boundaries</u>

The NSSS Sampling System is designed to permit the sampling of liquids, steam, and gases for radioactive and chemical control of plant primary fluids. [Reference 1, Table 1; Reference 2, Section 9.6.1] Five subsystems comprise the NSSS Sampling System: reactor coolant sampling, steam generator blowdown sampling, radioactive miscellaneous waste sampling, gas analyzing sampling, and post-accident sampling. [Reference 1, Table 1]

- <u>Reactor Coolant Sampling</u>: The purpose of the reactor coolant sampling subsystem is to sample liquids and gases for analysis and control of chemical and radiochemical concentrations. [Reference 3, Section 1.1.1] The reactor coolant sampling subsystem consists of a stainless steel sink enclosed inside a hood. The hood is ventilated by an individual blower through a high-efficiency filter. The hood contains piping, valves, coolers, instrumentation, and sample vessels necessary to take liquid and gaseous samples from various systems. One hood is installed for each unit inside the Sampling Room in the Auxiliary Building. Samples obtained from two locations in the pressurizer (liquid, vapor) and one from the Reactor Coolant System (RCS) hot leg can be controlled by three handswitches. Should any one of the remotely-operated sampling valves fail to close after a sample is taken, a second remotely-operated valve can be shut from the Control Room. These valves are also closed by a Safety Injection Actuation Signal. The remotely-operated valves are backed up by manually-operated valves at the reactor coolant sample hood. High-pressure samples flow through metering valves in order to reduce their pressure. High-temperature samples can be cooled in a sample cooler supplied with water from the Component Cooling (CC) System. [Reference 2, Section 9.6.2.1]

When 12- and 18-month fuel cycles were used at CCNPP, pressurizer samples were required at the beginning of each fuel cycle to assist in startup testing (e.g., rod worth testing). Since these samples are no longer being taken, the pressurizer surge line and vapor space sample headers are normally isolated by manually-operated valves. [Reference 4]

The original control valves (CVs) in the RCS hot leg sampling lines exhibited excessive seat/disk leakage caused by insufficient actuator spring closure force. This caused full system pressure drop to be taken across the upstream isolation valve, resulting in steam flashing and erosion of the valve seating surfaces. Replacement of these CVs was completed in 1993.

The reactor coolant sampling subsystem also provides a means for obtaining liquid samples from the RCS or the containment sump in the post-accident environment. [Reference 5] To provide this capability, modifications included rerouting and installation of tubing in the reactor coolant sampling subsystem hoods to permit draining post-accident liquid samples to the reactor coolant drain tank (RCDT) in lieu of the normal return path to the volume control tank. [Reference 6] This capability can be used to obtain samples from the RCS or the Safety Injection (SI) System. [Reference 2, Section 9.6.2.2]

- <u>Steam Generator Blowdown Sampling</u>: The purpose of the steam generator blowdown sampling subsystem is to provide a means for sampling of liquids from the steam generators to detect conditions that cause carryover, corrosion and fouling of heat transfer surfaces, and to aid in detection of a possible reactor coolant-to-steam generator leak. [Reference 3, Section 1.1.1] This subsystem also provides a means for sampling reactor coolant makeup water. [Reference 7] The steam generator blowdown sampling subsystem consists of one conditioning rack-panel unit and one ventilating hood installed for each unit; these are located inside the same Sampling Room as the reactor coolant sample hoods. [Reference 2, Section 9.6.2.3]

  The conditioning rack section of the steam generator blowdown subsystem contains isolation valves, primary coolers, rod-in-tube devices, an isothermal bath, and chiller. High pressure samples are passed through a pressure-reducing valve (rod-in-tube type) located downstream of the primary coolers and upstream of the isothermal bath. High-temperature samples first pass through a primary cooler (supplied with water from the CC System) and then through the isothermal bath. All samples pass through the isothermal bath, a large tank of demineralized water where temperature is maintained by a chiller unit. The chiller is supplied with cooling water from the CC System. Sample outlets from the conditioning rack are connected to the ventilating hood. [Reference 2, Section 9.6.2.3] The original sample chillers were replaced in 1992 when leakage could not be repaired.

The panel section of the steam generator blowdown subsystem contains conductivity and pH monitors, three hand switches for pressurizer sample selection, chiller controls, and an annunciator. The pH and conductivity of water in the steam generator blowdown sample lines are continuously monitored and alarm on abnormal conditions. In addition, pH and conductivity are trended on the computer-based display in the chemistry laboratory. High sample temperature (downstream of the isothermal bath) actuates a common alarm point. Any point alarming on the local annunciator will actuate a master trouble alarm in the Control Room. [Reference 2, Section 9.6.2.3]

The ventilating hood contains two stainless steel sinks and is ventilated by an individual blower through a high-efficiency filter. The radioactive miscellaneous sample subsystem, discussed below, is also located inside the ventilating hood for Unit 1. The steam generator blowdown part of the hood contains all piping, grab sample valves, instrumentation including pH and conductivity cells, and other equipment necessary to obtain samples for determining the chemical and radiochemical content of the steam generator blowdown and reactor coolant makeup water. [Reference 2, Section 9.6.2.3]

- Radioactive Miscellaneous Waste Sampling: The purpose of the radioactive miscellaneous waste sampling subsystem is to provide a means for sampling of liquids from various radioactive waste processing systems to determine the chemical and radiochemical content prior to discharge, and to aid in evaluation of waste system component performance. [Reference 3, Section 1.1.1] The radioactive miscellaneous waste sampling subsystem is located inside the ventilating hood for the Unit 1 steam generator blowdown sampling subsystem, and is used to obtain samples from which the chemical and radiochemical content of miscellaneous waste is determined. This subsystem is common to both units. All samples are low pressure and are cooled, as necessary, in sample coolers supplied with water from the CC System. This part of the hood contains isolation valves, piping, valves, and instrumentation necessary for obtaining liquid samples from both units. The analyses of these samples are performed in the laboratory located in the Auxiliary Building. [Reference 2, Section 9.6.2.4]

- Gas Analyzing Sampling: The purpose of the gas analyzing sampling subsystem is to provide a means for sampling of gases to determine: (a) the hydrogen concentration of the containment atmosphere and the reactor coolant waste tanks; and (b) the oxygen concentration in the pressurizer quench tanks and various miscellaneous waste systems. [Reference 2, Section 9.6.2.6; Reference 3, Section 1.1.1] The gas analyzing sampling subsystem is installed in the Cryogenics Room located in the Auxiliary Building at Elevation -10'-0" and consists of two hydrogen analyzer cabinets, two hydrogen sample select cabinets with separate manifolds for isolation valves and sample selection solenoid valves, and one oxygen analyzer cabinet with a manifold for isolation valves. The two analyzer cabinets used for hydrogen measurement each include a sample pump, cooler, tubing, valves, and analyzer elements. Separate control cabinets at Elevation 45'-0" in the Auxiliary Building include a hydrogen sequencer panel for selection of individual readouts, a sequencer for control of sample solenoid valves, local and remote analyzer indicators with a multipoint recorder in the Control Room, and alarm contacts for activation of a master alarm in the Control Room. The analyzer cabinet used for oxygen grab sample measurement includes a sample pump, cooler, piping, valves, and a sample syringe port. An exhaust system on the oxygen analyzer cabinet purges any hydrogen that may leak into the cabinet. Sample selection from the six containment locations for each hydrogen analyzer cabinet and the two quench tank locations for the oxygen analyzer cabinet can be controlled through remotely-operated solenoid valves. [Reference 2, Section 9.6.2.6]

The gas analyzing sampling subsystem also provides a means for obtaining grab samples of gases in the containment atmosphere in the post-accident environment. [Reference 3, Section 1.1.1] To provide this capability, a sample vessel was placed into each of the sampling lines coming from the west side of the Unit 1 and 2 Containment Buildings at Elevation 135'-0". These sample vessels are located at Elevation 45'-0" in the Auxiliary Building and allow syringe samples to be taken and analyzed in the laboratory. [Reference 2, Section 9.6.2.6]

The original hydrogen analyzing subsystem required modification because the sampling equipment did not meet the range (0% to 10%) or post-accident accessibility requirements of NUREG-0737, "Clarification of TMI Action Plan Requirements." In 1982, the control cabinets were relocated to Elevation 45'-0" in the Auxiliary Building, and two new cabinets with high-range hydrogen analyzers were installed at Elevation -10'-0" in the Auxiliary Building. [Reference 8]

- Post-Accident Sampling: The purpose of the skid-mounted Post-Accident Sampling System (PASS; no longer in service at CCNPP) was to provide a means for remote sampling of liquids and gases in the post-accident environment. [Reference 3, Section 1.1.1] The PASS, located at Elevation 45'-0" in the Auxiliary Building, contains piping, valves, coolers, and instrumentation necessary to sample either Unit 1 or Unit 2 RCS via either the normal RCS sampling line, or Unit 1 or Unit 2 Containment sumps via the low pressure SI System header. [Reference 2, Section 9.6.2.2]

  The PASS was installed initially in 1982 to meet the requirements of NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," and upgrades to conform to NUREG-0737 requirements were completed in 1987. [References 6 and 9] In 1985, multiple subcomponent failures demonstrated the PASS to be a maintenance-intensive and unreliable system. [Reference 10] For these reasons, BGE modified the reactor coolant sampling and gas analyzing subsystems to provide a post-accident capability that relies, with only one exception, on grab sample analyses to meet regulatory requirements for both the RCS and Containment atmosphere. [Reference 5] The original PASS is no longer in service, and the original PASS sample lines from the RCS and SI System have been disconnected to eliminate the potential of cross-contamination of samples between units. [Reference 11]

Aside from the component replacements noted above, operating experience relative to the NSSS Sampling System has shown that there have been no additional instances of significant degradation due to aging of passive, long-lived NSSS Sampling System components.

The following general categories of equipment and devices comprise the five subsystems of the NSSS Sampling System: [Reference 3, Section 1.1.2]

Accumulators	To store pressurized gases needed to perform sampling operations;
Air dryers	To remove moisture from air systems;
Piping	To convey fluids to perform system sample functions;

Valves and valve operators	CVs, check valves (CKVs), hand valves (HVs), and motor-operated valves, to provide system alignment, isolation, and protection;
Panels	To provide support for components;
Instruments	To measure system parameters, provide control/actuation signals;
Sample Vessels	To store sample fluids as part of the sample collection and testing process;
Heat Exchangers (HXs)	To remove heat from the sample fluids; and
Pumps	To transfer sample fluids for testing purposes.

System Interfaces

The NSSS Sampling System interfaces with the following systems and components: [Reference 3, Section 1.1.2; References 7 and 12 through 15]

- RCS (sample points);
- Demineralized Water and Condensate Storage System (water for make-up to the isothermal baths);
- CC System (water for cooling samples);
- SI System (sample points);
- Spent Fuel Pool Cooling System (sample points);
- Liquid Waste System (sample points, sample drainage, sample return flow);
- Chemical and Volume Control System (sample points, sample return flow);
- Nitrogen and Hydrogen System (nitrogen gas for sample dilution);
- Containment (sample points, sample return flow);
- Main plant vent (sample return flow);
- Waste Gas System (sample points, sample return flow); and
- Main Steam System (steam generator blowdown sample points).

System Scoping Results

The NSSS Sampling System is in scope for license renewal based on 10 CFR 54.4(a). The following intended functions of the NSSS Sampling 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, Section 1.1.3]

- To maintain the pressure boundary of the system (liquid and/or gas);
- To provide containment isolation of the NSSS Sampling System during a loss-of-coolant accident;
- To sample and analyze containment hydrogen gas concentration following an accident;
- To provide the capability to operate RCS hot leg sample valves to obtain samples following a loss-of-coolant accident;
- To provide seismic integrity and/or protection of safety-related components;
- To provide closure of the RCS hot leg sample isolation valve on receipt of a Safety Injection Actuation Signal;
- To maintain electrical continuity and/or provide protection of the electrical system; and

- To restrict flow to a specified value in support of a Design Basis Event response.

The following intended functions of the NSSS Sampling System were determined based on the requirements of §54.4(a)(3): [Reference 3, Section 1.1.3]

- To provide information used to assess the environs and plant conditions during and following an accident; and
- To maintain the functionality of electrical components as addressed by the Environmental Qualification (EQ) Program.

All components of the NSSS Sampling System that support intended functions based on the requirements of §54.4(a)(3) are also safety-related.

The NSSS Sampling System must safely perform intended functions during normal and Design Basis Event conditions. The gas analyzing subsystem and those portions of HXs that form part of the pressure boundary for the CC System are designed to meet Seismic Class I requirements. [References 7 and 12 through 16] Additionally, the following valves are designed to meet Seismic Class I requirements because they constitute the boundary between piping in interfacing systems, which complies with Section III of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, and non-Class piping in the cabinets: [Reference 2, Section 9.6.3]

- Charging pump discharge header entry valve (1[2]HVPS-172);
- Low pressure SI sample header entry valve (1[2]HVPS-193);
- Spent fuel pool filter inlet entry valve (0HVPS-226);
- Spent fuel pool demineralizer outlet entry valve (0HVPS-229);
- Steam generator bottom blowdown header entry valves (1[2]HVPS-126, 1[2]HVPS-139);
- Steam generator surface blowdown header entry valves (1[2]HVPS-128, 1[2]HVPS-137); and
- Steam generator header rod-in-tube valves (1[2]HVPS-129, 1[2]HVPS-140).

The remaining components within the associated cabinets for the reactor coolant sampling, steam generator blowdown sampling, and miscellaneous waste sampling subsystems are designed to meet Seismic Class II requirements. [Reference 2, Section 9.6.3]

The RCS sample piping within the NSSS Sampling System boundaries (i.e., piping in the pressurizer surge line and RCS hot leg sample headers between the sample points and the second manual isolation valve) complies with the design requirements for Class I piping in American National Standards Institute (ANSI) Nuclear Power Piping Code B31.7, 1969. [Reference 7; Reference 17, Piping Class CC-16] Other piping within the NSSS Sampling System boundaries (i.e., containment penetration portions of the reactor coolant sampling and gas analyzing sampling subsystems) complies with Class II requirements of ANSI B31.7. [References 7, 13, and 14; Reference 18, Piping Class CC-8; Reference 19, Piping Class HC-43] Tubing meets American Society for Testing and Materials (ASTM) Standard A450-68, which requires an eddy-current test for new and replacement tubing. [Reference 2, Section 9.6.3]

5.13.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the NSSS Sampling System that is within the scope of license renewal includes all safety-related components (electrical, mechanical, and instrument) and their supports. [Reference 20, Table 2; References 7 and 12 through 15] The safety-related portions of each subsystem are described below:

- The RCS sample header isolation CVs (specifically, those isolating piping from the pressurizer surge line, the pressurizer vapor space, and the RCS hot leg), the RCS sample isolation CV, all intervening piping, and the test/vent/drain root valves connected to the intervening piping are safety-related. The containment isolation solenoid-operated valves (SVs) in the sample return lines from the reactor coolant sample hoods to the RCDT, and the piping between these valves and RCS tubing inside containment, are also safety-related. These components form part of the containment pressure boundary.

  In addition, piping in the RCS sample headers between the RCS and the CVs, test valves connected to this piping, and isolation valves in the flow path are safety-related because they constitute the boundary from ASME Section III piping to non-Class piping.

  In each of the reactor coolant sample hoods, the sample cooler is also safety-related; the shell body and tubes form part of the pressure boundary for the CC System. Additionally, the hand valves in the sample lines from the charging pump discharge and the low pressure SI pump discharge constitute boundaries from ASME Section III piping to non-Class piping and are safety-related. The remaining components in the reactor coolant sample hoods are non-safety-related.

  For a simplified diagram of the reactor coolant sampling subsystem components described above, refer to Figure 5.13-1.

- The steam generator blowdown sampling subsystem components, from the sample points in the steam generator blowdown piping (i.e., two locations for each steam generator [surface and bottom blowdown]), through the tubes in the sample coolers, up to and including the rod-in-tube pressure-reducing HVs downstream of the sample coolers in the conditioning racks, are safety-related. These components form part of the pressure boundary for the Main Steam System. The shell body and tubes in these sample coolers also form part of the pressure boundary of the CC System. Additionally, the piping and tubing in the sample chillers in each of the conditioning rack panels are safety-related; they also form part of the pressure boundary for the CC System.

- The radioactive miscellaneous waste sampling subsystem HVs in the spent fuel pool filter and demineralizer sampling lines constitute boundaries from ASME Section III piping to non-Class piping and are safety-related. The four sample coolers in this subsystem are also safety-related; the shell body and tubes form part of the pressure boundary for the CC System.

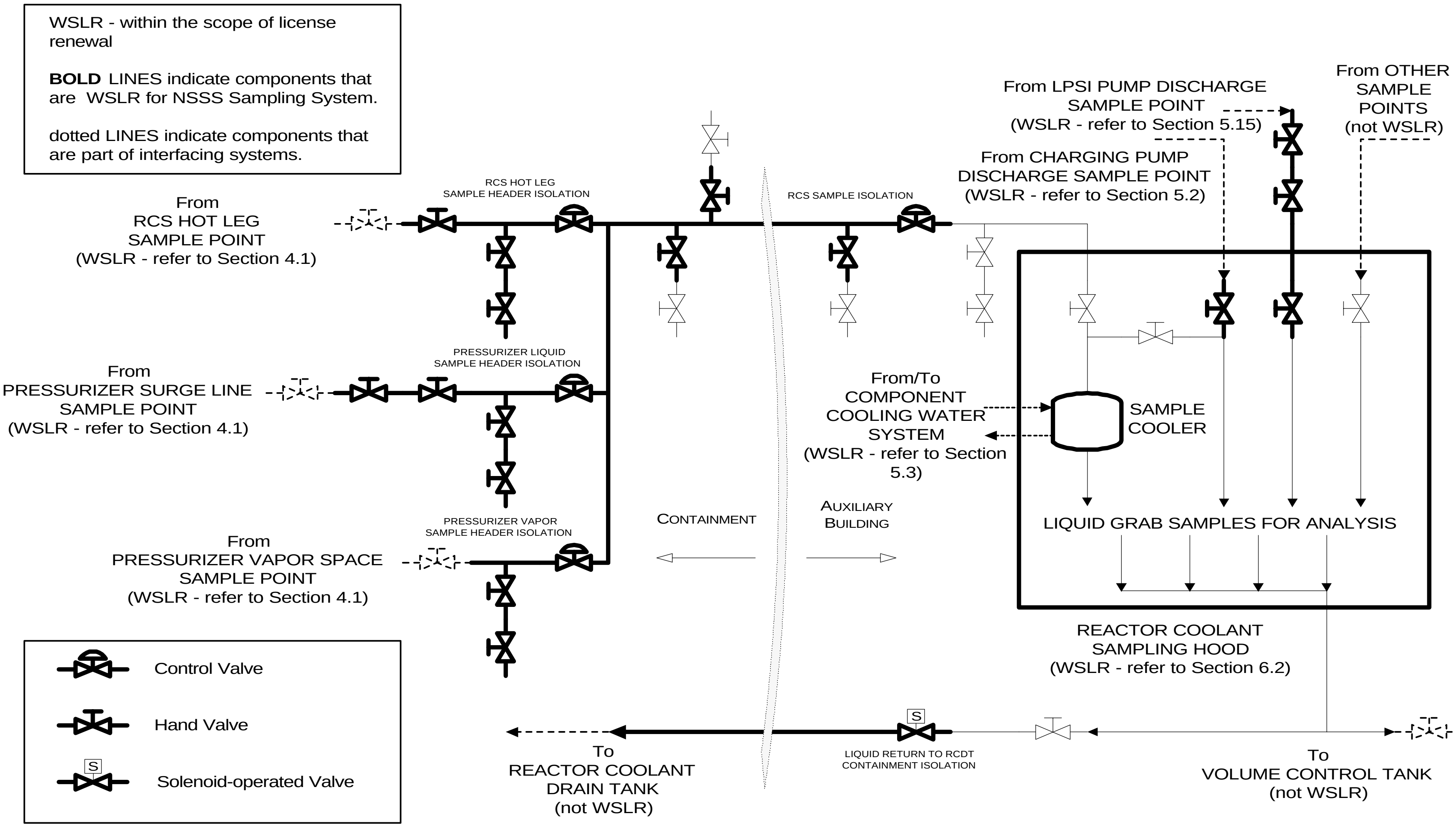

FIGURE 5.13-1

REACTOR COOLANT SAMPLING SUBSYSTEM
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

- All gas analyzing sampling subsystem piping and components associated with sampling and analysis of gases for hydrogen concentration are safety-related. This comprises separate piping/tubing in each Unit that leads from six sample points in containment, through containment isolation SVs and sample selection SVs to the hydrogen analyzer cabinet, through the analysis equipment in the cabinet, and through the gas return lines leading: (a) through containment isolation SVs to the Containment atmosphere; or (b) through SVs and CKVs to the common Auxiliary Building Heating & Ventilating System. The additional piping/tubing and normally-closed HVs that connect the sampling lines coming from the west side of the Unit 1 and 2 Containment Buildings at Elevation 135'-0" to each Unit's post-accident hydrogen gas sample vessel, as well as bottled gas cylinders and associated equipment used for instrument calibration, are also included. The containment isolation SVs, as well as the piping and components between them, form part of the containment pressure boundary. Additionally, all components in the flowpath described above are required to maintain the system pressure boundary when the hydrogen analyzers are placed in operation.

  Additionally, in the lines provided for sampling oxygen concentration for each Unit's pressurizer quench tank, the containment isolation SVs and the piping between these valves and the quench tank are safety-related. These components form part of the containment pressure boundary. The sample cooler in the oxygen analyzer cabinet is also safety-related; the shell body and tubes form part of the pressure boundary for the CC System. The remaining components associated with sampling and analysis of gases for oxygen concentration are non-safety-related.

- Because it is no longer in service and has been isolated from other safety-related equipment, all components in the original PASS are non-safety-related.

The following 33 device types in the NSSS Sampling System have been designated as within the scope of license renewal because they have at least one intended function: [Reference 3, Section 2.2 Table 2-1; Reference 20, Table 2]

Class "CC" Piping (stainless steel, primary rating 1500 psig at 1125°F)
Class "HC" Piping (stainless steel, primary rating 150 psig at 500°F)

Analyzer Alarm	Control Valve	Handswitch	Pump/Driver Assembly
Accumulator	Control Valve Operator	Hand Valve	Relay
Analyzer Element	Air Dryer	Heat Exchanger	Solenoid Valve
Analyzer Indicator	Voltage/Current Device	Power Lamp Indicator	Temperature Controller
Analyzer Recorder	Flow Indicator	Pressure Control Valve	Heater
Analyzer Converter (relay)	Flow Indicator Controller	Pressure Indicator	Position Indicating Lamp
Circuit Breaker	Flow Orifice	Panel	Position Switch
Check Valve	Fuse	Pressure Switch	

Some components in the NSSS Sampling System are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 3, Section 3.2; Reference 21, Section 3.0]

- 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 "to maintain electrical continuity and/or provide protection of the electrical system" for the NSSS Sampling System.
- Small-bore piping and tubing in the NSSS Sampling System and the associated tubing supports are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. This commodity evaluation partially addresses the passive intended function entitled "to maintain the pressure boundary of the system (liquid and/or gas)" for the NSSS Sampling System.

5.13.1.3 Components Subject to AMR

This section describes the components within the NSSS Sampling System that are subject to 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 CCNPP IPA Methodology Section 5.1, the following NSSS Sampling System functions were determined to be passive: [Reference 3, Table 3-1]

- Maintain the pressure boundary of the system (liquid and/or gas);
- Provide containment isolation of the system during a loss-of-coolant accident;
- Provide seismic integrity and/or protection of safety-related components;
- Maintain electrical continuity and/or provide protection of the electrical system; and
- Restrict flow to a specified value in support of a Design Basis Event response.

Device Types Subject to AMR

Of the 33 device types within the scope of license renewal for the NSSS Sampling System:

- Fourteen device types were associated with only active functions: Analyzer Alarm, Analyzer Indicator, Analyzer Recorder, Analyzer Converter (relay), Circuit Breaker, Voltage/Current Device, Fuse, Handswitch, Power Lamp Indicator, Relay, Temperature Controller, Heater, Position Indicating Lamp, and Position Switch;
- No device types were identified as subject to replacement over the period of extended operation;
- No device types in this system were evaluated in the AMR for a system addressed in another section of the BGE LRA; and
- One device type, Panel, is associated with a separate commodity evaluation. Panels in the NSSS Sampling System are subject to an AMR and are evaluated separately in the Electrical Panels Commodity Evaluation in Section 6.2 of the BGE LRA.

The remaining 18 device types, listed in Table 5.13-1, are subject to AMR and are included in the scope of this section. [Reference 3, Table 3-2; Reference 20, Table 2]

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies that 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 5.13-1

NSSS SAMPLING SYSTEM DEVICE TYPES SUBJECT TO AMR

Class CC Piping	Flow Indicator Controller
Class HC Piping	Flow Orifice
Accumulator	Hand Valve
Analyzer Element	Heat Exchanger
Check Valve	Pressure Control Valve
Control Valve	Pressure Indicator
Control Valve Operator	Pressure Switch
Air Dryer	Pump/Driver Assembly
Flow Indicator	Solenoid Valve

5.13.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the NSSS Sampling System components is given in Table 5.13-2, with plausible ARDMs identified by a check mark (✓) in the appropriate device type column. [Reference 3, Attachment 5s and Attachment 6s] A check mark indicates that the ARDM applies to at least one component for the device type listed. 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. Table 5.13-2 also identifies the group to which each ARDM/device type combination belongs. Exceptions are noted where appropriate. The following groups have been selected for the NSSS Sampling System:

Group 1: general corrosion of external surfaces due to leakage of borated water;

Group 2: crevice corrosion and pitting of internal surfaces exposed to chemically-treated water;

Group 3: general corrosion of internal surfaces for control valve operators (CVOPs) exposed to air from the Compressed Air System;

Group 4: fatigue for piping and valves associated with sampling the RCS hot leg;

Group 5: elastomer degradation for valve internals; and

Group 6: wear for CVs associated with sampling the RCS hot leg.

Table 5.13-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE NSSS SAMPLING SYSTEM

Potential ARDMs	Device Types																		Not Plausible for System
	-CC	-HC	ACC	AE	CKV	CV	CVOP	DRY	FI	FIC	FO	HV	HX	PCV	PI	PS	PUMP	SV	
Cavitation Erosion																			x
Corrosion Fatigue																			x
Crevice Corrosion												✓(2)	✓(2)					✓(2)	
Erosion Corrosion																			x
Fatigue	✓(4)					✓(4)						✓(4)							
Fouling																			x
Galvanic Corrosion																			x
General Corrosion						✓(1)	✓(3)					✓(1)	✓(1)						
Hydrogen Damage																			x
Intergranular Attack																			x
Microbiologically-Induced Corrosion																			x
Particulate Wear Erosion																			x
Pitting												✓(2)	✓(2)					✓(2)	
Radiation Damage																			x
Elastomer Degradation					✓(5)														
Saline Water Attack																			x
Selective Leaching																			x
Stress Corrosion Cracking																			x
Stress Relaxation																			x
Thermal Damage																			x
Thermal Embrittlement																			x
Wear						✓(6)													

✓ indicates plausible ARDM determination for this device type

(number) indicates the group in which this ARDM/device type combination is evaluated.

Note: Not every component within the device types listed here may be susceptible to a given ARDM. This is because components (and subcomponents) within a device type are not always fabricated from the same materials or subjected to the same environments. Exceptions for each device type will be indicated in the aging management subsection for each ARDM discussed in this report.

Sample coolers and chillers are included as components in the NSSS Sampling System because they perform a cooling function by reducing the temperature of the samples obtained. These HXs are within the scope of license renewal because they provide pressure boundary integrity for the interfacing systems, which is a passive intended function of both the CC System (which supplies cooling water to sample coolers in Groups 1 and 2) and the Main Steam System (which includes sample points for the steam generator blowdown sampling subsystem, with HXs evaluated in Group 2). [Reference 3, Attachment 3s for HXs]

Control valve operators are evaluated as components in the NSSS Sampling System because they perform positioning functions that are within the scope of license renewal for CVs in the RCS sample header (i.e., to operate following a loss-of-coolant accident, to close on applicable Safety Injection Actuation Signal, and to close following loss of AC power). These functions are active and do not require AMR for the CVOPs. However, these components also provide pressure boundary integrity, which is a passive intended function of the Compressed Air System (which supplies instrument air [IA] to the CVOPs, evaluated in Group 3). [Reference 3, Attachment 3s for CVOPs]

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.

Group 1 - (general corrosion of external surfaces) - Materials and Environment

Group 1 comprises the various NSSS Sampling System components that are exposed to climate-controlled air in the Auxiliary Building or the Containment and whose external surfaces are subject to general corrosion. The components in this group are included in the HX, CV, and HV device types. All of these components provide the passive intended function of maintaining the system pressure boundary. [Reference 3, Attachment 1] The applicable subcomponents in these device types are constructed of the following materials: [Reference 3, Attachments 4 and 5 for HXs, CVs, HVs]

- HXs - carbon steel end plates/piping for the miscellaneous waste evaporator concentrate pump discharge sample cooler (part of the radioactive miscellaneous waste sampling subsystem) and for sample coolers in the reactor coolant sample hoods;
- CVs - carbon steel nuts, alloy steel studs for CVs in the reactor coolant sampling subsystem; and
- HVs - carbon steel nuts, alloy steel studs for normally closed isolation/vent/drain/test HVs in the RCS sample header, and for normally open root, backup HVs in charging pump discharge sampling lines.

The external surfaces evaluated in Group 1 are not normally exposed to a corrosive environment, but may be exposed to boric acid as a result of leakage from the associated components. The possible effect of such leakage is general corrosion of susceptible external surfaces. The sources of potential leakage from components in Group 1 are listed below:

- For the miscellaneous waste evaporator concentrate pump discharge sample cooler, borated water inside the tubes with a design pressure of 150 psig, and normal operating temperature of 130°F; [Reference 3, Attachment 3s for HXs; Reference 22, Piping Class HC-2]

- For HXs, CVs, and HVs in the reactor coolant sampling subsystem, and for HVs in sampling lines from the charging pump, borated water with maximum operating pressures as high as 2485 psig (charging pump discharge), and normal operating temperatures as high as 653°F (saturation conditions in the pressurizer). [Reference 3, Attachment 6s for HXs, CVs, HVs; Reference 17, Piping Class CC-16; Reference 18, Piping Classes CC-7 and CC-8]

For all components evaluated in Group 1, the external surfaces are exposed to an environment of climate-controlled air in the Auxiliary Building or the Containment. [Reference 3, Attachment 3s] The containment atmosphere is applicable only to some of the CVs and HVs in the RCS sample header. During normal operation, temperature and humidity in the Auxiliary Building do not exceed 160°F and 70%, respectively. [Reference 23, page 54] For the general areas inside Containment, the maximum normal temperature and humidity values are 120°F and 70%, respectively. [Reference 23, pages 29, 30, 62, and 63]

Group 1 - (general corrosion of external surfaces) - Aging Mechanism Effects

General corrosion is thinning of a metal by the chemical attack of an aggressive environment at its surface. An important concern for pressurized water reactors is boric acid attack upon carbon steels and low alloy steels. General corrosion is not a concern for austenitic stainless steels. [Reference 3, Attachment 7s for HX, valve]

General corrosion is plausible for all carbon steel and alloy steel subcomponents in this group. Mechanical joints in pressure boundary subcomponents provide the opportunity for leakage of borated water onto external carbon steel and alloy steel component surfaces (i.e., end plate/piping ferrous materials for HXs, carbon steel and alloy steel body/bonnet bolting for valves). These components are particularly susceptible to significant acceleration of corrosion when exposed to boric acid in the concentrations present in the reactor coolant sampling and radioactive miscellaneous waste sampling subsystems. [Reference 3, Attachment 6s for HXs, CVs, HVs]

The result of this corrosion mechanism is a reduction in the integrity of the corroded parts and a resulting increase in the likelihood of mechanical failure. If unmanaged, long-term exposure to general corrosion could eventually result in loss of the pressure-retaining capability under current licensing basis (CLB) design loading conditions.

Group 1 - (general corrosion of external surfaces) - Methods to Manage Aging

Mitigation: Boric acid corrosion can be mitigated by minimizing leakage. The susceptible areas of the NSSS Sampling System (i.e., bolted joints) can be routinely observed for signs of borated water leakage, and appropriate corrective action can be initiated as necessary to eliminate leakage, clean spill areas, and assess any corrosion. [Reference 3, Attachment 6s for HXs, HVs]

Discovery: The effects of corrosion are generally detectable by visual techniques. Visual inspections would need to be performed to detect corrosion associated with leakage of fluids onto the external surfaces of NSSS Sampling System components. [Reference 3, Attachment 6s for HXs, HVs]

Group 1 - (general corrosion of external surfaces) - Aging Management Program(s)

Mitigation: The CCNPP Boric Acid Corrosion Inspection (BACI) Program (MN-3-301) is credited with mitigating the effects of boric acid corrosion through timely discovery of leakage of borated water and removal of any boric acid residue that is found. [Reference 3, Attachment 8] This program requires visual inspection of the components containing boric acid for evidence of leaks, quantification of any leakage indications, and removal of any leakage residue from component surfaces. [Reference 24] Further details on the BACI Program are detailed in the Discovery subsection below.

Discovery: Discovery of boric acid leakage is ensured by the BACI Program. [Reference 3, Attachment 8] This program also requires investigation of any leakage that is found. A visual examination of external surfaces is performed for components containing boric acid. [Reference 24]

The Inservice Inspection Program required the establishment of the BACI Program to systematically ensure that boric acid corrosion does not degrade the primary system boundary. [Reference 25, page 23, Section 5.8.A.1.] The program also applies to "valves in systems containing borated water which could leak onto Class 1 carbon steel components," and it identifies other plant areas to be examined. [Reference 24, Section 5.1B] The program controls examination, test methods, and actions to minimize the loss of structural and pressure-retaining integrity of components due to boric acid corrosion. [Reference 24, page 7, Section 3.0.C] The basis for the establishment of the program is Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." [Reference 24, Section 1.1]

The scope of the program is threefold in that it: (a) identifies locations to be examined; (b) provides examination requirements and methods for the detection of leaks; and (c) provides the responsibilities for initiating engineering evaluations and necessary corrective actions. [Reference 24, Section 1.2]

During each refueling outage, inservice inspection personnel perform a walkdown inspection to identify and quantify any leakage found at specific locations inside the Containment and in the Auxiliary Building. The inservice inspection ensures that all components where boric acid leakage has been previously documented are also examined in accordance with the requirements of this program. A second inspection of these components is performed prior to plant startup (at normal operating pressure and temperature) if leakage was identified previously and corrective actions were taken. [Reference 24, Sections 5.1 and 5.2]

Under the BACI Program, the walkdown inspections applicable to NSSS Sampling System components are type VT-2 (a type of visual examination described in ASME Section XI, IWA-2212). The VT-2 visual examinations include the accessible external exposed surfaces of pressure-retaining, non-insulated components; floor areas or equipment surfaces located underneath non-insulated components; vertical surfaces of insulation at the lowest elevation where leakage may be detected, and horizontal surfaces at each insulation joint for insulated components; floor areas and equipment surfaces beneath components and other areas where water may be channeled for insulated components whose external insulation surfaces are inaccessible for direct examination; and for discoloration or residue on any surface for evidence of boric acid accumulation. [Reference 24, Section 5.2]

If either leakage or corrosion is discovered, issue reports (IRs) are generated in accordance with CCNPP procedure QL-2-100, "Issue Reporting and Assessment," to document and resolve the deficiency.

Corrective actions address the removal of boric acid residue and inspection of the affected components for general corrosion. If general corrosion is found on a component, the IR provides for evaluation of the component for continued service and corrective actions to prevent recurrence. [Reference 24, Section 5.3]

The BACI Program has evolved with regard to boric acid leaks discovered during other types of walkdowns and inspections. The program specifies the minimum qualification level for inspectors evaluating boric acid leaks. Apparent leaks that are discovered during these other walkdowns/inspections are documented in IRs by the individual discovering the leak. These IRs are then routed to the inservice inspection group for closer inspection and evaluation by a qualified inspector. This approach provides for more boric acid leakage inspection coverage while still ensuring that appropriately-qualified individuals assess and quantify any resultant damage.

The corrective actions taken as a result of IRs under this program will ensure that NSSS Sampling System components containing borated water remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Since the ventilating hood for the Unit 1 steam generator blowdown sampling subsystem (which contains the radioactive miscellaneous waste sampling subsystem) is not within the scope of the BACI Program, CCNPP currently plans to include the miscellaneous waste evaporator concentrate pump discharge sample cooler in an Age-Related Degradation Inspection (ARDI) Program to verify that degradation of the end plates/piping due to general corrosion is not occurring. [Reference 3, Attachment 8]

The ARDI Program is 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 loading conditions 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.

Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Actions Program and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 1 - (general corrosion of external surfaces) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to general corrosion of external surfaces for NSSS Sampling System components:

- The HXs, CVs, and HVs in Group 1 contribute to maintaining the pressure boundary of interfacing systems. Their integrity must be maintained under all CLB design conditions.
- The materials of construction for subcomponents in this group are carbon steel or alloy steel.
- General corrosion is a plausible ARDM for this group because susceptible external surfaces are exposed to potential boric acid leakage from mechanical joints. If unmanaged, this ARDM could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- The corrosive effects of boric acid leakage will be managed by means of the BACI Program. When boric acid leakage is identified, either through required program inspections or through IRs resulting from other types of walkdowns and inspections, this program will ensure that corrosion induced by boric acid is discovered and that appropriate corrective action is taken.
- The miscellaneous waste evaporator concentrate pump discharge sample cooler will be subjected to a new ARDI Program. This program will examine a representative sample of the components for degradation, and ensure that appropriate corrective actions are initiated on the basis of the findings.

Therefore, there is a reasonable assurance that the effects of general corrosion will be adequately managed for external surfaces of NSSS Sampling System components 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 - (crevice corrosion and pitting of internal surfaces exposed to chemically-treated water) - Materials and Environment

Group 2 comprises the various NSSS Sampling System components that are exposed to chemically-treated water and whose internal surfaces are subject to crevice corrosion and pitting. The components in this group are included in the HX, HV, and SV device types. The SVs in this group provide a containment isolation function for the sample return lines from the reactor coolant sample hoods to the RCDT. [Reference 20, Table 2] The remaining components provide the passive intended function of maintaining the system pressure boundary. [Reference 3, Attachment 1] The applicable subcomponents in these device types are constructed of the following materials: [Reference 3, Attachments 4 and 5 for HXs, HVs, SVs]

- HXs - carbon steel end plates/piping and stainless steel shell, tubes, welds, capscrews, and fittings for sample coolers in the steam generator blowdown conditioning racks, the radioactive miscellaneous waste sampling subsystem, and the oxygen analyzer cabinet;
- HXs - carbon steel piping and copper tubing for sample chillers in steam generator blowdown conditioning racks;
- HVs - stainless steel body/bonnet, gland nut, stem, disk, and seat for normally closed isolation HVs in low pressure SI pump, spent fuel pool filter and demineralizer sampling lines;

- HVs - carbon steel body/bonnet and stem for normally open root, backup HVs in steam generator blowdown sampling lines;
- HVs - stainless steel body/bonnet, stem, union nut, and packing bolt for normally closed isolation HVs in steam generator blowdown sampling conditioning racks;
- HVs - stainless steel body/tubes, rod assembly, and nuts for rod-in-tube pressure-reducing HVs in steam generator blowdown sampling conditioning racks; and
- SVs - stainless steel body, bonnet, spring, and disc assembly for containment isolation SVs in the sample return lines from the reactor coolant sample hoods to the RCDT.

Piping and valves in the RCS sample header and in the charging pump sampling lines are excluded from Group 2. These portions of the NSSS Sampling System are subject to the hydrogen overpressure utilized as a corrosion inhibitor for the RCS. Due to the extremely low oxygen concentrations in the process fluid, the minimal impurity content that results, and stainless steel materials of construction, crevice corrosion and pitting are not considered plausible for the internal surfaces of these components. [Reference 3, Attachment 6s for CVs, HVs; Reference 17, Piping Class CC-16; Reference 18, Piping Class CC-8]

For all components evaluated in Group 2, the internal surfaces are exposed to an environment of chemically-treated water from the system being sampled, or from the CC System, or both. [Reference 3, Attachment 3s]

For the HXs in this group, stagnant flow conditions may exist due to the physical geometry of the components and due to idle operation for portions of the system. Stagnant flow may allow impurities in the process fluids to concentrate. [Reference 3, Attachment 6s for HXs] The applicable fluids in the HXs are identified below:

- For sample coolers in the NSSS Sampling System, the internal environment is chemically-treated water from the CC System between the inside of the shell and the outside of the tubes that contain the sample fluids being cooled. The CC System has a design pressure of 150 psig and maximum operational temperature of 167°F. [Reference 3, Attachment 3s for HXs; Reference 22, Piping Class HB-23] For these sample coolers, the fluids being cooled flow inside the tubes. The cooled fluids for sample coolers in the reactor coolant sample hoods and radioactive miscellaneous waste sampling subsystem are described in subsection Group 1 - Materials and Environment, above. The cooled fluid for sample coolers in the steam generator blowdown sampling subsystem is a saturated mixture of steam and feedwater with normal operating parameters of approximately 750 psig and 520°F. [Reference 26, Piping Class EB-14] The cooled fluid for the sample cooler in the oxygen analyzer cabinet is a radioactive mixture of gases with maximum operating pressures and temperatures as high as 150 psig and 303°F, respectively, from the RCS quench tank, waste gas decay tanks, or waste gas system piping. [Reference 19, Piping Class HC-43; Reference 27, Piping Class HC-29; Reference 28, Piping Class HC-60]
- For the sample chillers in the steam generator blowdown conditioning racks, the internal environment is also water from the CC System that is contained inside the piping connected to the chiller condenser and the chiller tubing. A liquid/vapor refrigerant mixture is contained in the chiller condenser shell surrounding the tubing. The normal operating pressure for the CC System is greater than the refrigerant condenser pressure. [Reference 3, Attachment 6 for sample chiller]

The internal environments for the valves in Group 2 are listed below:

- For HVs in sampling lines from the low pressure SI pump discharge headers: borated water with maximum operating pressures and temperatures as high as 450 psig and 300°F, respectively; [Reference 29, Piping Class GC-1]
- For HVs in sampling lines from the spent fuel pool filter and demineralizer: borated water with maximum operating pressures and temperatures as high as 148 psig and 155°F, respectively; and [Reference 22, Piping Class HC-4]
- For HVs in the steam generator blowdown sampling subsystem: a saturated mixture of steam and feedwater with normal operating parameters of approximately 750 psig and 520°F; and [Reference 26, Piping Class EB-14]
- For SVs in this group: borated water from the reactor coolant sample hoods with a maximum operating pressure and temperature of 55 psig and 303°F, respectively. [Reference 19, Piping Class HC-43]

Group 2 - (crevice corrosion and pitting of internal surfaces exposed to chemically-treated water) - Aging Mechanism Effects

Crevice corrosion and pitting are related forms of intensive, localized corrosion. Crevice corrosion occurs in crevices that are wide enough to permit liquid entry and narrow enough to maintain stagnant conditions. Such locations may include holes, gasket surfaces, lap joints, spaces under bolt heads, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. Pitting occurs when corrosion proceeds at one small location at a rate greater than the corrosion rate of the surrounding area. Pitting is an autocatalytic process that produces conditions that stimulate the continuing activity of the pit. In either case, the stagnant fluid within the pit or crevice tends to accumulate corrosive chemicals, and thereby to accelerate the local corrosion process. Crevice corrosion can initiate pitting in many cases. Pitting can result in complete perforation of the material. [Reference 3, Attachment 7s for HX, valve]

Crevice corrosion and pitting are plausible at mechanical joints (i.e., areas of HXs that are idled or not exposed to the general flow stream, and body/bonnet joints for valves) since the mechanical joint presents a crevice geometry at the sealing surfaces that may allow process fluids to stagnate and can concentrate environmentally-produced impurities. [Reference 3, Attachment 6s for HXs, HVs, SVs] Similar stagnation and impurity deposits are possible at other component interior crevices that are formed by close-fitting interface points at interior subcomponents (i.e., tubing for the sample chillers in steam generator blowdown conditioning racks, seating surfaces for containment isolation SVs, and various internal subcomponents for valves). [Reference 3, Attachment 6s for HXs, HVs, SVs] Therefore, crevice corrosion and pitting are plausible for all components in this group.

Group 2 - (crevice corrosion and pitting of internal surfaces exposed to chemically-treated water) - Methods to Manage Aging

Mitigation: Control of fluid chemistry in systems that interface with the NSSS Sampling System can significantly limit the effects of crevice corrosion and pitting. [Reference 3, Attachment 6s for HXs, HVs, SVs] The chemistry control program should monitor pertinent chemical parameters on a frequency that would allow for corrective actions to minimize creation of an environment conducive to corrosion.

Discovery: The effects of corrosion are generally detectable by visual techniques. Observation of corrosion products in chemistry samples can indicate unexpected system corrosion. Seating surface degradation can be discovered by testing the components that are susceptible to this ARDM. Pressure testing of the containment isolation SVs can provide for detection of leakage that could be the result of crevice corrosion and pitting of the valve seating surfaces. Internal surfaces of components that are not routinely inspected can be subjected to inspection to determine the extent of general and/or localized degradation that may be occurring. [Reference 3, Attachment 6s for HXs, HVs, SVs]

Group 2 - (crevice corrosion and pitting of internal surfaces exposed to chemically-treated water) - Aging Management Program(s)

Mitigation: Maintenance of proper fluid chemistry in systems that interface with the NSSS Sampling System will limit the effects of crevice corrosion and pitting on internal subcomponents for Group 2 HXs and valves. [Reference 3, Attachment 8]

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 30, Section 6.1.A] The program is based on Technical Specifications, BGE's interpretation of industry standards, and recommendations made by Combustion Engineering. [Reference 31, Section 2.0; Reference 32, Section 2.0]

Calvert Cliffs Technical Procedure CP-204, "Specification and Surveillance-Primary Systems," provides for monitoring and maintaining chemistry in the RCS and associated systems. [Reference 31, Section 2.0, Attachments 1 through 15] Control of primary water chemistry is credited with limiting the effects of crevice corrosion and pitting in NSSS Sampling System components that interface with primary systems. [Reference 3, Attachment 8]

Calvert Cliffs Technical Procedure CP-206, "Specifications and Surveillance-Component Cooling/Service Water Systems," provides for monitoring of CC System chemistry to control the concentrations of oxygen, chlorides, and other chemicals and contaminants. [Reference 33, Section 2.0, Attachment 1] Control of the water chemistry prevents a corrosive environment for NSSS Sampling System HXs that are cooled by water from the CC System. [Reference 3, Attachment 8]

Calvert Cliffs Technical Procedure CP-217, "Specification and Surveillance-Secondary Chemistry," provides for control of fluid chemistry in the steam generators in order to minimize the concentration of corrosive impurities (chlorides, sulfates, oxygen) and to optimize fluid pH. [Reference 32, Section 2.C, Attachments 1 through 13] It has been demonstrated that this chemistry control program, with its main focus on steam generator preservation, is successful at controlling corrosion rates in the balance of the secondary cycle. Control of secondary fluid chemistry minimizes the corrosive environment for components in the steam generator blowdown sampling subsystem, and limits the rate and effects of corrosion. [Reference 3, Attachment 8]

Each of the program procedures describes the surveillance and specifications for monitoring fluid chemistry for the applicable systems. They list the parameters to be monitored, the frequency for monitoring of each parameter, and the acceptable value or range of values for each parameter. [Reference 31, Attachments 1 through 15; Reference 32, Attachments 1 through 13; Reference 33, Attachment 1] Each parameter is measured at a procedurally-specified frequency (e.g., daily, weekly, monthly) and compared against a target value that represents a goal or predetermined warning limit. [Reference 31, Section 3.0; Reference 32, Section 3.0; Reference 33, Section 3.0] If a measured value is outside of its required range, corrective actions are taken (e.g., power reduction, plant shutdown) as prescribed by the procedure, thereby ensuring timely response to chemical excursions. [Reference 31, Section 6.0.C; Reference 32, Section 6.0.C; Reference 33, Section 6.0.C] The procedures provide for rapid assessment of off-normal chemistry parameters so that steps can be taken to return them to normal levels. [Reference 31, Section 2.0; Reference 32, Section 2.0]

The CCNPP Chemistry Program has been subject to periodic internal assessment activities. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their strength of performance and safety significance and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. [Reference 34, Section 1B.18] These activities, as well as other external assessments, help to maintain highly effective chemistry control, and facilitate continuous improvement through monitoring industry initiatives and trends in the area of corrosion control.

A review of operating experience identified no site-specific problems or events related to crevice corrosion or pitting that required significant changes or adjustments to the CCNPP Chemistry Program. It has been effective in its function of mitigating corrosion, and thereby preventing corrosion-related failures and problems. 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 (e.g., successful experimentation with a new alternate amine). In 1996, CP-206 was revised to include monitoring of dissolved iron as a method for discovering any unusual corrosion of carbon steel components. An internal BGE chemistry summary report for 1996 included recommendations to: (a) determine outage evolutions that can affect the CC/Service Water chemical parameters; and (b) take action to prevent chemistry parameters from being exceeded.

Discovery: Calvert Cliffs procedures STP M-571I-1(2), "Local Leak Rate Test, Penetrations 1D, 47A, 47B, 47C, 47D, 48A, 48B, 49A, 49B, 49C," which cover local leak rate testing (LLRT) for the sample return lines from the reactor coolant sample hoods to the RCDT, are part of the overall CCNPP Containment Leakage Rate Testing Program. [References 35 and 36] The CCNPP Containment Leakage Rate Testing 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, Option B, "Primary Reactor Containment Leakage

Testing for Water-Cooled Power Reactors." 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 37, Section 6.5.6; References 38 and 39]

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 valves that isolate the containment penetration piping for the sample return lines from the reactor coolant sample hoods to the RCDT are included in the scope of this program as part of the leakage testing for the associated containment penetrations. [Reference 37]

The LLRT is done on a performance-based testing schedule in accordance with Option B of 10 CFR Part 50, Appendix J, as implemented by CCNPP Technical Specifications. [References 37, 38, and 39]. Local leak rate testing presently includes the following procedural steps:

- Leak rate monitoring test equipment is connected to the appropriate test point.
- The test volume is pressurized to the LLRT Program test pressure, which 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.
- 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 that 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, plant personnel 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 containment isolation valve that changes the closing characteristic of the valve, an "as left" test must be performed on the penetration to ensure leakage rates are acceptable.

The corrective actions taken as part of the LLRT Program will ensure that the containment isolation SVs in the sample return lines from the reactor coolant sample hoods to the RCDT remain capable of performing their intended functions under all CLB conditions during the period of extended operation.

Baltimore Gas and Electric Company currently plans to include all Group 2 components in an ARDI Program to verify that unacceptable degradation of internal surfaces by crevice corrosion or pitting is not occurring. [Reference 3, Attachment 8] For a discussion of the elements of the ARDI Program, refer to subsection Group 1 - Aging Management Programs, above.

Group 2 - (crevice corrosion and pitting of internal surfaces exposed to chemically-treated water) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to crevice corrosion and pitting of internal surfaces for NSSS Sampling System components that are exposed to chemically-treated water:

- The Group 2 HXs and HVs contribute to maintaining the pressure boundary of interfacing systems, and the SVs provide a containment isolation function. The integrity of these components must be maintained under all CLB design conditions.
- The materials of construction for subcomponents in this group are carbon steel, stainless steel, or copper.
- Crevice corrosion and pitting are plausible ARDMs for this group and, if unmanaged, these ARDMs could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- Maintenance of proper fluid chemistry in primary systems (in accordance with CP-204) and secondary systems (in accordance with CP-217) that are sampled through the NSSS Sampling System will limit the effects of crevice corrosion and pitting on susceptible pressure boundary subcomponents for Group 2 HXs and valves. Chemistry control in accordance with CP-206 will ensure that the cooling water supplied to NSSS Sampling HXs is of an appropriate chemistry to minimize corrosion.
- The CCNPP LLRT Program performs leakage testing that could detect the effects of crevice corrosion and pitting on the seating surfaces of the containment isolation SVs in the sample return lines from the reactor coolant sample hoods to the RCDT (i.e., degraded leak tightness). This program ensures that appropriate corrective actions will be taken if significant leakage is discovered.
- All Group 2 components will be subjected to a new ARDI Program. This program will examine a representative sample of the components for degradation, and ensure that appropriate corrective actions are initiated on the basis of the findings.

Therefore, there is a reasonable assurance that the effects of crevice corrosion and pitting will be adequately managed for internal surfaces of NSSS Sampling System components exposed to chemically-treated water 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 3 - (general corrosion of internal surfaces exposed to compressed air) - Materials and Environment

Group 3 comprises the operators associated with CVs in the reactor coolant sampling lines whose internal surfaces are subject to general corrosion. The applicable subcomponents are constructed of the following materials: [Reference 3, Attachments 4 and 5 for CVOPs]

- For CVOPs associated with the CVs isolating sample piping from the pressurizer surge line and the pressurizer vapor space, carbon steel actuator cases, cast iron/steel yokes, and carbon steel bolting; and
- For CVOPs associated with the RCS sample isolation CVs and the CVs isolating sample piping from the RCS hot leg, ductile iron yokes and zinc-plated steel adjusting screws.

The internal environment for the CVOPs is normally compressed air supplied by the IA compressors in the Compressed Air System. The IA is very dry, filtered, and oil-free air, with normal dew point maintained at -40°F at the design pressure of 100 psig. [Reference 2, Section 9.10, Table 9-21] Occasionally, air that does not meet the same air quality standards may enter the IA supply due to operation of the plant air compressors (with minimal drying capacity) or the saltwater air compressors (with no air dryer), which serve as backups to the IA compressors. [References 40 through 43] Therefore, there is a possibility that moisture may enter the IA supply, although its effect is expected to be minimal due to the limited operation of these backup sources. [Reference 3, Attachment 8]

Group 3 - (general corrosion of internal surfaces exposed to compressed air) - Aging Mechanism Effects

The effects of general corrosion are discussed in subsection Group 1 - Aging Mechanism Effects, above.

General corrosion of all ferrous materials internal to the CVOPs is plausible because the materials of construction may occasionally be exposed to slightly moist air; however, this ARDM is also considered unlikely. At the normal dew point of -40°F, there is insufficient moisture to cause significant occurrences of this mechanism. The expected effects would be superficial rust speckles and a slight dusting of loose passive surface rust. The consequence of general corrosion damage to the affected components would be a loss of load-carrying cross-sectional area. [Reference 44, Attachment 6s and Attachment 8]

Group 3 - (general corrosion of internal surfaces exposed to compressed air) - Methods to Manage Aging

Mitigation: Maintaining IA quality within industry standards for dew point can ensure minimal degradation resulting from moisture for carbon steel/iron subcomponents exposed to compressed air. [Reference 3, Attachment 6s for CVOPs] An inspection performed on the piping immediately downstream of the saltwater air compressors, where the worst case of general corrosion in the IA supply is expected, revealed only very light surface rust on the inside of each piece. After more than 20 years in operation, approximately 60% of the pipe interior contained no rust and appeared similar to the inside of new pipe. Thickness measurements showed that the wall thickness averaged only 0.001 inch less than the nominal thickness of 0.179 inch. [Reference 44, Attachment 8] In order to assure that the compressed air quality remains within acceptable limits, the air quality should be periodically checked and compared against the industry standards. [Reference 44, Attachment 8] If testing shows a reduction in air quality, corrective actions can be initiated to return the air quality to normal.

Discovery: Since IA in the Compressed Air System is normally very dry, and since minimal corrosion is evident after more than 20 years of operation, continued maintenance of IA quality is deemed an adequate aging management technique for general corrosion control in components connected to the IA supply. [Reference 44, Attachment 8]

Group 3 - (general corrosion of internal surfaces exposed to compressed air) - Aging Management Program(s)

Mitigation: The CCNPP 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 those applicable to NSSS Sampling System components within the scope of license renewal. [Reference 45]

Calvert Cliffs Preventive Maintenance Checklists are executed by preventive maintenance tasks that are automatically scheduled and implemented in accordance with safety-related Preventive Maintenance Program procedures. [Reference 45]

Calvert Cliffs initiated a Preventive Maintenance Checklist following a review of recommendations resulting from industry operating experience. Preventive Maintenance Checklist IPM 10000 (10001), “Check Unit 1(2) Instrument Air Quality,” checks IA quality at three locations in the Compressed Air System: at the dryer outlet, at the furthest point from the dryer, and at the approximate mid-point between the other two. Measurements of dew point are taken every 12 weeks at these locations. [Reference 3, Attachment 8; References 46 and 47] Dew point data are reviewed, trended, and evaluated in accordance with approved procedures. If the air quality is determined to be abnormal, corrective action is initiated to return the air quality to normal and to investigate the condition of the dependent load internals (e.g., carbon steel pressure boundary subcomponents for CVOPs in reactor coolant sampling lines), as appropriate. [References 46 and 47] This process ensures IA quality is maintained in accordance with industry standards for moisture (dew point). Operating experience relative to IA quality control has shown that the air normally provided is very dry and contains little particulate matter. [Reference 44, Attachment 8]

The Preventive Maintenance Program has been evaluated by the NRC as part of its routine licensee assessment activities. The plant Maintenance Program also has had numerous levels of management review, all the way down to the specific implementation procedures. Specific responsibilities are assigned to BGE personnel for evaluating and upgrading the Preventive Maintenance Program, and for initiating changes to the Preventive Maintenance Program based on system performance. These assessments and controls provide reasonable assurance that the Preventive Maintenance Program will continue to be an effective method of mitigating the effects of general corrosion on internal surfaces of the CVOPs exposed to compressed air. [Reference 45]

Discovery: Continued implementation of the mitigation technique discussed above should ensure that exposure of the CVOP internal surfaces to moisture will continue to be minimal. Since the saltwater air compressors only provide a backup to essential loads normally supplied by the IA compressors, introduction of moisture from this source will also be minimal. Corrosion of the CVOP internal surfaces is not expected to result in significant levels of degradation. It is deemed that the mitigation techniques described above are adequate aging management practices for corrosion, and no discovery techniques are necessary for Group 3 components. [Reference 44, Attachment 8]

Group 3 - (general corrosion of internal surfaces exposed to compressed air) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to general corrosion of internal surfaces for NSSS Sampling System components that are exposed to compressed air:

- The CVOPs associated with CVs in the reactor coolant sampling lines contribute to maintaining the pressure boundary of the Compressed Air System. Their integrity must be maintained under all CLB design conditions.
- The materials of construction for subcomponents in this group are carbon steel, zinc-plated steel, or iron.
- General corrosion is a plausible ARDM for this group because susceptible materials are exposed to potentially moisture-laden air from the Compressed Air System. If unmanaged, these ARDMs could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- Periodic monitoring and maintenance of IA dryness (in accordance with IPM 10000 [10001]) will mitigate the effects of corrosion on ferrous pressure boundary subcomponents for CVOPs in reactor coolant sampling lines.

Therefore, there is a reasonable assurance that the effects of general corrosion will be adequately managed for internal surfaces of NSSS Sampling System components exposed to compressed air 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 4 - (fatigue for piping and valves associated with sampling the RCS hot leg) - Materials and Environment

Group 4 comprises components in the reactor coolant sampling subsystem associated with sampling the RCS hot leg for which fatigue is a plausible ARDM. Specifically, this group consists of the following NSSS Sampling System components that are depicted in Figure 5.13-1:

- RCS hot leg sample header isolation CV (1[2]CVPS-5467);
- RCS sample isolation CV (1[2]CVPS-5464);
- RCS sample header test connection root valve (1[2]HVPS-196);
- RCS sample header telltale root valve (1[2]HVPS-200);
- RCS sample header vent valve (1[2]HVPS-401);
- RCS hot leg sample header test connection root valve (1[2]HVPS-403);
- RCS hot leg sample header test connection backup valve (1[2]HVPS-404); and

- Intervening pipe segments (1#CC8-1001, -1002, -1003 (2#CC8-2001, -2002, -2003)).

All of these components provide the passive intended function of maintaining the system pressure boundary. [Reference 3, Attachment 1] The applicable subcomponents in these device types are constructed of the following materials: [Reference 3, Attachments 4 and 5 for pipe, CVs, HVs]

- Piping - stainless steel pipe, fittings, and welds;
- CVs - carbon steel nuts, alloy steel studs, and stainless steel body/bonnet; and
- HVs - carbon steel nuts, alloy steel studs, and stainless steel body/bonnet.

The original design code for the piping in this group is ANSI B31.7 Class II. [Reference 18, Piping Class CC-8] At CCNPP, the original system design assumed a stress range reduction factor of one, which corresponds to 7000 full-range thermal cycles during the anticipated life of the plant. Replacement of the original CVs in the RCS hot leg sampling lines was completed in 1993. The new valves were designed in accordance with Class 1 requirements for valves one-inch and under in ASME Section III (1977 Edition, including the Summer 1978 Addenda). [Reference 48]

Similar NSSS Sampling System piping and valves, from the pressurizer surge line and vapor space sample points up to and including the associated sample header isolation CVs, are excluded from Group 4. It has been conservatively estimated that components in the pressurizer surge line and vapor space sample headers have experienced no more than 450 full-range thermal cycles since installation. Since samples from the pressurizer are no longer being taken, no additional thermal fatigue cycles are being experienced by these components.

The internal environment for pressure boundary subcomponents in this group is borated water at an operating pressure of approximately 2250 psia. [Reference 2, Section 4.1.1, Table 4-1]. Normal sampling operations cause rapid temperature transients in the sampling line from ambient (about 100°F) to the normal RCS hot leg operating temperature and back to ambient (i.e., differential temperature of up to 500°F). [Reference 3, Attachment 6s for pipe, CVs, HVs]

The external environment is climate-controlled air in the Auxiliary Building and the Containment. [Reference 3, Attachment 3s] Refer to subsection Group 1 - Materials and Environment, above, for additional discussion.

Group 4 - (fatigue for piping and valves associated with sampling the RCS hot leg) - Aging Mechanism Effects

Fatigue is the process of progressive localized structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points in the material. This process 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 occurs. Failures may occur at either a high or low number of cycles in response to various kinds of loads (e.g., mechanical or vibrational loads, thermal cycles, or pressure cycles). Low-cycle fatigue involves stressing of materials, often into the plastic range, with the number of cycles usually being less than 10^5. This mechanism is typically associated with thermal gradients created in restrained members during rapid heatup or cooldown. A component subjected to sufficient cycling with significant strain rates accumulates fatigue damage, which potentially can lead to crack initiation and crack growth. The cracks may then propagate under continuing cyclic strains. [Reference 3, Attachment 7s for pipe, CVs, HVs; Reference 49]

Low-cycle thermal fatigue is plausible for the devices in this group since they experience severe thermal cycling during routine RCS sampling operations (which occur several times each week in accordance with CP-204). [Reference 3, Attachment 6s for pipe, CVs, HVs; Reference 31, Attachments 1 through 3]

Baltimore Gas and Electric Company has not discovered any low-cycle fatigue-related failures in the NSSS Sampling System. However, there have been occurrences in similar applications at other facilities, including cracks found in the inlet opening and around the base of the valve bore area in RCS hot leg sampling line CVs at Arizona Public Service's Palo Verde Nuclear Generating Station.

These aging mechanisms, if unmanaged, could eventually result in crack initiation and growth such that the Group 4 components may not be able to perform their pressure boundary function under CLB design loading conditions.

Group 4 - (fatigue for piping and valves associated with sampling the RCS hot leg) - Methods to Manage Aging

Mitigation: The effects of low-cycle fatigue can be mitigated by proper system design and material selection, and by operational practices that reduce the number and severity of thermal transients on the RCS hot leg sampling piping. [Reference 3, Attachment 6s for CVs, HVs]

Discovery: As discussed above, low-cycle fatigue was addressed in the original design for the RCS hot leg sampling lines. Additional RCS sampling (e.g., that required for a 60-year period of operation) could result in more than the number of full-range thermal cycles estimated in the original system design. The accumulation of fatigue effects on components in the RCS hot leg sampling lines can be monitored by counting the number of the thermal transients and by performing analysis to predict the remaining life of the affected components.

Group 4 - (fatigue for piping and valves associated with sampling the RCS hot leg) - Aging Management Program(s)

Mitigation: The number and severity of thermal transients experienced by components in the RCS sampling lines is dependent on RCS sampling requirements established by the CCNPP Chemistry Program. Maintaining the established sampling frequencies precludes modification of plant operating practices to reduce thermal cycles on the NSSS Sampling System. Therefore, there are no practicable means available (beyond proper system design and material selection) to mitigate the effects of thermal fatigue.

Discovery: The CCNPP Fatigue Monitoring Program (FMP) has been established to monitor and track fatigue usage of limiting components of the NSSS and the steam generators. Reference 50 was used in the development of this program. Eleven fatigue critical locations in these systems have been selected for monitoring of fatigue usage. These represent the most bounding locations for critical thermal transients. [Reference 51, Sections 1.1, 1.2.A, 2.1.E, 6.0]

The FMP utilizes two methods to track fatigue usage:

- One method is to track the number of critical thermal and pressure test transients (i.e., cycle counting) and compare them to the number allowed in the system design analysis. The system design analysis is performed assuming a particular number and severity of various transients. In accordance with either ASME Section III or ANSI B31.7, 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, the component remains within its design basis.
- The other method is to determine the fatigue life of a component using a calculated cumulative usage factor (CUF), which is defined as a normalized measure of total fatigue damage accumulated by a component as a result of all stress cycles that the component has experienced during its service life. The CUF can be calculated and tracked through plant life using thermal cycle counting or stress-based analysis techniques. In accordance with the ASME Boiler and Pressure Vessel Code, the component remains within its design basis for allowable fatigue life if the CUF remains less than or equal to one. [Reference 51, Sections 1.2.A, 3.0.B, 3.0.F]

Both methods use actual plant operating data. At CCNPP, the usage factor for several locations is calculated through stress-based analysis, which is the more rigorous of the two methods. Since the FMP monitors actual fatigue usage, a more realistic CUF is calculated. The data for thermal transients is collected, recorded, and analyzed using a computer program that evaluates input data from plant instrumentation. The computer software is used to analyze plant data associated with real transients and to predict the number of thermal cycle transients for 40 and 60 years of plant operation based on the historical records. [Reference 51, Section 3.0.F]

Plant parameter data is collected on a periodic basis and reviewed to ensure that the data represents actual transients. Valid data is entered into the computer program that counts the critical transient cycles and calculates the CUFs. The data is tracked in accordance with procedures that are governed by a quality assurance program that meets 10 CFR Part 50, Appendix B, criteria. The transient data is evaluated and the CUFs are calculated on a semi-annual basis, which provides a readily predictable approach to the alert value. Acceptable conditions exist, since no crack initiation would be predicted, when the calculated CUF for any given component is less than one, or when the design allowable number of cycles for the component has not been exceeded. In order to stay within the design basis, corrective action is initiated well in advance of the CUF approaching one or the number of cycles approaching the design allowable, so that appropriate corrective actions can be taken in a timely and coordinated manner. [Reference 51, Sections 1.2.A, 5.0]

Tracking the usage for the limiting components ensures that all remaining components will also remain below their fatigue limits. The FMP will perform an engineering evaluation to determine if the low-cycle fatigue usage for the piping and valves in the RCS hot leg sampling line is bounded by the existing bounding components. If these components are not bounded, they will be added to the FMP. Inclusion of these devices in the FMP may require a suitable alternative to thermal cycle counting. This alternative may consist of verification of the fatigue reduction factor for these components with full consideration given to the magnitude and frequency of the thermal cycles imposed by RCS sampling evolutions. [Reference 3, Attachment 10]

Since the FMP has been initiated, no locations have reached the limit on fatigue usage and no cracking due to low-cycle fatigue has been discovered. The FMP has undergone several modifications since its inception. Stress-based analysis was added to the computer software to calculate the CUFs for several locations due to unique thermal transients experienced and the unique geometries involved. Other modifications have been made to the FMP 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.

The CCNPP FMP has been inspected by the NRC, which noted that the program has been developed toward providing assurance that fatigue life usage of primary system components has not exceeded limits provided for in ASME Section III. In addition, the NRC noted that the FMP can be used to identify components where fatigue usage may challenge the remaining and extended life of the components and can provide a basis for corrective action where necessary. [Reference 52]

To further address fatigue for license renewal, CCNPP participated in a task, sponsored by the Electric Power Research Institute, to demonstrate the industry fatigue position. The task applied industry-developed methodologies to identify fatigue-sensitive component locations that may require further evaluation or inspection for license renewal and evaluate environmental effects, as necessary. The program objective included the development and justification of aging management practices for fatigue at various component locations for the renewal period. The demonstration systems were the Feedwater System, the pressurizer surge line in the RCS, and the letdown and charging subsystem in the Chemical and Volume Control System. [Reference 53, Page 3]

<u>Evaluation of Thermal Fatigue Effects to Address Generic Safety Issue 166</u>:

Generic Safety Issue 166, Adequacy of Fatigue Life of Metal Components, presents concerns identified by the NRC that must be evaluated as part of the license renewal process. The NRC staff concerns about fatigue for license renewal fall into the following five categories: [Reference 53, Page 2; Reference 54]

- The first category, adequacy of the fatigue design basis when environmental effects are considered, does not apply to the RCS hot leg sampling line because of stringent RCS water chemistry controls, exceptionally low oxygen concentrations (less than five parts per billion), and stainless steel materials used in fabrication of the affected piping and valve subcomponents.
- The second category concerns the adequacy of both the number and severity of design-basis transients. The engineering evaluation addressing fatigue in the RCS hot leg sampling line, discussed above, will consider the magnitude and frequency of the thermal cycles imposed by RCS sampling evolutions. [Reference 3, Attachment 10]
- The third category, adequacy of inservice inspection requirements and procedures to detect fatigue indications, does not apply because CCNPP does not rely on inservice inspection as the sole means for detection of fatigue.
- The fourth category, adequacy of the fatigue design basis for Class 1 piping components designed in accordance with ANSI B31.1, does not apply because the intervening pipe segments in this group are designed in accordance with ANSI B31.7, Class II.
- The final category, adequacy of actions to be taken when the fatigue design basis is potentially compromised, as discussed above, is adequately addressed by the CCNPP FMP.

Group 4 - (fatigue for piping and valves associated with sampling the RCS hot leg) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to fatigue for NSSS Sampling System piping and valves in the RCS hot leg sampling lines:

- Piping and valves in the RCS hot leg sampling line contribute to maintaining the system pressure boundary. Their integrity must be maintained under all CLB design conditions.
- The materials of construction for subcomponents in this group are carbon steel, stainless steel, or alloy steel.
- Fatigue is a plausible ARDM for this group because the components are subject to severe thermal cycling several times each week during routine RCS sampling operations. If unmanaged, this ARDM could eventually result in crack initiation and growth such that the components may not be able to perform their pressure boundary function under CLB conditions.
- The FMP monitors fatigue usage at bounding locations to ensure that NSSS components and the steam generators remain within their design basis. The FMP will be modified to include an engineering evaluation of the piping and valves in the RCS hot leg sampling line.

Therefore, there is a reasonable assurance that the effects of fatigue will be adequately managed for components in the RCS hot leg sampling lines 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 5 - (elastomer degradation for valve internals) - Materials and Environment

Group 5 consists of the CKVs in the gas return line to containment from the PASS cabinet whose internals are subject to elastomer degradation. These CKVs provide the passive intended function of maintaining the system pressure boundary. [Reference 3, Attachment 1] The internals for these CKVs are constructed of elastomers and stainless steel. [Reference 3, Attachments 4 and 5 for CKVs] The CKV internals are exposed to environments containing potentially radioactive gases from the containment atmosphere (described in subsection Group 1 - Materials and Environment, above). [Reference 3, Attachment 3s]

Group 5 - (elastomer degradation for valve internals) - Aging Mechanism Effects

When an elastomer ages, the primary mechanisms involved are scission, crosslinking, and changes associated with the compounding ingredients. Scission is the process of breaking molecular bonds, typically due to ozone attack, ultraviolet light, or radiation. Crosslinking is the process of creating molecular bonds between adjacent long-chain molecules, typically due to oxygen attack, heat, or curing. Scission results in increased elongation, decreased tensile strength, and decreased modulus; crosslinking has the opposite effects (i.e., decreased elongation, increased tensile strength, and increased modulus). The compounding ingredients used in an elastomer/rubber may be affected by evaporation, leaching, or mutation over their service life. [Reference 3, Attachment 7s for valves]

The seating surfaces for components in this group are constructed from elastomers, which are subject to the degradation described above. Degradation of any of these subcomponents would result in process fluid leakage past the seal, and eventual failure of the pressure boundary function.

Group 5 - (elastomer degradation for valve internals) - Methods to Manage Aging

Mitigation: The degradation of elastomers is related to time, material selection, and the environment. Apart from removal of the items from their environment, either as part of a permanent modification or under a periodic replacement program, there are no reasonable methods of mitigating the effects of these ARDMs for the subject subcomponents.

Discovery: Seating surface degradation for the internals of these CKVs can be detected through visual inspection.

Group 5 - (elastomer degradation for valve internals) - Aging Management Program(s)

Mitigation: As part of the in-place retirement of the PASS, the tubing between the CKVs in the gas return line to containment and the PASS cabinet will be capped; as a result, the CKV internals will continue to serve as the system pressure boundary when the hydrogen analyzers are placed in operation. [Reference 3, Attachment 10; Reference 55] Since removal of the CKV internals from their environment is not planned, there are no programs credited with mitigating the effects of elastomer degradation for the components in this group.

Discovery: Baltimore Gas and Electric Company currently plans to include the CKVs in the gas return line to containment from PASS in an ARDI Program to verify that unacceptable elastomer degradation of the valve internals is not occurring. For a discussion of the elements of the ARDI Program, refer to subsection Group 1 - Aging Management Programs, above.

Group 5 - (elastomer degradation for valve internals) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to elastomer degradation for the CKVs in the gas return line to containment from PASS:

- The CKVs in the gas return line to containment from PASS contribute to maintaining the pressure boundary of the NSSS Sampling System. The integrity of these components must be maintained under all CLB design conditions.
- The materials of construction for seating surfaces of these components include elastomers.
- Elastomer degradation is a plausible ARDM for this group because the valve internals are affected by scission, crosslinking, and changes associated with compounding ingredients in their installed locations. If unmanaged, degradation of these subcomponents could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- The CKVs in the gas return line to containment from PASS will be subjected to a new ARDI Program. This program will examine a representative sample of the components for degradation, and ensure that appropriate corrective actions are initiated on the basis of the findings.

Therefore, there is a reasonable assurance that the effects of elastomer degradation will be adequately managed for CKVs in the gas return line to containment from PASS 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 6 - (wear for CVs associated with sampling the RCS hot leg) - Materials and Environment

Group 6 consists of the CVs in the reactor coolant sampling subsystem associated with sampling the RCS hot leg whose seating surfaces are subject to wear. Specifically, this group consists of the RCS hot leg sample header isolation CV (1[2]CVPS-5467) and the RCS sample isolation CV (1[2]CVPS-5464) as depicted in Figure 5.13-1. These CVs provide the passive intended function of maintaining the system pressure boundary. [Reference 3, Attachment 1] Additionally, the seating surfaces of these CVs provide a containment isolation boundary. The valve disk and cage are constructed of stainless steel. [Reference 3, Attachments 4 and 5 for CVs]

As described in subsection Group 4 - Materials and Environment, above, the internal environment affecting these valves is borated water in the reactor coolant sampling subsystem. As described in subsection Group 1 - Materials and Environment, above, the external environment is climate-controlled air in the Auxiliary Building and the Containment. [Reference 3, Attachment 3]

Over a 60-year service life, these valves can be expected to be cycled between 9,000 and 10,000 times to support routine hot leg sample operations. Similar NSSS Sampling System CVs associated with the pressurizer surge line and vapor space sample headers are excluded from Group 6 since samples from the pressurizer are no longer being taken.

Group 6 - (wear for CVs associated with sampling the RCS hot leg) - Aging Mechanism Effects

Wear for the Group 6 valve internals results from relative motion between two surfaces (adhesive wear). Motions may be linear, circular, or vibratory in inert or corrosive environments. In addition to material loss from this mechanism, impeded relative motion between two surfaces held in intimate contact for extended periods may result in galling/self-welding. Wear rates may accelerate as expanded clearances result in higher contact stresses. [Reference 3, Attachment 7 for Valves]

The Group 6 valve internals are required to maintain the containment pressure boundary. Wear is considered plausible for the seating surfaces of the CVs in the RCS hot leg sampling lines because they may experience cyclic relative motion at tight-fitting surfaces. Movement between the internal subcomponent parts during normal valve operation can result in a gradual loss of material, which could result in a small amount of leakage. If left unmanaged, wear could eventually result in a loss of leak tightness such that the Group 6 components may not be able to perform their pressure boundary and containment isolation functions under CLB conditions.

Group 6 - (wear for CVs associated with sampling the RCS hot leg) - Methods to Manage Aging

Mitigation: Since wear of the valve internal subcomponent parts is dependent on the frequency of valve operation, decreased operation of the valves would slow the degradation of the valve seating surfaces. Proper material selection for the valve internal parts can also slow the effects of wear. It should also be noted that periodic valve operation can actually reduce the likelihood of the galling/self-welding phenomenon.

Discovery: Wear can be discovered by inspecting the CVs that are susceptible to this ARDM. In addition, the effects of wear can be detected by performing leak rate testing. Since wear occurs gradually over time, periodic testing can be used to discover minor leakage so that corrective actions can be taken prior to the loss of an intended function.

Group 6 - (wear for CVs associated with sampling the RCS hot leg) - Aging Management Program(s)

Mitigation: Operation of the CVs in Group 6 is dependent on RCS sampling requirements established by the CCNPP Chemistry Program. Maintaining the established sampling frequencies precludes modification of plant operating practices to reduce wear on the NSSS Sampling System. Therefore, there are no practicable means available (beyond proper material selection) to mitigate the effects of wear.

Discovery: Calvert Cliffs procedures STP M-571A-1(2), "Local Leak Rate Test, Penetrations 1A, 1B, 1C," which cover local leak rate testing (LLRT) for the RCS hot leg sampling containment penetrations, are part of the overall CCNPP Containment Leakage Rate Testing Program. [References 56 and 57] The valves that isolate the containment penetration piping for the RCS hot leg sample header are included in the scope of this program as part of the leakage testing for the associated containment penetrations. [Reference 37] The CCNPP Containment Leakage Rate Testing Program is discussed further in subsection Group 2, - Aging Management Programs, above.

The corrective actions taken as part of the LLRT Program will ensure that the CVs in the RCS hot leg sampling lines remain capable of performing their intended functions under all CLB conditions during the period of extended operation.

Group 6 - (wear for CVs associated with sampling the RCS hot leg) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to wear for the Group 6 components in the NSSS Sampling System:

- The CVs in the RCS hot leg sampling lines contribute to maintaining the system pressure boundary and provide containment isolation. Their integrity must be maintained under all CLB design conditions.
- The material for the seating surfaces of these valves is stainless steel.
- Wear is a plausible ARDM for the seating surfaces of these valves because of the repeated relative motion resulting from routine sampling operations. If unmanaged, wear could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- The CCNPP LLRT Program performs leakage testing which could detect the effects of wear on the seating surfaces of the CVs in the RCS hot leg sampling lines (i.e., degraded leak tightness). This program ensures that appropriate corrective actions will be taken if significant leakage is discovered.

Therefore, there is a reasonable assurance that the effects of wear will be adequately managed for the CVs in the RCS hot leg sampling lines 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.

5.13.3 Conclusion

The aging management programs discussed for the NSSS Sampling System are listed in Table 5.13-3. 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 NSSS Sampling 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 5.13-3

AGING MANAGEMENT PROGRAMS FOR THE NSSS SAMPLING SYSTEM

	Program	Credited As
Existing	CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program"	Program for mitigation and discovery of general corrosion for external surfaces of sample coolers, CVs, and HVs (included in Group 1) that are exposed to borated water (due to leakage) by performing visual inspections.
Existing	CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems"	Program for mitigation of crevice corrosion and pitting for internal surfaces of sample coolers, HVs, and SVs (included in Group 2) that are exposed to borated water (as process fluid) by controlling chemistry conditions.
Existing	CCNPP Technical Procedure CP-206, "Specification and Surveillance Component Cooling/Service Water System"	Program for mitigation of crevice corrosion and pitting for internal surfaces of HXs (included in Group 2) that are exposed to chemically-treated water from the CC System by controlling chemistry conditions in the CC System.
Existing	CCNPP Technical Procedure CP-217, "Specifications and Surveillance: Secondary Chemistry"	Program for mitigation of crevice corrosion and pitting for internal surfaces of sample coolers and HVs (included in Group 2) that are exposed to steam and feedwater in the steam generator blowdown sampling subsystem (as process fluid) by controlling chemistry conditions.
Existing	CCNPP Surveillance Test M-571I-1(2), "Local Leak Rate Test, Penetrations 1D, 47A, 47B, 47C, 47D, 48A, 48B, 49A, 49B, 49C"	Program for discovery and management of leakage that could be the result of crevice corrosion and pitting for seating surfaces of the containment isolation SVs in the sample return lines from the reactor coolant sample hoods to the RCDT (included in Group 2).
Existing	CCNPP Preventive Maintenance Checklists IPM 10000 (10001), "Check Unit 1(2) Instrument Air Quality"	Program for mitigation of general corrosion for CVOPs (included in Group 3) by controlling IA quality.
Existing	CCNPP Surveillance Test M-571A-1(2), "Local Leak Rate Test, Penetrations 1A, 1B, 1C"	Program for discovery and management of leakage that could be the result of wear for seating surfaces of the CVs in the RCS hot leg sampling lines (included in Group 6).

	Program	Credited As
Modified	CCNPP FMP • Evaluate piping and valves in the RCS hot leg sampling line under the FMP	Program for discovery and management of thermal fatigue for piping and valves in the RCS hot leg sampling line (Group 4) by evaluating low-cycle fatigue usage.
New	ARDI Program	Program for discovery and management of general corrosion for external surfaces of the miscellaneous waste evaporator concentrate pump discharge sample cooler (included in Group 1) by identifying and correcting degraded conditions. Program for discovery and management of crevice corrosion and pitting for internal surfaces of HXs, HVs, and SVs (included in Group 2) by identifying and correcting degraded conditions. Program for discovery and management of elastomer degradation for internals of the CKVs in the gas return line to containment from PASS (included in Group 5) by identifying and correcting degraded conditions.

5.13.4 References

1. CCNPP Life Cycle Management System and Structure Screening Results, Revision 4
2. CCNPP Updated Final Safety Analysis Report (UFSAR), Units 1 and 2, Revision 20
3. CCNPP Aging Management Review Report, "NSSS Sampling System," Revision 2
4. CCNPP Operating Instruction, OI-31B, "NSSS Sampling System," Revision 10
5. Letter from Mr. D. H. Jaffe (NRC) to Mr. J. A. Tiernan (BGE) dated May 6, 1986, "Safety Evaluation, Post Accident Sampling System, NUREG-0737, Item II.B.3"
6. Letter from Mr. J. A. Tiernan (BGE) to NRC Document Control Desk, dated March 11, 1988, "Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318 Report of Changes, Tests and Experiments"
7. BGE Drawing 60724SH0001, "Reactor Coolant and Waste Process Sample System, Post Accident Sampling System," Revision 45
8. Letter from Mr. R. W. Starostecki (NRC) to Mr. A. E. Lundvall, Jr. (BGE) dated March 25, 1983, "RI Inspection 50-317/83-05, 50-318/83-05"
9. Letter from Mr. A. E. Lundvall, Jr. (BGE) to Mr. R. A. Clark (NRC), dated November 30, 1982, "Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318 TMI Action Plan Item II.B.3"
10. Letter from Mr. L. B. Russell (BGE) to T. E. Murley (NRC), dated October 25, 1985, "Calvert Cliffs Nuclear Power Plant Units 1 and 2, Inoperability of Post-Accident Sampling System"
11. Letter from Mr. T. T. Martin (NRC) to Mr. J. A. Tiernan (BGE) dated April 1, 1987, "Combined Inspection Nos. 50-317/87-03 and 50-318/87-03"
12. BGE Drawing 60724SH0002, "Reactor Coolant and Waste Process Sample System, Post Accident Sampling System," Revision 12
13. BGE Drawing 60724SH0003, "Reactor Coolant and Waste Process Sample System, Post Accident Sampling System," Revision 24
14. BGE Drawing 60744SH0001, "Gas Analyzing System," Revision 14
15. BGE Drawing 60744SH0002, "Gas Analyzing System," Revision 13
16. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 2
17. BGE Drawing 92769SH-CC-2, "M-601 Piping Class Summary," Revision 20
18. BGE Drawing 92769SH-CC-1, "M-601 Piping Class Summary," Revision 23
19. BGE Drawing 92769SH-HC-4, "M-601 Piping Class Summary," Revision 21
20. CCNPP Sampling (NSSS) System Component Level ITLR Screening Results, Revision 1
21. CCNPP Aging Management Review Report, "Instrument Line Commodity," Revision 1
22. BGE Drawing 92769SH-HC-1, "M-601 Piping Class Summary," Revision 26

23. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0
24. CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program," Revision 1
25. CCNPP Administrative Procedure MN-3-110, "Inservice Inspection of ASME Section XI Components," Revision 2
26. BGE Drawing 92769SH-EB-2, "M-601 Piping Class Summary," Revision 19
27. BGE Drawing 92769SH-HC-3, "M-601 Piping Class Summary," Revision 20
28. BGE Drawing 92769SH-HC-6, "M-601 Piping Class Summary," Revision 27
29. BGE Drawing 92769SH-GC-1, "M-601 Piping Class Summary," Revision 23
30. CCNPP Nuclear Program Directive CH-1, "Chemistry Program," Revision 1
31. CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems," Revision 8
32. CCNPP Technical Procedure CP-217, "Specifications and Surveillance: Secondary Chemistry," Revision 5
33. CCNPP Technical Procedure CP-206, "Specifications and Surveillance Component Cooling/Service Water System," Revision 3
34. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48
35. CCNPP Surveillance Test Procedure M-571I-1, "Local Leak Rate Test, Penetrations 1D, 47A, 47B, 47C, 47D, 48A, 48B, 49A, 49B, 49C" (Unit 1), Revision 0
36. CCNPP Surveillance Test Procedure M-571I-2, "Local Leak Rate Test, Penetrations 1D, 47A, 47B, 47C, 47D, 48A, 48B, 49A, 49B, 49C" (Unit 2), Revision 1
37. Letter from Mr. A. W. Dromerick (NRC) Mr. C. H. Cruse (BGE), dated February 11, 1997, "Issuance of Amendments for CCNPP Unit No. 1 (TAC No. M97341) and Unit No. 2 (TAC No. M97342)" [Amendment Nos. 219/196]
38. 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors"
39. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated November 26, 1996, "Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318 License Amendment Request: Adoption of 10 CFR Part 50, Appendix J, Option B for Types B and C Testing"
40. BGE Drawing 60712SH0001, "Compressed Air System, Instrument Air and Plant Air," Revision 46
41. BGE Drawing 60712SH0003, "Compressed Air System, Instrument Air and Plant Air," Revision 75
42. BGE Drawing 62712SH0001, "Compressed Air System, Instrument Air and Plant Air," Revision 37

43. BGE Drawing 62712SH0003, "Compressed Air System, Instrument Air and Plant Air," Revision 80

44. CCNPP Aging Management Review Report, "Compressed Air System," Revision 4

45. CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," Revision 5

46. CCNPP NUCLEIS Database Repetitive Tasks 10191024 (20191022), "Check Unit 1 (2) Instrument Air Quality at Selected System Low Points"

47. CCNPP Preventive Maintenance Checklists IPM 10000 (10001), "Check Unit 1(2) Instrument Air Quality," Revision 2

48. CCNPP Specification No. SP-248D, "Nuclear Class Control Valves," Revision 2

49. "Metal Fatigue in Engineering," H. O. Fuchs and R. I. Stephens, John Wiley & Sons, Copyright 1980

50. Combustion Engineering Owners Group Task 571, Report No. CE-NPSD-634-P, "Fatigue Monitoring Program for Calvert Cliffs Nuclear Power Plants Units 1 and 2," April 1992

51. CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring," Revision 0

52. 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"

53. BGE Procurement Specification 6422284S, "Technical Services to Evaluate Thermal Fatigue Effects on Calvert Cliffs Nuclear Power Plant Systems Requiring Aging Management Review for License Renewal," Revision 0

54. NUREG-0933, Generic Safety Issue 166, "Adequacy of Fatigue Life of Metal Components," Revision 1, June 30, 1995

55. CCNPP Engineering Service Package ES199601279, "Isolate the Unused PASS System from the Remainder of the Plant," June 5, 1996

56. CCNPP Surveillance Test Procedure M-571A-1, "Local Leak Rate Test, Penetrations 1A, 1B, 1C" (Unit 1), Revision 0

57. CCNPP Surveillance Test Procedure M-571A-2, "Local Leak Rate Test, Penetrations 1A, 1B, 1C" (Unit 2), Revision 0

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]

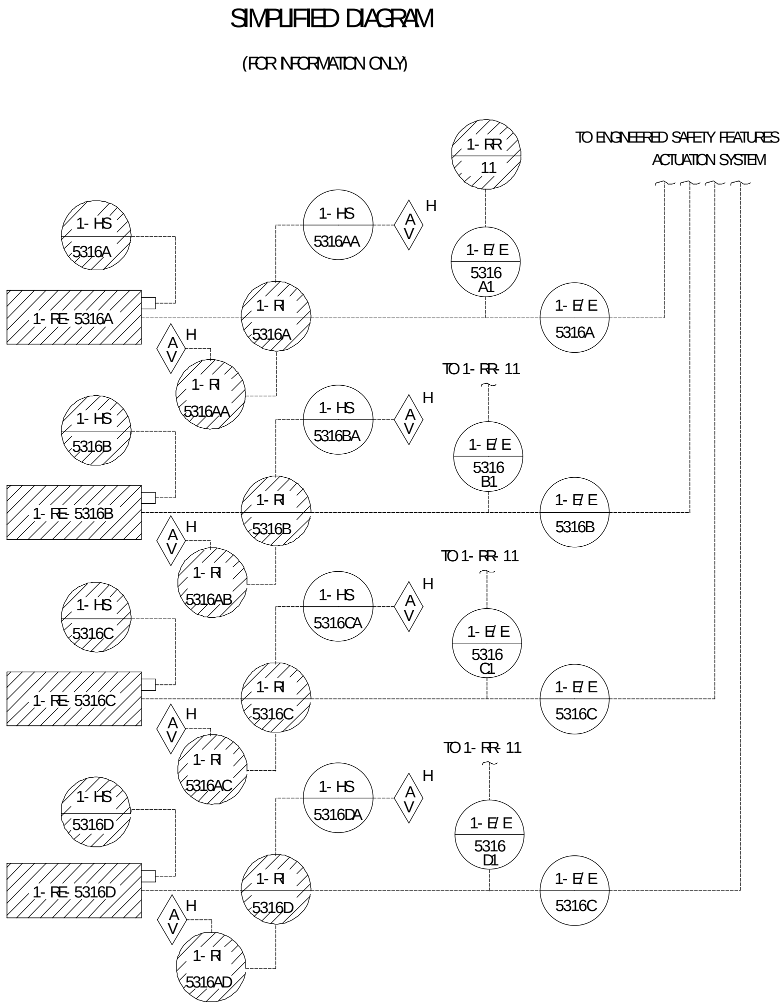

FIGURE 5.14-1

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.

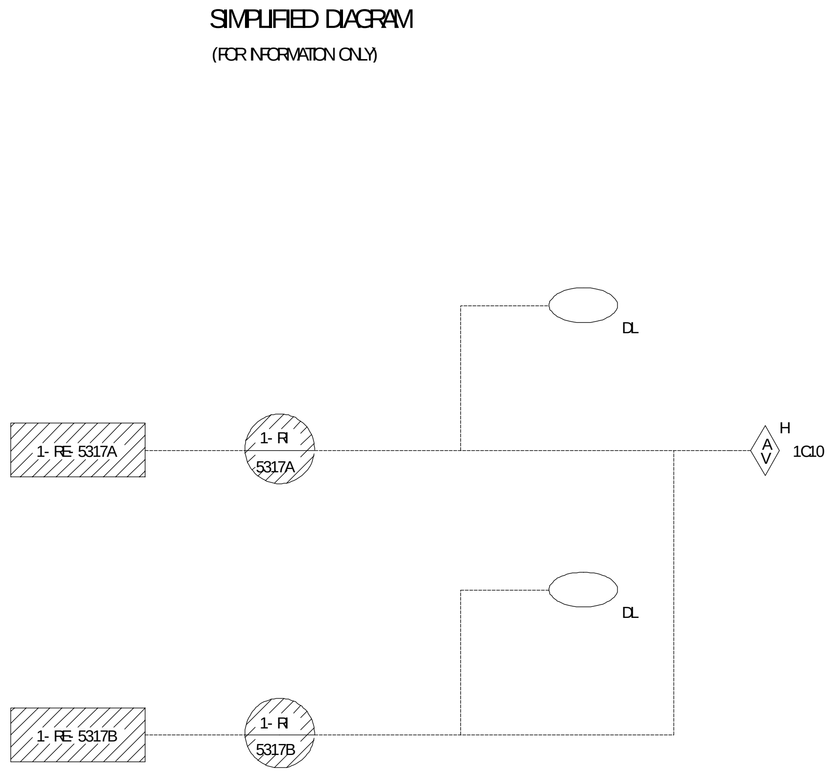

FIGURE 5.14-2

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.

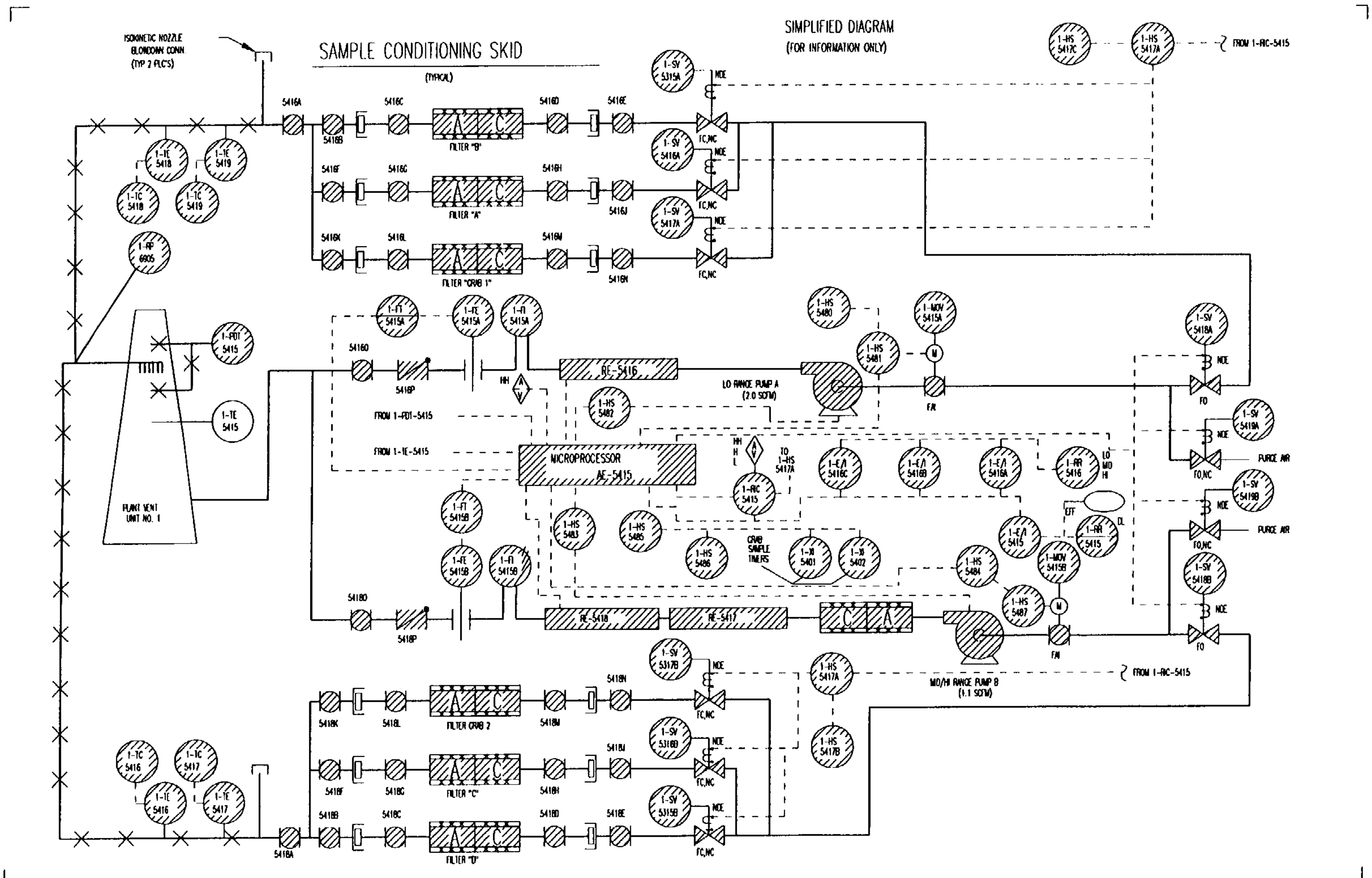

FIGURE 5.14-3
CCNPP UNIT I - WIDE RANGE EFFLUENT GAS RADIATION MONITORS
(TYPICAL FOR UNIT 2)

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.

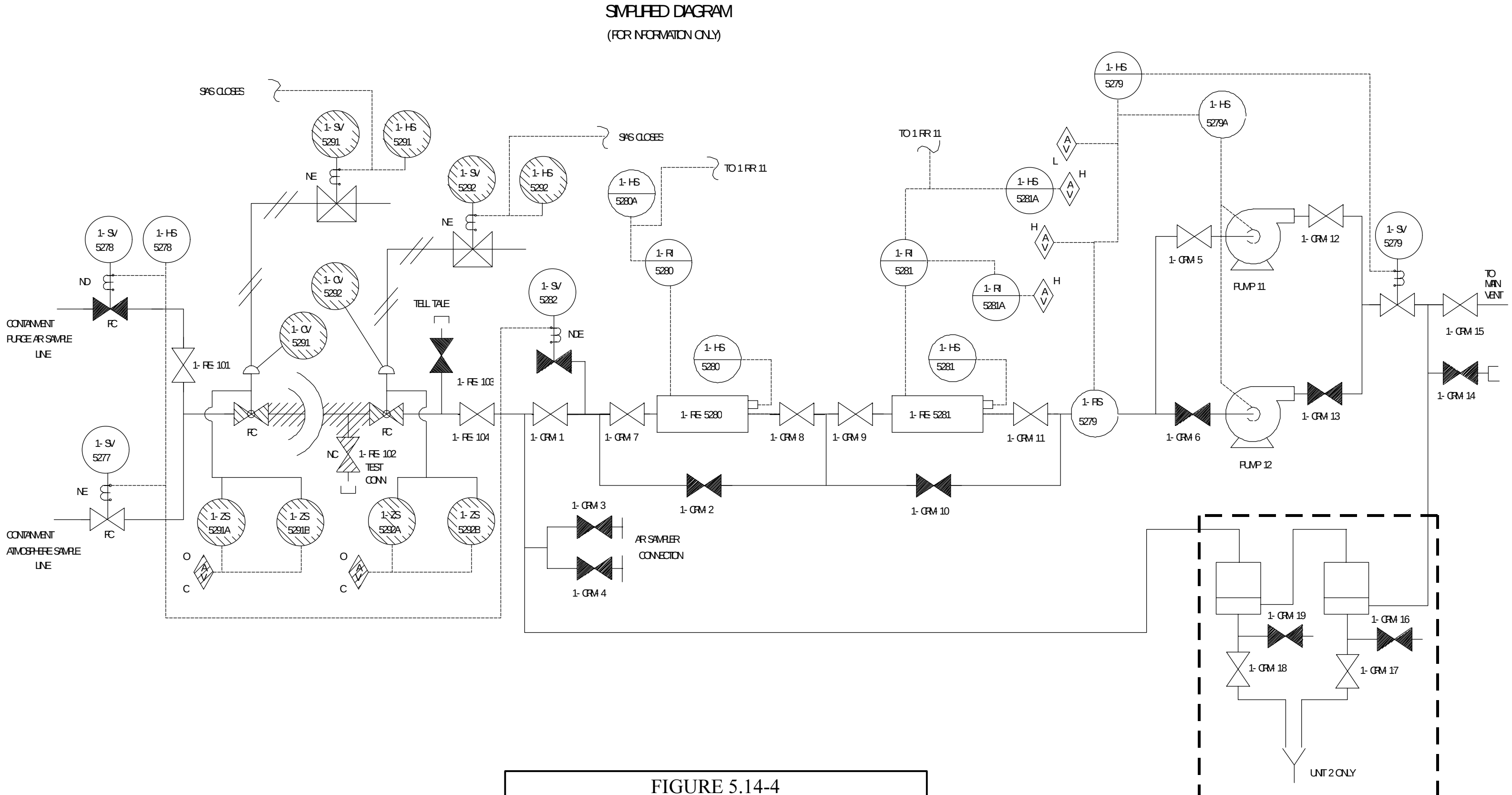

FIGURE 5.14-4

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.

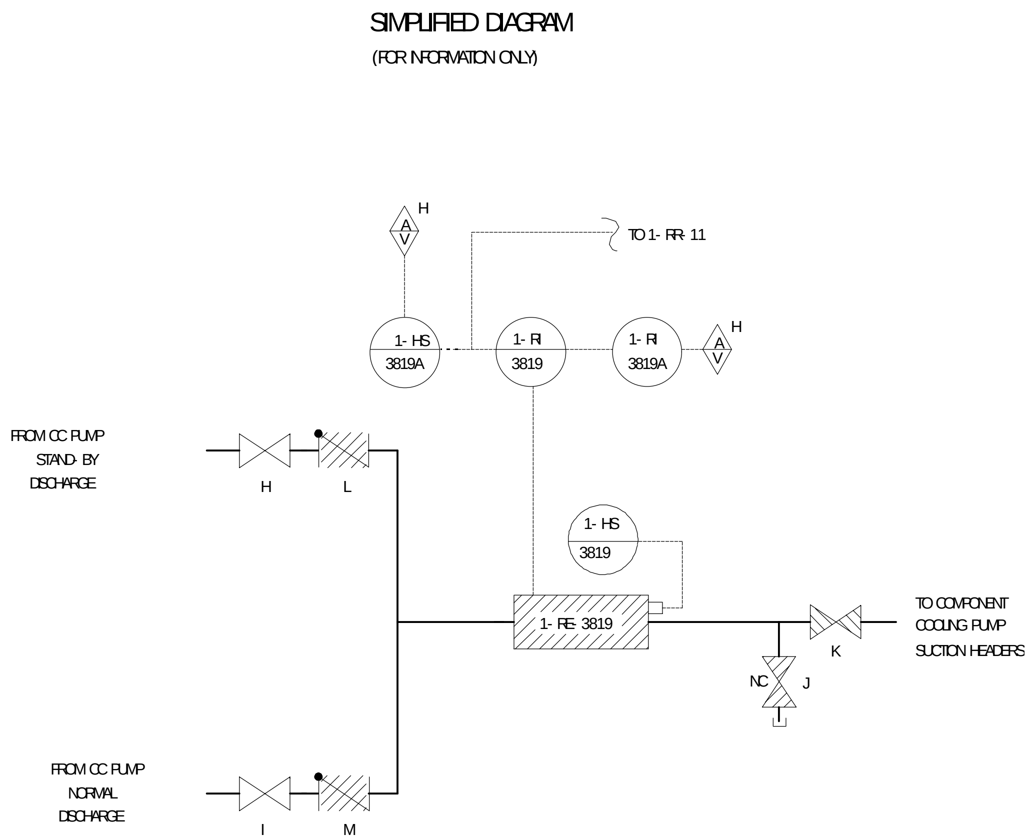

FIGURE 5.14-5

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.

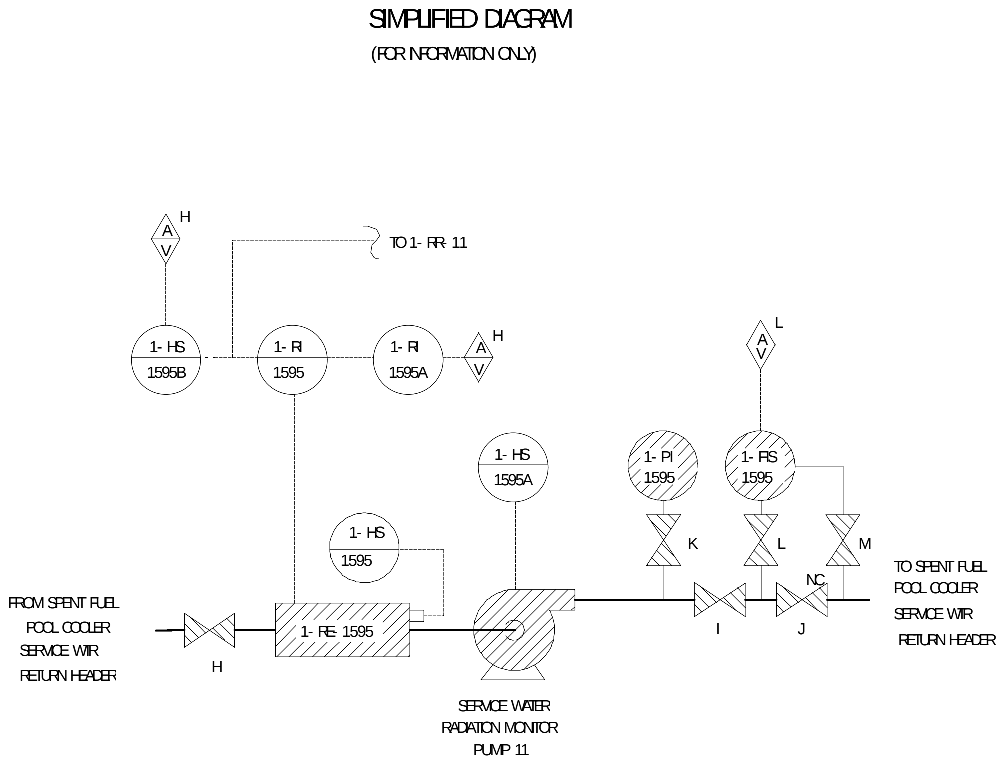

FIGURE 5.14-6

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.

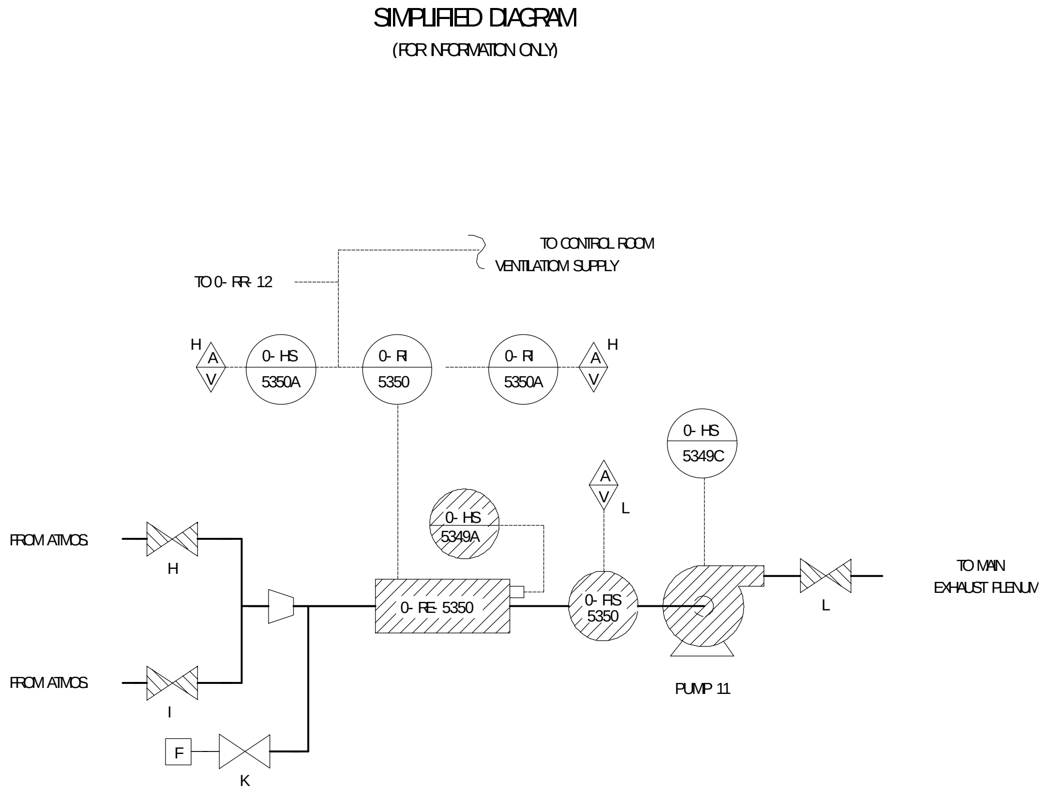

FIGURE 5.14-7

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)

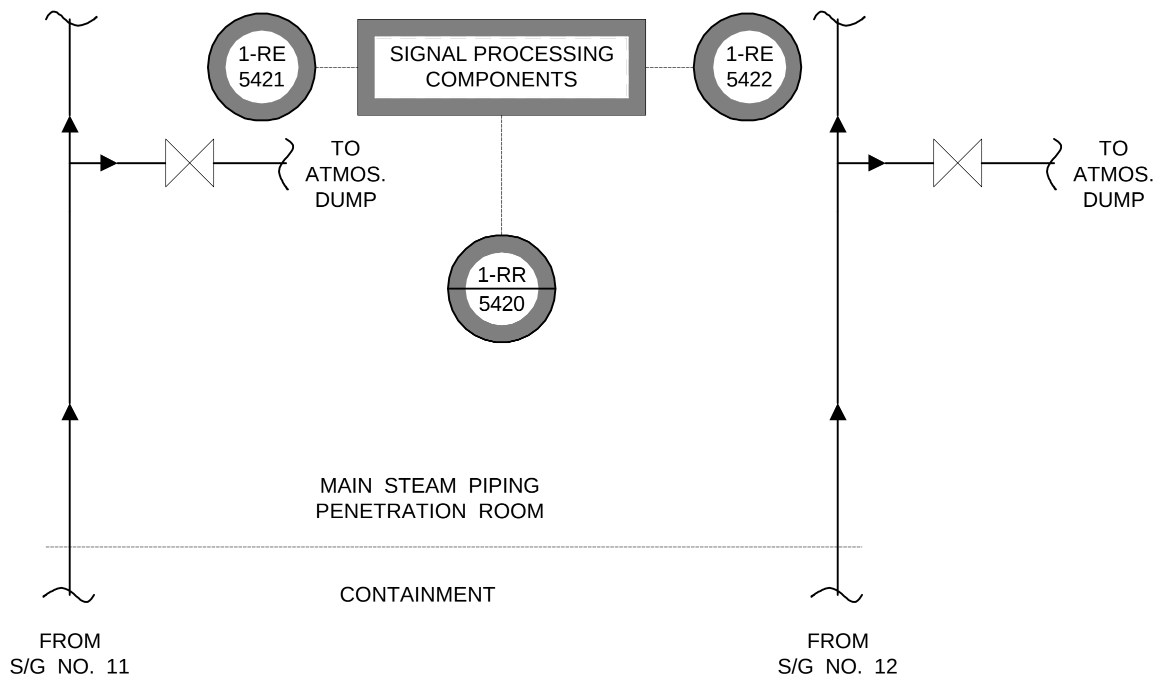

FIGURE 5.14-8

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

5.15 Safety Injection System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Safety Injection (SI) System. The SI 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.

5.15.1 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.

Representative historical operating experience pertinent to aging 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.

Section 5.15.1.1 presents the results of the system level scoping, 5.15.1.2 the results of the component level scoping, and 5.15.1.3 the results of scoping to determine components subject to an AMR.

5.15.1.1 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.

<u>System Description/Conceptual Boundaries</u>

The major functions of the SI System are to: (a) supply emergency core cooling in the unlikely event of a Loss-of-Coolant Accident; and (b) increase shutdown margin following the rapid cooldown of the Reactor Coolant System (RCS) caused by a rupture of a main steam line. These functions are performed by injecting borated water into the RCS. [Reference 1, Section 1.1.1; Reference 2, Section 6.3.1] The SI System is also utilized to: (a) remove heat from the RCS during plant cooldown once RCS temperature is below 300°F; (b) maintain suitable RCS temperatures during refueling and maintenance operations; and (c) provide storage capacity for borated water needed for spent fuel pool (SFP) and refueling pool operations. [Reference 1, Section 1.1.1; Reference 2, Sections 6.3.1, 6.3.2.4, and 9.2.4] During normal plant operations, the SI System is maintained in a standby mode with components aligned for injection to the RCS. [Reference 3, Section 5.0]

APPENDIX A - TECHNICAL INFORMATION
5.15 - SAFETY INJECTION SYSTEM

The SI System consists of high-pressure and low-pressure subsystems that provide borated water to four SI headers, each connected to associated cold leg piping in the RCS. In addition to the associated piping, valves, controls, and instrumentation, the SI System for each CCNPP Unit comprises the following major components: [Reference 2, Sections 6.3.1 and 6.3.2]

- Three electric motor-driven high-pressure safety injection (HPSI) pumps, each with an associated seal cooler;
- Two electric motor-driven low-pressure safety injection (LPSI) pumps, each with an associated seal heat exchanger (HX);
- Four safety injection tanks (SITs); and
- A refueling water tank (RWT), with an associated electric motor-driven pump and heat exchanger (RWTHX).

In 1989, a bent vertical support in the Unit 1 LPSI suction piping was identified. Investigation determined that securing one LPSI pump while others were running resulted in slamming of the secured pump's discharge check valve (CKV) and a subsequent water hammer transient of sufficient magnitude to deform several supports. Following a design evaluation, the damaged supports were replaced with upgraded supports. [Reference 4] Operating procedures were modified to require throttling flow prior to securing a pump if two LPSI pumps are running.

In 1994, a non-isolable leak at a welded fitting in the discharge test piping for 22A SIT resulted in plant shutdown. Metallurgical analysis of the cracked weld concluded that high-cycle fatigue caused cracking at the weld joint. [Reference 5] Changes had been made to the support installed at this connection during replacement of the SIT outlet CKV in 1993. Other locations were evaluated and found to be acceptable. [Reference 6] Vibration measurements and computer modeling subsequent to the failure showed that the pipe support configuration introduced a high potential for harmonic oscillation, coinciding with the excitation frequency of the RCS, to occur. [Reference 5] The test connection was replaced and the pipe support configuration was changed to prevent vibration at the critical frequency.

In 1998, damage was found on the stanchion and restraining steel of a pipe support located on the common LPSI pump discharge header in Unit 1. The cause of the damage is currently understood to be the result of water hammer loading caused by LPSI pump discharge CKV slam(s). The cause of the apparent CKV slam(s) is still under investigation.

In the past, cracking occurred at certain other welds in SI System piping. [References 7, 8, and 9] In each case, inspection and/or evaluation concluded that similar piping and components in the remainder of the SI System for both units were not experiencing similar effects. [References 9 and 10] Analysis following each event determined that cracking was due to high-cycle fatigue caused by vibration inherent in the design of the system. Reconfiguration of the affected piping and associated supports has prevented recurrence of cracking at each location. [References 9 and 11] Since normal and design operating conditions result in neither excessive cycling nor significant mechanical/vibrational loading conditions, high-cycle fatigue is not plausible for the SI System.

Many other SI System components have been disassembled over the plant's operating history with no unusual or unexpected signs of wear or degradation noted.

The SI System is composed of the following general categories of equipment and devices: [Reference 1, Section 1.1.2; Reference 2, Section 6.3.2.4; Reference 12, Table 2]

Piping	Convey borated water to perform system functions;
Valves	Control valves (CVs), CKVs, hand valves (HVs), motor-operated valves (MOVs), and relief valves (RVs), which provide containment isolation and system alignment/isolation/protection;
Instruments	Measure system flow rates, tank levels, and temperatures;
Tanks	Store borated water used for injection into the RCS and for refueling purposes;
HXs	Provide a heat sink for seal cooling water for system pumps, and prevent freezing of borated water in the RWT; and
Pumps	Provide motive force to move borated water into the RCS, into the SITs, and into the RWT.

System Interfaces

The SI System has interfaces with 11 plant systems. These interfaces and their applicability for license renewal are discussed below.

The following interfaces with the SI System are within the scope of license renewal:

- Engineered Safety Features Actuation System (ESFAS) [Reference 1, Section 1.1.2] The ESFAS supplies control signals to SI System components in response to Design Basis Event (DBE) conditions. When a Safety Injection Actuation Signal (SIAS) has been generated, the ESFAS provides a signal to: (a) start two HPSI pumps and both LPSI pumps; (b) open the LPSI header, main HPSI header, auxiliary HPSI header, and SIT outlet MOVs; and (c) close the SIT CKV leakage and leakoff to reactor coolant drain tank CVs. When the inventory in the RWT is nearly depleted, signals from SI System level switches cause a Recirculation Actuation Signal (RAS) to be generated in the ESFAS. In response, the ESFAS provides a signal to: (a) open the containment sump discharge MOVs; (b) shut down the LPSI pumps; and (c) close the mini-flow return to RWT isolation MOVs. [Reference 2, Section 6.3.3] This interface involves cables/conduits associated with transmitting signals between the ESFAS and the SI System, as well as controls associated with the pumps and valves.
- RCS [Reference 1, Section 1.1.2] The SI System has several interfaces with the RCS. The RCS supplies control signals to SI System MOVs in response to RCS pressure. When pressurizer pressure exceeds preset values, the RCS provides signals to: (a) open the SIT outlet MOVs; and (b) prevent opening of the shutdown cooling (SDC) header return isolation MOV outside containment. [Reference 2, Sections 6.3.1 and 9.2.6] This interface involves cables/conduits associated with transmitting signals to the SI System, and controls associated with the MOVs. The SI System piping interfaces with the RCS at the discharge of the loop inlet CKVs. Each of these four connections allows injection of borated water to the reactor pressure vessel through an inlet nozzle in the associated RCS cold leg piping in the event emergency core cooling is needed. [References 13 and 14] During a normal plant shutdown, this piping is also used to supply SDC flow from the LPSI pumps. The SI System piping also interfaces with the RCS piping at the outlet

of the SDC header return isolation MOV inside containment, allowing return of SDC flow. [Reference 2, Section 4.1.2]

- Containment Spray (CS) System [Reference 1, Section 1.1.2] The SI System piping has several interfaces with the CS System. On CS pump start in response to a SIAS, the SI System provides borated water to the CS pump suction header from the RWT. Prior to initiation of a Containment Spray Actuation Signal, flow from the CS System returns to the RWT through the CS pump mini-flow return CKVs. [Reference 2, Section 6.4.4] After a RAS initiation, operators may choose to divert a portion of the cooled water from the CS headers to the suction of the HPSI pumps. [Reference 2, Section 6.3.1] In the SDC mode of operation, borated water from the LPSI pump discharge header flows through the shutdown cooling heat exchanger (SDCHX) to the LPSI return header on its way into the RCS cold leg. [Reference 2, Section 9.2.1] Additional connections to the CS System allow flow: (a) from the SDC return header to flow instrumentation in the SI System flowpath used during purification; (b) from the SDC return header to the RWT return header; and (c) from the CS header to the RWT return header. [Reference 3, Section 6.5; Reference 15, Sections 6.11 and 6.12; Reference 16, Section 6.2]
- Component Cooling (CC) System [Reference 1, Section 1.1.2] The CC System provides flow to the LPSI pump seal HXs and HPSI pump seal coolers, as well as cooling water piped directly to the bearing housings and stuffing box jackets for these pumps. [References 17 through 21]
- SFP Cooling System [Reference 1, Section 1.1.2] The SI System provides makeup water for the SFP through a piping connection and valve at the RWT. [Reference 2, Section 6.3.2.4] The SI System piping also interfaces with the SFP Cooling System at the LPSI pump suction header to provide additional SFP cooling when the complete core is removed from the reactor vessel and temporarily stored in the SFP. [Reference 2, Section 9.2.1; Reference 16, Sections 6.11 and 6.12; Reference 22]
- Chemical and Volume Control System (CVCS) [Reference 1, Section 1.1.2] The SI System piping has several interfaces with the CVCS. One connection allows the charging pumps to discharge to the auxiliary HPSI header as an alternate charging path to the RCS. [References 23 and 24] Two other connections provide for reactor coolant purification during SDC operations. Another connection allows transfer of borated water between the CVCS and the RWT. [References 25 and 26]
- Primary Containment System [References 27 and 28] Two recirculation headers in the SI System connect to the emergency sump inside containment. After a RAS initiation, the HPSI pumps take suction directly from the emergency sump. [Reference 2, Section 6.3.1]

The following interfaces with the SI System are not within the scope of license renewal:

- Compressed Air System [Reference 1, Section 1.1.2] The Compressed Air System provides instrument air for operation of CVs in the SI System. [References 29 and 30]
- Nitrogen and Hydrogen System [Reference 1, Section 1.1.2] A distribution header in the Nitrogen and Hydrogen System provides nitrogen gas used to pressurize the SITs. [Reference 2, Section 6.3.2.3]
- Plant Heating System [Reference 1, Section 1.1.2] The Plant Heating System provides hot water flow through the shell side of the RWTHX; borated water from the RWT is circulated through the

tube side of the RWTHX to prevent freezing of the RWT contents in winter. [Reference 2, Section 6.3.2.4]

- Liquid Waste System [References 31 through 34] The SI System has several interfaces with the Liquid Waste System. Drainage from the RWT, the RWT circulating pump casing, and the RWT circulating pump RV is collected by the miscellaneous waste processing subsystem. [Reference 2, Section 11.1.2.1.3] Flow from the SIT leakoff return lines is directed to the reactor coolant drain tank during normal operation. [Reference 2, Section 11.1.2.1.2]

Figures 5.15-1 and 5.15-2 comprise a simplified diagram of the SI System and are provided for information only. These figures depict the major SI System components and interfaces discussed above.

System Scoping Results

The SI System is in scope for license renewal based on 10 CFR 54.4(a). The following intended functions of the SI 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 12, Table 1]

- To provide borated water to the RCS for reactivity control, and pressure and level control in response to DBEs upon SIAS;
- To provide borated water to the RCS for reactivity control, and pressure and level control (passively) when RCS pressure drops below 200 psig;
- To recirculate lost coolant back to the RCS and CS System (Recirculation Mode);
- To send a signal to ESFAS for RAS;
- To provide long-term core flush via hot leg injection;
- To provide containment isolation of the SI system during a Loss-of-Coolant Accident;
- To maintain the pressure boundary of the system (liquid and/or gas);
- To maintain mechanical operability and/or provide protection of the mechanical system;
- To provide borated water from the RWT to the CS pumps;
- To maintain electrical continuity and/or provide protection of the electrical system;
- To provide makeup water from the RWT to the SFP during a fuel handling incident; and
- To restrict flow to a specified value in support of a DBE response.

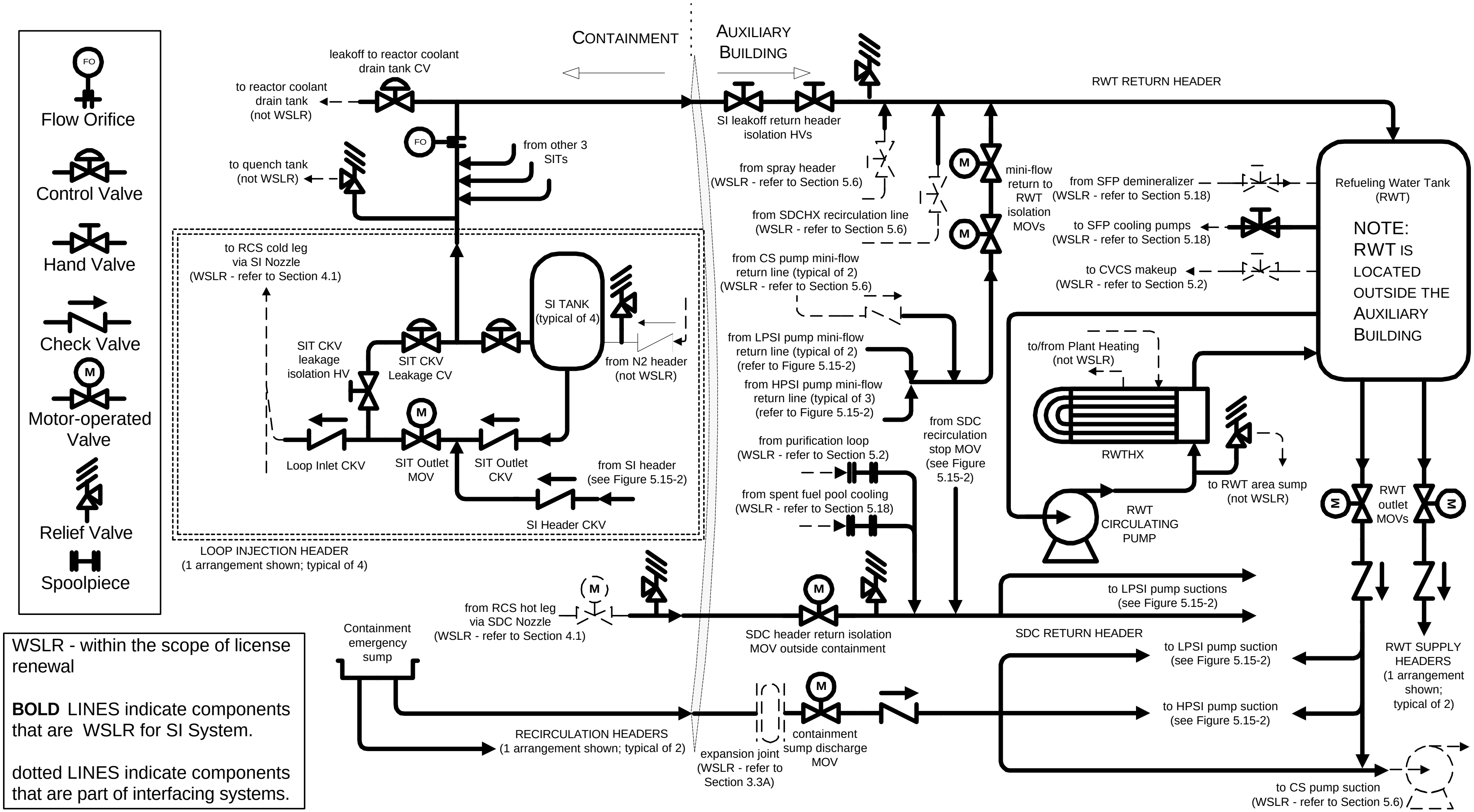

FIGURE 5.15-1

SAFETY INJECTION SYSTEM
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

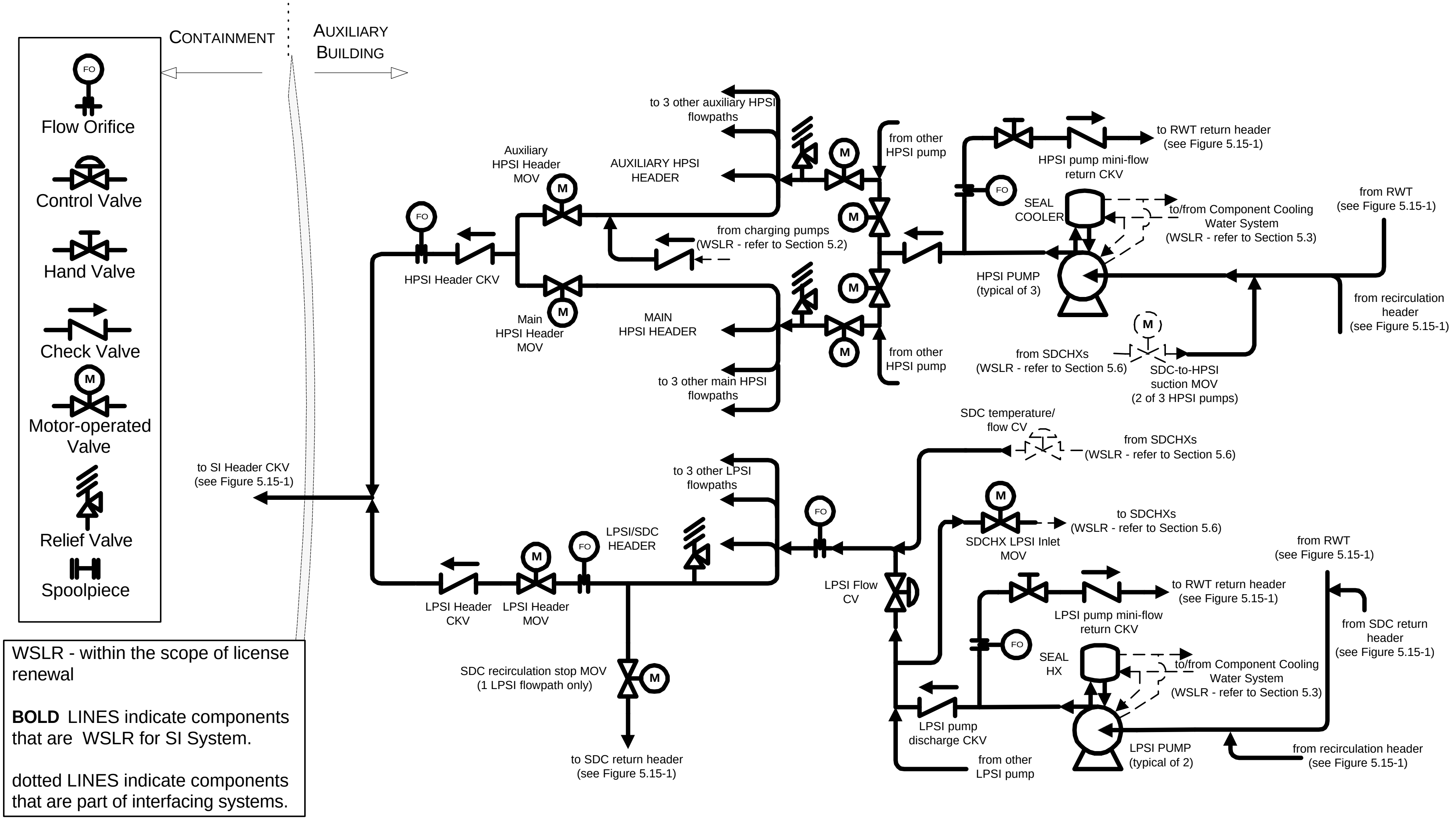

FIGURE 5.15-2

SAFETY INJECTION SYSTEM
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

The following intended functions of the SI System were determined based on the requirements of §54.4(a)(3): [Reference 12, Table 1]

- For fire protection (§50.48) - To: (a) provide RCS pressure and inventory control to ensure safe shutdown in the event of a postulated severe fire; (b) provide RCS heat removal by realigning and operating in the SDC mode; and (c) prevent inadvertent dumping of the SITs when RCS temperature is less than 300°F.
- For environmental qualification (§50.49) - To: (a) provide information used to assess the environs and plant condition during and following an accident; and (b) maintain functionality of electrical components as addressed by the Environmental Qualification Program.
- For station blackout (§50.63) - To: (a) provide valve position indication and closure of containment isolation valves; and (b) provide RCS isolation to maintain RCS inventory.

All components of the SI System that meet the environmental qualification or station blackout criteria of 54.4(a)(3) are also safety-related. [Reference 12, Table 2] Some of the components that meet the fire protection criteria are non-safety-related and are within the scope of license renewal only because of the 54.4(a)(3) criteria. [Reference 12, Table 2]

All components of the SI System that support the above functions, with the exception of the non-safety-related instrumentation and controls supporting the fire protection functions, meet Seismic Category I requirements. [Reference 12, Table 2; References 17, 18, 22 through 28, and 31 through 35] The SI System piping provided with the HPSI and LPSI pumps is designed in accordance with United States of America Standard Code for Pressure Piping, Power Piping, B31.1.0-1967. [References 36, 37, and 38] All other piping in the SI System complies with the following criteria in American National Standards Institute (ANSI) Nuclear Power Piping Code B31.7, 1969: [Reference 2, Section 6.3.2.6]

- Design requirements for Class I piping apply to: (a) all SI System piping between the SI header CKVs, the SIT outlet MOVs, the SIT CKV leakage CVs, and the RCS interface at the loop inlet CKVs; (b) SIT discharge piping from the SIT outlet CKVs to the SIT outlet MOVs; and (c) SDC piping between the interface with RCS (i.e., at the outlet of the SDC header return isolation MOV inside containment) and the SDC header return isolation MOV outside containment. [Reference 39, Piping Class CC-4; Reference 40, Piping Classes CC-13 and CC-14]
- Design requirements for Class III piping apply to: (a) all SI System piping from the interfaces with the SFP Cooling System and CVCS to the spoolpiece connecting to the LPSI discharge header; and (b) all piping associated with the RWT heating flowpath. [Reference 41, Piping Class HC-4; Reference 42, Piping Class HC-23]
- Design requirements for Class II piping apply to all remaining piping in the SI System. [Reference 41, Piping Class HC-3; Reference 43, Piping Classes DC-1 and DC-2; Reference 44, Piping Classes GC-1, GC-3, GC-4, GC-5, GC-7, and GC-9; Reference 39, Piping Class CC-6; Reference 40, Piping Class CC-13]

The design parameters for major SI System components are presented in Section 6.3.2 of the CCNPP Updated Final Safety Analysis Report.

5.15.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the SI System that is within the scope of license renewal includes all components (electrical, mechanical, and instrument) and their supports associated with the storing and delivering of borated water to the RCS. The following system flowpaths allow transfer of borated water to the RCS interface at each of the four loop inlet CKVs (refer to Figure 5.15-1): [Reference 2, Sections 6.3.1 and 9.2.2; Reference 12, Table 2; References 27, 28, and 31 through 34]

- Injection mode flowpath (post-DBE operations after a SIAS; motive force provided by HPSI pumps) - from the RWT, through the running HPSI pumps (i.e., two of the three installed pumps), and from there to the SI header CKVs and loop inlet CKVs by way of both: (a) a main HPSI header and four main HPSI header MOVs; and (b) an auxiliary HPSI header and four auxiliary HPSI header MOVs;
- Injection mode flowpath (post-DBE operations after a SIAS; motive force provided by LPSI pumps) - from the RWT, through both LPSI pumps, into a common discharge header, through the LPSI flow CV, the four LPSI header MOVs, to the SI header CKVs and loop inlet CKVs;
- Injection mode flowpath (post-DBE operations after RCS pressure drops below approximately 200 psig; motive force provided by pressurized SITs) - from each of the four SITs, through the open SIT outlet CKVs and SIT outlet MOVs, to the loop inlet CKVs;
- Recirculation mode flowpath (post-DBE operations after a RAS; motive force provided by HPSI pumps) - from the interface with the containment emergency sump, through the containment sump discharge MOVs, and through the HPSI injection mode flowpath described above; and
- SDC mode flowpath (motive force provided by LPSI pumps) - from the RCS interface at the outlet of the SDC header return isolation MOV inside containment, through the SDC header return isolation MOV outside containment, and through the LPSI injection mode flowpath described above, with a portion of the borated water passing through the SDCHX LPSI inlet MOV into the CS System. After passing through the SDCHXs and the SDC temperature/flow CV in the CS System, this fluid re-enters the SI System on the downstream side of the LPSI flow CV, rejoining the remainder of the borated water in the SDC mode flowpath.

The following system flowpaths form parts of the system pressure boundary and are also included within the scope of license renewal for the SI System: [Reference 2, Section 6.3.2; Reference 12, Table 2; References 25 through 28, and 31 through 34]

- Minimum-flow recirculation flowpaths for pumps (motive force provided by associated pumps) - from the discharge headers for each HPSI and LPSI pump through an associated flow orifice and mini-flow return CKV, and from the CS System interface at the outlet of each CS pump mini-flow return CKV, through the mini-flow return to RWT isolation MOVs, through the common RWT recirculation header back into the RWT;
- Circulation flowpath for the RWT - from the RWT, through the RWT circulating pump, the tubes in the RWTHX, and back into the RWT;

  NOTE: The RWTHX bonnets/covers/tubes and associated stainless steel welds form a part of the SI System pressure boundary. The intended function for other subcomponent parts of the RWTHX (i.e., the shell and associated carbon steel welds, fittings, studs, nuts, and vessel supports) is to provide structural support for the tube assembly. A pressure boundary breach of the Plant Heating System will not impact this support function. [Reference 1, Attachment 6 for HXs]

- SDC recirculation flowpaths - from the CS System interfaces in the SDC return header up to and including the following:

  Through the SDCHX recirculation stop CV to the LPSI pump suction header; or

  The common RWT recirculation header; or

  Through the SI-to-CVCS flow instrumentation to the CVCS interface at the outlet of the SDC supply to CVCS backup HV; and

- Leakoff return flowpaths for each SIT - from the SI System piping between the SIT outlet and loop inlet CKVs, through the SIT CKV leakage CV, through common leakoff return piping and a flow orifice up to and including the following:

  To the Liquid Waste System interface at the outlet of the leakoff-to-reactor coolant drain tank CV, or

  Through the normally closed SI leakoff return header isolation HVs to the common RWT recirculation header.

Additional components that form parts of the system pressure boundary along these flowpaths (e.g., piping, instruments, seal coolers and HXs for pumps, SIT fill-and-drain CVs, normally closed HVs, RVs, solenoid-operated valves in instrument air supply piping) and their supports are also included within the scope of license renewal for the SI System. [Reference 12, Table 2; References 17, 18, 22, 25 through 28, and 31 through 34]

The following 53 device types in the SI System have at least 1 intended function: [Reference 1, Table 2-1]

Class "CC" Piping (stainless steel, primary rating 1500 psig at 1125°F)		Pressure Indicator
Class "DC" Piping (stainless steel, primary rating 900 psig at 1125°F)		Pressure Switch
Class "GC" Piping (stainless steel, primary rating 300 psig at 1125°F)		Pressure Transmitter
Class "HC" Piping (stainless steel, primary rating 150 psig at 500°F)		Pump/Driver Assembly
Circuit Breaker	Hand Valve	Relief Valve
Check Valve	Heat Exchanger	Relay
Coil	Current/Pneumatic Device	Solenoid
Control Valve	Ammeter	Solenoid Valve
Control Valve Operator	Power Lamp Indicator	Temperature Element
Disconnect Switch/Link	Level Indicator	Temperature Indicator
Voltage/Current Device	Level Indicator Alarm	Tank
Flow Element	Level Switch	Temperature Recorder
Flow Indicator	Level Transmitter	Temperature Transmitter
Flow Indicator Controller	Level Device (Relay)	Power Supply
Flow Orifice	4kV Motor	Expansion Joint
Flow Transmitter	125/250Vdc Motor	Position Indicator
Fuse	Motor Operated Valve	Position Indicating Lamp
Flow Device (Relay)	Motor Operated Valve Operator	Position Switch
Handswitch	4kV Local Control Station (Disconnect/Link)	Position Transmitter

Some components in the SI System are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 1, Section 3.2]

- Except for the RWTHX supports that are addressed in this report, 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. The RWTHX supports are evaluated as subcomponents of the HX device type. [Reference 1, Attachment 5 for HXs.]
- 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 SI System.
- Instrument tubing and piping and the associated tubing 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. This commodity evaluation partially addresses the passive intended function entitled "maintain the pressure boundary of the system (liquid and/or gas)" for the SI System.

5.15.1.3 Components Subject to AMR

This section describes the components within the SI System that are subject to 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 CCNPP IPA Methodology Section 5.1, the following SI System functions were determined to be passive: [Reference 1, Table 3-1]

- To maintain the pressure boundary of the system (liquid and/or gas);
- To maintain electrical continuity and/or provide protection of the electrical system; and
- To restrict flow to a specified value in support of a DBE response.

Device Types Subject to AMR

Of the 53 device types within the scope of license renewal for the SI System: [Reference 1, Table 3-2 and Attachment 3 for XJs; Reference 45, Attachment 4A]

- Twenty-nine device types were associated with only active functions: Circuit Breaker, Coil, CV Operator, Disconnect Switch/Link, Voltage/Current Device, Flow Indicator Controller, Fuse, Flow Device (Relay), Handswitch, Current/Pneumatic Device, Ammeter, Power Lamp Indicator, Level Indicator, Level Indicator Alarm, Level Device (Relay), 4kV Motor, 125/250Vdc Motor, MOV Operator, 4kV Local Control Station (Disconnect/Link), Relay, Solenoid, Solenoid Valve, Temperature Recorder, Temperature Transmitter, Power Supply, Position Indicator, Position Indicating Lamp, Position Switch, and Position Transmitter;

- Level Transmitters associated with the containment emergency sump are subject to periodic replacement based on a qualified life or specified time period;
- One device type in this system, Expansion Joint, was evaluated in the AMR for the Containment System, addressed in Section 3.3A of the BGE LRA; and
- Seven device types are associated with a separate commodity evaluation. Level Transmitters associated with the RWTs and SITs, as well as Flow Indicators, Flow Transmitters, Level Switches, Pressure Indicators, Pressure Switches, and Pressure Transmitters in the SI System are evaluated separately in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

The remaining 16 device types, listed in Table 5.15-1, are subject to AMR and are included in the scope of this section. [Reference 1, Table 3-2] Except for HVs, all components of each listed device type are addressed in this section. Manual drain, equalization, and isolation valves in SI instrument lines that are subject to AMR are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. The manual root valves that are used to isolate these components are evaluated in this section. [Reference 45, Attachments 4 and 4A]

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies that 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 5.15-1

SAFETY INJECTION SYSTEM DEVICE TYPES SUBJECT TO AMR

Class CC Piping (-CC)	Hand Valve (HV)
Class DC Piping (-DC)	Heat Exchanger (HX)
Class GC Piping (-GC)	Motor Operated Valve (MOV)
Class HC Piping (-HC)	Pump/Driver Assembly (PUMP)
Check Valve (CKV)	Relief Valve (RV)
Control Valve (CV)	Temperature Element (TE)
Flow Element (FE)	Temperature Indicator (TI)
Flow Orifice (FO)	Tank (TK)

5.15.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the SI System components is given in Table 5.15-2, with plausible ARDMs identified by a check mark (✓) in the appropriate device type column. [Reference 1, Table 4-2 and Attachment 1] A check mark indicates that the ARDM applies to at least one component for the device type listed. 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. Table 5.15-2 also identifies the group to which each ARDM/device type combination belongs. Exceptions are noted where appropriate. The following groups have been selected for the SI System:

Group 1: general corrosion of external surfaces due to leakage of borated water;

Group 2: general corrosion, crevice corrosion, and/or pitting of internal surfaces exposed to chemically-treated water;

Group 3: microbiologically-induced corrosion (MIC) of internal surfaces for recirculation header piping connected to the emergency sump inside containment;

Group 4: fatigue for piping and valves exposed to thermal transients;

Group 5: stress corrosion cracking (SCC) near RWT penetrations and associated welds; and

Group 6: weathering of RWT perimeter seal.

Table 5.15-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE SAFETY INJECTION SYSTEM

Potential ARDMs	Device Types																Not Plausible for System
	-CC	-DC	-GC	-HC	CKV	CV	FE	FO	HV	HX	MOV	PUMP	RV	TE	TI	TK	
Cavitation Erosion																	x
Crevice Corrosion	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	
Dynamic Loading																	x
Erosion Corrosion																	x
Fatigue	✓(4)				✓(4)	✓(4)			✓(4)		✓(4)						
Fouling																	x
Galvanic Corrosion																	x
General Corrosion	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)			✓(1)	✓(1)	✓(1)	✓(1)	✓(1)			✓(1)	
Hydrogen Damage																	x
Intergranular Attack																	x
MIC				✓(3)													
Particulate Wear Erosion																	x
Pitting	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	
Radiation Damage																	x
Rubber/Elastomer Degradation																	x
Selective Leaching																	x
SCC																✓(5)	
Thermal Damage																	x
Thermal Embrittlement																	x
Wear																	x
Weathering																✓(6)	

✓ indicates plausible ARDM determination for this device type

(number) indicates the group in which this ARDM/device type combination is evaluated.

Note: Not every component within the device types listed here may be susceptible to a given ARDM. This is because components (and subcomponents) within a device type are not always fabricated from the same materials or subjected to the same environments. Exceptions for each device type will be indicated in the aging management subsection for each ARDM discussed in this report.

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.

Group 1 - (general corrosion of external surfaces) - Materials and Environment

Group 1 comprises the various SI System components whose external surfaces are subject to general corrosion. The components in this group are included in the -CC, -DC, -GC, -HC, CKV, CV, HV, HX, MOV, PUMP, RV, and TK device types. All of these components provide the passive intended function of maintaining the system pressure boundary. [Reference 1, Attachment 1] The applicable subcomponents in these device types are constructed of the following materials: [Reference 1, Attachments 4 and 5 for all device types except FEs, FOs, TEs, and TIs]

- Piping - carbon steel nuts and alloy steel studs;
- CKVs - carbon steel nuts and alloy steel studs;
- CVs - carbon steel nuts and alloy steel studs;
- HVs - carbon steel nuts and alloy steel studs for all HVs except the Unit 1 RWT return from SFP cooling HV;
- HVs - external surfaces of carbon steel body for the Unit 1 RWT return from SFP cooling HV;
- HXs - carbon steel nuts and alloy steel studs; carbon steel vessel supports for RWTHXs; external surfaces of the cast iron case/cover for pump seal coolers and HXs;
- MOVs - carbon steel nuts and alloy steel studs;
- PUMPs - carbon steel nuts and alloy steel studs for HPSI, LPSI pumps;
- RVs - carbon steel nuts and alloy studs for the SI leakoff and SDC return header RVs outside containment; and
- TKs - carbon steel nuts and alloy studs for the RWTs; external surfaces of the carbon steel shell and skirt plate for the SITs.

The external surfaces evaluated in Group 1 are not normally exposed to a corrosive environment, but may be exposed to boric acid as a result of leakage from the associated components or nearby systems and components that contain borated water. The possible effects of such leakage include general corrosion of susceptible external surfaces. A potential source of borated water leakage is the internal environment for the components in Group 1, with some normal service conditions as high as 2235 psig and 604°F. [Reference 1, Attachment 6s for all device types except FEs, FOs, TEs, and TIs; Reference 39, Piping Classes CC-4 and CC-6; Reference 40, Piping Classes CC-13 and CC-14; Reference 41, Piping Classes HC-3 and HC-4; Reference 42, Piping Class HC-23; Reference 43, Piping Classes DC-1 and DC-2; Reference 44, Piping Classes GC-1, GC-3, GC-4, GC-5, GC-7, and GC-9;]

For the RWTs, the external surfaces are exposed to the normal outside atmosphere at the CCNPP site, including fluctuating temperatures and humidity, sunlight, rain, freezing rain, ice, and snow. [Reference 1, Attachment 3 for TKs] For all other components evaluated in Group 1, the external surfaces are exposed to an environment of climate-controlled air in either the Auxiliary Building or the Containment.

[Reference 1, Attachment 3s] During normal operation, temperature and humidity in the Auxiliary Building do not exceed 160°F and 70%, respectively. [Reference 46, page 54] For the general areas inside containment where SI System components are located, the maximum normal temperature and humidity values are 120°F and 70%, respectively. [Reference 46, pages 29, 30, 62, and 63]

Group 1 - (general corrosion of external surfaces) - Aging Mechanism Effects

General corrosion is thinning of a metal by the chemical attack of an aggressive environment at its surface. An important concern for pressurized water reactors is boric acid attack upon carbon steels and low alloy steels. General corrosion is not a concern for austenitic stainless steels. [Reference 1, Attachment 7s for all device types except FEs, FOs, TEs, and TIs]

General corrosion is plausible for all carbon steel, alloy steel, and cast iron subcomponents in this group. Mechanical joints in pressure boundary subcomponents provide the opportunity for leakage of borated water onto external component surfaces. The carbon steel and alloy steel surfaces are particularly susceptible to significant acceleration of corrosion when exposed to boric acid in the concentrations present in the SI System. [Reference 1, Attachment 6s for all device types except FEs, FOs, TEs, and TIs]

The result of this corrosion mechanism is a reduction in the integrity of the corroded parts and a resulting increase in the likelihood of mechanical failure. If unmanaged, long-term exposure to general corrosion could eventually result in loss of the pressure-retaining capability under current licensing basis (CLB) design loading conditions.

Group 1 - (general corrosion of external surfaces) - Methods to Manage Aging

Mitigation: Boric acid corrosion can be mitigated by minimizing leakage. The susceptible areas of the SI System (i.e., mechanical joints) can be routinely observed for signs of borated water leakage, and appropriate corrective action can be initiated as necessary to eliminate leakage, clean spill areas, and assess any corrosion. [Reference 1, Attachment 6s for all device types except FEs, FOs, TEs, and TIs]

Discovery: The effects of corrosion are generally detectable by visual techniques. Visual inspections would need to be performed to detect corrosion associated with leakage of fluids onto the external surfaces of SI System components. [Reference 1, Attachment 6s for all device types except FEs, FOs, TEs, and TIs]

Group 1 - (general corrosion of external surfaces) - Aging Management Program(s)

Mitigation: The CCNPP Boric Acid Corrosion Inspection (BACI) Program (MN-3-301) is credited with mitigating the effects of boric acid corrosion through timely discovery of leakage of borated water and removal of any boric acid residue that is found. [Reference 1, Attachment 8] This program requires visual inspection of the components containing boric acid for evidence of leaks, quantification of any leakage indications, and removal of any leakage residue from component surfaces. [Reference 47] Further details on the BACI Program are detailed in the Discovery subsection below.

Discovery: Discovery of boric acid leakage is ensured by the BACI Program. [Reference 1, Attachment 8] This program also requires investigation of any leakage that is found. A visual examination of external surfaces is performed for components containing boric acid. [Reference 47]

The Inservice Inspection Program required the establishment of the BACI Program to systematically ensure that boric acid corrosion does not degrade the primary system boundary. [Reference 48, Section 5.8.A.1.] The program also applies to "valves in systems containing borated water which could leak onto Class 1 carbon steel components," and it identifies other plant areas to be examined. [Reference 47, Section 5.1B] The program controls examination, test methods, and actions to minimize the loss of structural and pressure-retaining integrity of components due to boric acid corrosion. [Reference 47, Section 3.0.C] The basis for the establishment of the program is Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." [Reference 47, Section 1.1]

The scope of the program is threefold in that it: (a) identifies locations to be examined; (b) provides examination requirements and methods for the detection of leaks; and (c) provides the responsibilities for initiating engineering evaluations and necessary corrective actions. [Reference 47, Section 1.2]

During each refueling outage, inservice inspection personnel perform a walkdown inspection to identify and quantify any leakage found at specific locations inside the Containment and in the Auxiliary Building. The inservice inspection ensures that all components where boric acid leakage has been previously documented are also examined in accordance with the requirements of this program. A second inspection of these components is performed prior to plant startup (at normal operating pressure and temperature) if leakage was identified previously and corrective actions were taken. [Reference 47, Sections 5.1 and 5.2]

Under the BACI Program, the walkdown inspections applicable to SI System components are type VT-2 (a type of visual examination described in the American Society of Mechanical Engineers [ASME] Boiler and Pressure Vessel Code, Section XI, IWA-2212). The VT-2 visual examinations include the accessible external exposed surfaces of pressure-retaining, non-insulated components; floor areas or equipment surfaces located underneath non-insulated components; vertical surfaces of insulation at the lowest elevation where leakage may be detected, and horizontal surfaces at each insulation joint for insulated components; floor areas and equipment surfaces beneath components and other areas where water may be channeled for insulated components whose external insulation surfaces are inaccessible for direct examination; and for discoloration or residue on any surface for evidence of boric acid accumulation. [Reference 47, Section 5.2]

If either leakage or corrosion is discovered, issue reports (IRs) are generated in accordance with CCNPP procedure QL-2-100, "Issue Reporting and Assessment," to document and resolve the deficiency. Corrective actions address the removal of boric acid residue and inspection of the affected components for general corrosion. If general corrosion is found on a component, the IR provides for evaluation of the component for continued service and corrective actions to prevent recurrence. [Reference 47, Section 5.3]

The BACI Program has evolved with regard to boric acid leaks discovered during other types of walkdowns and inspections. The program specifies the minimum qualification level for inspectors evaluating boric acid leaks. Apparent leaks that are discovered during these other walkdowns/inspections are documented in IRs by the individual discovering the leak. These IRs are then routed to the inservice inspection group for closer inspection and evaluation by a qualified inspector. This approach provides for more boric acid leakage inspection coverage while still ensuring that appropriately qualified individuals assess and quantify any resultant damage.

The corrective actions taken as a result of IRs under this program will ensure that SI System components containing borated water remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Group 1 - (general corrosion of external surfaces) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to general corrosion of external surfaces for SI System components:

- The components in Group 1 contribute to maintaining the system pressure boundary, and their integrity must be maintained under all CLB design conditions.
- The materials of construction for subcomponents in this group are carbon steel, alloy steel, or cast iron.
- General corrosion is a plausible ARDM for this group because the susceptible external surfaces are exposed to potential boric acid leakage from mechanical joints. If unmanaged, this ARDM could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- The corrosive effects of boric acid leakage will be managed by means of the BACI Program. When boric acid leakage is identified, either through required program inspections or through IRs resulting from other types of walkdowns and inspections, this program will ensure that corrosion induced by boric acid is discovered and that appropriate corrective action is taken.

Therefore, there is a reasonable assurance that the effects of general corrosion will be adequately managed for external surfaces of SI System components 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 - (general corrosion, crevice corrosion, and/or pitting of internal surfaces) - Materials and Environment

Group 2 comprises the various SI System components that are exposed to chemically-treated water and whose internal surfaces are subject to general corrosion, crevice corrosion, and/or pitting. The components in this group are included in all SI System device types. The internals for the SI header CKVs, the loop inlet CKVs, the SIT outlet CKVs, and the SDC header return isolation MOV outside containment function to reduce the possibility of inter-system leakage when none of the associated system flowpaths allowing transfer of borated water to/from the RCS is active. [Reference 49] Likewise, the internals for the LPSI header MOVs, the main HPSI header MOVs, and the auxiliary HPSI header MOVs act as pressure-retaining boundaries for the Containment when their associated injection flowpaths are not active. [Reference 1, Attachment 3s for MOVs] The seating surfaces for the SI header CKVs, the SDC header return isolation MOV outside containment, and the SI leakoff return isolation HVs also act as pressure-retaining boundaries for the Containment. [Reference 1, Attachment 3s for CKVs, MOVs, and HVs] The remaining components provide the passive intended function of maintaining the system pressure boundary. [Reference 1, Attachment 1] The applicable subcomponents in these device types are constructed of the following materials: [Reference 1, Attachments 4 and 5 for all device types; Reference 50]

- Piping - internal surfaces of stainless steel fittings and flanges, as well as hidden surfaces of carbon steel nuts and alloy steel studs; also, internal surfaces of stainless steel pipe and welds for small-bore piping;
- CKVs - internal surfaces of stainless steel body/bonnet, as well as hidden surfaces of carbon steel nuts and alloy steel studs; also, various cobalt-based, nickel-based, or iron-based alloy facing materials associated with the internals for the SI header CKVs; and stainless steel/stellite internals for the loop inlet and SIT outlet CKVs;
- CVs - internal surfaces of stainless steel body/bonnet and stem, as well as hidden surfaces of carbon steel nuts and alloy steel studs;
- FEs - stainless steel;
- FOs - stainless steel orifice plates;
- HVs - internal surfaces of stainless steel body/bonnet and stem, as well as hidden surfaces of carbon steel nuts and alloy steel studs, for all HVs except the Unit 1 RWT return from SFP cooling HV; also, stainless steel disc/seat for those HVs that are normally closed;
- HVs - internal surfaces of the rubber lined carbon steel body and stainless steel stem for the Unit 1 RWT return from SFP cooling HV;
- HXs - hidden surfaces of carbon steel nuts and alloy steel studs for all HXs; stainless steel tubing and weld connection, brass flex connector, and internal surfaces of the cast iron case/cover for the HPSI pump seal coolers and LPSI pump seal HXs; stainless steel bonnets/covers/tubes and welds for the RWTHXs;
- MOVs - stainless steel wedge and seat ring for the SDC header return isolation MOV outside containment; stainless steel/stellite disc/seat for the containment sump discharge MOVs; internal surfaces of stainless steel body/bonnet and stem, as well as hidden surfaces of carbon steel nuts and alloy steel studs, for all MOVs;
- PUMPs - internal surfaces of the mechanical seals (nickel binder for tungsten carbide wearing surfaces; some with stainless steel seal ring body), stainless steel casing, and shaft, as well as hidden surfaces of carbon steel nuts and alloy steel studs for the HPSI and LPSI pumps;
- PUMPs - internal surfaces of stainless steel casing and shaft, and hidden surfaces of stainless steel nuts and studs for the RWT circulating pumps;
- RVs - Inconel or stellite disc, stainless steel spindle and spring/washer, and internal surfaces of stainless steel base/cylinder/adjusting bolt for pump and injection header RVs;
- RVs - stainless steel nozzle/disc, spindle point/adjusting bolt, spring/washer, hidden surfaces of carbon steel nuts and alloy steel studs, and internal surfaces of stainless steel body/bonnet for SI leakoff and SDC return header RVs outside containment;
- RVs - stellite disc, stainless steel spindle, adjusting bolt, spring/washer, and internal surfaces of stainless steel base/cylinder for SDC return header RVs inside containment;

- TEs - stainless steel;
- TIs - stainless steel well;
- TKs - internal surfaces of stainless steel shell, manhole, penetrations, and welds, as well as hidden surfaces of carbon steel nuts and alloy steel studs for the RWT; and
- TKs - internal surfaces of carbon steel shell (clad with stainless steel) and stainless steel manway for the SITs, as well as hidden surfaces of the associated stainless steel nuts and studs.

Except as noted below, the internal surfaces for all components evaluated in Group 2 are exposed to the borated water environment described in subsection Group 1 - Materials and Environment, above. For SI System HXs, the inside of the shell and the outside of the tubes containing the borated water are exposed to the following fluids:

- For the HPSI pump seal coolers and LPSI pump seal HXs, chemically-treated water from the CC System, with a design pressure of 150 psig and maximum operational temperature of 167°F. [Reference 1, Attachment 3s for HXs; Reference 51, Piping Class HB-23]
- For the RWTHXs, untreated well water from the Plant Heating System, with a design pressure of 150 psig and maximum operational temperature of 200°F. [Reference 1, Attachment 3s for HXs; Reference 51, Piping Class HB-29]

Since the SI System is maintained in a standby mode during normal operations, stagnant internal conditions result in overall component temperatures close to ambient. These conditions may also allow impurities in the process fluid to concentrate. [Reference 1, Attachment 6s for all device types]

Group 2 - (general corrosion, crevice corrosion, and/or pitting of internal surfaces) - Aging Mechanism Effects

General corrosion is described in subsection Group 1 - Aging Mechanism Effects, above. Crevice corrosion and pitting are related forms of intensive, localized corrosion. Crevice corrosion occurs in crevices that are wide enough to permit liquid entry and narrow enough to maintain stagnant conditions. Such locations may include spaces under nuts and/or bolt heads, holes, gasket surfaces, lap joints, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. Pitting occurs when corrosion proceeds at one small location at a rate greater than the corrosion rate of the surrounding area. Pitting is an autocatalytic process that produces conditions that stimulate the continuing activity of the pit. In either case, the stagnant fluid within the pit or crevice tends to accumulate corrosive chemicals such as chlorides and sulfates, and thereby to accelerate the local corrosion process. Crevice corrosion can initiate pitting in many cases. Pitting can result in complete perforation of the material. [Reference 1, Attachment 7s for all device types]

Crevice corrosion and pitting are plausible for all subcomponents in this group. Additionally, general corrosion is plausible for the internal surfaces of all carbon steel and cast iron subcomponents in this group. For the Unit 1 RWT return from SFP cooling HV, long-term exposure to borated water can result in permeation and cracking of the rubber liner designed to protect internal surfaces of its carbon steel valve body from corrosion effects. These ARDMs are plausible at mechanical joints (e.g., flanges, body/bonnet joints, welded joints in small-bore piping) since they present a crevice geometry at the sealing surfaces that may allow process fluids to stagnate and cause concentration of environmentally-produced impurities. [Reference 1, Attachment 6s for all device types] Similar stagnation and impurity deposits are possible at other component interior crevices that are formed by close-fitting interface points at interior subcomponents (e.g., tubes/tubesheets in HXs, fittings in piping, pump shafts, valve stems, valve seating surfaces). [Reference 1, Attachment 6s for -CC Piping, -DC Piping, -GC Piping, -HC Piping, CKVs, CVs, HVs, HXs, MOVs, PUMPs, RVs, TEs, TIs, and TKs]

Group 2 - (general corrosion, crevice corrosion, and/or pitting of internal surfaces) - Methods to Manage Aging

Mitigation: Control of fluid chemistry in the SI System and interfacing systems can significantly limit the effects of general corrosion, crevice corrosion, and pitting. [Reference 1, Attachment 6s for all device types] The chemistry control program should monitor pertinent chemical parameters on a frequency that would allow for corrective actions to minimize creation of an environment conducive to corrosion.

Discovery: The effects of corrosion are generally detectable by visual techniques. During repairs related to leakage in the loop inlet CKVs, visual methods have identified minor pitting on valve discs and seats. Lapping of the valve seats and replacement of valve discs has been used to restore the valves. Seating surface degradation can be discovered by testing the components that are susceptible to this ARDM. Degradation of CKV seating surfaces can be discovered by monitoring for system leakage and performing leak rate testing. Pressure testing of the SDC header return isolation MOV outside containment and the SI leakoff return isolation HVs can provide for detection of leakage that could be the result of crevice corrosion and pitting of the valve seating surfaces. Internal surfaces of components that are not routinely inspected can be subjected to inspection to determine the extent of general and/or localized degradation that may be occurring. [Reference 1, Attachment 6s for all device types]

Group 2 - (general corrosion, crevice corrosion, and/or pitting of internal surfaces) - Aging Management Program(s)

Mitigation: Maintenance of proper fluid chemistry in the SI System and interfacing systems will limit the effects of general corrosion, crevice corrosion, and pitting on internal surfaces for Group 2 subcomponents. [Reference 1, Attachment 8]

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 52, Section 6.1.A] The program is based on Technical Specifications, BGE's interpretation of industry standards, and recommendations made by Combustion Engineering. [Reference 53, Section 2.0]

Calvert Cliffs Technical Procedure CP-204, "Specification and Surveillance-Primary Systems," provides for monitoring and maintaining chemistry in the RCS and associated systems. [Reference 53, Section 2.0, Attachments 1 through 15] Control of primary water chemistry is credited with limiting the effects of crevice corrosion and pitting in SI System components. [Reference 1, Attachment 8]

Calvert Cliffs Technical Procedure CP-206, "Specifications and Surveillance-Component Cooling/Service Water Systems," provides for monitoring of CC System chemistry to control the concentrations of oxygen, chlorides, and other chemicals and contaminants. [Reference 54, Section 2.0, Attachment 1] Control of the water chemistry provides an environment that limits the rate of degradation and its effects for the LPSI pump seal HXs and HPSI pump seal coolers, which are cooled by water from the CC System. [Reference 1, Attachment 8]

Calvert Cliffs Technical Procedure CP-202, "Specifications and Surveillances-Demineralized Water, Safety Related Battery Water, & Well Water Systems," provides for monitoring of pH levels in well water. [Reference 55, Section 2.0, Attachment 6] Observing that significant changes in well water chemistry have not occurred is an effective method to ensure that the environment on the shell side of the RWTHXs, which are heated by well water from the Plant Heating System, has not been altered to the extent that the rate of degradation is affected. [Reference 1, Attachment 8]

Each of the program procedures describes the surveillance and specifications for monitoring fluid chemistry for the applicable systems. They list the parameters to be monitored, the frequency for monitoring of each parameter, and the acceptable value or range of values for each parameter. [Reference 53, Attachments 1 through 15; Reference 54, Attachment 1; Reference 55, Attachment 6] Each parameter is measured at a procedurally-specified frequency (e.g., daily, weekly, monthly) and compared against a target value that represents a goal or predetermined warning limit. [Reference 53, Section 3.0; Reference 54, Section 3.0; Reference 55, Section 3.0] If a measured value is outside of its required range, corrective actions are taken (e.g., power reduction, plant shutdown) as prescribed by the procedure, thereby ensuring timely response to chemical excursions. The procedures provide for rapid assessment of off-normal chemistry parameters so that steps can be taken to return them to normal levels. [Reference 53, Section 6.0.C; Reference 54, Section 6.0.C; Reference 55, Section 6.0.C]

The CCNPP Chemistry Program has been subject to periodic internal assessment activities. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their level of performance and safety significance and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. [Reference 56, Section 1B.18] These activities, as well as other external assessments, help to maintain highly effective chemistry control, and facilitate continuous improvement through monitoring industry initiatives and trends in the area of corrosion control.

A review of operating experience identified no site-specific problems or events related to general corrosion, crevice corrosion, or pitting that required significant changes or adjustments to the CCNPP Chemistry Program. It has been effective in its function of mitigating corrosion and controlling corrosion-related failures and problems within acceptable limits. In 1996, CP-206 was revised to include monitoring of dissolved iron as a method for discovering any unusual corrosion of carbon steel components. Self-assessments of chemistry control performance have resulted in activities to reduce the number of times that chemistry parameters exceed action levels (e.g., additional scheduling coordination for outage evolutions that could affect CC/Service Water chemical parameters).

Discovery: General corrosion, crevice corrosion, and pitting of internal surfaces for Group 2 components are managed through a combination of monitoring, testing, and inspection activities at CCNPP.

- The loop inlet CKVs, SIT outlet CKVs, and SI header CKVs require leak rate testing under the CCNPP Pump and Valve Inservice Testing (IST) Program. [Reference 57] This program was established to implement IST in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, as required by 10 CFR 50.55a(f). Section XI, Subsection IWV, directs each licensee to comply with the applicable portions of ASME/ANSI OM-10. American Society of Mechanical Engineers/ANSI OM-10 provides the rules and requirements for IST of CCNPP valves, including the types of tests required, frequency of testing, test methods, test pressures, acceptance criteria, and reporting requirements. In addition to the general Code requirements discussed above, there are additional interpretations and positions that have come about as a result of past regulatory and licensee actions, including NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants." [References 57, 58, and 59]

  Pressure in the piping between the loop inlet CKVs and the SIT outlet CKVs is continuously monitored by instrumentation, with an indication in the Control Room. [References 32 and 34] Monitoring these indications, which demonstrate functionally adequate seat tightness of the loop inlet CKVs on an ongoing basis in lieu of leak rate testing, is part of the overall CCNPP Pump and Valve IST Program. [Reference 57, Attachment 1 - Section 5.4 and Relief Request No. VR-08] Excessive backleakage through a loop inlet CKV would result in alarm actuation and assessment of the leakage. To ensure such leakage from the RCS will be detected, observation of alarm function is documented as part of the SIT outlet CKV closure verification described below. [References 60 and 61, Section 6.5] If unidentified RCS leakage exceeds the acceptance criteria provided in the CCNPP Technical Specifications, the applicable abnormal operations procedures are implemented. Appropriate corrective actions are determined in accordance with the CCNPP Technical Specifications, Surveillance Test Program procedures, and the CCNPP Corrective Actions Program. [References 59, 62, and 63] Historically, this method has been effective in identifying the sources of RCS leakage.

  Calvert Cliffs procedures STP O-65J-1(2), which verify the closure and seat leakage integrity of the SIT outlet CKVs and the SI header CKVs, are also part of the overall CCNPP Pump and Valve IST Program. [References 60 and 61] Testing is implemented by CCNPP Technical Specification 4.0.5. [References 58 and 64] The SIT outlet CKVs and the SI header CKVs are tested in accordance with ASME/ANSI OM-1987, including OMa-1988 Addenda. Leak testing of these valves is required every two years in accordance with the Pump and Valve IST Program - Third Ten-Year Interval. [Reference 57] Completion of the SIT outlet CKV and SI header CKV closure verification in accordance with STP O-65J-1(2) satisfies the biennial seat leakage measurement requirement. [References 60 and 61, Section 2.0.B] For the SIT outlet CKVs, this verification presently includes the following procedural steps: [References 60 and 61, Section 6.5]

  Pressure is applied to the CKV in the reverse flow direction (i.e., the CKV is seated), and the instrumentation that monitors pressure between the loop inlet CKVs and the SIT outlet CKVs is checked for proper indication and alarm function.

  Level in the associated SIT is monitored, and leakage is quantified by recording the change in level during the period of the test (minimum duration of 20 minutes).

For the SI header CKVs, closure verification presently includes the following procedural steps: [References 60 and 61, Section 6.6]

Test equipment is connected to the appropriate test point.

Pressure is applied to the CKV in the reverse flow direction (i.e., the CKV is seated).

If a pressure increase on the upstream (low pressure) side of the valve indicates CKV leakage, leakage is quantified by: (a) establishing a reference pressure; and (b) recording the volume and duration of leakage collected in a suitable container on the upstream side of the valve.

In both cases, the measured leak rate is corrected for test pressure and compared against acceptance criteria for each individual valve and a cumulative CKV leakage limit. If the corrected leakage is less than or equal to the acceptance criteria, the test is satisfactory. If not, the affected equipment is declared inoperable and appropriate corrective actions are determined in accordance with CCNPP IST Program procedures and the CCNPP Corrective Actions Program.

- Calvert Cliffs procedures STP M-571G-1(2) and M-571L-1(2), which cover local leak rate testing (LLRT) for the SI leakoff return isolation HVs and the SDC header return isolation MOV outside containment, respectively, are part of the overall CCNPP Containment Leakage Rate Testing Program. [References 65 through 68] The CCNPP Containment Leakage Rate Testing 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, Option B, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." 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 64, Section 6.5.6; References 69 and 70]

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 valves that isolate the containment penetration piping for the SDC return header and the SI leakoff return header are included in the scope of this program as part of the leakage testing for the associated containment penetrations. [Reference 64]

The LLRT is done on a performance-based testing schedule in accordance with Option B of 10 CFR Part 50, Appendix J, as implemented by CCNPP Technical Specifications. [References 64, 69, and 70] Local leak rate testing presently includes the following procedural steps:

Leak rate monitoring test equipment is connected to the appropriate test point.

The test volume is pressurized to the LLRT Program test pressure, which 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.

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 that 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, plant personnel 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 containment isolation valve that changes the closing characteristic of the valve, an “as left” test must be performed on the penetration to ensure leakage rates are acceptable.

- Baltimore Gas and Electric Company will include all Group 2 components in an Age-Related Degradation Inspection (ARDI) Program to verify that unacceptable degradation of internal surfaces is not occurring, thereby validating the effectiveness of the CCNPP Chemistry Program in mitigating the effects of general corrosion, crevice corrosion, or pitting. [Reference 1, Attachment 8]

  The ARDI Program is 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 loading conditions 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.

Any corrective actions that are required by the Pump and Valve IST Program, the LLRT Program, or the ARDI Program, will be taken in accordance with the CCNPP Corrective Actions Program and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 2 - (general corrosion, crevice corrosion, and/or pitting of internal surfaces) - 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 internal surfaces for SI System components that are exposed to chemically-treated water:

- The components in Group 2 contribute to maintaining the system pressure boundary. Additionally, certain CKVs and MOVs function to reduce the possibility of inter-system leakage when none of the associated flowpaths allowing transfer of borated water to/from the RCS is active; some CKVs, MOV, and HVs also act as pressure-retaining boundaries for the Containment. The integrity of these components must be maintained under all CLB design conditions.
- The materials of construction for subcomponents in this group include cast iron, carbon steel, alloy steel, stainless steel, and brass, as well as various facing materials.
- General corrosion, crevice corrosion, and pitting are plausible ARDMs for this group and, if unmanaged, these ARDMs could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- Maintenance of proper fluid chemistry in the SI System (in accordance with CP-204) will limit the effects of general corrosion, crevice corrosion, and pitting on susceptible pressure boundary subcomponents for Group 2 components. Controlling the chemistry of water in the CC System (in accordance with CP-206) and monitoring chemistry of the well water supplying the Plant Heating System (in accordance with CP-202) will ensure that the water supplied to SI System HXs is of an appropriate chemistry to minimize corrosion.
- The CCNPP Pump and Valve IST Program incorporates monitoring pressure indications associated with the loop inlet CKVs. This activity, combined with assessments performed in the event of alarm actuation, detects leakage that could result from crevice corrosion and pitting on the seating surfaces of the loop inlet CKVs. Corrective actions to address abnormal leakage are directed by Technical Specifications.
- The CCNPP Pump and Valve IST Program performs leak testing of the SIT outlet CKVs and the SI header CKVs; the CCNPP LLRT Program performs leakage testing of the SDC header return isolation MOV outside containment and the SI leakoff return isolation HVs. These programs are credited with detecting leakage that could result from crevice corrosion and pitting on the seating surfaces of the listed valves. These programs ensure that appropriate corrective actions will be taken if significant leakage is discovered.
- All Group 2 components will be subjected to a new ARDI Program. This program will examine a representative sample of the components for degradation, and ensure that appropriate corrective actions are initiated on the basis of the findings.

Therefore, there is a reasonable assurance that the effects of general corrosion, crevice corrosion, and pitting will be adequately managed for internal surfaces of SI System components exposed to chemically-treated water 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 3 - (MIC of internal surfaces) - Materials and Environment

Group 3 consists of the two recirculation headers in the SI System connected to the emergency sump inside containment whose internals are subject to MIC. This stainless steel piping provides the passive intended function of maintaining the system pressure boundary. [Reference 1, Attachments 4 and 5 for -HC Piping]

This section of piping is filled from the RWT prior to starting up following a refueling outage; therefore, the internal surfaces of this piping are exposed to stagnant borated water in the emergency sump. Filling these lines provides a thermal barrier to prevent significant heatup of the containment sump discharge MOV bonnets caused by fluid entering the emergency sump inside containment after a DBE and prior to a RAS. [Reference 3, Section 6.16; Reference 71] Since this body of water is left open to the atmosphere inside containment for extended periods of time (i.e., the refueling cycle), it is capable of supporting microbes introduced to the system. [Reference 1, Attachment 6 for -HC Piping; Reference 72] Refer to subsection Group 1 - Materials and Environment, above, for discussion of the atmosphere inside containment.

Group 3 - (MIC of internal surfaces) - Aging Mechanism Effects

Microbiologically-induced corrosion is accelerated corrosion of materials resulting from surface microbiological activity. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria are most commonly associated with these corrosion effects. Microbiologically-induced corrosion most often results in pitting, followed by excessive deposition of corrosion products. Essentially any system that uses untreated water and most commonly-used materials are susceptible to MIC. [Reference 1, Attachment 7 for Piping] Long-term exposure of the recirculation header piping to microbe activity may result in localized material loss and, if left unmanaged, could eventually result in loss of pressure-retaining capability under CLB design loading conditions. [Reference 1, Attachment 6 -HC Piping]

Group 3 - (MIC of internal surfaces) - Methods to Manage Aging

Mitigation: Industry studies indicate that MIC can be prevented through adding biocides to the system fluid, increasing fluid temperature above 200°F, and/or using flow to eliminate long-term stagnation. [Reference 72]

Discovery: The effects of corrosion are generally detectable by visual techniques. [Reference 72] Internal surfaces of the recirculation headers can be subjected to inspection to determine the extent of localized degradation that may be occurring. [Reference 1, Attachment 6 for -HC Piping]

Group 3 - (MIC of internal surfaces) - Aging Management Program(s)

Mitigation: Maintaining the thermal barrier precludes elimination of the stagnant body of water at ambient temperature from the recirculation headers. Since BGE does not treat the process fluid for microbes, there are no programs credited with mitigating the effects of MIC for the components in this group. [Reference 1, Attachment 8; Reference 72]

Discovery: Baltimore Gas and Electric Company will include the recirculation headers connected to the emergency sump inside containment in an ARDI Program to verify that unacceptable degradation of internal surfaces by MIC is not occurring. [Reference 1, Attachment 8] For a discussion of the elements of the ARDI Program, refer to subsection Group 2 - Aging Management Programs, above.

Group 3 - (MIC of internal surfaces) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to MIC of internal surfaces for the SI System recirculation headers:

- The recirculation headers connected to the emergency sump inside containment contribute to maintaining the system pressure boundary, and their integrity must be maintained under all CLB design conditions.
- This group consists of stainless steel piping.
- Microbiologically-induced corrosion is a plausible ARDM because the stagnant water in this piping is exposed to the containment atmosphere for extended periods of time. If unmanaged, this ARDM could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- The recirculation header piping will be subjected to a new ARDI Program. This program will examine a representative sample of the components for degradation, and ensure that appropriate corrective actions are initiated on the basis of the findings.

Therefore, there is a reasonable assurance that the effects of MIC will be adequately managed for internal surfaces of the SI System recirculation headers 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 4 - (fatigue for piping and valves exposed to thermal transients) - Materials and Environment

Group 4 comprises SI System components in the SIT injection and SDC mode flowpaths for which fatigue is a plausible ARDM. Specifically, this group consists of the following SI System components that are depicted in Figure 5.15-1:

- SI header CKVs (1[2]CKVSI-118, -128, -138, -148), SIT outlet CKVs (1[2]CKVSI-215, -225, -235, -245), SIT outlet MOVs (1[2]MOV614, 624, 634, 644), loop inlet CKVs (1[2]CKVSI-217, -227, -237, -247), and the intervening pipe segments (1#CC4-1001, -1002, -1003, -1004, -1009, -1010, -1011, -1012 (2#CC4-2001, -2002, -2003, -2004, -2009, -2010, -2011, -2012); 1#CC13-1009, -1010, -1011, -1012 [2#CC13-2009, -2010, -2011, -2012]);
- SIT CKV leakage CVs (1[2]CVSI-618, -628, -638, -648), SIT CKV leakage isolation HVs (1[2]HVSI-699, -700, -701, -702), and the associated SIT recirculation piping connecting to the SI header (1#CC4-1013, -1014, -1015, -1016 [2#CC4-2013, -2014, -2015, -2016]); and
- SDC return header piping from the RCS interface at the outlet of the SDC header return isolation MOV inside containment (1#CC14-1004 [2#CC14-2004]), up to and including the SDC header return isolation MOV outside containment (1[2]MOV651).

All of these components provide the passive intended function of maintaining the system pressure boundary. [Reference 1, Attachment 1] Additionally, the SI header CKVs and the SDC header return isolation MOV outside containment are required to maintain both the reactor coolant pressure boundary and the containment pressure boundary when none of the associated system flowpaths allowing transfer of borated water to/from the RCS is active. [Reference 1, Attachment 3s for CKVs, MOVs; Reference 49] The pressure-retaining subcomponents in these device types are constructed of carbon steel, alloy steel, and stainless steel, as well as various facing materials, as described in subsections Group 1 and Group 2 - Materials and Environment, above. [Reference 1, Attachments 4 and 5 for pipe, CKVs, CVs, HVs, MOVs; Reference 50]

Except for piping between the SIT outlet CKVs and the SIT outlet MOVs, the original design code for the piping in this group is ANSI B31.7 Class I. [Reference 39, Piping Class CC-4; Reference 40, Piping Class CC-14] Components in this piping, which comprise the Class I portion of the SDC mode flowpath, were designed to withstand up to 500 SDC initiation transients during the anticipated life of the plant, consisting of rapid temperature rises from ambient (70°F) to 300°F. The piping between the SIT outlet CKVs and the SIT outlet MOVs was originally designed in accordance with ANSI B31.7 Class II requirements, but was subsequently upgraded to Class I requirements. [Reference 40, Piping Class CC-13]

Additional thermal stresses are imposed on the piping and valves between the SIT outlet CKVs and the loop inlet CKVs due to thermal stratification effects. Stratification in the SI line has been shown to exist, and was found to be dependent primarily on the temperature difference between the RCS cold leg and the ambient temperature. These pipe segments have relatively hot fluid on the RCS side of the closed loop inlet CKVs and relatively cold fluid on the SIT side of the closed SIT outlet CKVs. Natural convection caused by the presence of these hot and cold boundaries produces thermal stratification, evidenced by observed top-to-bottom wall temperature differences of up to 145°F in this piping. [References 73]

Since the SI System vent/drain/test HVs, instrument isolation HVs, and RVs connected to the piping in Group 4 are generally thin-wall components, they do not experience the large temperature gradients that would be necessary to cause significant degradation. Likewise, the normal and design operating conditions applied to SI System components that are not associated with the above flowpaths result in neither the quantity of cycles nor the loading conditions (mechanical, vibrational, thermal, and/or pressure) necessary to cause significant degradation. Therefore, except for the components comprising Group 4, fatigue is not plausible for the SI System.

The internal surfaces for components in this group are exposed to the borated water environment described in subsection Group 1 - Materials and Environment, above. [Reference 1, Attachment 6s for -CC Piping, CKVs, CVs, HVs, MOVs; Reference 39, Piping Class CC-4; Reference 40, Piping Class CC-14] The external environment is climate-controlled air in the Containment. [Reference 1, Attachment 3s] Since the SI System is maintained in a standby mode during normal operations, component temperatures range from ambient to approximately 300°F under the influence of the natural circulation flow in the piping between the closed SIT outlet and loop inlet CKVs. [Reference 73] During reactor cooldown, the Group 4 components subjected to thermal stratification cool to temperatures approaching ambient. Initiation of SDC also causes a rapid temperature transient for other components in the SDC mode flowpath from ambient (about 70°F) to RCS temperature (no greater than 300°F). [Reference 2, Section 9.2.4]

Group 4 - (fatigue for piping and valves exposed to thermal transients) - Aging Mechanism Effects

Fatigue is the process of progressive localized structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points in the material. This process 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 occurs. Failures may occur at either a high or low number of cycles in response to various kinds of loads (e.g., mechanical or vibrational loads, thermal cycles, or pressure cycles). Low-cycle fatigue involves stressing of materials, often into the plastic range, with the number of cycles usually being less than 10^5. This mechanism is typically associated with thermal gradients created in thick sections (e.g., > 1") or in restrained members during rapid heatup or cooldown. A component subjected to sufficient cycling with significant strain accumulates fatigue damage, which potentially can lead to crack initiation and crack growth. The cracks may then propagate under continuing cyclic stresses. For plant equipment operating in a corrosive environment, growth of fatigue cracks may be subsequently dominated by corrosion advance. Such environmental effects must be considered during system design. [Reference 1, Attachment 7s for pipe, valves; Reference 74]

Low-cycle thermal fatigue is plausible for the devices in this group since they experience cyclical thermal loading and pressurization that contribute to fatigue accumulation. [Reference 1, Attachment 6s for pipe, CKVs, CVs, HVs, MOVs; Reference 73] The limiting locations for these transients are in the RCS piping (i.e., the SI nozzles and the SDC outlet nozzle). [Reference 75, Section 3.3.2 and Table 5-1] This aging mechanism, if unmanaged, could eventually result in crack initiation and growth such that the Group 4 components may not be able to perform their pressure boundary function under CLB design loading conditions.

Group 4 - (fatigue for piping and valves exposed to thermal transients) - Methods to Manage Aging

Mitigation: The effects of low-cycle fatigue can be mitigated by proper system design and material selection, and by operational practices that reduce the number and severity of thermal transients on the susceptible components. [Reference 1, Attachment 6s for pipe, CKVs, CVs, HVs, MOVs]

Discovery: Fatigue cracks can be discovered by inspecting components; the scope and frequency of inspections can be established based on the likelihood that fatigue cracks have initiated. As discussed above, low-cycle fatigue was addressed in the original design for the components in the SDC mode flowpath by determination of an allowable number of full-range thermal cycles for the anticipated life of the plant. The accumulation of fatigue effects on these components can be monitored by counting the number of thermal transients and by performing analysis to predict the remaining life of the affected components.

Group 4 - (fatigue for piping and valves exposed to thermal transients) - Aging Management Program(s)

Mitigation: As part of general operating practice, plant operators minimize the duration 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.

Discovery: The CCNPP Fatigue Monitoring Program (FMP) has been established to monitor and track fatigue usage of limiting components of the Nuclear Steam Supply System, including the SI System, and the steam generators. Reference 75 was used in the development of this program. Eleven fatigue critical locations in these systems have been selected for monitoring of fatigue usage. These represent the most bounding locations for critical thermal transients. For components in the SI System, fatigue usage is bounded by the fatigue usage of the SI nozzles and the SDC outlet nozzle in the RCS. [Reference 76, Sections 1.1, 1.2.A, 2.1.E, 6.0

The FMP utilizes two methods to track fatigue usage:

- One method is to track the number of critical thermal and pressure test transients (i.e., cycle counting) 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 B31.7, 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, the component remains within its design basis.
- The other method is to determine the fatigue life of a component using a calculated cumulative usage factor (CUF), which is defined as a normalized measure of total fatigue damage accumulated by a component as a result of all stress cycles that the component has experienced during its service life. The CUF can be calculated and tracked through plant life using thermal cycle counting or stress-based analysis techniques. In accordance with the ASME Boiler and Pressure Vessel Code, the component remains within its design basis for allowable fatigue life if the CUF remains less than or equal to one. [Reference 76, Sections 1.2.A, 3.0.B, 3.0.F]

Both methods use actual plant operating data. At CCNPP, the usage factor for several locations, including the SI nozzles and the SDC outlet nozzle in the RCS, is calculated using thermal cycle counting. Since the FMP monitors actual fatigue usage, a more realistic CUF is calculated. The data for thermal transients is collected, recorded, and analyzed using a computer program that evaluates input data from plant instrumentation. The computer software is used to analyze plant data associated with real transients and to predict the number of thermal cycle transients for 40 and 60 years of plant operation based on the historical records. For the SI System, the allowable number of initiation of SDC cycles is 500. Based on actual occurrences to date, partial cycle analysis for the initiation of SDC transient predicts that Unit 1 will experience 30 effective full cycles for 40 years of plant operation and 45 effective full cycles for 60 years. Similarly, Unit 2 projections estimate 29 effective full cycles for 40 years and 43 effective full cycles for 60 years. [Reference 76, Section 3.0.F]

Plant parameter data is collected on a periodic basis and reviewed to ensure that the data represents actual transients. Valid data is entered into the computer program that counts the critical transient cycles and calculates the CUFs. The data is tracked in accordance with procedures that are governed by a quality assurance program that meets 10 CFR Part 50, Appendix B, criteria. The transient data is evaluated and the CUFs are calculated on a semi-annual basis, which provides a readily predictable approach to the alert value. Acceptable conditions exist, since no crack initiation would be predicted, when the calculated CUF for any given component is less than one, or when the design allowable number of cycles for the component has not been exceeded. In order to stay within the design basis, corrective action is initiated well in advance of the CUF approaching one or the number of cycles approaching the design allowable, so that appropriate corrective actions can be taken in a timely and coordinated manner. [Reference 76, Sections 1.2.A, 5.0]

Since the FMP has been initiated, no locations have reached the limit on fatigue usage and no cracking due to low-cycle fatigue has been discovered. The FMP has undergone several modifications since its inception. Stress-based analysis was added to the computer software to calculate the CUFs for several locations due to unique thermal transients experienced and the unique geometries involved. Other modifications have been made to the FMP 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.

The CCNPP FMP has been inspected by the NRC, which noted that the program has been developed toward providing assurance that fatigue life usage of primary system components has not exceeded limits provided for in ASME Section III. In addition, the NRC noted that the FMP can be used to identify components where fatigue usage may challenge the remaining and extended life of the components and can provide a basis for corrective action where necessary. [Reference 77]

Since its inception in 1988, BGE has participated in the extensive program undertaken by the Combustion Engineering Owners Group to address thermal stratification concerns. In response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," BGE identified the potential for thermal stratification in the piping between the SIT outlet CKVs and the loop inlet CKVs, and subsequently confirmed the natural convection phenomenon described in subsection Group 4 - Materials and Environment, above. [References 73 and 78] Since the current piping analysis for the affected portions of the SI System does not include the additional stresses imposed by thermal stratification, BGE will complete an engineering review of the industry's task reports and determine: (a) any necessary changes to the piping analyses of record for the SI System, including the Group 4 pipe segments; and (b) the impact of such changes on fatigue usage parameters used by the FMP.

To further address fatigue for license renewal, CCNPP participated in a task, sponsored by the Electric Power Research Institute, to demonstrate the industry fatigue position. The task applied industry-developed methodologies to identify fatigue-sensitive component locations that may require further evaluation or inspection for license renewal and evaluate environmental effects, as necessary. The program objective included the development and justification of aging management practices for fatigue at various component locations for the renewal period. The demonstration systems were the Feedwater System, the pressurizer surge line in the RCS, and the letdown and charging subsystem in the CVCS. [Reference 79, page 3]

Evaluation of Thermal Fatigue Effects to Address Generic Safety Issue 166:

Generic Safety Issue 166, Adequacy of Fatigue Life of Metal Components, presents concerns identified by the NRC that must be evaluated as part of the license renewal process. The NRC staff concerns about fatigue for license renewal fall into the following five categories: [Reference 79, page 2; Reference 80]

- The first category, adequacy of the fatigue design basis when environmental effects are considered, does not apply to the Group 4 components because of stringent RCS water chemistry controls, exceptionally low oxygen concentrations (less than five parts per billion), and stainless steel materials used in fabrication of the affected piping and valve subcomponents.

- The second category concerns the adequacy of both the number and severity of design-basis transients. The engineering review addressing thermal stratification in the SIT injection mode flowpath, discussed above, will evaluate the impact of this phenomenon on design basis transients considered in the piping analyses of record for the SI System.
- The third category, adequacy of inservice inspection requirements and procedures to detect fatigue indications, does not apply because CCNPP does not rely on inservice inspection as the sole means for detection of fatigue.
- The fourth category, adequacy of the fatigue design basis for Class 1 piping components designed in accordance with ANSI B31.1, does not apply because the piping in this group is designed in accordance with ANSI B31.7, Class I.
- The final category, adequacy of actions to be taken when the fatigue design basis is potentially compromised, as discussed above, is adequately addressed by the CCNPP FMP.

Group 4 - (fatigue for piping and valves exposed to thermal transients) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to fatigue for Group 4 components:

- Piping and valves in the SIT injection and SDC mode flowpaths contribute to maintaining the reactor coolant pressure boundary, the containment pressure boundary, and/or the SI System pressure boundary. Their integrity must be maintained under all CLB design conditions.
- The materials of construction for subcomponents in this group are carbon steel, alloy steel, and stainless steel, as well as various facing materials.
- Fatigue is a plausible ARDM for this group because the components are subject to severe thermal cycling during initiation of SDC and/or RCS heatup/cooldown. If unmanaged, this ARDM could eventually result in crack initiation and growth such that the components may not be able to perform their intended functions under CLB conditions.
- The FMP monitors fatigue usage at bounding locations to ensure that the Group 4 components remain within their design basis and includes acceptance criteria to ensure timely corrective action is taken prior to degradation that would compromise the pressure boundary and containment isolation functions.
- The results of industry studies to address the issue of thermal stratification in piping connected to the RCS will be reviewed, and changes in the design analyses for piping in Group 4 will be made as necessary.

Therefore, there is a reasonable assurance that the effects of fatigue will be adequately managed for susceptible components in the SI System 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 5 - (SCC near RWT penetrations and associated welds) - Materials and Environment

Group 5 consists of heat-affected zones in the stainless steel base metal near the RWT penetrations and associated welds that are subject to SCC. [Reference 1, Attachments 4 and 5] Nozzle penetrations for SI System piping connected to the RWT consist of stainless steel pipe penetrating the tank wall joined by a full penetration groove weld with a fillet cap. An additional reinforcement plate or penetration seal plate is similarly welded to the outer diameter of the pipe and the tank wall, forming a narrow crevice. "Telltale" holes are drilled through these plates on the horizontal centerline. [Reference 81] The RWT provides the passive intended function of maintaining the system pressure boundary. [Reference 1, Attachment 1]

The internal environment at the RWT penetrations is borated water with normal operating parameters of up to 90 psig and 105°F. [Reference 1, Attachment 6s for -HC Piping and TKs; Reference 42, Piping Class HC-23] The external surfaces of the RWT penetrations and welds are exposed to the normal outside atmosphere at the CCNPP site. [Reference 1, Attachment 6 for RWTs] In the crevice formed between the reinforcement plate and the RWT wall, moisture from the outside atmosphere could accumulate.

Group 5 - (SCC near RWT penetrations and associated welds) - Aging Mechanism Effects

Stress corrosion cracking refers to selective corrosive attack along or across material grain boundaries. This ARDM requires applied or residual tensile stress, susceptible materials (such as austenitic stainless steels), and oxygen and/or ionic species (e.g., chlorides/sulfates). Common sources of residual stress include thermal processing and stress risers created during surface finishing, fabrication, or assembly. The heat input during welding can result in a locally-sensitized region that is susceptible to SCC. [Reference 1, Attachment 7 for TKs]

Root cause evaluations of crack indications at the RWT penetrations have concluded that residual stresses were introduced at these particular locations by the procedures and specifications applied during tank fabrication. Due to the low operating pressures involved and the tough, ductile nature of the construction materials (i.e., Type 304 stainless steel), this ARDM is not expected to result in catastrophic failure. [Reference 1, Attachment 6 for RWTs] However, this aging mechanism, if unmanaged, could result in initiation of cracks, through-wall propagation, and leakage, such that the affected RWT penetrations and welds may not be able to perform their pressure boundary function under CLB design loading conditions.

Since all pipe segments in the injection mode, recirculation mode, and SDC mode flowpaths may not have any flow due to flushing or performance testing for periods of at least 30 days during normal reactor operation, they were recognized as portions of the SI System with a high likelihood of containing stagnant oxygenated borated water. Except for the indications near the RWT penetrations noted above, inservice inspections and additional examinations have concluded that the integrity of welds in these portions of the SI System have not been affected by service environment and residual stresses that have induced pipe cracking in the industry. [References 82 and 83]

Group 5 - (SCC near RWT penetrations and associated welds) - Methods to Manage Aging

Mitigation: For heat-affected zones near the RWT penetrations and associated welds, weld repair of identified cracks can mitigate this ARDM by removing the material affected by residual stresses. Additionally, control of fluid chemistry in the RWT can minimize the introduction of impurities at these locations; refer to subsection Group 2 - Methods to Manage Aging, above. [Reference 1, Attachment 6 for RWTs]

Discovery: The effects of SCC near the RWT penetrations and associated welds are detectable by visual inspection. Leakage from cracks at locations susceptible to SCC can be detected by observation of the "telltale" holes in the associated reinforcement plates. If necessary, internal surfaces of the RWTs can be subjected to examination to determine any localized degradation that may be occurring. [Reference 1, Attachment 6 for RWTs]

Group 5 - (SCC near RWT penetrations and associated welds) - Aging Management Program(s)

Mitigation: Observation of a dried boric acid buildup during a system walkdown led to discovery of a pinhole leak inside an outlet nozzle on the Unit 2 RWT. Metallographic examination of material from the excavated area concluded that the leak was caused by SCC at the penetration weld. A weld repair of the affected nozzle was completed in 1993.

Maintenance of proper fluid chemistry in accordance with CP-204, as discussed in subsection Group 2 - Aging Management Programs, above, will limit the effects of SCC. [Reference 1, Attachment 8]

Discovery: Calvert Cliffs Administrative Procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of leakage that may result from SCC near the RWT penetrations and associated welds by performance of visual inspections during plant walkdowns. [Reference 1, Attachment 8 for RWTs] The purpose of the program is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. [Reference 84, Section 1.1]

Under this program, responsible personnel perform periodic walkdowns of their assigned structures and systems. Walkdowns may also be performed as required for reasons such as: material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when the system is initially pressurized, energized, or placed in service); and as required for plant modifications. [Reference 84, Section 5.1]

One of the objectives of the program is to assess the condition of the CCNPP structures, systems, and components such that any abnormal or degraded condition will be identified, documented, and corrective actions taken before the condition proceeds to failure of the structures, systems, and components to perform their intended functions. Conditions adverse to quality are documented and resolved by the CCNPP Corrective Actions Program. [Reference 84, Sections 5.1.C, 5.2.A.1, and 5.2.A.5]

The program provides guidance for identification of specific types of degradation or conditions when performing the walkdowns. Inspection items related to aging management include the following: [Reference 84, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion;

- Effects that may have been caused by ARDMs such as damaged supports; concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, or inadequate support of components (e.g., missing, detached , or loose fasteners and clamps).

The Structure and System Walkdown Program enhances the familiarity of responsible personnel with their assigned systems and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance personnel alone. The program has been improved recently through incorporation of significant additional guidance on specific activities to be included in the scope of structures walkdowns. A structure performance assessment is currently required for fluid-retaining tanks that serve equipment important to safety at CCNPP at least once every six years. The assessment includes a review of each structural component that could degrade the overall performance of the tank (including RWT penetrations and associated welds). [Reference 84, Sections 1.2.B.7 and 5.3, and Attachment 9]

The program described above will be modified to: (a) specifically identify the field-erected storage tanks within the scope of the performance assessments (including the RWT); (b) provide additional visual inspection criteria specific to detecting leakage near the RWT penetrations; and (c) add guidance regarding approval authority for significant departures from the walkdown scope/schedule specified.

Since the susceptible locations are not normally accessible for direct visual inspection, BGE will complete an engineering review of SCC at the RWT penetrations that will either: (a) confirm that detection of minor leakage from the “telltale” holes, by itself, will adequately manage SCC at the susceptible locations prior to a challenge to the structural integrity of the penetrations under design basis conditions (e.g., analyze using a “leak-before-break” methodology); or (b) include the RWT penetrations and associated welds in an ARDI Program to verify that unacceptable degradation due to SCC at these locations is not occurring. [Reference 1, Attachment 8] For a discussion of the elements of the ARDI Program, refer to subsection Group 2 - Aging Management Programs, above.

The modified Structure and System Walkdown Program, combined with the results of the engineering review described above, will ensure that degraded conditions due to SCC are identified and corrected such that the RWT penetrations and associated welds will be capable of performing their intended function consistent with CLB design conditions.

Group 5 - (SCC near RWT penetrations and associated welds) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to SCC for heat-affected zones near the RWT penetrations and associated welds:

- The RWT penetrations and their associated welds contribute to maintaining the system pressure boundary. Their integrity must be maintained under all CLB design conditions.
- Nozzle penetrations for SI System piping connected to the RWT are fabricated of stainless steel. Residual stresses were introduced at these locations during tank fabrication.

- Stress corrosion cracking is considered to be a plausible ARDM for the heat-affected zones near the RWT penetrations and associated welds, since moisture may accumulate in the narrow crevice between the reinforcement plate and the RWT wall. If unmanaged, this ARDM could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- Maintenance of proper fluid chemistry in the SI System (in accordance with CP-204) will limit the effects of SCC at the susceptible locations of the RWT.
- The CCNPP Structure and System Walkdowns Program provides for periodic walkdowns of SI System components, including the RWT. The program will be modified to specify more clearly the scope and control of periodic performance assessments as they apply to detection of leakage that could result from SCC near the RWT penetrations and associated welds. The program will provide for the discovery of such leakage, and ensure appropriate actions are taken in a timely manner to prevent loss of function.
- Based on the results of an engineering review of SCC at the RWT penetrations, these locations may be subjected to a new ARDI Program. This program will examine a representative sample of the components for degradation, and ensure that appropriate corrective actions are initiated on the basis of the findings.

Therefore, there is a reasonable assurance that the effects of SCC will be adequately managed for the RWT penetrations and associated welds 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 6 - (weathering of RWT perimeter seal) - Materials and Environment

The RWT perimeter seal is fibrated cold plastic coal tar pitch flashing, an elastomeric material. [Reference 85] This subcomponent supports maintenance of the system pressure boundary by preventing moisture penetration under the RWT. The RWT perimeter seal is exposed to the normal outside atmosphere at the CCNPP site. [Reference 1, Attachment 6 for RWTs]

Group 6 - (weathering of RWT perimeter seal) - Aging Mechanism Effects

Exposure to sunlight, changes in humidity, ozone cycles, snow, rain, ice, and temperature and pressure fluctuations contribute to the weathering ARDM. The effects of weathering on most materials, including the RWT perimeter seal, are evidenced by a decrease in elasticity (e.g., drying out), an increase in hardness, and shrinkage. [Reference 1, Attachments 6 and 7]

Weathering is plausible for the RWT perimeter seal because it is exposed to the outside environment. If left unmanaged for an extended period of time, the materials of construction will become brittle and lose their capability to prevent moisture penetration under the RWT.

Group 6 - (weathering of RWT perimeter seal) - Methods to Manage Aging

Mitigation: Since weathering is caused by exposure of the susceptible materials to environmental conditions, which are not feasible to control (e.g., light, heat, oxygen, ozone, water), there are no reasonable methods to mitigate its effects. The discovery method discussed below is deemed adequate to manage this ARDM. [Reference 1, Attachment 8]

Discovery: The RWT perimeter seal itself does not perform the passive intended function of maintaining the system pressure boundary; however, it plays a role in mitigating corrosion of the RWT bottom by providing a moisture barrier. [Reference 1, Attachment 6 for RWTs] Periodic visual inspections can be made of the RWT perimeter seal to detect its degradation. Based on the results of the inspections, the perimeter seal can be repaired or replaced in order to maintain its sealing capabilities. [Reference 1, Attachment 8]

Group 6 - (weathering of RWT perimeter seal) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited for mitigation of weathering.

Discovery: Calvert Cliffs procedure MN-1-319 is described in subsection Group 5 - Aging Management Programs, above. Performance of visual inspections during plant walkdowns specified in this procedure provides for discovery of weathering for the RWT perimeter seal. [Reference 1, Attachment 8 for RWTs; Reference 84, Sections 1.2.B.7 and 5.3, and Attachment 9] Modifications to this program will include additional visual inspection criteria specific to the perimeter seal. The modified program will ensure that degraded conditions due to weathering are identified and corrected such that the RWT perimeter seal will be capable of performing its intended function consistent with CLB design conditions.

Group 6 - (weathering of RWT perimeter seal) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to weathering of the RWT perimeter seal:

- The RWT perimeter seal plays a role in mitigating corrosion of the tank bottom by providing a moisture barrier, thereby helping to maintain the pressure boundary function of the SI System. This capability must be maintained during the period of extended operation.
- The RWT perimeter seal is subject to weathering when exposed to the normal outside atmosphere at the CCNPP site. If unmanaged, this ARDM could result in the loss of the seal's moisture-retaining capability and subsequent corrosion of the RWT.
- The CCNPP Structure and System Walkdowns Program provides for periodic walkdowns of SI System components, including the RWT. The program will be modified to specify more clearly the scope and control of periodic performance assessments. The program will provide for the discovery of weathering for the RWT perimeter seal, and ensure appropriate actions are taken in a timely manner to correct degraded components or protective coatings.

Therefore, there is reasonable assurance that the effects weathering will be adequately managed for the RWT perimeter seal such that it will be capable of performing its intended function consistent with the CLB during the period of extended operation under all design loading conditions.

5.15.3 Conclusion

The aging management programs discussed for the SI System are listed in Table 5.15-3. 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 SI 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 5.15-3

AGING MANAGEMENT PROGRAMS FOR THE SAFETY INJECTION SYSTEM

	Program	Credited As
Existing	CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program"	Program for mitigation and discovery of general corrosion for external surfaces of piping, CKVs, CVs, HVs, HXs, MOVs, RVs, pumps, and tanks (included in Group 1) that are exposed to borated water (due to leakage) by performing visual inspections.
Existing	CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems"	Program for mitigation of general corrosion, crevice corrosion, and/or pitting for internal surfaces of all SI System device types (included in Group 2) that are exposed to borated water (as process fluid) by controlling chemistry conditions. Program for mitigation of SCC near RWT penetrations and associated welds (included in Group 5) that are exposed to borated water (as process fluid) by controlling chemistry conditions.
Existing	CCNPP Technical Procedure CP-206, "Specification and Surveillance Component Cooling/Service Water System"	Program for mitigation of general corrosion, crevice corrosion, and/or pitting for internal surfaces of the LPSI pump seal HXs and HPSI pump seal coolers (included in Group 2) that are exposed to chemically-treated water from the CC System by controlling chemistry conditions in the CC System.
Existing	CCNPP Technical Procedure CP-202, "Specification and Surveillances Demineralized Water, Safety Related Battery Water, & Well Water Systems"	Program for mitigation of crevice corrosion and pitting for internal surfaces of the RWTHXs (included in Group 2) that are exposed to well water from the Plant Heating System by monitoring well water chemistry conditions.
Existing	CCNPP Surveillance Test Procedure M-571G-1(2), "Local Leak Rate Test, Penetrations 9, 10, 23, 24, 37, 39" CCNPP Surveillance Test Procedure M-571L-1(2), "Local Leak Rate Test, Penetration 41"	Program for discovery and management of leakage that could be the result of crevice corrosion and pitting for seating surfaces of the SDC header return isolation MOV outside containment and the SI leakoff return isolation HVs (included in Group 2).
Existing	CCNPP Pump and Valve IST Program	Program for discovery and management of leakage that could be the result of crevice corrosion and pitting for seating surfaces of the loop inlet CKVs, the SI header CKVs, and the SIT outlet CKVs (included in Group 2).

	Program	Credited As
Existing	CCNPP FMP	Program for discovery and management of thermal fatigue for piping and valves in the SIT injection and SDC mode flowpaths (included in Group 4) by monitoring and evaluating low-cycle fatigue usage.
Modified	Structure and System Walkdowns (MN-1-319) • Specify scope and control of periodic structure performance assessments	Program for discovery and management of SCC near RWT penetrations and associated welds (included in Group 5) by performing visual inspections. Program for discovery and management of weathering effects for the RWT perimeter seal (included in Group 6) by performing visual inspections.
New	ARDI Program	Program for discovery and management of general corrosion, crevice corrosion, and/or pitting for internal surfaces of all SI System device types (included in Group 2) by identifying and correcting degraded conditions. Program for discovery and management of MIC for internal surfaces of the recirculation header piping (included in Group 3) by identifying and correcting degraded conditions. Program for discovery and management of SCC near RWT penetrations and associated welds (included in Group 5) by identifying and correcting degraded conditions. NOTE: Susceptible locations near the RWT penetrations will be included in this program, as necessary, based on the results of an engineering review of SCC at the RWT penetrations.
Not Applicable	CCNPP Engineering Review of Combustion Engineering Owners Group Task Reports related to NRC Bulletin 88-08 • Review results of industry studies to address the issue of thermal stratification in piping connected to the RCS and determine changes to piping analyses and fatigue usage parameters, as necessary	Determine contribution of thermal stratification effects to thermal fatigue for piping and valves in the SIT injection mode flowpath (included in Group 4) by evaluating industry studies and revising current analyses.

	Program	Credited As
Not Applicable	CCNPP Engineering Review of SCC at the RWT Penetrations • Confirm that detection of minor leakage by visual inspection will adequately manage SCC prior to a challenge of the structural integrity of the RWT penetrations under design basis conditions, or include the susceptible locations in an ARDI Program, as necessary	Determine the acceptability of periodic inspections for leakage near the RWT penetrations and associated welds (included in Group 5) for discovery and management of SCC by engineering analysis.

5.15.4 References

1. CCNPP Aging Management Review Report, "Safety Injection System," Revision 2
2. CCNPP Updated Final Safety Analysis Report, Units 1 and 2, Revision 21
3. CCNPP Operating Instructions, OI-3A-1(2), "Safety Injection and Containment Spray, Unit 1(2)," Revision 3
4. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated August 17, 1990, forwarding Licensee Event Report 89-007-01, "Damaged LPSI/Shutdown Cooling Suction Piping Restraint"
5. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated August 10, 1994, "Licensee Event Report 94-003, Reactor Shutdown for Leak From Fatigue Crack in Safety Injection Tank Line"
6. Letter from Mr. C. J. Cowgill (NRC) to Mr. R. E. Denton (BGE), dated August 25, 1994, "NRC Region I Resident Inspection Report Nos. 50-317/94-24 and 50-318/94-24 (July 3, 1994 - August 6, 1994)"
7. Letter from Mr. J. R. Lemons (BGE) to NRC Document Control Desk, dated April 22, 1987, forwarding Licensee Event Report 87-003-00, "Failure of Inlet Piping to Relief Valve [2-RV-439]"
8. Letter from Mr. W. V. Johnston (NRC) to Mr. J. A. Tiernan (BGE), dated June 15, 1987, "Inspection No. 50-318/87-15"
9. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated February 14, 1991, "Licensee Event Report 90-030, Revision 00"
10. Letter from Mr. E. C. Wenzinger (NRC) to Mr. J. A. Tiernan (BGE), dated May 6, 1987, "NRC RI Inspection 50-317/87-06, 50-318/87-06"
11. Letter from Mr. J. R. Lemons (BGE) to NRC Document Control Desk, dated June 5, 1987, forwarding Licensee Event Report 87-004-00, "Failure of Inlet Piping to Relief Valve [2-RV-439]"
12. CCNPP Component Level Scoping Results, "System 052 - Safety Injection System," Revision 2
13. BGE Drawing 60729SH0001, "Reactor Coolant System," Revision 62
14. BGE Drawing 62729SH0001, "Reactor Coolant System," Revision 73
15. CCNPP Operating Instructions, OI-2D-1(2), "Purification System Operation, Unit 1(2)," Revision 3
16. CCNPP Operating Instructions, OI-3B-1(2), "Shutdown Cooling, Unit 1(2)," Revision 7
17. BGE Drawing 60710SH0001, "Component Cooling System," Revision 36
18. BGE Drawing 62710SH0001, "Component Cooling System," Revision 35
19. BGE Drawing 12103-0002, "Piping - Bearing & Stuffing Box Cooling with Seal Circulation," Revision 1
20. BGE Drawing 12102-0001, "Seal Piping," Revision 2

21. BGE Drawing 12102-0003, “Manifold Piping - Series System,” Revision 1
22. BGE Drawing 60716, “Spent Fuel Pool Cooling, Pool Fill & Drain Systems,” Revision 47
23. BGE Drawing 60730SH0002, “Chemical and Volume Control System,” Revision 51
24. BGE Drawing 62730SH0002, “Chemical and Volume Control System,” Revision 40
25. BGE Drawing 60730SH0003, “Chemical and Volume Control System,” Revision 33
26. BGE Drawing 62730SH0003, “Chemical and Volume Control System,” Revision 33
27. BGE Drawing 60731SH0003, “Safety Injection & Containment Spray Systems,” Revision 21
28. BGE Drawing 62731SH0003, “Safety Injection & Containment Spray Systems,” Revision 17
29. BGE Drawing 60712SH0001, “Compressed Air System, Instrument Air and Plant Air,” Revision 46
30. BGE Drawing 62712SH0003, “Compressed Air System, Instrument Air and Plant Air,” Revision 89
31. BGE Drawing 60731SH0001, “Safety Injection & Containment Spray Systems,” Revision 65
32. BGE Drawing 60731SH0002, “Safety Injection & Containment Spray Systems,” Revision 36
33. BGE Drawing 62731SH0001, “Safety Injection & Containment Spray Systems,” Revision 63
34. BGE Drawing 62731SH0002, “Safety Injection & Containment Spray Systems,” Revision 34
35. CCNPP Engineering Standard ES-011, “System, Structure, and Component (SSC) Evaluation,” Revision 2
36. Combustion Engineering Specification No. 68-487-410, “General Engineering Specification for Safety System Pump,” Revision 0
37. Combustion Engineering Specification No. 8067-487-401, “Project Engineering Specification for a High Pressure Safety Injection Pump,” Revision 2
38. Combustion Engineering Specification No. 8067-487-402, “Project Engineering Specification for a Low Pressure Safety Injection Pump,” Revision 2
39. BGE Drawing 92769SH-CC-1, “M-601 Piping Class Summary,” Revision 23
40. BGE Drawing 92769SH-CC-2, “M-601 Piping Class Summary,” Revision 20
41. BGE Drawing 92769SH-HC-1, “M-601 Piping Class Summary,” Revision 26
42. BGE Drawing 92769SH-HC-3, “M-601 Piping Class Summary,” Revision 20
43. BGE Drawing 92769SH-DC-1, “M-601 Piping Class Summary,” Revision 19
44. BGE Drawing 92769SH-GC-1, “M-601 Piping Class Summary,” Revision 23
45. CCNPP Life Cycle Management Pre-Evaluation Results, “Safety Injection System (052),” Revision 2
46. CCNPP Engineering Standard ES-014, “Summary of Ambient Environmental Service Conditions,” Revision 0

47. CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program," Revision 1
48. CCNPP Administrative Procedure MN-3-110, "Inservice Inspection of ASME Section XI Components," Revision 2
49. Letter from Mr. J. A. Tiernan (BGE) to Mr. R. A. Capra (NRC), dated July 7, 1987, "Response to Generic Letter 87-06, Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves"
50. BGE Drawing 12320-0012, "Forged Bolted Bonnet Swing Check Valve," Revision 23
51. BGE Drawing 92769SH-HB-3, "M-601 Piping Class Summary," Revision 29
52. CCNPP Nuclear Program Directive CH-1, "Chemistry Program," Revision 1
53. CCNPP Technical Procedure CP-204, "Specification and Surveillance-Primary Systems," Revision 8
54. CCNPP Technical Procedure CP-206, "Specifications and Surveillance-Component Cooling/Service Water System," Revision 3
55. CCNPP Technical Procedure CP-202, "Specifications and Surveillances-Demineralized Water, Safety Related Battery Water, & Well Water Systems," Revision 5
56. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48
57. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated October 1, 1997, "Response to Questions on the Third Ten-Year Inservice Test Program for Safety-Related Pumps and Valves"
58. CCNPP Administrative Procedure EN-4-102, "ASME Pump and Valve Testing," Revision 1
59. CCNPP Administrative Procedure EN-4-104, "Surveillance Testing," Revision 1
60. CCNPP Surveillance Test Procedure O-65J-1, "Safety Injection Check Valve Quarterly Operability Test" (Unit 1), Revision 6
61. CCNPP Surveillance Test Procedure O-65J-2, "Safety Injection Check Valve Quarterly Operability Test" (Unit 2), Revision 8
62. CCNPP Surveillance Test Procedure O-27-1, "Reactor Coolant System Leakage Evaluation" (Unit 1), Revision 16
63. CCNPP Surveillance Test Procedure O-27-2, "Reactor Coolant System Leakage Evaluation" (Unit 2), Revision 14
64. Letter from Mr. A. W. Dromerick (NRC) Mr. C. H. Cruse (BGE), dated February 11, 1997, "Issuance of Amendments for CCNPP Unit No. 1 (TAC No. M97341) and Unit No. 2 (TAC No. M97342)" [Amendment Nos. 219/196]
65. CCNPP Surveillance Test Procedure M-571G-1, "Local Leak Rate Test, Penetrations 9, 10, 23, 24, 37, 39" (Unit 1), Revision 0
66. CCNPP Surveillance Test Procedure M-571G-2, "Local Leak Rate Test, Penetrations 9, 10, 23, 24, 37, 39" (Unit 2), Revision 1

67. CCNPP Surveillance Test Procedure M-571L-1, "Local Leak Rate Test, Penetration 41" (Unit 1), Revision 0

68. CCNPP Surveillance Test Procedure M-571L-2, "Local Leak Rate Test, Penetration 41" (Unit 2), Revision 0

69. 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors"

70. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated November 26, 1996, "Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318 License Amendment Request: Adoption of 10 CFR Part 50, Appendix J, Option B for Types B and C Testing"

71. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated February 13, 1996, "Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318 Response to Request for Additional Information - Generic Letter 95-07, Pressure Locking and Thermal Binding of Safety-Related, Power-Operated Gate Valves, [TAC Nos. M93444 & M93445]"

72. Letter from Mr. L. E. Philpot (Gilbert/Commonwealth, Inc.) to Mr. J. Rycyna (BGE), dated August 29, 1995, "MIC Position Paper"

73. Combustion Engineering Owners Group Task 818, Report No. CE-NPSD-963-01, "Temperature Distributions and Structural Analysis of Safety Injection Piping Subject to Thermal Stratification," September 1995

74. "Metal Fatigue in Engineering," H. O. Fuchs and R. I. Stephens, John Wiley & Sons, Copyright 1980

75. Combustion Engineering Owners Group Task 571, Report No. CE-NPSD-634-P, "Fatigue Monitoring Program for Calvert Cliffs Nuclear Power Plants Units 1 and 2," April 1992

76. CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring," Revision 0

77. 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"

78. Letter from Mr. J. A. Tiernan (BGE) to NRC Document Control Desk, dated September 29, 1988, "Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318 NRC Bulletin 88-08: Thermal Stresses in Piping Connected to Reactor Coolant Systems"

79. BGE Procurement Specification 6422284S, "Technical Services to Evaluate Thermal Fatigue Effects on Calvert Cliffs Nuclear Power Plant Systems Requiring Aging Management Review for License Renewal," Revision 0

80. NUREG-0933, Generic Safety Issue 166, "Adequacy of Fatigue Life of Metal Components," Revision 1

81. BGE Drawing 12329B-0005, "Miscellaneous Nozzles & Sump Details - 41'-6" ϕ x 41'-6" HG. Refueling Tank," Revision 2

82. Letter from Mr. A. E. Lundvall, Jr. (BGE) to Mr. B. H. Grier (NRC), dated August 24, 1979, "IE Bulletin No. 79-17"

83. Letter from Mr. A. E. Lundvall, Jr. (BGE) to Mr. B. H. Grier (NRC), dated November 27, 1979, "IE Bulletin No. 79-17 Revision 1 (Pipe Cracks in Stagnant Borated Water Systems at PWR Plants)"

84. CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns," Revision 0

85. BGE Drawing 61813, "Yard Tank Foundations Sheet 1," Revision 5

5.16 Saltwater System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Saltwater (SW) System. The SW 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 LRA.

5.16.1 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 device types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.16.1.1 presents the results of the system level scoping, 5.16.1.2 the results of the component level scoping, and 5.16.1.3 the results of scoping to determine components subject to an AMR.

5.16.1.1 System Level Scoping

This section begins with a description of the system that 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 SW System is a safety-related system. Each CCNPP unit has three SW pumps that provide the driving head to move SW from the intake structure, through the system, and back to the circulating water discharge conduits. A simplified diagram of the system is provided in Figure 5.16-1. The system is designed such that each pump has sufficient head and capacity to provide cooling water for the Service Water (SRW) System, Component Cooling (CC) System, and Emergency Core Cooling System (ECCS) pump room air coolers, as required by 10 CFR Part 50, Appendix A. [Reference 1, Section 1.1.1; Reference 2]

The SW System in each unit consists of two subsystems. Each subsystem provides SW to a SRW heat exchanger, a CC heat exchanger, and an ECCS pump room air cooler in order to transfer heat from these heat exchangers and coolers to the Chesapeake Bay. Seal water for the circulating water pumps (which supply water to the main condensers) is supplied by both subsystems. [Reference 1, Section 1.1.1]

During normal operation, both subsystems in each unit are in operation with one pump running on each header and a third pump in standby. If needed, the standby pumps can be lined-up to either supply header in their respective units. The SW flow through the SRW and CC heat exchangers is throttled to provide sufficient cooling to the heat exchangers, while maintaining total subsystem flow below a maximum value. [Reference 1, Section 1.1.1]

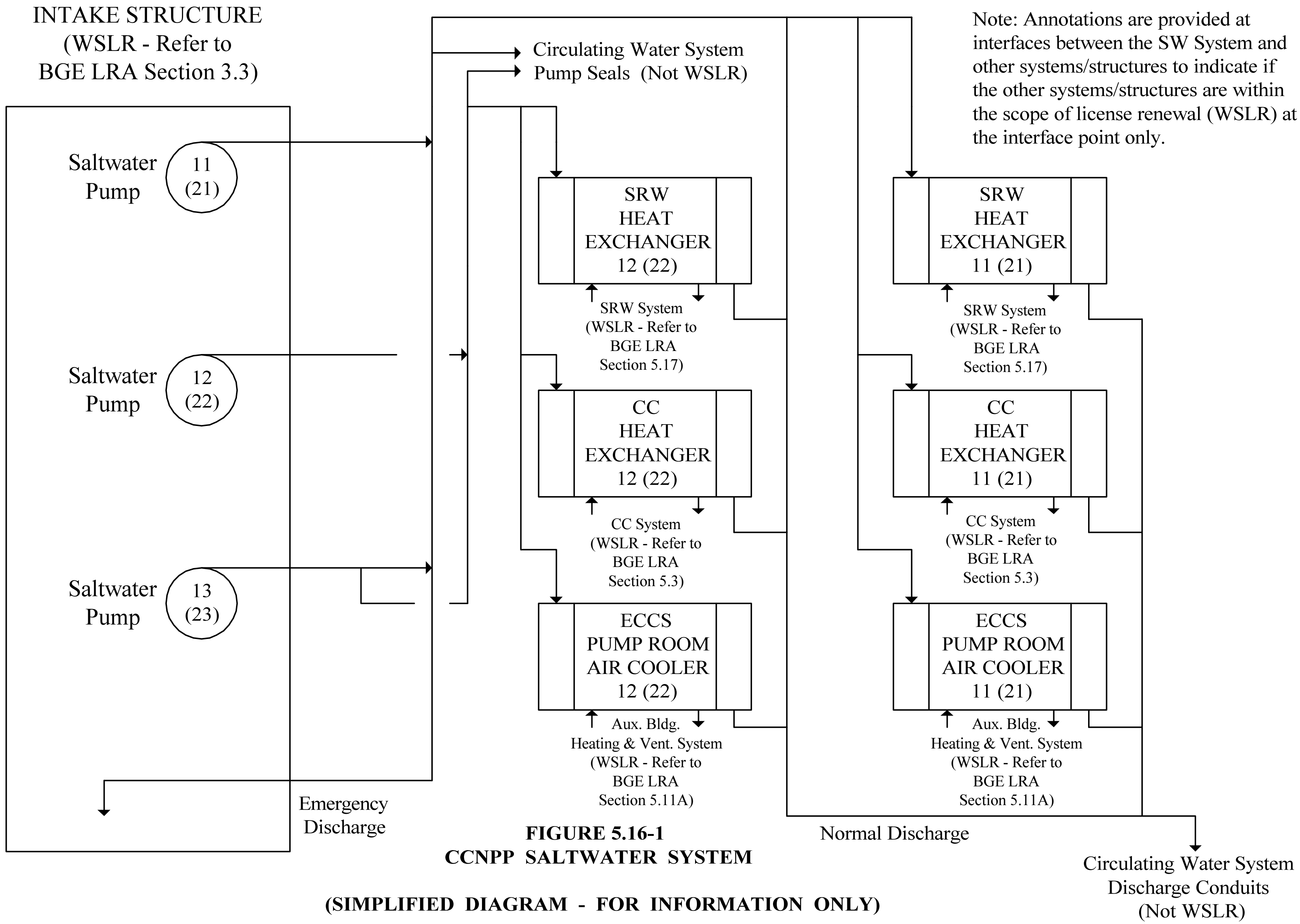

FIGURE 5.16-1
CCNPP SALTWATER SYSTEM

(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

Operation following a loss-of-coolant accident has two phases: before the Recirculation Actuation Signal (RAS) and after the RAS. One subsystem can satisfy the cooling requirements of both phases. [Reference 1, Section 1.1.1]

After a loss-of-coolant accident but before a RAS, each subsystem will cool an SRW heat exchanger and an ECCS pump room air cooler. Flow to the ECCS pump room air cooler is initiated only if required due to high room temperature. The minimum required SW flow is 16,830 gpm to each SRW heat exchanger, and 400 gpm to each ECCS pump room air cooler. There is no flow to the CC heat exchangers. System flow is not throttled. [Reference 1, Section 1.1.1; Reference 3]

When a RAS occurs, the minimum required flow to each SRW heat exchanger is reduced to 9,500 gpm, and each ECCS pump room air cooler remains at 400 gpm. Flow is restored to the CC heat exchangers at a minimum required amount of 5,500 gpm each. System flow is throttled for this phase. [Reference 1, Section 1.1.1]

In defining the scope of the SW System evaluation, an exception was made to the boundary convention. The SRW and CC heat exchangers are included in the scope of this evaluation even though heat exchangers are normally considered part of the systems they cool. This exception was made because age-related degradation is much more severe on the SW side of the heat exchangers. [Reference 1, Section 1.1.2]

Operating Experience:

Representative historical operating experience pertinent to aging is provided in this section and other appropriate sections 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.

During the 1984 CCNPP Unit 2 refueling outage, two through-wall holes occurred during work on the SW side of one CC heat exchanger channel head in preparation for coal tar epoxy application. The CC heat exchanger through-wall attack was attributed to graphitic corrosion. A visual examination was subsequently conducted on the operating Unit 1 CC and SRW heat exchanger channel heads. Two of the CC heat exchangers had three areas with apparent through-wall weepage. Unit 1 was then shut down and all CC and SRW heat exchangers were examined. Due to the size, location, and number of areas found below minimum wall on the channel heads, several repairs or channel head replacements were made. All CC and SRW heat exchanger channel heads were coated with coal tar epoxy to prevent future corrosion. These graphitic corrosion problems were the subject of NRC Information Notice No. 84-71. As shown in Table 5.16-4, the current design for these heat exchangers uses neoprene rubber linings in the channel heads rather than the coal tar epoxy coating used previously. [References 4 and 5]

The SW System has experienced through-wall pressure boundary failures of carbon steel aboveground piping lined with concrete, including occurrences in 1984 and 1991. The cause of the failures was due to failure of the concrete lining and subsequent corrosion of the bare metal exposed to SW. A modification has been performed to replace the aboveground concrete-lined piping with rubber-lined piping. [References 6 and 7]

In 1990, a pin hole leak was observed in the discharge piping of one of the Unit 1 SW pumps. The cause of the leak was localized corrosion of an inner weld connecting a slip-on flange to the pipe and localized corrosion of the pipe between welds. The corrosion occurred because of the failure of the grout lining that was applied during construction to protect field welds. Corrective actions included inspection of other flanges in the SW System. Grout lining deficiencies were found on other flanges and, in each case, the grout was removed and replaced with an epoxy-type lining. [References 8 and 9]

The SW side of the SRW heat exchangers has experienced erosion corrosion in the past. During the spring 1994 Unit 1 refueling outage, 140 plugged tubes were replaced in the No. 11 SRW heat exchanger. These tubes had previously been plugged due to leakage. During the replacement, it was discovered that there was severe tube wall thinning in the first three to four inches of the inlet end of the tubes. Tube damage was apparently caused by erosion corrosion on the tube side. Further inspection indicated that similar damage was widespread in both the No. 11 and 21 SRW heat exchangers. This problem was temporarily addressed by installing sleeves in the inlet end of the tubes. The existing heat exchangers also have experienced degraded thermal performance due to fouling. These problems have required frequent cleaning of the heat exchangers, which restricts operational flexibility. Due to the erosion corrosion and thermal performance problems, BGE plans to replace the existing tube and shell SRW heat exchangers with new plate and frame heat exchangers having increased thermal performance capability. The materials chosen for the new heat exchangers (Titanium for the plates and EPDM *[Ethylene Propylene Diene Monomer]* for the gaskets) and the method by which they will be assembled will provide deterrence to the erosion corrosion problem that damaged the existing heat exchangers. [Reference 3]

Nuclear Regulatory Commission Generic Letter 89-13 outlined concerns regarding the safe operation and maintenance of open-cycle cooling water systems. For CCNPP Units 1 and 2, the open-cycle cooling water system in the scope of Generic Letter 89-13 is the SW System. In response to Generic Letter 89-13, BGE committed to establishing a routine inspection and maintenance program for the SW piping and components to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade system performance. Specific actions completed by BGE are as follows: [Reference 10]

- Differential pressure across each SRW heat exchanger is monitored twice per shift. The SRW heat exchangers and the CC heat exchangers are bulleted periodically.
- The program for cleaning and inspecting the SRW, CC, and ECCS heat exchangers was established.
- The piping ultrasonic thickness inspection program was reviewed and revised.
- An underground piping inspection program was established.

<u>System Interfaces:</u>

The SW System interfaces with the following systems: [Reference 2; Reference 11, Section 9.5.2.3]

- SRW System;
- CC System;
- Auxiliary Building Heating and Ventilation System (ECCS pump room air coolers);
- Circulating Water System;
- Compressed Air System; and

- Engineered Safety Features Actuation System.

Interfaces in the major flow path are indicated on Figure 5.16-1.

System Scoping Results

The SW System is in scope for license renewal based on 10 CFR 54.4(a). The following intended functions of the SW 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 12, Table 1]

- Provide the vital auxiliary function of supplying cooling water to the CC and SRW Heat Exchangers and the ECCS Pump Room Air Coolers during design basis events;
- To maintain the pressure boundary of the system (liquid and/or gas);
- To maintain electrical continuity and/or provide protection of the electrical system; and
- To restrict flow to a specified value in support of a design basis event response.

The following intended functions of the SW System were determined based on the requirements of §54.4(a)(3): [Reference 12, Table 1]

- For environmental qualification (10 CFR 50.49) - To maintain functionality of electrical components as addressed by the Environmental Qualification Program;
- For fire protection (10 CFR 50.48) - To provide the ultimate heat sink for the SRW and CC Systems to ensure safe shutdown in the event of a postulated severe fire; and
- For post-accident monitoring - To provide information used to assess the environs and plant condition during and after an accident.

5.16.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the SW System that is within the scope of license renewal includes the components (electrical, mechanical, and instrumentation) and their supports along the system flowpath shown in Figure 5.16-1. These components include the SW pumps and motors, the SRW and CC heat exchangers, the ECCS pump room air coolers, the basket strainers located upstream of the ECCS pump room air coolers, air accumulators for control valves, and the associated piping, valves, instruments, and controls. [Reference 1, Section 1.1.2; Reference 2; Reference 12, Table 2]

A total of 40 device types within the SW System were designated as within the scope of license renewal because they have at least one intended function: These device types are listed in Table 5.16-1. [Reference 1, Table 2-1, Attachment 3s]

TABLE 5.16-1

SW SYSTEM DEVICE TYPES WITHIN THE SCOPE OF LICENSE RENEWAL

Device Code	Device Description	Device Code	Device Description
-JE2	Red Brass Piping	LY	Level Relay
-JG1	70-30 Copper-Nickel Piping	MA	4kV Motor
-LC2	Cast Iron or Carbon Steel Piping with Cement Mortar Lining	MOV	Motor-Operated Valve
-LJ1	Carbon Steel Piping with Neoprene Lining	NA	4kV Local Control Station
-MC6	Carbon Steel Piping with Saran or Neoprene Lining	PCV	Pressure Control Valve
-MC8	Carbon Steel Piping with Kynar Lining	PDI	Differential Pressure Indicator
ACC	Accumulator	PDIS	Differential Pressure Indicating Switch
BS	Basket Strainer	PI	Pressure Indicator
CKV	Check Valve	PS	Pressure Switch
COIL	Coil	PT	Pressure Transmitter
CV	Control Valve	PUMP	Pump/Driver Assembly
FO	Flow Orifice	RV	Relief Valve
FU	Fuse	RY	Relay
HIC	Hand Indicator Controller	SV	Solenoid Valve
HS	Hand Switch	TI	Temperature Indicator
HV	Hand Valve	TP	Temperature Test Point
HX	Heat Exchanger	TS	Temperature Switch
I/P	Current to Pneumatic Transducer	XJ	Expansion Joint
II	Ammeter	ZL	Position Indicating Lamp
JL	Power Indicating Lamp	ZS	Position Switch

In addition, some components within the scope of license renewal are common to many plant systems and perform the same passive functions regardless of system. These components are not included in the above table and are as follows:

- Structural supports for piping, cables and components;
- Electrical cabling; and
- Instrument lines (i.e., tubing and small bore piping), and the associated tubing supports, instrument valves (e.g., equalization, vent, drain, isolation), and fittings.

5.16.1.3 Components Subject to AMR

This section describes the components within the SW System that are subject to 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 system reports, evaluated in commodity reports, or remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following SW System functions were determined to be passive: [Reference 1, Table 3-1]

- To maintain the pressure boundary of the system (liquid and/or gas);
- To maintain electrical continuity and/or provide protection of the electrical system; and
- To restrict flow to a specified value in support of a design basis event.

Device Types Subject to AMR

Of the 40 device types within the scope of license renewal shown in Table 5.16-1:

- Fourteen device types (Coil, Fuse, Hand Indicator Controller, Hand Switch, Ammeter, Power Indicating Lamp, Level Relay, 4 kV Motor, Motor Operated Valve, 4 kV Local Control Station, Relay, Temperature Switch, Position Indicating Lamp, Position Switch) only have active intended functions. [Reference 1, Table 3-2].
- One device type (Expansion Joints) is subject to periodic replacement. Some current/pneumatic transmitters and some solenoid valves are also subject to periodic replacement. [Reference 1, Table 3-2; Reference 13, Attachment 2]
- Five device types (Differential Pressure Indicator, Differential Pressure Indicating Switch, Pressure Switch, Pressure Indicator, Pressure Transmitter) are evaluated in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. [Reference 1, Table 3-2]

The remaining 20 device types, listed in Table 5.16-2, are subject to AMR and are included in the scope of this report. Unless otherwise annotated, all components of each listed type are covered. [Reference 1, Table 3-2, Attachment 3s]

TABLE 5.16-2

SW SYSTEM DEVICE TYPES REQUIRING AMR

Device Code	Device Description	Device Code	Device Description
-JE2	Red Brass Piping	FO	Flow Orifice
-JG1	70-30 Copper-Nickel Piping	HV	Hand Valve*
-LC2	Cast Iron or Carbon Steel Piping with Cement Mortar Lining	HX	Heat Exchanger
-LJ1	Carbon Steel Piping with Neoprene Lining	I/P	Current to Pneumatic Transducer**
-MC6	Carbon Steel Piping with Saran or Neoprene Lining	PCV	Pressure Control Valve
-MC8	Carbon Steel Piping with Kynar Lining	PUMP	Pump/Driver Assembly
ACC	Accumulator	RV	Relief Valve
BS	Basket Strainer	SV	Solenoid Valve**
CKV	Check Valve	TI	Temperature Indicator
CV	Control Valve	TP	Temperature Test Point*

* Instrument line manual drain, equalization, and isolation valves and some temperature test points in the SW System that are subject to AMR are evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of BGE LRA. Instrument line manual root valves and the remaining temperature test points are evaluated in this report. [Reference 13, Attachment 4A]

** Some current/pneumatic transmitters and some solenoid valves are subject to periodic replacement. [Reference 13, Attachment 2]

Some components in the SW System are common to many plant systems and perform the same passive function regardless of system (i.e., structural supports, electrical cabling, and instrument lines as discussed in Section 5.16.1.2 above). Therefore, these components are not included in the 40 SW System device types discussed above, and they were evaluated as follows:

- Structural supports for piping, cables and components in the SW 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 cabling for components in the SW 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. This commodity evaluation completely addresses the SW System passive intended function, “To maintain electrical continuity and/or provide protection of the electrical system.”
- Instrument lines (i.e., tubing and small bore piping), and the associated tubing supports, instrument valves (e.g., equalization, vent, drain, isolation), and fittings for components in the SW System that are subject to AMR are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. This commodity evaluation addresses the SW System passive intended function, “To maintain the pressure boundary of the system (liquid and/or gas)” for instrument lines, and the associated supports, instrument valves, and fittings.

The only passive functions associated with the SW System that are not completely addressed by one of the commodity evaluations discussed above are:

- To maintain the pressure boundary of the system (liquid and/or gas); and
- To restrict flow to a specified value in support of a design basis event.

Therefore, only the two functions listed above for the 20 device types listed in Table 5.16-2 are addressed by the remainder of this section.

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.

5.16.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the SW System components is given in Table 5.16-3, with plausible ARDMs identified by a check mark (✓) in the appropriate device type column. [Reference 1, Tables 4-1 and 4-2] A check mark indicates that the ARDM applies to at least one component for the device type listed. 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 5.16-3 also identifies the group to which each ARDM/device type combination belongs. The following groups have been selected for the SW System:

Group 1 - Includes device types without internal lining subject to crevice corrosion, general corrosion, microbiologically-induced corrosion (MIC), and pitting.

Group 2 - Includes device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation.

Group 3 - Includes device types with air internal environments subject to general corrosion.

Group 4 - Includes the CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation.

Group 5 - Includes the ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting.

Group 6 - Includes flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting.

TABLE 5.16-3

POTENTIAL AND PLAUSIBLE ARDMs FOR THE SW SYSTEM

Potential ARDMs	Device Types																			
	-JE	-JG	-LC	-LJ	-MC	ACC	BS	CKV	CV	FO	HV	HX	I/P	PCV	PUMP	RV	SV	TI	TP	Not Plausible for System
Cavitation Corrosion																				x
Corrosion Fatigue																				x
Crevice Corrosion	✓(1)	✓(1)	✓(2)	✓(2)	✓(2)		✓(2)	✓(1, 2)	✓(1, 2)	✓(6)	✓(1, 2)	✓(4, 5)			✓(2)	✓(1)		✓(1)	✓(1)	
Dynamic Loading																				x
Elastomer Degradation				✓(2)	✓(2)				✓(2)		✓(2)	✓(4)								
Electrical Stressors																				x
Erosion Corrosion										✓(6)		✓(4)								
Fatigue																				x
Fouling																				x
Galvanic Corrosion			✓(2)	✓(2)	✓(2)		✓(2)	✓(2)	✓(2)		✓(2)				✓(2)					
General Corrosion		✓(1)	✓(2)	✓(2)	✓(2)	✓(3)	✓(2)		✓(2, 3)		✓(2, 3)	✓(4, 5)		✓(3)	✓(2)				✓(1)	
Hydrogen Damage																				x
Intergranular Attack																				x
MIC	✓(1)	✓(1)	✓(2)	✓(2)	✓(2)		✓(2)	✓(1, 2)	✓(1, 2)	✓(6)	✓(1, 2)	✓(4, 5)			✓(2)	✓(1)		✓(1)	✓(1)	
Oxidation																				x
Particulate Wear Erosion			✓(2)							✓(6)										
Pitting	✓(1)	✓(1)	✓(2)	✓(2)	✓(2)		✓(2)	✓(1, 2)	✓(1, 2)	✓(6)	✓(1, 2)	✓(4, 5)			✓(2)	✓(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(s) in which the ARDM/device type combination is evaluated

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 to managing aging, aging management program(s), and aging management demonstration.

Group 1 (Device types without internal lining subject to crevice corrosion, general corrosion, MIC, and pitting) - Materials and Environment

As shown in Table 5.16-3, Group 1 applies to device types -JE, -JG, CKV, CV, HV, RV, TI, and TP that are subject to crevice corrosion, general corrosion, MIC, and pitting.

Group 1 consists of piping, valves, temperature indicators, and temperature test points without any lining on their internal surfaces. [Reference 1, Attachment 1 for Group IDs JE-01, JG-01, CKV-01, CV-05, HV-01/02/03/06/07/10/11, RV-01, TI-01, TP-01]

All of the Group 1 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

The internal environment for all of the Group 1 components is SW. [Reference 1, Attachment 3s]

Crevice corrosion, MIC, and pitting are plausible for each of the Group 1 device types. One or more of these ARDMs are plausible for the metal internal subcomponent parts that are exposed to the process fluid (i.e., SW). General corrosion is only plausible for Group 1 device types -JG and TP. Crevice corrosion, pitting, and/or general corrosion are plausible for metal external subcomponent parts (e.g., bolting) that may be exposed to leakage of the process fluid. [Reference 1, Attachment 1, Attachment 4s, 5s, and 6s]

The materials of the Group 1 components subject to plausible crevice corrosion, MIC, and pitting include: red brass, 70-30 copper-nickel, bronze, stainless steel, and monel. The Group 1 components subject to general corrosion include bolting constructed of low alloy steel and carbon steel. [Reference 1, Attachment 1, Attachment 4s and 5s]

Group 1 (Device types without internal lining subject to crevice corrosion, general corrosion, MIC, and pitting) - Aging Mechanism Effects

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, and other mechanical joints that have a crevice geometry. The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. Crevice corrosion is closely related to pitting corrosion and can initiate pits (i.e., loss of material) in many cases. In an oxidizing environment, a crevice can set up a differential aeration cell to concentrate an acid solution within the crevice. Even in a reducing environment, alternate wetting and drying can concentrate aggressive ionic species to cause pitting and crevice corrosion. [Reference 1, Attachment 7s]

Pitting is a form of localized attack with greater corrosion rates at some locations than at others. This form of corrosion essentially produces holes of varying depth to diameter ratios in the metal. These pits are, in many cases, filled with oxide debris, especially in ferritic materials such as carbon steel. High concentrations of impurity anions such as chlorides and sulfates tend to concentrate in the oxygen depleted pit region, giving rise to a potentially concentrated aggressive solution in this zone. [Reference 1, Attachment 7s]

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The consequences of the damage are loss of load-carrying cross-sectional area. General corrosion requires an aggressive environment and materials susceptible to that environment. [Reference 1, Attachment 7s]

Microbiologically-induced corrosion is accelerated corrosion of materials resulting from surface microbiological activity. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria are most commonly associated with corrosion effects. This ARDM most often results in pitting, followed by excessive deposition of corrosion products. Stagnant or low flow areas are most susceptible, and sedimentation aggravates the problem. Any system that uses untreated water, or is buried, is particularly susceptible. Consequences range from leakage to excessive differential pressure and flow blockage. Essentially all systems and most commonly used materials are susceptible. Temperatures from about 50°F to 120°F are most conducive to MIC. [Reference 1, Attachment 7s]

Crevice corrosion and pitting are plausible for the internal metal surfaces of the Group 1 components since they are subjected to an aggressive SW environment. The components are susceptible to pitting and crevice corrosion due to the presence of sulfates and chlorides. Dissolved oxygen and stagnant fluid aggravates the pitting. [Reference 1, Attachment 6s]

General corrosion, crevice corrosion, and pitting are plausible for bolting of the Group 1 components. Although the bolting is not exposed to the process fluid, the potential for leakage of brackish water from the system onto the bolts exists. [Reference 1, Attachment 6s]

Microbiologically-induced corrosion is plausible for the internal metal surfaces of the Group 1 components due to the use of raw, untreated SW. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria may be present in the process fluid. [Reference 1, Attachment 6s]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 1 components may not be able to perform their pressure boundary function under current licensing basis (CLB) conditions.

Group 1 (Device types without internal lining subject to crevice corrosion, general corrosion, MIC, and pitting) - Methods to Manage Aging

Mitigation: Corrosion can be mitigated by design through the proper selection of materials. The occurrence of corrosion is expected to be limited, and is not likely to affect the intended function of components constructed of corrosion resistant materials such as brass, bronze, copper-nickel alloys, and stainless steel developed for SW service. Therefore, there are no additional mitigation measures deemed practical. The discovery activities discussed below are deemed adequate to manage aging for the Group 1 components. [Reference 1, Attachment 8]

Discovery: Visual inspections of representative components can be used to provide assurance that significant corrosion is not occurring for the Group 1 components. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the components will continue to perform their intended functions during the period of extended operation. [Reference 1, Attachment 8]

Group 1 (Device types without internal lining subject to crevice corrosion, general corrosion, MIC, and pitting) - Aging Management Program(s)

Mitigation: Since there are no mitigation measures deemed practical, there are no programs credited with mitigating aging for the Group 1 components.

Discovery: To verify that no significant crevice corrosion, general corrosion, MIC, or pitting is occurring on the Group 1 components, a new plant program will be developed to provide 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 program details are provided below. [Reference 1, Attachment 1 for Group IDs JE-01, JG-01, CKV-01, CV-05, HV-01/02/03/06/07/10/11, RV-01, TI-01, TP-01]

ARDI Program

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.

Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Actions Program, QL-2, and will ensure that the Group 1 components remain capable of performing their passive intended functions under all CLB conditions.

Group 1 (Device types without internal lining subject to crevice corrosion, general corrosion, MIC, and pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 1 components:

- The Group 1 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.

- Crevice corrosion, general corrosion, MIC, and pitting are plausible for the Group 1 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- The ARDI Program will conduct inspections of representative components to discover the effects of crevice corrosion, general corrosion, MIC, and pitting, and will contain acceptance criteria that ensure corrective actions will be taken such that the components remain capable of performing their passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, MIC, and pitting will be managed for the Group 1 components such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 2 (Device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation) - Materials and Environment

As shown in Table 5.16-3, Group 2 applies to device types -LC, -LJ, -MC, BS, CKV, CV, HV, and PUMP that are subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation.

Group 2 consists of piping, basket strainers, valves, and pumps with lining on their internal surfaces. [Reference 1, Attachment 1 for Group IDs LC-01, LJ-01, MC-01, BS-01, CKV-02, CV-03/04, HV-04/05, PUMP-01]

All of the Group 2 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

The internal environment for all of the Group 2 components is SW. Most of the device type -LC piping is below ground (i.e., external environment is soil). The external surfaces of the buried piping is protected from the soil per standard industry practice with a multiple layer wrap and enamel coating. [Reference 1, Attachment 3s, Attachment 6 for Group ID LC-01]

The Group 2 components are lined to protect the underlying metal surfaces from the aggressive SW environment. The metal surfaces can potentially be subjected to the SW environment in locations where the lining has failed. The Group 2 lining materials include: cement mortar, neoprene, saran, kynar, Belzona (brand name), Tuboscope (brand name), Buna-N, natural rubber, hard rubber, polypropylene, and coal tar epoxy. The underlying metal materials include: cast iron, ductile iron, cast steel, and carbon steel. [Reference 1, Attachment 1]

Crevice corrosion, galvanic corrosion, MIC, and pitting are plausible for each of the Group 2 device types. One or more of these ARDMs are plausible for the metal internal subcomponent parts that could be exposed to the SW process fluid if the lining failed. Crevice corrosion, galvanic corrosion, MIC, and pitting are also plausible for the external surfaces of the buried piping that could be exposed to soil if the coating failed. Crevice corrosion, pitting, and general corrosion are plausible for metal external parts (e.g., bolting, cap screws) that may be exposed to leakage of the process fluid. The materials of the

Group 2 components subject to general corrosion include low alloy steel and carbon steel. [Reference 1, Attachment 1, Attachment 4s, 5s, and 6s]

Particulate wear erosion is only plausible for the Group 2 piping with cement mortar lining. Elastomer degradation is plausible for Group 2 components with lining constructed of neoprene, Buna-N, natural rubber, and hard rubber. [Reference 1, Attachment 4s, 5s, and 6s]

Group 2 (Device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation) - Aging Mechanism Effects

The aging mechanism effects for crevice corrosion, general corrosion, MIC, and pitting are as discussed above for Group 1.

Galvanic corrosion is an accelerated corrosion caused by dissimilar metals in contact in a conductive solution. Galvanic corrosion requires two dissimilar metals in physical or electrical contact, developed potential (material dependent), and conducting solution. [Reference 1, Attachment 7s]

Particulate wear erosion is loss of material caused by mechanical abrasion due to relative motion between the solution and material surface. This mechanism requires high velocity fluid and entrained particles, and turbulent flow regions, flow direction change, and/or impingement. Most materials are susceptible to varying degrees depending upon the severity of the environmental factors. [Reference 1, Attachment 7s]

Elastomers may degrade over time due to extended exposure to light, heat, oxygen, ozone, water, or radiation. When an elastomer ages, there are three mechanisms primarily involved: [Reference 1, Attachment 7s]

- Scission - The process of breaking of molecular bonds, typically due to ozone attack, ultraviolet light, or radiation;
- Crosslinking - The process of creating molecular bonds between adjacent long-chain molecules, typically due to oxygen attack, heat, or curing; and
- Compound ingredient evaporation, leaching, mutation, etc.

Scission and crosslinking have a major impact on physical property changes in elastomers. Scission results in increased elongation, decreased tensile strength, and decreased modulus. Crosslinking results in changes opposite to scission, i.e., decreased elongation, increased tensile strength, and increased modulus. For piping liner applications, elastomers are bonded to the inside surface of the pipe to prevent corrosive fluids from coming in contact with piping material. Piping liner debonding may occur if incorrect practices occurred during liner application. Piping liner debonding and degradation may result in failure of the elastomer material and allow the process fluid to come in contact with the underlying metal piping. [Reference 1, Attachment 7s]

As discussed in the Materials and Environment section above, the Group 2 components are lined to protect the underlying metal surfaces from the aggressive SW environment. The internal metal surfaces of the Group 2 components are susceptible to localized SW corrosive attack (i.e., crevice corrosion and pitting) in the event that there is lining failure. Galvanic corrosion (e.g., at an interface between a stainless steel thermowell and a carbon steel pipe) and MIC (e.g., due to bacteria in the SW) may also be a concern at locations of damaged lining. [Reference 1, Attachment 6s]

Crevice corrosion, galvanic corrosion, MIC, and pitting are plausible (although not likely) for the external surfaces of the buried piping (device type -LC) if the protective coating fails. However, SW inside the piping is a more aggressive environment than the homogeneous soil conditions that exist under the Turbine Building where the piping is located. In addition, the impressed current cathodic protection system and the site grounding grid provide some protection from galvanic and stray current corrosion on the external surfaces. Thus, corrosive attack is considered much more likely on the interior of the piping than on the exterior. [Reference 1, Attachment 6 for Group ID -LC-01]

General corrosion, crevice corrosion, and pitting are plausible for the bolting and cap screw subcomponents of the Group 2 components. Although these external subcomponents are not exposed to the process fluid, the potential for leakage of SW from the system exists. [Reference 1, Attachment 6s]

Particulate wear erosion is plausible for Group 2 piping with cement mortar lining. The lining is susceptible to deterioration from chemical attack by SW on concrete hydration products, alkali-aggregate expansion, and abrasive wear (erosion) due to entrained particles in the SW. Cement mortar lining failure will result in exposure of the underlying metal piping surfaces to localized corrosive attack. [Reference 1, Attachment 6 for Group ID -LC-01]

Elastomer degradation is plausible for Group 2 components with lining constructed of neoprene, Buna-N, natural rubber, and hard rubber due to the combined effects of scission, crosslinking, and changes associated with compound ingredients. Significant degradation is not expected due to the service conditions. However, lining failure will result in exposure of the underlying metal component surfaces to localized corrosive attack. [Reference 1, Attachment 6s]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 2 components may not be able to perform their pressure boundary function under CLB conditions.

Group 2 (Device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation) - Methods to Manage Aging

Mitigation: The effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting for the Group 2 components are mitigated by design, by protecting the inner surfaces of the components with corrosion resistant linings. The lining provides physical separation of the susceptible metal surfaces from the aggressive SW environment.

The effects of crevice corrosion, galvanic corrosion, MIC, and pitting on the external surfaces of the buried piping are mitigated by design, by protecting the external surface with a protective coating. The coating provides physical separation of the susceptible metal piping from the soil. In addition, the impressed current cathodic protection system and the site grounding grid provide some protection from galvanic and stray current corrosion on the external surfaces. No other aging management methods are deemed necessary for managing galvanic corrosion on the external surfaces of the buried piping.

Since particulate wear erosion of the Group 2 cement mortar-lined piping is caused by mechanical abrasion due to entrained particles in the SW process flow, there are no reasonable methods to mitigate its effects. Similarly, since elastomer degradation of the Group 2 lined surfaces is caused by exposure of susceptible materials to environmental conditions that are not feasible to control (e.g., heat, oxygen, water, ozone), there are no reasonable methods to mitigate its effects. The discovery methods discussed below are deemed adequate to manage these ARDMs.

Discovery: The occurrence of corrosion is expected to be limited and not likely to affect the intended function of the Group 2 components so long as their corrosion-resistant linings remain intact. Visual inspections can be performed for signs of liner degradation and corrosion. If significant degradation is found, appropriate corrective actions can be taken to ensure that the components continue to perform their intended functions during the period of extended operation. [Reference 1, Attachment 8]

Group 2 (Device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation) - Aging Management Program(s)

Mitigation: For crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting, the mitigation measures are provided by design features (i.e., corrosion resistant lining). For particulate wear erosion and elastomer degradation, there are no reasonable mitigation measures. Therefore, there are no programs credited with mitigating aging for the Group 2 components.

Discovery: Most of the Group 2 components are subject to periodic inspection through existing plant preventive maintenance (PM) activities as part of the CCNPP PM Program. These activities provide an effective means to discover and manage the age-related degradation effects on the components. The CCNPP PM Program and the specific maintenance activities are discussed in detail below. [Reference 1, Attachment 1 for Group IDs LC-01, LJ-01, BS-01, CKV-02, CV-03/04, HV-04, PUMP-01, Attachment 8]

Group 2 components that are not inspected by the PM Program will be included in a new plant program. The Group 2 components covered by this program include saran, kynar, or neoprene-lined carbon steel piping (device type -MC) and hand valves (device type HV) constructed of ductile iron or cast steel. These components are subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, and elastomer degradation. The program will inspect a representative sample of susceptible areas of the system for signs of liner degradation and corrosion. If any significant degradation is found, the program will provide appropriate corrective actions to ensure that the Group 2 components continue to perform their intended functions during the period of extended operation. The program is considered an ARDI Program as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA). The program details are described above in the Group 1 Aging Management Program section. [Reference 1, Attachment 1 for Group IDs MC-01, HV-05; Attachment 8, Attachment 10]

CCNPP PM Program

The CCNPP PM 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. [Reference 14, Section 1.1]

The program is governed by CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," and covers all PM activities for nuclear power plant structures and equipment within the plant, including the SW System components within the scope of license renewal. References 15, 16, and 17 were used in the development of this program. [Reference 14, Section 2.1]

The PM Program includes periodic inspection of specific components through various maintenance activities. These activities provide an effective means to discover and manage the age-related degradation effects on these components. The program requires that an Issue Report be initiated according to CCNPP Procedure QL-2-100, "Issue Reporting and Assessment," for deficiencies noted during performance of PM tasks. Corrective actions are taken to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions. [Reference 1, Section 4.3; Reference 14, Section 5.2.B.1.f]

Specific responsibilities are assigned to BGE personnel for evaluating and upgrading the PM Program and for initiating program improvements based on system performance. Issue Reports are initiated according to CCNPP Procedure QL-2-100 to request changes to the program that could improve or correct plant reliability and performance. Changes to the PM Program that require Issue Reports included changes to the PM task scope, frequency, process changes, results from operating experience reviews, as well as other types of changes. [Reference 14, Sections 5.1.A and 5.4]

The PM Program is subject to periodic internal assessment. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their strength of performance and safety significance, and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. An audit performed in 1997 of the CCNPP Maintenance Program (which includes the PM Program) concluded that the program is effectively implemented at CCNPP. No age-related degradation issues were identified. [Reference 18, Section 1B.18]

For the Group 2 components, the specific maintenance activities that manage the effects of aging are as follows:

- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion and pitting of cement mortar-lined piping (device type -LC) is carried out by periodic inspection through Repetitive Tasks 10122066, 10122067, 10122068, 20122070, 20122071, 20122072. These repetitive tasks are performed during refueling outages to inspect the interior surface of the piping to verify that degradation is not occurring, and corrective actions are taken to repair any deficiencies discovered. [Reference 1, Attachments 1 and 8 for Group ID LC-01]
- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting and elastomer degradation of neoprene-lined piping (device type -LJ) is carried out by periodic inspection through Repetitive Tasks 10122063, 10122064, 10122065, 20122067, 20122068, 20122069. These repetitive tasks are performed during refueling outages to inspect the interior surface of the piping to verify that degradation is not occurring, and corrective actions are taken to repair any deficiencies discovered. [Reference 1, Attachments 1 and 8 for Group ID LJ-01]

- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting for ECCS pump room air cooler basket strainers (device type BS) is carried out by periodic inspection and testing through PM Checklists MPM04004 and MPM04194. Checklist MPM04004 is performed every 12 weeks and MPM04194 is performed every 48 weeks. These checklists include steps to inspect for signs of leakage and corrosion and to verify the integrity of the liner. This activity detects degradation of the pressure boundary or bolting, and corrective actions are taken to repair any deficiencies discovered. [Reference 1, Section 4.3, Attachments 1 and 8 for Group ID BS-01]
- Management of crevice corrosion, galvanic corrosion, MIC, and pitting for SW pump discharge check valves (device type CKV) is carried out by periodic inspection and testing through PM Checklists MPM12200 and MPM12201. These PM checklists are performed on a six-year frequency to inspect the lining and body of the valves for degradation. These routine activities identify any degradation of the pressure boundary, and corrective actions are taken to repair any deficiencies discovered. [Reference 1, Section 4.3, Attachments 1 and 8 for Group ID CKV-02]
- Management of crevice corrosion, galvanic corrosion, MIC, pitting, and elastomer degradation of control valves (device type CV) associated with the ECCS pump room air coolers is carried out by periodic inspection and overhaul through Repetitive Tasks 10122096 through 10122102, and 20122100 through 20122106. These repetitive tasks are performed every six years. The occurrence of corrosion and liner degradation is expected to be limited and is not likely to affect the intended function of the valves. Periodic valve overhaul verifies that degradation is not occurring and corrective actions are taken to repair any deficiencies that are discovered. [Reference 1, Attachments 1, 3, and 8 for Group ID CV-03; Reference 12, Table 2]
- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, and elastomer degradation of control valves (device type CV) associated with the SRW heat exchangers is carried out by periodic inspection and testing through PM Checklists MPM01001 and MPM01181. These PM checklists are performed on a bi-annual frequency to inspect the lining and bodies of the valves for corrosion. These routine activities identify any degradation of the pressure boundary and corrective actions are taken to repair any deficiencies that are discovered. Checklist MPM01001 will be modified to add other SRW heat exchanger control valves that are not currently included in the checklist. [Reference 1, Attachments 1, 3, and 8 for Group ID CV-04, Attachment 10; Reference 12, Table 2]
- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, and elastomer degradation of the hand valves (device type HV) that provide the path to the circulating water discharge conduits is carried out by periodic inspection through Repetitive Tasks 10122068 and 20122072. These repetitive tasks are performed during refueling outages. Periodic inspection of valves during piping inspection verifies that degradation is not occurring, and corrective actions are taken to repair any deficiencies discovered. [Reference 1, Attachments 1, 3, and 8 for Group ID HV-04; Reference 2; Reference 12, Table 2]
- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting for the SW pumps is carried out by pump inspection and overhaul through CCNPP Procedure PUMP-3, "Saltwater Pump Overhaul." These activities are performed as required based on pump performance trends or corrective action requirements. The procedure requires that the pump volute be inspected for signs of wear, erosion, corrosion, scratches, or cracks. Performance of this activity will identify degradation of the pump casings. Corrective actions are taken to repair any

deficiencies discovered. [Reference 1, Section 4.3, Attachments 1 and 8 for Group ID PUMP-01; Reference 19, Page 29]

Group 2 (Device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 2 components:

- The Group 2 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- Crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation are plausible for the Group 2 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- The PM Program conducts periodic inspections of specific components through performance of various maintenance activities that provide the means to discover the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation for specific components. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions.
- For Group 2 components that are not inspected by the PM Program, the ARDI Program will conduct inspections of representative components to discover the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, and elastomer degradation, and will contain acceptance criteria that ensure corrective actions will be taken such that the components remain capable of performing their passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation will be managed for the Group 2 components such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 3 (Device types with air internal environments subject to general corrosion) - Materials and Environment

As shown in Table 5.16-3, Group 3 applies to device types ACC, CV, HV, and PCV that are subject to general corrosion.

Group 3 consists of accumulators and valves that have air internal environments. [Reference 1, Attachment 1 for Group IDs ACC-01, CV-01, CV-02, HV-09, PCV-02]

All of the Group 3 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

The internal environment for all the Group 3 components is instrument air (IA). The IA supply is normally provided by the IA compressors and is very dry, filtered, oil-free air. Particle size, dew point, and oil hydrocarbons are controlled in accordance with industry standards. Occasionally, air that does not meet the same air quality standards may enter the IA System due to operation of the plant air compressors or the SW air compressors, which serve as backups to the IA compressors. Therefore, there is a possibility that moisture may enter the IA supply, although its effect is expected to be limited since the backup compressors are operated on a short-term basis. An inspection performed on the piping immediately downstream of the SW air compressors, where the worst case of general corrosion is expected, revealed only very light surface rust on the inside of each piece. After more than 20 years in operation, approximately 60% of the pipe interior contained no rust and appeared similar to the inside of new pipe. Measurements showed negligible loss of wall thickness. [Reference 1, Attachment 3s, Attachment 8; Reference 11, Section 9.10; Reference 20, Attachment 8]

General corrosion is plausible for the internal carbon steel and iron subcomponent parts of the Group 3 components. [Reference 1, Attachment 1, Attachment 4s, 5s, and 6s]

Group 3 (Device types with air internal environments subject to general corrosion) - Aging Mechanism Effects

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The consequences of the damage are loss of load-carrying cross-sectional area. General corrosion requires an aggressive environment and materials susceptible to that environment. This ARDM is plausible for the Group 3 components because susceptible materials of construction are exposed to potentially moist air. However, the exposure of these components to moisture is expected to be minimal and short-term and is not expected to result in significant levels of degradation. [Reference 1, Attachment 7s, Attachment 8]

The expected effects of general corrosion on the internal carbon steel and iron subcomponent parts would be superficial rust speckles and a slight dusting of loose surface rust. [Reference 1, Attachment 6s]

This aging mechanism, if unmanaged, could eventually result in a loss of material such that the Group 3 components may not be able to perform their pressure boundary function under CLB conditions.

Group 3 (Device types with air internal environments subject to general corrosion) - Methods to Manage Aging

Mitigation: The effects of general corrosion for the Group 3 components can be mitigated by minimizing their exposure to an aggressive environment (i.e., minimizing moisture in the IA supply). As discussed above, the exposure of these components to moisture is expected to be minimal and short-term and is not expected to result in significant levels of degradation. Continued maintenance of the IA System air quality to industry standards will ensure minimal component degradation. [Reference 1, Attachments 6s, Attachment 8]

Discovery: There are no methods deemed necessary to discover general corrosion since the aging effects are expected to be minimal and can be mitigated by continued maintenance of the IA System air quality.

Group 3 (Device types with air internal environments subject to general corrosion) - Aging Management Program(s)

Mitigation: Moisture in the IA supply is minimized through PM checklists that are performed as part of the PM Program. The PM program details are described above in the Group 2 Aging Management Program section. For the Group 3 components, the specific maintenance activities that mitigate the effects of general corrosion are as follows:

- Calvert Cliffs initiated Preventive Maintenance Checklist IPM 10000 (10001), “Check Unit 1(2) Instrument Air Quality,” following a review of industry operating experience. The industry operating experience recommends maintaining the air quality within the requirements of Instrument Society of America (ISA) Standard ISA-S-7.3, “Quality Standard for Instrument Air.” Standard ISA-S-7.3 recommends limits for maximum particle size, dew point temperature, and oil content. Preventive Maintenance Checklist IPM 10000 (10001), checks instrument air quality at three locations in the IA System: at the dryer outlet, at the furthest point from the dryer, and at the approximate mid-point between the other two. The checklist is performed in accordance with CCNPP Repetitive Tasks 10191024 (20121022), “Check Unit 1(2) Instrument Air Quality at System Low Points.” Measurements of dew point and particulate count are taken every 12 weeks. According to procedure, dew point data and particulate sample results are reviewed and trended. If it is determined the air quality is abnormal, corrective action is initiated to return the air quality to normal and the condition of the dependent load internals is investigated, as appropriate. This process ensures instrument air quality is maintained in accordance with industry standards for moisture (dew point). Operating experience relative to instrument air quality control has shown that the air normally provided is very dry and contains little particulate matter. [Reference 1, Section 4.3, Attachments 1 and 8; References 21 and 22]

Discovery: Since there are no methods deemed necessary to discover general corrosion, there are no programs credited with discovery of the aging effects due to this ARDM.

Group 3 (Device types with air internal environments subject to general corrosion) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 3 components subject to general corrosion:

- The Group 3 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- General corrosion is plausible for the Group 3 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- The PM Program minimizes moisture in the IA System through performance of various maintenance activities that provide the means to mitigate the effects of general corrosion. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of general corrosion will be managed for the Group 3 components such that they will be capable of performing their pressure boundary function, consistent with the CLB, during the period of extended operation.

Group 4 (CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation) - Materials and Environment

As shown in Table 5.16-3, Group 4 applies to device type HX that is subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation.

Group 4 consists of the CC and SRW heat exchangers. [Reference 1, Attachments 1 and 3 for Group ID HX-01]

All of the Group 4 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

The subcomponent parts of the Group 4 heat exchangers, part materials, internal environment for each part, and plausible aging mechanisms are shown in the following table. [Reference 1, Attachments 4, 5, and 6 for Group ID HX-01]

TABLE 5.16-4

CC AND SRW HEAT EXCHANGERS

Subcomponent Part	Material	Environment	Plausible ARDMs
Shell	Carbon Steel	treated water	crevice corrosion general corrosion pitting
Channel Heads	Carbon Steel	SW	crevice corrosion MIC pitting
Tube Sheets	Aluminum-Bronze	treated water and SW	crevice corrosion MIC pitting
Tubes	Copper-Nickel	treated water and SW	crevice corrosion erosion corrosion MIC pitting
Channel and Channel Head Lining	Rubber/Neoprene	SW	elastomer degradation
Bolting	Carbon or Low Alloy Steel	N/A - external to process fluid	crevice corrosion general corrosion pitting

As discussed above in Section 5.16.1.1, the CCNPP SRW heat exchanger tubes have experienced erosion corrosion in the past. Baltimore Gas and Electric Company currently plans to replace the existing tube and shell SRW heat exchangers with new plate and frame heat exchangers that are more resistant to erosion corrosion. The SRW heat exchangers are scheduled to be replaced prior to the period of extended operation. [Reference 3]

Group 4 (CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation) - Aging Mechanism Effects

The aging mechanism effects for crevice corrosion, general corrosion, MIC, and pitting are as discussed above for Group 1. Elastomer degradation is discussed in Group 2.

Erosion corrosion is an increased rate of attack on a metal because of the relative movement between a corrosive fluid and the metal surface. Mechanical wear or abrasion can be involved, characterized by grooves, gullies, waves, holes, or valleys on the metal surface. Erosion is a mechanical action of a fluid and/or particulate matter on a metal surface, without the influence of corrosion. The corrosive process is accelerated because the erosion removes the protective oxide film, which results in chemical attack or dissolution of the underlying metal. Inlet tube erosion corrosion occurs in heat exchangers, due to turbulence of flow from the heat exchanger head into the smaller tubes, within the first few inches of the tube. [Reference 1, Attachment 7]

Crevice corrosion and pitting are plausible for the shell because stagnant conditions may develop in idled portions of the system. [Reference 1, Attachments 5 and 6]

General corrosion is plausible for the shell because the material of construction is susceptible to this ARDM. [Reference 1, Attachments 5 and 6]

Crevice corrosion, MIC, and pitting are plausible for the channel heads if the channel head lining material (rubber/neoprene) fails (see elastomer degradation discussion below). The wall of the channel heads is susceptible to these ARDMs at the locations of damaged lining. [Reference 1, Attachments 5 and 6]

Crevice corrosion and pitting are plausible for the tube sheets and the tubes in a SW environment. These components are susceptible to these ARDMs due to the presence of sulfates and chlorides. Dissolved oxygen and stagnant fluid will aggravate pitting. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Microbiologically-induced corrosion is plausible for the tube sheets and the tubes due to the use of raw, untreated SW. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria may be present in the process fluid. Stagnant or low flow areas are most susceptible, and sedimentation aggravates the problem. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Erosion corrosion is plausible for the inlet side of the heat exchanger tubes due to susceptible materials and flow conditions. It is also plausible based on plant operating experience as discussed above in Section 5.16.1.1.

Elastomer degradation is plausible for the channel and channel head lining due to the combined effects of scission, crosslinking, and changes associated with compound ingredients. Significant degradation is not expected due to the service conditions. However, lining failure will result in exposure of the underlying metal component surfaces to localized corrosive attack. [Reference 1, Attachments 5 and 6]

Crevice corrosion, general corrosion, and pitting are plausible for the bolting. Although these external components are not exposed to the process fluid, the potential for leakage of SW from the system exists. [Reference 1, Attachments 5 and 6]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 4 components may not be able to perform their pressure boundary function under CLB conditions.

Group 4 (CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation) - Methods to Manage Aging

Mitigation: For the shell side of the heat exchangers, the effects of crevice corrosion, general corrosion, and pitting can be mitigated by minimizing the exposure of the shell to an aggressive environment. Maintaining CC System and SRW System chemistry conditions to minimize impurities will aid in the prevention of most corrosive mechanisms. [Reference 1, Attachment 8]

For the tube side of the heat exchanger (i.e., channel heads, tube sheets, tubes, channel and channel head lining, and bolting), the components are subject to a SW environment. Therefore, it is not feasible to control water chemistry. Corrosion of the channel heads is mitigated by the rubber/neoprene lining. However, some corrosion may occur if the lining fails. Some corrosion protection is also provided by sacrificial anodes that are installed in the channel heads. Therefore, discovery methods are deemed necessary to manage aging for these components.

Discovery: For the shell side of the heat exchangers, the occurrence of corrosion is expected to be limited and is not likely to affect the intended function of the heat exchangers. Visual inspections can be used to provide additional assurance that no significant degradation is occurring. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the heat exchangers continue to perform their intended function during the period of extended operation. [Reference 1, Attachment 8]

For the tube side of the heat exchangers, visual inspections and testing can determine if any degradation is occurring. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the heat exchangers continue to perform their intended function during the period of extended operation. [Reference 1, Attachment 8]

Group 4 (CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation) - Aging Management Program(s)

Mitigation: Calvert Cliffs Technical Procedure CP-206, "Specification and Surveillance for Component Cooling/Service Water Systems," is credited with managing the effects of crevice corrosion, general corrosion, and pitting for the shell side of the heat exchangers. The program provides for monitoring and maintaining CC System and SRW System chemistry to control the concentrations of oxygen, chlorides, other chemicals, and contaminants. The water is treated with hydrazine to minimize the amount of oxygen in the water, which aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal piping or component degradation. [Reference 1, Attachment 8; Reference 23, Section 2.0]

Calvert Cliffs Technical Procedure CP-206 describes the surveillance and specifications for monitoring the CC System and SRW System fluid. CP-206 lists the parameters to monitor, the frequency of monitoring these parameters, and the target and action levels for the fluid parameters. The parameters monitored by CP-206 are pH, hydrazine, chloride, dissolved oxygen, dissolved copper, dissolved iron, suspended solids, gamma activity, and tritium activity (normally not radioactive systems). [Reference 23, Attachment 1]

These chemistry parameters are currently monitored on a frequency ranging from three times per week to once a month. All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter. Two of the parameters, pH and hydrazine, have action levels associated with them. If a target value or action level is not met, corrective actions are prescribed by the procedure, thereby ensuring timely response to chemical excursions. [Reference 23, Section 6.0.C, Attachment 1]

Operational experience related to CCNPP Technical Procedure CP-206 has shown no problems related to use of this procedure. In 1996, CP-206 was revised to include dissolved iron as a chemistry parameter. Dissolved iron was added to CP-206 to act as a method to discover any unusual corrosion of the CC System and SRW System components. [Reference 24]

Calvert Cliffs Technical Procedure CP-206 provides for a prompt review of CC System and SRW System chemistry parameters so that steps can be taken to return chemistry parameters to normal levels and, thus, minimize degradation due to corrosion mechanisms. [Reference 1, Attachment 8; Reference 23, Section 6.0.C]

Discovery: To verify that no significant crevice corrosion, general corrosion, or pitting is occurring for the shell side of the heat exchangers, a new plant program will be developed to provide inspections of a representative sample of susceptible areas for signs of degradation. The program is considered an ARDI Program as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA). The program details are discussed above in the Aging Management Program section for Group 1. [Reference 1, Attachment 8]

The tube side of the heat exchangers are subject to periodic inspection and testing through existing PM activities as part of the CCNPP PM Program. These activities provide an effective means to discover and manage the age-related degradation effects on the heat exchanger tube side subcomponent parts. The CCNPP PM Program details are discussed above in the Aging Management Program section for Group 2. The specific maintenance activities that manage the effects of aging for the tube side of the heat exchangers are as follows: [Reference 1, Attachment 8]

- Preventive Maintenance Checklists MPM00005 and MPM00006 are performed every two years to perform eddy current testing of the heat exchanger tubes. This routine activity will identify any degradation of the pressure boundary and corrective actions are taken to repair any deficiencies that are discovered. [Reference 1, Attachment 8]
- Periodic cleaning and inspection of the tube side is carried out through Repetitive Tasks 10112052, 10112053, 10152023, 10152024, 20112006, 20112027, 20152020, and 20152021. These tasks inspect the channel heads, bolts, and sacrificial anodes, and clean the tubes every quarter (12 weeks). Periodic cleaning and inspection verifies that degradation is not occurring and corrective actions are taken to repair any deficiencies that are discovered. [Reference 1, Attachment 8]

Group 4 (CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 4 components:

- The Group 4 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- Crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation are plausible for the Group 4 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- For the shell side of the heat exchangers, Calvert Cliffs Technical Procedure CP-206 mitigates the effects of crevice corrosion, general corrosion, and pitting by maintaining CC System and SRW System chemistry conditions, and contains acceptance criteria that ensure timely correction of adverse chemistry parameters.

- For the shell side of the heat exchangers, the ARDI Program will conduct inspections of a representative sample of susceptible areas to discover signs of degradation, and will contain acceptance criteria that ensure corrective actions will be taken such that the heat exchangers remain capable of performing their passive intended functions under all CLB conditions.
- For the tube side of the heat exchangers, the PM Program conducts periodic inspection and testing through performance of various maintenance activities that provide the means to discover degradation. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation will be managed for the Group 4 components such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 5 (ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting) - Materials and Environment

As shown in Table 5.16-3, Group 5 applies to device type HX that are subject to crevice corrosion, general corrosion, MIC, and pitting.

Group 5 consists of the ECCS pump room air coolers. [Reference 1, Attachments 1 and 3 for Group ID HX-02]

All of the Group 5 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

The internal environment for the heat exchangers is SW on the tube side and air on the shell side. [Reference 1, Attachment 3]

Crevice corrosion, MIC, and pitting are plausible for the heat exchanger channel heads and the tubes. The channel heads are constructed of cast iron and the tubes are copper-nickel. Crevice corrosion, general corrosion, and pitting are plausible for heat exchanger bolting which is constructed of carbon and low alloy steel. [Reference 1, Attachment 1, Attachment 4, 5, and 6]

There are no plausible ARDMs on the shell side of the ECCS pump room air coolers due to the air internal environment. [Reference 1, Attachments 3, 4, and 5]

Group 5 (ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting) - Aging Mechanism Effects

The aging mechanism effects for crevice corrosion, general corrosion, MIC, and pitting are as discussed above for Group 1.

The channel heads are lined with coal tar epoxy to protect the cast iron wall from the aggressive SW environment. Crevice corrosion, MIC, and pitting are plausible for the channel heads if the coal tar epoxy lining material fails. The wall of the channel heads is susceptible to these ARDMs at the locations of the damaged lining. [Reference 1, Attachments 5 and 6]

Crevice corrosion and pitting are plausible for the tubes in a SW environment. These components are susceptible to these ARDMs due to the presence of sulfates and chlorides. Dissolved oxygen and stagnant fluid will aggravate pitting. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Microbiologically-induced corrosion is plausible for the tubes due to the use of raw, untreated SW. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria may be present in the process fluid. Stagnant or low flow areas are most susceptible, and sedimentation aggravates the problem. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Crevice corrosion, general corrosion, and pitting are plausible for the bolting. Although these external components are not exposed to the process fluid, the potential for leakage of SW from the system exists. [Reference 1, Attachments 5 and 6]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 5 components may not be able to perform their pressure boundary function under CLB conditions.

Group 5 (ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting) - Methods to Manage Aging

Mitigation: For the tube side of the heat exchanger (i.e., channel heads, tubes, and bolting), the components are subject to a SW environment. Therefore, it is not feasible to control water chemistry. Some corrosion protection is provided by sacrificial anodes that are installed in the channel heads. The discovery methods discussed below are deemed adequate to manage aging for these components.

Discovery: For the tube side of the heat exchangers, visual inspections and testing can be used to determine if any degradation is occurring. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the heat exchangers continue to perform their intended function during the period of extended operation. [Reference 1, Attachment 8]

Group 5 (ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting) - Aging Management Program(s)

Mitigation: Since there are no feasible mitigation methods, there are no programs credited with mitigating aging for the Group 5 components.

Discovery: The tube side of the heat exchangers are subject to periodic inspection and testing through existing PM activities as part of the CCNPP PM Program. These activities provide an effective means to discover and manage the age-related degradation effects on the heat exchanger tube side subcomponent parts. The CCNPP PM Program details are discussed above in the Aging Management Program section for Group 2. The specific maintenance activities that manage the effects of aging for the tube side of the heat exchangers are as follows: [Reference 1, Attachment 8]

- Preventive Maintenance Checklists MPM05000 and MPM05101, which are associated with the ECCS pump room air coolers, are performed every 24 weeks. Checklist MPM05000 replaces the sacrificial anodes, and Checklist MPM05101 inspects the channel heads and the tubes. Checklist MPM05101 presently calls for performance of a visual inspection of the tubes by using a light at one end of the heat exchanger while examining the tubes from the opposite end. Any debris found in the tubes is removed. Operating experience with this PM activity has indicated that there is little indication of age-related degradation of the tubes. In order to enhance the tube inspections, Checklist MPM05101 will be modified to visually inspect internal surfaces of a sample of the tubes at both the inlet and outlet ends of the heat exchanger. This maintenance activity will include appropriate surface cleaning of the tube surfaces that are inspected, and will include a requirement to inspect for roughness or irregularities that might indicate corrosion mechanisms are active. These routine activities will identify any degradation of the pressure boundary, and corrective actions will be taken to repair any deficiencies discovered. [Reference 1, Attachment 8]

Group 5 (ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 5 components:

- The Group 5 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- Crevice corrosion, general corrosion, MIC, and pitting are plausible for the Group 5 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- For the tube side of the heat exchangers, the PM Program conducts periodic inspection and testing through performance of various maintenance activities that provide the means to discover and manage age-related degradation effects. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, MIC, and pitting will be managed for the Group 5 components such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 6 (Flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting) - Materials and Environment

As shown in Table 5.16-3, Group 6 applies to device type FO that is subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting.

Group 6 consists of flow orifices. [Reference 1, Attachment 1 for Group ID FO-01]

All of the Group 6 components have the passive intended functions to maintain pressure boundary integrity and to restrict flow to a specified value in support of a design basis event. [Reference 1, Attachment 1]

The internal environment for all of the Group 6 components is SW. [Reference 1, Attachment 3]

Crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting are plausible for the internal surfaces of the flow orifices. The flow orifices are constructed of stainless steel. [Reference 1, Attachment 4, 5, and 6]

Group 6 (Flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting) - Aging Mechanism Effects

The aging mechanism effects for crevice corrosion, MIC, and pitting are as discussed above for Group 1. Erosion corrosion is discussed in Group 4. Particulate wear erosion is discussed in Group 2.

Crevice corrosion and pitting are plausible for the flow orifices in a SW environment. These components are susceptible to these ARDMs due to the presence of sulfates and chlorides. Dissolved oxygen and stagnant fluid will aggravate pitting. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Microbiologically-induced corrosion is plausible for the flow orifices due to the use of raw, untreated SW. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria may be present in the process fluid. Stagnant or low flow areas are most susceptible, and sedimentation aggravates the problem. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Erosion corrosion and particulate wear erosion are plausible for the flow orifices due to susceptible material of construction in an aggressive SW environment. These ARDMs may result in a loss of the inner diameter surface area that has the potential to adversely affect the intended flow restriction function. [Reference 1, Attachments 5 and 6]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 6 components may not be able to perform their pressure boundary and flow restriction functions under CLB conditions.

Group 6 (Flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting) - Methods to Manage Aging

Mitigation: The stainless steel material of construction for the flow orifices is designed to mitigate most forms of corrosion. Since the flow orifices are subject to a SW environment it is not feasible to control water chemistry. The discovery methods discussed below are deemed adequate to manage aging for these components.

Discovery: Visual inspections can be used to determine if any degradation is occurring. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the flow orifices continue to perform their intended functions during the period of extended operation. [Reference 1, Attachment 8]

Group 6 (Flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting) - Aging Management Program(s)

Mitigation: Since there are no feasible mitigation methods, there are no programs credited with mitigating aging for the Group 6 components.

Discovery: All except one of the Group 6 flow orifices are subject to periodic inspection through existing PM activities as part of the CCNPP PM Program. These activities provide an effective means to discover and manage the age-related degradation effects. The CCNPP PM Program details are discussed above in the Aging Management Program section for Group 2. The specific maintenance activities that manage the effects of aging for the flow orifices are as follows: [Reference 1, Attachment 8]

- Periodic inspection of the flow orifices is carried out through Repetitive Tasks 10122095 and 20122099. These tasks are performed every six years. Periodic inspection verifies that degradation is not occurring and corrective actions are taken to repair any deficiencies that are discovered. [Reference 1, Attachments 8 and 10]

As discussed above, one of the Group 6 flow orifices is not subject to periodic inspection through existing PM activities. This orifice (Unit 1 SRW heat exchanger SW emergency outlet orifice) was installed as part of a piping modification that was implemented in the 1993-1994 timeframe. Routine inspection of this orifice is not currently performed due to infrequent use of the flow path in which the orifice is installed. To verify that no significant age-related degradation is occurring for this orifice, it will be included in the ARDI Program inspections. The program details are discussed above in the Aging Management Program section for Group 1.

Group 6 (Flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 6 components:

- The Group 6 components have the passive intended functions to maintain pressure boundary integrity and to restrict flow under CLB conditions.
- Crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting are plausible for the Group 6 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary and flow restriction functions under CLB conditions.
- The PM Program conducts periodic inspection through performance of various maintenance activities that provide the means to discover and manage age-related degradation effects. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions.
- For the orifice that is not inspected by the PM Program, the ARDI Program will conduct inspections to discover signs of degradation and will contain acceptance criteria that ensure corrective actions will be taken such that the orifice remains capable of performing its passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting will be managed for the Group 6 components such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

5.16.3 Conclusion

The aging management programs discussed for the SW 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 such that the intended functions of the SW System components 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 5.16-5

LIST OF AGING MANAGEMENT PROGRAMS FOR THE SW SYSTEM

	Program	Credited For
Existing	CCNPP Technical Procedure CP-206, "Specifications and Surveillance for Component Cooling/Service Water System"	Mitigation of the effects of crevice corrosion, general corrosion, and pitting for the shell side of the Group 4 heat exchangers.
Existing	CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program"	Governs the specific maintenance activities shown below.
Modified	For Group 2: Repetitive tasks 10122063 through 10120268; 10122096 through 10122102; 20122067 through 20122072; and 20122100 through 20122106 Checklists MPM04004; MPM04194; MPM12200; MPM12201; MPM01001 (modification needed); and MPM01181 Procedure PUMP-03	Discovery of the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation for the Group 2 components.
Existing	For Group 3: Checklists IPM10000 and IPM10001	Mitigation of the effects of general corrosion for the Group 3 components.
Existing	For Group 4: Repetitive tasks 10112052; 10112053; 10152023; 10152024; 20112006; 20112027; 20152020; and 20152021 Checklists MPM00005 and MPM00006	Discovery of the effects of crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation for the tube side of the Group 4 heat exchangers.
Modified	For Group 5: Checklists MPM05000 and MPM05101 (modification needed)	Discovery of the effects of the crevice corrosion, general corrosion, MIC, and pitting for the tube side of the Group 5 heat exchangers.
Modified	For Group 6: Repetitive tasks 10122095 (modification needed) and 20122099	Discovery of the effects of crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting for the Group 6 components.

	Program	Credited For
New	ARDI Program	Discovery of the effects of crevice corrosion, general corrosion, MIC, and pitting for the Group 1 components. Discovery of the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, and elastomer degradation for the Group 2 components that are not inspected by the PM Program. Discovery of the effects of crevice corrosion, general corrosion, and pitting for the shell side of the Group 4 heat exchangers. Discovery of the effects of crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting for the Group 6 Unit 1 SRW overboard balancing orifice.

5.16.4 References

1. CCNPP "Aging Management Review Report for the Saltwater System," Revision 4, February 11, 1997
2. CCNPP Drawing 60708SH0002, "Circulating Salt Water Cooling System," Revision 78
3. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated May 16, 1997, "License Amendment Request: Service Water Heat Exchangers Replacement"
4. Letter from Mr. L. B. Russell (BGE) to NRC Document Control Desk, dated July 3, 1984, Transmittal of Licensee Event Report 84-05, Revision 1
5. NRC Information Notice 84-71, "Graphitic Corrosion of Cast Iron in Salt Water," September 6, 1984
6. Letter from Mr. E. C. Wenzinger (NRC) to Mr. A. E. Lundvall, Jr. (BGE), dated February 6, 1985, "NRC: RI Inspection 50-317/84-31, 50-318/84-31"
7. Letter From Mr. G. C. Creel (BGE) to NRC Document Control Desk, dated November 27, 1991, "Temporary Non-Code Repair of ASME Code Class 3 Piping"
8. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated June 4, 1990, CCNPP License Event Report LER 90-17, "Leaking Weld and Bio-Fouling in Saltwater System"
9. Letter from Mr. C. J. Cowgill (NRC) to Mr. G. C. Creel (BGE), dated July 12, 1990, "NRC Region I Resident Inspection Report Nos. 50-317/90-13 and 50-318/90-13 (June 3, 1990 to June 30, 1990)"
10. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated June 30, 1994, "Final Response to Generic Letter 89-13"
11. CCNPP Updated Final Safety Analysis Report, Revision 20
12. CCNPP Component Level Screening Results for the Salt Water Cooling System, Revision 3, July 15 1996
13. CCNPP "Component Pre-Evaluation for the Salt Water System," Revision 4, December 30, 1996
14. CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," Revision 5, September 27, 1996
15. INPO 85-032, "Preventive Maintenance," December 1988
16. INPO 85-037, "Reliable Power Station Operation," October 1985
17. INPO Good Practice MA-319, "Preventive Maintenance Program Enhancement," December 1992
18. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48, March 28, 1997
19. CCNPP Procedure PUMP-3, "Saltwater Pump Overhaul," Revision 3, May 25, 1991
20. CCNPP "Aging Management Review Report for the Compressed Air System," Revision 4, August 11, 1997

21. CCNPP NUCLEIS Database, Preventative Maintenance Checklists IPM 10000 (10001), "Check Unit 1 (2) Instrument Air Quality," December 13, 1996

22. CCNPP NUCLEIS Database, Repetitive Tasks 10191024 (20191022), "Check Unit 1 (2) Instrument Air Quality at Selected System Low Points"

23. CCNPP Technical Procedure CP-206, "Specifications and Surveillance Component Cooling/Service Water System," Revision 3, November 4, 1996

24. CCNPP 1996 Component Cooling and Service Water System Assessment, February 26, 1997

5.17 Service Water System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Service Water (SRW) System. The SRW 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. The results are presented below. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

5.17.1 Scoping

System level scoping describes boundaries for plant systems and structures, develops screening tools that 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 associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.17.1.1 presents the results of the system level scoping, 5.17.1.2 the results of the component level scoping, and 5.17.1.3 the results of scoping to determine components subject to AMR.

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

5.17.1.1 System Level Scoping

This section begins with a description of the system that 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 SRW System in each CCNPP unit is a closed loop cooling water system that supplies chemistry-controlled water in normal operation to two safety-related, Seismic Category I trains and a common non-safety-related, non-seismic train. The safety-related trains supply cooling water to the spent fuel pool (SFP) heat exchanger, containment cooling units, blowdown recovery heat exchangers, and the emergency diesel generators (EDGs). The non-safety-related train provides cooling water to various Turbine Building loads. [Reference 1, Sections 1.1.1, 1.1.2]

The scope of the SRW AMR includes all safety-related SRW pressure boundary components relied on for mitigation of Design Basis Events. This includes both SRW trains in the Auxiliary Building and Containment Building, all components up to and including the Turbine Building SRW Header Isolation Valves, and components downstream of the check valves in the return piping from the Turbine Building to the suction header of each Auxiliary Building train. [Reference 1, Appendix B] The Turbine Building loads are not safety-related and are isolated on a Safety Injection Actuation Signal. [Reference 1, Section 1.1.1] Service water piping and valves associated with the instrument and plant air compressors and aftercoolers are within the scope of license renewal to support fire protection functions as described in Section 5.10 of this BGE LRA. [Reference 2, Section 4.2] The remaining Turbine Building loads are not within the scope of license renewal.

The system for each unit has been divided into two trains in the Auxiliary Building to meet single failure criteria. Each safety-related train is comprised of the following major components: [Reference 1, Section 1.1.2]

Piping and Valves	Alignment and transport of cooling water from the pumps to the various loads.
Head Tank	Each safety-related train contains one head tank which maintains the SRW System pressure and allows for thermal expansion. Demineralized water makeup to the head tank is automatically controlled by level controllers. Additional makeup capacity may be provided from the Condensate System. [Reference 3, Section 9.5.2.2]
Pumps/Motors	Each safety-related train contains one single-stage, double-volute, centrifugal pump driven by an electric motor. An additional pump/motor combination is available for use by either subsystem. The two SRW pumps are powered from separate Engineered Safety Feature 4 kV buses, and the third pump is capable of being powered from either Engineered Safety Features' 4 kV bus. In the event that one bus is unavailable, the capability to manually transfer the third pump to the operating bus exists. A low discharge header pressure will annunciate in the Control Room and the operator can then manually activate the standby pump. [Reference 3, Section 9.5.2.2]
SRW/Saltwater (SW) Heat Exchangers	Each SRW train contains one shell and tube-type heat exchanger that transfers heat from the SRW System in the shell to the SW System in the tube side of the heat exchanger.
SFP Heat Exchangers	One horizontal, counterflow heat exchanger supplied by one SRW train per unit maintains the SFP water temperature below the design temperature.
Containment Coolers	Four containment coolers are provided in each unit to remove heat from the containment during normal plant operation and in the event of a loss-of-coolant incident. Any cooler can be supplied from any train. During normal operation, only those coolers required to remove the heat load are operating.
EDG Coolers	Three EDGs are supplied with cooling water from the SRW System (Unit 1 supplies No. 1B EDG, Unit 2 supplies Nos. 2A and 2B EDGs). Each diesel generator contains three separate single pass, shell and tube-type heat exchangers used to cool the lube oil, diesel jacket water, and diesel air subsystems.

Blowdown Recovery Heat Exchanger	One blowdown recovery heat exchanger is supplied by one SRW train per unit for the final blowdown cooling step.
Instruments	Measure flow rates, pressure and temperature. Provide alarm and initiate automatic actions.

Supply and return line redundancy is provided for containment cooling units and EDGs. Redundancy for the SFP coolers is provided by cooling one SFP cooler from each unit. Radiation monitors are installed in the SRW return header from the SFP coolers to detect possible in-leakage of radioactive liquids through the heat exchangers. [Reference 3, Section 9.5.2.2]

During normal operation, both subsystems are required and are independent to the degree necessary to assure the safe operation and shutdown of the plant assuming a single failure. During shutdown, operation of the SRW System is the same as normal operation, except that the heat loads are reduced as is the SW flow required to remove heat from the system. [Reference 3, Section 9.5.2.2]

During the Loss-of-Coolant Accident (LOCA) mode of operation, each of the two trains for the two units will cool a maximum of two containment air coolers and one EDG. Although Unit 2 trains have identical heat loads and flow requirements for LOCA operations, Unit 1 trains do not have identical heat loads as Unit 1 has only one SRW-cooled EDG. Number 12 SRW train cools No. 1B EDG, and No. 1A EDG is cooled from an independent cooling source located in the safety-related Diesel Generator Building. The original design heat removal capability of three of the four containment cooling units was to provide the same heat removal capability as the Containment Spray System. The analysis of these systems operating together post-LOCA is presented in Section 14.20 of the CCNPP Updated Final Safety Analysis Report (UFSAR). [Reference 3, Section 9.5.2.2]

The Turbine Building SRW Header Isolation Valves separate the safety-related portion of the system from the non-safety-related portion. These valves close on a Safety Injection Actuation Signal, but they do not close automatically upon a seismic event. Calvert Cliffs has evaluated a postulated SRW System pipe rupture in the Turbine Building that renders both Auxiliary Building SRW subsystems inoperable following a seismic event [Reference 4]. It has been concluded the non-safety-related portions of the SRW System are adequately rugged to withstand a design basis earthquake [Reference 5]. This ruggedness is credited in preserving system inventory regardless of Turbine Building SRW Header Isolation Valve leakage rate. [Reference 6]

The non-safety-related SRW piping in the Turbine Building and safety-related piping in the Auxiliary Building were both originally designed to [United States of America Standard] USAS B31.1 (1969 Edition through summer 1972 Addenda) and both are subject to the same environmental service conditions and chemistry controls. [Reference 1, Appendix B]

<u>SRW System Functions</u> [Reference 7, Table 1]

The basic SRW System functions are as follows:

1. To remove heat from the plant's containment cooling units, SFP, and EDG heat exchangers and transfer that heat to the SW System;
2. To serve as an intermediate barrier between various auxiliary systems and the SW System; and

3. To provide additional heat removal capacity during a LOCA.

System Operating Experience

The following are operating experiences related to the SRW System with the potential for affecting the intended functions of the components or system.

Following a routine tube cleaning of the one of the SRW heat exchangers in 1980, several low pressure alarms were received on the SRW subsystems. A manual reactor trip was then initiated due to high main turbine bearing temperature. The cause of the event was a failed tube in the Unit 1 instrument air compressor aftercooler which allowed air to enter the SRW System. Air became trapped in the idled heat exchanger and air ingress exceeded the air removal capability of the constant vent valves, causing the air binding of the system when the heat exchanger was returned to service. [Reference 8] A CCNPP design change was implemented to provide greater air removal from the SRW System. This design change included changes to alarms and indications.

Calvert Cliffs has experienced recurring SRW heat exchanger tube leakage for the past several years. The cause of this leakage is due primarily to erosion and corrosion aging mechanisms. In 1985, CCNPP installed 8-inch long sleeves in the inlet section of each tube (both plugged and unplugged) in the No. 11 SRW heat exchanger. Total SRW System leakage was measured at 0.43 gallons per minute following this repair. This low leakage rate was evaluated as not safety significant. Routine monitoring of SRW head tank levels and weekly surveillance to quantify SRW System leakage are adequate to alert operators of an increasing leak rate condition. [Reference 9]

These events demonstrate that CCNPP modifies and maintains the SRW System to ensure that the SRW components remain capable of performing their intended function under current licensing basis (CLB) conditions.

System Interfaces

All safety-related portions of the SRW System are within scope for license renewal. Evaluation of the SRW heat exchangers was included in the SW System AMR, and evaluations of the heat exchangers cooled by the SRW System were included in their respective systems' AMRs. Figure 5.17-1 shows the SRW System flow path and components, including the systems and components that interface with the SRW System. Figure 5.17-1 is simplified and provided for information only. A list of SRW System interfaces is given below: [Reference 3, Section 9.5.2.2].

- Containment coolers*
- Fairbanks Morse EDG heat exchangers*
- SFP coolers*
- Steam generator blowdown recovery heat exchangers*
- Condensate system*
- Demineralized water system*

Turbine Building Loads

- Generator isolated three phase bus duct coolers
- Exciter air coolers

- Generator hydrogen coolers
- Stator liquid coolers (Unit 1 only)
- Circulating water system priming pump seal water coolers
- Condenser vacuum pump seal water coolers
- Feed pump turbine lube oil coolers
- Condensate booster pump lube oil and seal water coolers
- Instrument and plant air compressors and aftercoolers*
- Turbine lube oil cooler
- Electro-hydraulic oil coolers
- Turbine Building sample cooling system
- Makeup demineralized water system degasifier vacuum pumps (Unit 1 only)
- Nitrogen compressor and aftercooler (Unit 1 only)
- Seal oil system coolers (Unit 2 only)
- Auxiliary Feedwater Pump Room air cooler

The SRW System interfaces listed above are not all within the scope of license renewal. Those systems or system components interfacing with the SRW System that are within the scope of license renewal are noted with an asterisk (*) above and are shown in Figure 5.17-1 as noted with an asterisk. Cooling water to the instrument and plant air compressors are within the scope for license renewal for fire protection and are evaluated in Section 5.10, Fire Protection, in the BGE LRA. Those portions of the SRW System within the scope of license renewal are indicated by solid lines in Figure 5.17-1. Those portions of the SRW System that are not within the scope of license renewal are indicated by a dashed line in Figure 5.17-1. Where a system, component, commodity, or structure interface is within the scope of license renewal, that system will be addressed by the respective section of this application for that system, structure, or component.

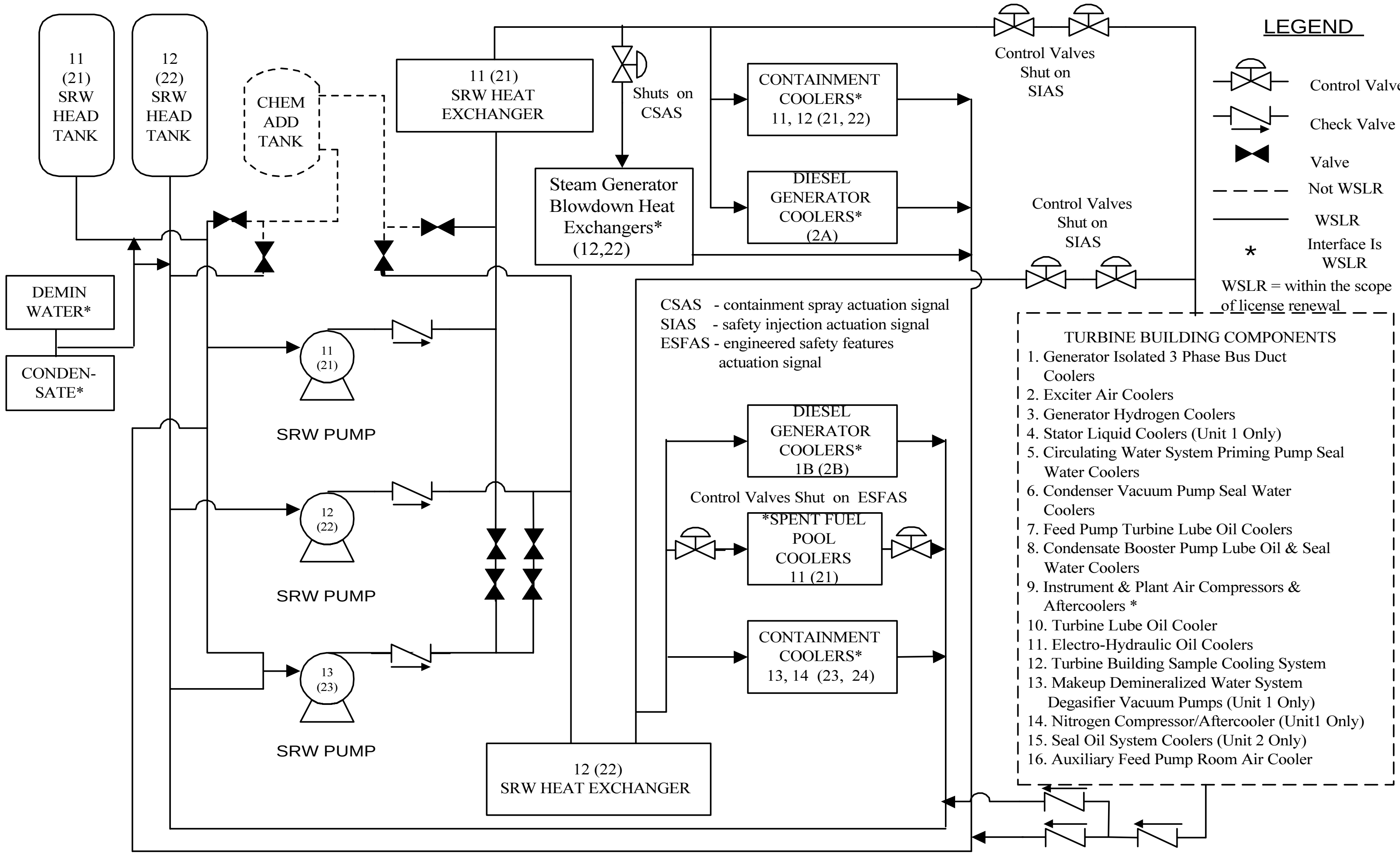

FIGURE 5.17-1
SERVICE WATER SYSTEM - SIMPLIFIED DIAGRAM (Information Only)

System Scoping Results

The SRW System is in the scope for license renewal based on 10 CFR 54.4(a). In accordance with Section 4.1.1 of the CCNPP IPA Methodology, the following list of system intended functions was determined based on the requirements of 10 CFR 54.4(a)(1) and (2): [Reference 10, Table 1]

- Serves as a vital auxiliary to Engineered Safety Features Actuation Signal by processing signals; and as a vital auxiliary to the EDGs, SFP coolers, and containment coolers by providing cooling water;
- To provide seismic integrity and/or protection of safety-related components;
- To maintain electrical continuity and/or provide protection of the electrical system; and
- To maintain the pressure boundary of the system liquid.

The following intended functions of the SRW System were determined based on the requirements of 10 CFR 54.4(a)(3): [Reference 10, Table 1]

- For environmental qualification (§50.49) - Maintain functionality of the electrical components as addressed by the Environmental Qualification Program.
- For fire protection (§50.48) - Provide required cooling water to the EDGs, containment coolers, and instrument air/plant air compressor loads to ensure safe shutdown in the event of a postulated severe fire.
- For post accident monitoring - To provide information used to assess the environs and plant condition during and following an accident.

The SRW System components performing 54.4(a)(1) and (2) intended functions are safety-related, and are subject to the applicable Codes identified in UFSAR Section 9.5, Table 9-17.

5.17.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the SRW System that is within the scope of license renewal consists of piping, components (i.e., heat exchangers, pumps and tanks), supports, instrumentation, and cables that are relied on for mitigation of Design Basis Events, Post-Accident Monitoring, Environmental Qualification and Fire Protection.

A total of 38 device types within these SRW equipment types were designated as within the scope of license renewal based on these intended functions. These device types are listed in Table 5.17-1. [Reference 1, Section 2.2]

Several components are common to many plant systems and perform the same passive functions regardless of system. These components are listed below:

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

5.17.1.3 Components Subject to AMR

This section describes the components of the SRW System that are subject to an AMR. It begins with a listing of passive intended functions and then dispositions the device types previously listed as either 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 SRW System functions were determined to be passive: [Reference 1, Table 3-1]

- To maintain the pressure boundary of the system liquid;
- To provide seismic integrity and/or protection of safety-related components; and
- To maintain electrical continuity and/or provide protection of the electrical system.

TABLE 5.17-1
SERVICE WATER SYSTEM DEVICE TYPES

Device Description	Device Type
Piping Line	-HB
Check Valve	CKV
Coil	COIL
Control Valve	CV
Voltage/Current Device	E/I
Flow Element	FE
Flow Indicator	FI
Flow Orifice	FO
Flow Transmitter	FT
Fuse	FU
Hand Switch	HS
Hand Valve	HV
Heat Exchanger	HX
Ammeter	II
Power Light Indicator	JL
Level Gage	LG
Level Switch	LS
Level Transmitter	LT
4kV Motor	MA
125/250VDC Motor	MD
4kV Local Control Station	NA
125/250VDC Local Control Station	ND
Pressure Differential Indicating Controller	PDIC
Pressure Indicator	PI
Panel	PNL
Pressure Switch	PS
Pressure Transmitter	PT
Pump/Driver Assembly	PUMP
Radiation Element	RE
Relief Valve	RV
Relay	RY
Temperature Element	TE
Temperature Indicator	TI
Temperature Indicator Alarm	TIA
Tank	TK
Power Supply	YX
Position Indicating Lamp	ZL
Position Switch	ZS

Device Types Subject to AMR

The device types of the SRW System, and the associated supports, cables, and tubing, were reviewed and dispositioned as follows: [Reference 1, Section 3-2, Table 3-2]

- Sixteen device types, including the coil, voltage/current device, flow indicator, fuse, hand switch, ammeter, power light indicator, level switch, 4 kV motor, 125/250 VDC motor, pressure indicator, relay, temperature indicating alarm, power supply, position indicating lamp, and position switch, are only associated with active functions.
- The SRW heat exchanger is a device type that is evaluated in the SW System in Section 5.16 of the BGE LRA.
- Six device types, including the flow transmitter, level gauge, level transmitter, differential pressure indicating controller, pressure switch, and pressure transmitter, are evaluated in the Instrument Line Commodity Evaluation in Section 6.4 of the BGE LRA. Some hand valves that are isolable by instrument root valves are also evaluated in the Instrument Lines Commodity Evaluation.
- Three device types, 4kV local control station, 125/250VDC local control station, and panel, are dispositioned in the Electrical and Instrument Panels Commodity Evaluation in Section 6.2 of the BGE LRA. This commodity evaluation partially addresses the SRW System intended function, “To provide seismic integrity and/or protection of safety related components.”
- Structural supports for piping, cables, instruments, and components in the SRW 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. This commodity evaluation partially addresses the SRW System passive intended function, “To provide seismic integrity and/or protection of safety related components.”
- Electrical cabling for components in the SRW System that are subject to AMR 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 SRW System passive intended function, “To maintain electrical continuity and/or provide protection of the electrical system.”
- Instrument tubing and piping, associated instrument valves, and fittings (generally everything from the outlet of the final root valve up to and including the instrument) are all evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. This commodity evaluation addresses the SRW System passive intended function, “To maintain the pressure boundary of the system liquid.”

As a result of the commodity evaluations presented above, the only passive function associated with the SRW System is the following:

- To maintain the pressure boundary of the system liquid.

Of the 38 device types originally within the scope of license renewal, only 12 device types remain that have this passive intended function (pressure boundary) and are long-lived. These 12 SRW device types are listed in Table 5.17-2. The 12 device types are subject to AMR for the SRW System, and are the subject of the remainder of this report. [Reference 1, Table 3-2]

TABLE 5.17-2

DEVICE TYPES REQUIRING AMR FOR SERVICE WATER SYSTEM

Piping (-HB)
Check Valve (CKV)
Control Valve (CV)
Flow Element (FE)
Flow Orifice (FO)
Hand Valve (HV)
Pump/Driver Assembly (PUMP)
Radiation Element (RE)
Relief Valve (RV)
Temperature Element (TE)
Temperature Indicator (TI)
Tank (TK)

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.

5.17.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the SRW System device types is given in Table 5.17-3. The plausible ARDMs are identified in the table by a check mark (✓) in the appropriate column. For the AMR, some SRW device types have a number of groups and subgroups associated with them because of the diversity of materials used in their fabrication. A check mark indicates that the ARDM applies to at least one group or subgroup for the device type listed. The device types listed in Table 5.17-3 are those previously identified in Table 5.17-2 as passive and long-lived. [Reference 1, Tables 4-1, 4-2] For efficiency in presenting the results of these evaluations in this report, ARDM/device type combinations are grouped where there are similar characteristics and the discussion is applicable to all device types within that group. Exceptions are noted where appropriate. For this report the device types are grouped according to plausible ARDMs as follows:

Group 1 - crevice corrosion/pitting
Group 2 - erosion corrosion
Group 3 - general corrosion
Group 4 - selective leaching
Group 5 - wear

TABLE 5.17-3

POTENTIAL AND PLAUSIBLE ARDMs FOR THE SERVICE WATER SYSTEM

Potential ARDMs	Device Types for Which ARDM is Plausible											
	-HB	CKV	CV	FE	FO	HV	PUMP	RE	RV	TE	TI	TK
Cavitation Corrosion												
Contamination/Sediment												
Corrosion Fatigue												
Crevice Corrosion	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)
Dynamic Loading												
Electrical Stressors												
Erosion/Corrosion	✓(2)											
Fatigue												
Fouling												
Fretting												
Galvanic Corrosion												
General Corrosion	✓(3)	✓(3)	✓(3)			✓(3)	✓(3)		✓(3)		✓(3)	✓(3)
Hydrogen Damage												
Intergranular Attack												
MIC												
Particulate Wear Erosion												
Pitting	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)
Radiation Damage												
Rubber Degradation												
Saline Water Attack												
Selective Leaching			✓(4)			✓(4)	✓(4)					
Stress Corrosion Cracking												
Thermal Damage												
Thermal Embrittlement												
Wear									✓(5)			

MIC - Microbiologically Influenced Corrosion
✓ indicates plausible ARDM determination for component(s) within the Device Type
(#) - indicates the group in which this ARDM is evaluated

Note: Not every subgroup within the device types listed here may be susceptible to a given ARDM. This situation occurs because subgroups within a device type are not always fabricated from the same materials or subjected to the same environment. Exceptions for each device type will be indicated in the materials and environment section for each ARDM discussed in this report.

Crevice corrosion and pitting are grouped together in this report because they both affect the same device types, have similar effects, and are addressed by the same aging management programs.

The following discussions present information on plausible ARDMs. The discussions are grouped by ARDM and address the plausible ARDM, the device types affected, the materials and environment pertinent to the ARDM, the methods to manage aging, aging mechanism effects and the aging management program(s). There is then a summary of the aging management demonstration.

Group 1 (crevice corrosion/pitting) - Materials and Environment

Table 5.17-3 shows that the crevice corrosion and pitting ARDMs are plausible for all the SRW System device types listed. The material characteristics for each device type that are pertinent to these ARDMs are listed below: [Reference 1, -HB-01, CKV-01/02/03, CV-01/02/03, FE-01, FO-01, HV-01 to HV-08, PUMP-01/02, RE-01, RV-01/02, TI-01/02, TK-01, Attachments 4, 5, 6]

- Piping - carbon steel;
- Check valves - carbon steel bodies;
- Control valves - some groups have carbon steel bodies, some have stainless steel or stellited shafts and stainless steel discs, and some have cast iron bodies;
- Flow elements - stainless steel;
- Flow orifices - stainless steel;
- Hand valves - some groups have carbon steel, cast iron, cast brass and brass bodies; some have stainless steel stems or shafts, and some have carbon steel or stainless steel discs; and some have stainless steel internals;
- Pumps - carbon steel or cast iron casings, and some have bronze bushings, cast iron or bronze impeller/shafts, and iron seals;
- Radiation elements - stainless steel;
- Relief valves - some groups have carbon steel or stainless steel bodies;
- Temperature elements - stainless steel;
- Temperature indicators - some groups are either carbon steel or stainless steel; and
- Tanks - carbon steel.

The internal environment of the SRW System is chemically-treated water at a normal service pressure of 102 psig (design rating 150 psig) and a normal operational temperature of 130°F (design rating of 300°F). [Reference 11] The SRW System includes a number of components (i.e., valves, instruments) that are flange bolted, welded in place, or are gasketed. Within the SRW System there are regions of low or stagnant coolant flow conditions.

Group 1 (crevice corrosion/pitting) - Aging Mechanism Effects

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. Crevice corrosion is closely related to pitting and can initiate pits in many cases. In an oxidizing environment, a crevice can set up a differential aeration cell to concentrate an acid solution within the crevice. Even in a reducing environment, alternate wetting and drying can concentrate aggressive ionic species to cause pitting and crevice corrosion. Pitting is a form of localized attack with greater corrosion rates at some locations than at others. These pits are, in many cases, filled with oxide debris, especially in ferritic materials such as carbon steel. Deep pitting is more common with passive metals, such as austenitic stainless steels, than with non-passive metals. In many cases, erosion corrosion, fretting corrosion, and crevice corrosion can also lead to pitting. It can also occur at locations of relatively stagnant coolant or water, such as in carbon steel piping of cooling systems. [Reference 1, Pipe-Attachment 7]

Long-term exposure to environments conducive to these ARDMs may result in crevice corrosion/pitting which, if unmitigated, could eventually result in loss of material and pressure-retaining capability under CLB design loading conditions. The components listed above are sometimes subject to stagnant flow conditions, or have crevices associated with them. [Reference 1, Attachments 6s] Therefore, crevice corrosion/pitting have been determined to be plausible ARDMs for which aging effects must be managed for the SRW System.

Group 1 (crevice corrosion/pitting) - Methods to Manage Aging

Mitigation: Maintaining an environment of purified water with controls on pH, oxygen, suspended solids and chlorides during normal plant operation can mitigate this ARDM. [Reference 1, Pipe Attachment 6] The initial formation of a passive oxide layer (magnetite) on the interior surface also mitigates the effects of crevice corrosion/pitting by minimizing the exposure of bare metal to system fluids.

Discovery: Inspection of a representative sample of susceptible areas of the system for the signs of crevice corrosion/pitting could identify whether this ARDM is actually occurring in the SRW System. Maintenance/overhaul of SRW System components also provide opportunities to inspect for signs of crevice corrosion/pitting.

Group 1 (crevice corrosion/pitting) - Aging Management Program(s)

Mitigation: Calvert Cliffs Chemistry Procedure (CP) CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems," provides for monitoring and maintaining SRW chemistry to control the concentrations of oxygen, chlorides, other chemicals and contaminants. The water is treated with hydrazine to minimize the amount of oxygen in the water, which aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal piping or component degradation. [Reference 1, Attachment 8]

CP-206 describes the surveillance and specifications for monitoring the SRW System fluid. CP-206 lists the parameters to monitor, the frequency of monitoring these parameters, and the target and action levels for the SRW System fluid parameters. The parameters monitored by CP-206 are pH, hydrazine, chloride, dissolved oxygen, dissolved copper, dissolved iron, suspended solids, gamma activity, and tritium activity (Note: SRW is normally not a radioactive system). [Reference 12, Attachment 1]

These chemistry parameters are currently monitored on a frequency ranging from three times per week to once a month. All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter. Two of the parameters, pH and hydrazine, have action levels associated with them. For pH the current action level is less than 9.0 or greater than 9.8, for hydrazine the current action level is less than 5 or greater than 25 parts per million (ppm). Refer to Attachment 1 in CP-

206 for the specific monitoring frequency and target values for each chemistry parameter. [Reference 12, Attachment 1]

Operating Experience

Operational experience related to CP-206 has shown no problems related to use of this procedure with respect to the SRW System. In 1996, CP-206 was revised to include dissolved iron as a chemistry parameter. Dissolved iron was added to CP-206 to act as a method to discover any abnormal corrosion of the SRW components.

An internal BGE chemistry summary report for 1996 described the CCNPP Unit 1 and Unit 2 CC/SRW Systems chemistry as excellent. Action levels for all four systems were only exceeded on eight occasions, or approximately 0.7% of the time during the year. Over 70% of the action levels entered were due to major system changes during the 1996 refueling outage. The report recommends determining outage evolutions that can affect the CC/SRW chemical parameters and taking appropriate action to prevent chemistry targets from being exceeded.

The SRW System usually operates within normal parameters except when the system is restarted after an outage lay-up. During an outage lay-up, the SRW System experiences some minor corrosion when the internal component surfaces are exposed to air. After the SRW System is returned to service and flow is once again established, some of this minor corrosion is removed from the pipe inner surface and released into the system where it is detected. It was discovered that suspended solids spike when one SRW header is taken out-of-service for heat exchanger cleaning, and total system flow is then directed through the in-service heat exchanger. One or two days after the SRW System is aligned to normal, the suspended solids levels drop to the normal value of less than 10 parts per billion.

Calvert Cliffs procedure CP-206 provides for a prompt review of SRW chemistry parameters so that steps can be taken to return chemistry parameters to normal levels and thus minimize the effects of crevice corrosion/pitting.

Discovery: The SRW pumps are inspected for crevice corrosion/pitting using the CCNPP PUMP-15, "Service Water Pump Overhaul," procedure. PUMP-15 instructs the user to inspect certain pump components for erosion, wear, and mechanical damage. The procedure will be modified to include inspections for crevice corrosion/pitting on the pump casing and bushings. The procedure directs the user to contact the System Engineer if any of these indications are found, and to replace parts as necessary. [Reference 13] The PUMP-15 overhauls and inspections are performed as required based on pump performance trends or corrective actions requirements. [Reference 1, Attachment 8]

The remaining SRW System components (including the SRW radiation monitoring pumps) susceptible to crevice corrosion/pitting will be included in the Aging Related Degradation Inspection (ARDI) Program to verify that degradation of the components is not occurring. This program will examine representative components to determine if they will be capable of performing their intended function under all CLB design loading conditions during the period of extended operation. These examinations will be performed prior to the period of extended operation. [Reference 1, Attachment 8] The ARDI Program is defined in the CCNPP IPA Methodology presented in Section 2.0 of this application.

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.

Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Action Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 1 (crevice corrosion/pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the corrosion of the SRW System device types susceptible to crevice corrosion/pitting:

- The SRW device types susceptible to these ARDMs have an intended function of maintaining the system pressure boundary under CLB design conditions.
- Crevice corrosion/pitting is plausible for the device types discussed in the material and environment section above, which could lead to loss of pressure-retaining boundary integrity.
- CP-206 will mitigate the effects of crevice corrosion/pitting on SRW System device types by controlling the range of specific chemical additives and providing action levels that ensure timely correction of adverse chemistry parameters.
- The CCNPP ARDI Program will be utilized to discover any crevice corrosion/pitting that may be of concern for the SRW System components. Inspections will be performed, and appropriate corrective action will be taken if crevice corrosion/pitting is discovered.
- The CCNPP Technical Procedure PUMP-15 will be modified to inspect susceptible pump components for crevice corrosion/pitting and general corrosion. Any indications of these ARDMs will be reported to the System Engineer and corrective actions taken.

Therefore, there is reasonable assurance that the effects of crevice corrosion/pitting on SRW System device types will be managed in order to maintain their intended function under all design loadings required by the CLB during the period of extended operation.

Group 2 (erosion corrosion) - Materials and Environment

Table 5.17-3 shows that erosion corrosion is only plausible for the SRW System piping. The SRW System piping is made from carbon steel that is fabricated into straight sections, bends, and tees. The internal environment of the SRW System is demineralized water treated with hydrazine to lower the dissolved oxygen level. [Reference 1, Pipe-Attachment 6]. The internal environment of the SRW System is chemically-treated water at a normal service pressure of 102 psig (design rating 150 psig) and a normal operational temperature of 130°F (design rating of 300°F). [Reference 11]

Group 2 (erosion corrosion) - Aging Mechanism Effects

Carbon steel piping bends, tees, and areas with disturbances in the flowstream are especially vulnerable to erosion corrosion. The SRW System is treated with hydrazine which scavenges the dissolved oxygen and minimizes the effects of general corrosion, however, the lower oxygen content increases the susceptibility of the piping to the effects of erosion corrosion. The expected effect of erosion corrosion is a general thinning of the material in areas of higher turbulence due to removal of the protective magnetite coating. [Reference 1, Pipe-Attachment 6]

The occurrence of erosion corrosion is highly dependent upon material of construction and the fluid flow conditions. Carbon or low alloy steels are particularly susceptible when in contact with high velocity water (single or two phase) with disturbances in the flowstream, low oxygen levels, and a fluid pH < 9.3. Maximum erosion corrosion rates are expected in carbon steel at 130-140°C (single phase) and 180°C (two-phase). [Reference 1, Pipe-Attachment 7]

Long-term exposure to erosion corrosion could lead to material loss and, if unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. Therefore, erosion corrosion has been determined to be a plausible ARDM for which aging effects must be managed for the SRW System.

Group 2 (erosion corrosion) - Methods to Manage Aging

Mitigation: The effects of erosion corrosion can be mitigated by selecting resistant materials and/or maintaining optimal fluid chemistry conditions. The low flow velocity in the SRW System minimizes its susceptibility to erosion corrosion.

Discovery: Erosion corrosion can be discovered and monitored by nondestructive examination of potentially affected areas. Inspection of a representative sample of susceptible areas of the system for the signs of erosion corrosion could identify whether this ARDM is a concern in the SRW System piping.

Group 2 (erosion corrosion) - Aging Management Program(s)

Mitigation: There are no programs credited with mitigating the effects of erosion corrosion on the SRW System piping.

Discovery: The SRW System piping will be included in an ARDI Program to verify that degradation of the piping is not occurring. This program will examine representative piping to determine if it will be capable of performing its intended function under all CLB design loading conditions during the period of extended operation. These examinations will be performed prior to the period of extended operation. For further discussion of the elements of the ARDI Program, see the Group 1 (crevice corrosion/pitting) discussion for Aging Management Programs under the Discovery section. [Reference 1, Attachment 8]

To ensure that the non-safety-related Turbine Building SRW piping maintains its seismic adequacy, SRW ARDI results (which will be based on safety-related pressure boundary component inspections) will be evaluated for applicability to the non-safety-related SRW piping. The non-safety-related SRW piping in the Turbine Building and safety-related piping in the Auxiliary and Containment Buildings were both originally designed to USAS B31.1 (1969 Edition through summer 1972 Agenda) and both are subject to the same environmental service conditions and chemistry controls. The applicability evaluation will also consider, at a minimum, flow rate and configuration differences between safety-related and non-safety-related SRW piping. These ARDI results will then be able to provide an indication of this ARDM's significance on non-safety-related SRW piping in the Turbine Building. Applying the ARDI results of the safety-related portion of the system to the non-safety-related portion of the system will ensure compliance with the CLB during the period of extended operation. [Reference 1, Appendix B]

Inspection of some pipe locations found a tightly-adhering layer of magnetite on the inside of the SRW piping. Evidence of erosion corrosion was not found during these system lay-up examinations. The evidence of tightly-adhering magnetite indicates that the piping has good corrosion resistant characteristics. To date, there have been no indications of significant erosion corrosion in the SRW System.

Group 2 (erosion corrosion) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the SRW System piping and erosion corrosion:

- The SRW System piping provides a pressure-retaining boundary; therefore, its integrity must be maintained under CLB design conditions.
- Erosion corrosion is expected to be minimal but is considered plausible for the SRW System piping. This mechanism could result in the loss of piping material and lead to the loss of the pressure-retaining boundary.
- The ARDI piping program will provide for discovery of significant erosion corrosion in piping. Inspections of representative piping will be performed, and appropriate corrective action will be taken if erosion corrosion is discovered.

Therefore, there is reasonable assurance that the effects of erosion corrosion of SRW piping will be managed in order to maintain the SRW System piping pressure boundary integrity consistent with the CLB during the period of extended operation.

Group 3 (general corrosion) - Materials and Environment

Table 5.17-3 shows that general corrosion is plausible for eight of the SRW device types. The SRW System device types susceptible to general corrosion and their material characteristics are listed below: [Reference 1, -HB-01, CKV-01/02/03, CV-01/02/03/04, HV-01 to HV-07, PUMP-01/02, RV-01/02, TI-01, TK-01, Attachments 4, 5, 6]

- Piping - carbon steel;
- Check valves - carbon steel bodies and discs;
- Control valves - some groups have carbon steel or cast iron bodies;
- Hand valves - some groups have carbon steel bodies or cast iron bodies; some have carbon steel or Ni Resist discs;
- Pump - cast iron or carbon steel casings, and some have cast iron impeller/shafts, and iron seals;
- Relief valve - some groups have carbon steel bodies;
- Temperature indicator - some groups are carbon steel; and
- Tank - carbon steel.

The internal environment of the SRW System is chemically-treated water at a normal service pressure of 102 psig (design rating 150 psig) and a normal operational temperature of 130°F (design rating of 300°F). [Reference 11] The external environment is ambient atmospheric air inside the containment and Auxiliary Buildings, which is climate controlled. The environment of the Containment Building during normal operations has a maximum 70% relative humidity and maximum temperature of 120°F. [Reference 14, Attachment 1, Table 1, page 13 of 14] During normal operation the Auxiliary Building ambient air maximum relative humidity is 70% with a maximum temperature of 160°F (Main Steam Penetration Room). [Reference 14, Attachment 1, Table 1, page 5 of 14] The temperature and humidity in the Auxiliary Building will vary slightly according to specific local conditions.

The internal environment for the SRW air-operated control valves is normally compressed air supplied by the instrument air compressors. The instrument air is very dry, filtered, and oil-free air. Particle size, dewpoint, and oil hydrocarbons are controlled for the instrument air supply in accordance with [Instrument Society of America] ISA S7.3 [Reference 3, Section 9.10.2]

The Instrument Air System is maintained in accordance with industry standards for moisture (dewpoint) and particulate concentrations. However, the possibility of occasional exposure to moisture exists from operation of the SW air compressors (no dryer) or cross-tie with the Plant Air System (minimal drying capability). The exposure to moisture for compressed air systems is minimal and short term, and is not expected to result in significant levels of degradation of the SRW carbon steel components. [Reference 1, Attachment 8]

Group 3 (general corrosion) - Aging Mechanism Effects

Carbon steel is susceptible to general corrosion in water containing oxygen. General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The consequences of the damage are loss of load carrying cross-sectional area. [Reference 1, Attachment 6s] The ARDM is plausible for the device types listed above.

Long-term exposure of carbon steel to untreated water may result in general corrosion/area material loss and, if unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. Therefore, general corrosion has been determined to be a plausible ARDM for which aging effects must be managed for the SRW System.

General corrosion is also plausible for the SRW System air-operated control valves because the carbon steel is exposed to slightly moist air. The expected effects would be superficial rust speckles and a slight dusting of loose passive surface rust. [Reference 1, CV-04, Attachment 6]

Group 3 (general corrosion) - Methods to Manage Aging

Mitigation: The effects of general corrosion can be mitigated with a chemistry control program. Such a program includes monitoring of system chemistry on a frequency capable of detecting abnormal conditions in a timely fashion. Thus, corrective actions may be taken prior to reaching conditions conducive to corrosion.

Maintenance and verification of Instrument Air System air quality to industry standards will ensure minimal degradation of internal surfaces of air operators. [Reference 1, Attachment 8]

Discovery: Inspecting a representative sample of susceptible areas of the SRW System for the signs of general corrosion prior to the period of extended operation can determine whether this ARDM is degrading the intended function of the SRW System components. Maintenance/overhaul of SRW System components also provide opportunities to inspect for signs of general corrosion.

Group 3 (general corrosion) - Aging Management Program(s)

Mitigation: Calvert Cliffs procedure CP-206 provides for monitoring of the SRW chemistry to control the concentrations of oxygen, chlorides, other chemicals, and contaminants. The water is treated with hydrazine to minimize the amount of oxygen, which aids in minimizing most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal interior piping or component degradation. [Reference 1, Attachment 8]

The CCNPP Preventive Maintenance Checklists IPM10000, “Check Unit 1 Instrument Air Quality,” and IPM10001, “Check Unit 2 Instrument Air Quality,” provide verification of air dryer effectiveness. The purpose of these activities is to ensure that the moisture content of the Instrument Air System is as low as possible to mitigate the effects of general corrosion on air-operated valves. Preventive Maintenance Tasks that execute these checklists are automatically scheduled and implemented in accordance with safety-related Preventive Maintenance Program procedures. These tasks periodically check the Instrument Air System air quality at low points in the system. Measurements of dewpoint and particulate count are taken at three locations per unit. According to procedure, dewpoint data and particulate sample results are provided to the System Engineer. [References 15, 16, 17]

Discovery: The occurrence of general corrosion is expected to be limited and is not likely to affect the intended function of the system components. The ARDI Program is intended to provide the additional assurance needed to conclude that the effects of plausible aging are being effectively managed for the period of extended operation. The ARDI Program will focus on the effects of plausible ARDMs and the affected components. The results from implementation of the ARDI Program are to be used to determine actions required to ensure that the affected components continue to support the identified passive intended functions throughout the period of extended operation. [Reference 1, Attachment 8] For further details of the ARDI Program, refer to the discussion under Group 1 (crevice corrosion/pitting) - Aging Management Programs.

The SRW pumps are inspected for general corrosion using the CCNPP PUMP-15 procedure. PUMP-15 instructs the user to inspect certain pump components for erosion, wear, and mechanical damage. The procedure will be modified to include inspections for general corrosion on the pump casing. The procedure directs the user to contact the System Engineer if any of these indications are found, and to replace parts as necessary. [Reference 13] The PUMP-15 overhauls and inspections are performed as required based on pump performance trends or corrective actions requirements. [Reference 1, Attachment 8]

Group 3 (general corrosion) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the general corrosion of SRW System equipment:

- The SRW System device types subject to this ARDM provide a pressure-retaining boundary function so their integrity must be maintained under CLB design loading conditions.
- General corrosion is plausible for some of the SRW System device types. If not managed, this ARDM could lead to material loss and impaired capability of the components to perform their passive intended function of retaining the SRW pressure boundary.
- Calvert Cliffs procedure CP-206 is a program that will mitigate the effects of general corrosion on SRW System device types by controlling chemistry and provides action levels for critical chemistry parameters.
- The CCNPP Technical Procedure PUMP-15 will be modified to inspect susceptible pump components for crevice corrosion/pitting and general corrosion. Any indications of these ARDMs will be reported to the System Engineer and corrective actions will be taken.
- The CCNPP Preventive Maintenance Checklists IMP10000 and IPM10001 provide for periodic maintenance and verification of air dryer effectiveness to ensure that general corrosion does not degrade the SRW air-operated control valves’ ability to perform their intended function.
- A new CCNPP ARDI Program will be utilized to discover general corrosion that may be of concern for the SRW System. Inspections will be performed, and appropriate corrective action will be taken if general corrosion is discovered.

Therefore, there is reasonable assurance that the effects of general corrosion will be managed in order to maintain the SRW System components’ pressure boundary integrity consistent with the CLB during the period of extended operation.

Group 4 (selective leaching) - Materials and Environment

Table 5.17-3 shows that selective leaching is plausible for the SRW device types listed. The SRW System device types susceptible to selective leaching and their material characteristics are listed below: [Reference 1, Attachment 1, and CV02, HV04/05/06/07/08, and PUMP-02, Attachments 4, 5, 6]

- Control valves - those with cast iron bodies;

- Hand valves - those with cast iron bodies/bonnets and discs, or brass bodies, or cast brass bases and shells; and
- Pumps - those groups with cast iron casings.

The internal environment of the SRW System is chemically-treated water at a normal service pressure of 102 psig (design rating 150 psig) and a normal operational temperature of 130°F (design rating of 300°F). [Reference 11] This SRW water is treated with hydrazine to lower the dissolved oxygen level. [Reference 1, Pipe-Attachment 6] Certain regions of the SRW System have low or stagnant flow conditions.

Group 4 (selective leaching) - Aging Mechanism Effects

Selective leaching is the removal of one element from a solid alloy by corrosion processes. The most common example is the selective removal of zinc in brass alloys (dezincification). Similar processes occur in other alloy systems in which aluminum, iron, cobalt, chromium, and other elements are removed. There are two types of selective leaching, layer-type, and plug-type. Layer-type is a uniform attack, whereas plug-type is extremely localized leading to pitting. Overall dimensions do not change appreciably. Selective leaching requires susceptible materials and a corrosive environment. Conducive environmental conditions include high temperature, stagnant aqueous solution, and porous inorganic scale. Acidic solutions and oxygen may aggravate the mechanism. [Reference 1, Valve Attachment 7]

The device types discussed in the materials and environmental section above are susceptible to the ARDM (for lined valve bodies, the liner is not credited with aging management; it is conservatively assumed that the material is in contact with the fluid due to degradation of the rubber liner). The device types are exposed to flow conditions and may be exposed to stagnant conditions. The expected effect of selective leaching is cracking. [Reference 1, CV Attachment 6, SV Attachment 6]

Some cast irons are susceptible to a selective leaching process called "graphitic corrosion." The iron or steel matrix leaches from the material leaving a porous mass consisting of a graphite network, voids, and rust. The cast iron loses strength and its metallic properties. [Reference 18, Valve Attachment 7]

Long-term exposure to a conducive environment may result in selective leaching and, if unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. Therefore, selective leaching has been determined to be a plausible ARDM for which aging effects must be managed for the SRW System.

Group 4 (selective leaching) - Methods to Manage Aging

Mitigation: Maintaining a SRW System environment of purified water with controls on pH, suspended solids, and chlorides during normal plant operation can mitigate this ARDM. The addition of hydrazine to lower the SRW System dissolved oxygen level assists in the mitigation of this mechanism. [Reference 1, Attachments 6, 8]

Discovery: Inclusion of SRW System device types in an inspection program that examines a representative sample of susceptible areas of the system for the signs of selective leaching prior to the period of extended operation could identify whether this ARDM is of concern for the SRW device types.

Group 4 (selective leaching) - Aging Management Program(s)

Mitigation: CP-206 provides for monitoring of the SRW chemistry to control the concentrations of oxygen, chlorides, other chemicals, and contaminants. The water is treated with hydrazine to minimize the amount of oxygen in the water, which aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal component degradation. [Reference 1, Attachment 8] Refer to the discussion of CP-206 under Group 1 (crevice corrosion/pitting), Aging Management Programs.

Discovery: The SRW System device types listed here will be included in the ARDI Program to verify that degradation of SRW device types due to selective leaching is not excessive. Refer to the ARDI discussion under Group 1 (crevice corrosion/pitting), Aging Management Programs for more details on this program. [Reference 1, Attachment 8]

Group 4 (selective leaching) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to selective leaching for the SRW device types listed here:

- The control valves, hand valves, and pumps described here act as a pressure-retaining boundary, and their integrity must be maintained under CLB design conditions.
- Selective leaching is plausible for the valve and pump device types discussed in the Materials and Environmental section above, which could lead to the loss of the pressure-retaining boundary function of the SRW System.
- Calvert Cliffs CP-206 is a program that mitigates the effects of selective leaching on SRW System device types by controlling chemistry, and provides action levels for critical chemistry parameters.
- The CCNPP ARDI Program will be utilized to discover selective leaching that may be of concern for the SRW System components. Inspections will be performed, and appropriate corrective action will be taken if selective leaching is discovered.

Therefore, there is a reasonable assurance that the effects of selective leaching will be managed in order to maintain the components' intended function under all design loadings required by the CLB during the period of extended operation.

Group 5 (wear) - Materials and Environment

Table 5.17-3 shows that wear is plausible for relief valves in the SRW System. The valve bodies are either fabricated from stainless steel or carbon steel and have stainless seats and discs. However, it is only the stainless steel discs and valve seats that are susceptible to wear. [Reference 1, Attachment 1, and RV01/02, Attachments 4, 5, 6]

The internal environment of the SRW System is chemically-treated water at a normal service pressure of 102 psig (design rating 150 psig) and a normal operational temperature of 130°F (design rating of 300°F).

[Reference 11] During normal plant operation, relief valves are usually closed. Some valves may remain in the closed position for an extended period of time before being actuated.

Group 5 (wear) - Aging Mechanism Effects

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard, abrasive particles (abrasive wear), or sliding motions under the influence of a corrosive environment (fretting). In addition to material loss from the above wear mechanisms, impeded relative motion between two surfaces held in intimate contact for extended periods may result in galling/self welding. Motions may be linear, circular, or vibratory in inert or corrosive environments. The most common result of wear is damage to one or both surfaces involved in the contact. Wear most typically occurs in components that experience considerable relative motion, such as valves and pumps, in components that are held under high loads with no motion for long periods (e.g., valves, flanges), or in clamped joints where relative motion is not intended but occurs due to a loss of clamping force (e.g., tubes in supports, valve stems in seats, springs against tubes). Wear rates increase as worn surfaces experience higher contact stresses than the surfaces of the original geometry. [Reference 1, Valve, Attachment 7]

Valve discs may periodically relieve pressure and experience movement against the seat. The expected effect of wear is a progressive loss of material on the subcomponent. The SRW device types are therefore susceptible to this ARDM. [Reference 1, RV, Attachment 6] The subcomponents of the device types are not located in the SRW fluid flow stream. Movement of the subcomponent is expected to occur infrequently.

Group 5 (wear) - Methods to Manage Aging

Mitigation: There are no reasonable methods of mitigating wear of the relief valves seating surfaces during their infrequent operation. Relief valves that infrequently operate can be periodically bench tested to verify the valve is not leaking or sticking.

Discovery: Wear can be discovered by inspecting and testing the valve device types that are susceptible to this ARDM. Routine bench testing and inspection can identify wear and sticking of the relief valve seating surfaces.

Group 5 (wear) - Aging Management Program(s)

Mitigation: Since wear cannot be avoided during plant operation, there are no programs credited with mitigating wear due to relative motion between two surfaces. However, the program mentioned below in the discovery section can mitigate the effects of galling/self welding (sticking) by periodically bench testing (actuating) the relief valves.

Discovery: The CCNPP Mechanical Preventative Maintenance (MPM) Checklists MPM01013, MPM01147, MPM01153, and MPM01155, "Relief Valves," direct the removal, testing, and reinstallation of the satisfactorily tested relief valves. The checklists refer to another procedure for the performance and acceptance of the relief valve setpoint tests. These preventive maintenance checklists are performed at a four- to five-year interval. [References 19, 20, 21, 22] Routine bench testing and inspection will identify wear of the relief valve seating surfaces. [Reference 1, Attachment 8]

Group 5 (wear) - Demonstration of Aging Management

Based on the information presented above, it can be concluded that:

- The SRW relief valves described here act as a pressure-retaining boundary, and their integrity must be maintained under CLB design conditions.
- Wear is plausible for the relief valves discussed in the materials and environment section above, which could lead to the loss of the pressure-retaining boundary function of the SRW System.
- The CCNPP MPM01013, MPM01147, MPM01153, and MPM01155 Checklists direct the removal, relief setpoint testing, and reinstallation of SRW relief valves. Routine bench testing and inspection will identify wear of the relief valve seating surfaces.

Therefore, there is a reasonable assurance that the effects of wear will be managed in order to maintain the SRW relief valves intended function under all design loadings required by the CLB during the period of extended operation.

5.17.3 Conclusion

The aging management programs discussed for the SRW System are listed in Table 5.17-4. 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 such that the intended functions of the SRW System components 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 5.17-4

LIST OF AGING MANAGEMENT PROGRAMS FOR THE SERVICE WATER SYSTEM

	Program	Credited For
Existing	Specifications and Surveillance for CC/SRW Systems, CCNPP CP-206	Mitigating the effects of crevice corrosion/pitting (Group 1), general corrosion (Group 3), and selective leaching (Group 4) of SRW System components by monitoring and controlling the SRW chemistry.
Existing	Periodic maintenance and verification of dryer effectiveness: IPM10000, "Check Unit 1 Instrument Air Quality," and IPM10001, "Check Unit 2	Mitigation of general corrosion (Group 3) of the SRW air-operated valves. The exposure to moisture is minimal and short-term, and is not expected to result in significant levels of degradation of the carbon steel components.

	Instrument Air Quality"	
Existing	Checklists for SRW Relief Valves; MPM01013, MPM01147, MPM01153, and MPM01155	Discovery of wear (Group 5) of the SRW System relief valves. They are performed on a four- to five-year interval to remove and test SRW System relief valves.
Modified	SRW Pump Overhaul, CCNPP PUMP-15	Will be modified for the discovery of crevice corrosion/pitting (Group 1) and general corrosion (Group 3) of the SRW pumps through inspection and overhaul. These activities are performed as required based on pump performance trends or corrective action requirements.
New	ARDI Program	Discovery of crevice corrosion/pitting (Group 1), erosion corrosion (Group 2), general corrosion (Group 3), and selective leaching (Group 4). The results from implementation of the ARDI Program are to be used to determine actions required to ensure that the affected components continue to support the identified passive intended functions throughout the period of extended operation.

5.17.4 References

1. "Service Water System Aging Management Review," Revision 1, October 18, 1996
2. CCNPP "Fire Protection Aging Management Review," Revision 1, January 29, 1997
3. Calvert Cliffs Nuclear Power Plant, Updated Final Safety Analysis Report, Revision 20
4. Letter from Mr. R. E. Denton to NRC Document Control Clerk, dated December 14, 1990, LER-89-023, Revision 2, "Postulated Rupture in Non-Safety-Related Service Water Subsystem (SRW) Could Cause Failure of Both Safety-Related Subsystems"
5. CCNPP "Evaluation of Isolation Provisions for SRW System," July 7, 1993
6. Letter from Mr. L. T. Doerflein (NRC) to Mr. R. E. Denton (BGE), dated October 16, 1995, "NRC Region I Inspection Report Nos. 50-317/95-08 and 50-318/95-08"
7. CCNPP System Level Scoping Results (SLSR), Revision 4, April 6, 1995
8. Letter from Mr. L B. Russell (BGE) to Mr. B. H. Grier (NRC), dated June 3, 1980, Licensee Event Report 80-27/IT, Two-week Follow-up Report for LER 80-27/IT
9. Letter from Mr. C. J. Cowgill (NRC) to Mr. R. E. Denton (BGE), dated March 31, 1995, NRC "Region I Integrated Inspection Report Nos. 50-317/95-01 and 50-318/95-01 (January 1, 1995 - February 21, 1995)"
10. CCNPP Technical Procedure Component Level ITLR Screening Results, SRW System, Revision 1, August 8, 1996
11. CCNPP Drawing 92769SH-HB-3, "M-601 Piping Class Summary," Revision 28
12. CCNPP CP-206, "Specifications and Surveillance Component Cooling/Service Water System," Revision 3, November 4, 1996
13. CCNPP Technical Procedure PUMP-15, "SRW Pump Overhaul," Revision 1, February 4, 1997
14. Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0, November 8, 1995
15. CCNPP IPM10000, "Check Unit 1 Instrument Air Quality," Revision 0, September 10, 1991
16. CCNPP IPM10000, "Check Unit 2 Instrument Air Quality," Revision 0, September 10, 1991
17. CCNPP Repetitive Task 10191024, "Check Unit 1 Instrument Air Quality at Selected System Lowpoints"
18. CCNPP "Component Cooling System Aging Management Review," Revision 1, November 7, 1996
19. CCNPP MPM01013 Checklist Sheet, "Remove Relief Valve, Test and Reinstall," Revision 0, January 28, 1992
20. CCNPP MPM01147 Checklist Sheet, "Remove Relief Valve, Test and Reinstall," Revision 0, December 24, 1991
21. CCNPP MPM01153 Checklist Sheet, "Remove Relief Valve, Test and Reinstall," Revision 0, December 24, 1991
22. CCNPP MPM01147 Checklist Sheet, "Remove Relief Valve, Test and Reinstall," Revision 0, December 24, 1991

5.18 Spent Fuel Pool Cooling System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Spent Fuel Pool Cooling System (SFPCS). The SFPCS 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.

5.18.1 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.

Representative historical operating experience pertinent to aging 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.

Section 5.18.1.1 presents the results of the system level scoping, 5.18.1.2 the results of the component level scoping, and 5.18.1.3 the results of scoping to determine components subject to an AMR.

5.18.1.1 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.

<u>System Description/Conceptual Boundaries</u>

The SFPCS consists of two half-capacity pumps and two half-capacity heat exchangers in parallel, a bypass filter which removes insoluble particulates, a bypass demineralizer which removes soluble ions, and various piping, valves, and instrumentation. [Reference 1, Section 9.4.2] The spent fuel pool (SFP) itself, which is covered in Section 3.3 (Structures) of the BGE LRA, is located in the Auxiliary Building. It is divided into two identical halves, each serving one reactor unit. Both new fuel and spent fuel may be stored in the pool. [Reference 1, Section 1.2.9.4]

The fuel racks in both halves of the SFP have been replaced to increase the storage density. It has been shown by analysis that the SFPCS has sufficient capacity to support the increased heat loads. These changes have therefore not affected the SFPCS. [Reference 2]

Following several instances of cracking of SFPCS piping, a detailed study was performed (in early 1990) to determine the root cause and appropriate remedy. Reference 3 presents the conclusions of the study, and the resulting recommendations. It was determined that the cracking was due to high-cycle fatigue caused by cavitation-induced vibration inherent in the original design of the system. Certain orifices and valves were modified to eliminate system cavitation. Implementation of these improvements has prevented recurrence of cracking in SFPCS piping. Since normal service loads do not result in significant vibration or other dynamic loading conditions, fatigue is not plausible for SFPCS. [Reference 4, Attachment 6s for Pipe]

The primary functions of the SFPCS are:

- to remove decay heat from the spent fuel stored in the SFP; [Reference 4, Section 1.1.1]
- to provide cooling for the refueling pools; [Reference 4, Section 1.1.1]
- to maintain clarity and low activity levels in the SFP, in the refueling pools, and in the refueling water tanks; [Reference 4, Section 1.1.1]
- to transfer water to and from the refueling water tanks. [Reference 4, Section 1.1.1]

The SFPCS is composed of the following general categories of equipment and devices: [Reference 4, Section 1.1.2]

Piping	To convey fuel pool water to the heat exchangers and filters and back to the appropriate pool; also, to transfer water to and from the refueling water tanks;
Valves	Check, hand, and relief valves, which provide containment isolation, system alignment/isolation and over-pressure protection;
Instruments	Measure flow rates, pressure and temperatures; provide indication and alarm;
Filter/Strainer	Remove entrained solids and fine particulate matter;
Demineralizer	Remove dissolved chemical and radioactive impurities;
Pumps	Pump water through the system; and
Heat Exchangers	Transfer fuel decay heat from the system water to the Service Water (SRW) System.

Figure 5.18-1 is a simplified diagram of the SFPCS. This figure shows the portions of the SFPCS addressed in this section of the BGE LRA and the primary process flow systems' interfaces. [Reference 5]

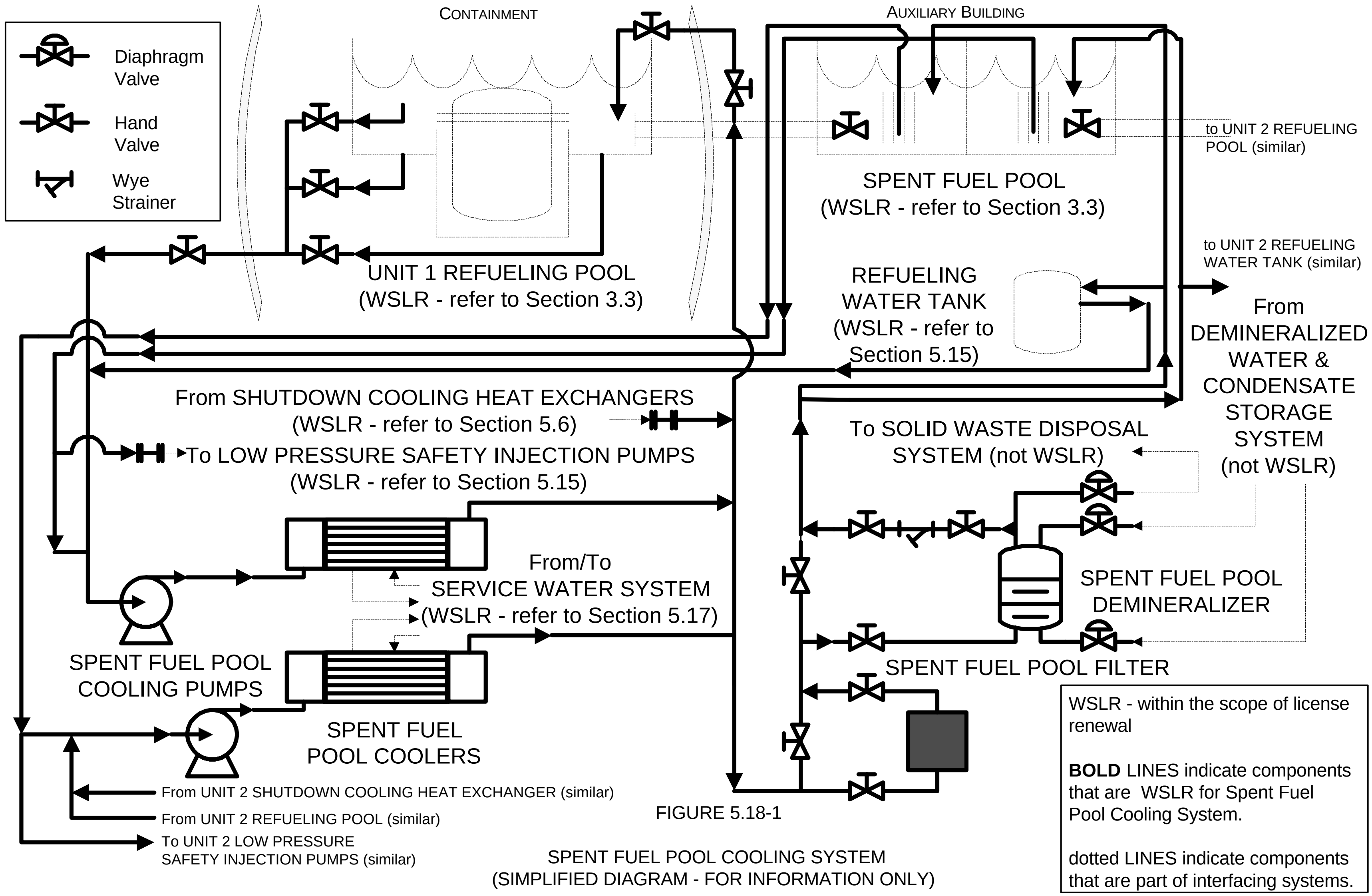

FIGURE 5.18-1

SPENT FUEL POOL COOLING SYSTEM
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

System Interfaces

The SFPCS primary process flow interfaces with the following systems and components: [Reference 5]

- SRW System (cooling water supply);
- Safety Injection System (Refueling Water Tanks, Low Pressure Safety Injection Pumps);
- Containment Spray System (Shutdown Cooling Heat Exchangers);
- Refueling Pool (covered in Section 3.3, Structures, of the BGE LRA);
- Demineralized Water and Condensate Storage System (makeup water source); and
- Solid Waste Disposal System (spent resin discharge).

System Scoping Results

The SFPCS is in scope for license renewal based on 10 CFR 54.4(a). The following intended functions of the SFPCS 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, Section 1.1.3; Reference 6, Table 1]

- Provide containment isolation in the event of a Loss-of-Coolant Accident or a Control Element Assembly Ejection event;
- Provide heat removal for SFP water and refueling pool water with the initiation of a Fuel Handling Incident or a Boron Dilution Event;
- Maintain pressure boundary of the system; and
- Maintain electrical continuity and/or provide protection of the electrical system.

No intended functions of the SFPCS were determined based on the requirements of §54.4(a)(3). [Reference 6, Table 1]

5.18.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the SFPCS that is within the scope of license renewal includes all components (electrical, mechanical, and instrument) and their supports from the refueling and SFPs through the SFP cooling pumps, heat exchangers, filter, and demineralizer, and back to the refueling and SFPs. It also includes the isolation valves in the lines to the interfacing systems.

Table 5.18-1 (in Section 5.18.1.3) lists the specific device types in the SFPCS that have been designated as within the scope of license renewal because they have at least one intended function. [Reference 4, Section 2.2 Table 2-1]

Some components in the SFPCS are common to many other plant systems and have been included in separate commodity AMRs that address those components for the entire plant. These components include the following: [Reference 4, Section 3.2]

- 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, except that the supports for the SFPCS filter and demineralizer are addressed herein.

- 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 SFPCS.
- Instrument tubing and piping and the associated supports, instrument valves and fittings, and the pressure boundaries of the instruments themselves, are all addressed in BGE LRA Section 6.4 (Instrument Lines). In general, Section 6.4 addresses everything from the outlet of the final root valve up to and including the instrument.

5.18.1.3 Components Subject to AMR

This section describes the components within the SFPCS that are subject to AMR. It begins with a listing of passive intended functions, and then determines which device types are subject to AMR by dispositioning each device type as either:

- associated only with active functions;
- subject to scheduled replacement;
- evaluated in other sections of the BGE LRA; or
- remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following SFPCS functions were determined to be passive: [Reference 4, Table 3-1, p 3-2]

- Provide containment isolation during a Control Element Assembly Ejection and during Loss-of-Coolant Accident;
- Maintain electrical continuity and/or provide protection of the electrical system; and
- Maintain the pressure boundary of the system.

Device Types Subject to AMR

Table 5.18-1 presents the results of the SFPCS device type pre-evaluation. [Reference 4, Table 3-2] Since the aging analysis in the AMR is carried out partly in consideration of equipment type, rather than device type, equipment type designators are also shown. This table lists all of the device types that have at least one intended function, and provides additional information relevant to the determination as to whether or not the device type is to be included in the subsequent analyses of this section. That determination is based upon the three scoping columns as follows:

- Passive: Device types having at least one passive function are marked accordingly. A device type will be included in AMR only if it has at least one passive function. Several device types are excluded from AMR since they do not have any passive functions.
- Replace on Basis of Time: Device types that are replaced on a pre-established schedule would not be subjected to additional aging as a result of license renewal, and are therefore excluded from AMR. None of the SFPCS device types fall into this category.

- Addressed Elsewhere: If a discussion in another section of the BGE LRA adequately addresses a device type used in the SFPCS, then that section is cited in this column and the device type is not addressed in this section. The hand valve device type (HV) is marked as "partially" addressed because some instrumentation hand valves are addressed in Section 6.4 of the BGE LRA, and the remaining hand valves are addressed in this section.

Table 5.18-1

SFPCS DEVICE TYPE DISPOSITION

		√ => "yes"; ( ) => "partial"; blank => "no"				
Device Type	**Device Type Description**	**Passive**	**Replace on Basis of Time**	**Addressed Elsewhere (see note)**	**SFPCS AMR**	**Equipment Type**
-HC	Pipe Line with Piping Code of "HC"	√			√	Pipe
BS	Basket Strainer	√			√	Filter
CKV	Check Valve	√			√	Valve
COIL	Coil					
FE	Flow Element	√			√	Element
FI	Flow Indicator	√		6.4		
FIS	Flow Indicator Switch	√		6.4		
FL	Filter	√			√	Filter
FO	Flow Orifice	√			√	Pipe
FU	Fuse					
HS	Handswitch					
HV	Hand Valve	√		(6.4)	(√)	Valve
HX	Heat Exchanger	√			√	Heat Exchanger
IX	Demineralizer/Ion Exchanger	√			√	Demineralizer
JL	Power Lamp Indicator					
MB	480V Motor					
MD	125/250 VDC Motor					
PDI	Pressure Differential Indicator	√		6.4		
PDIS	Pressure Differential Indicator Switch	√		6.4		
PI	Pressure Indicator	√		6.4		
PS	Pressure Switch	√		6.4		
PMP	Pump/Driver Assembly	√			√	Pump
RV	Relief Valve	√			√	Valve
RY	Relay					
TI	Temperature Indicator	√			√	Indicator
TS	Temperature Switch	√			√	Switch
YS	Wye Strainer	√			√	Filter
ZL	Position Indicating Lamp					

NOTE: An entry in the column labeled "Addressed Elsewhere" in the above table indicates the BGE LRA section in which the item is addressed. Items designated "partial" are not fully covered in the referenced section. See text for details.

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies that 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.

As indicated in Table 5.18-1, several device types have no passive function and several others are addressed in other sections of the BGE LRA. The device types remaining to be covered in this section are clearly indicated on the table, and are summarized in Table 5.18-2:

Table 5.18-2

DEVICE TYPES SUBJECT TO AMR

Class HC Piping	Heat Exchanger
Basket Strainer	Demineralizer/Ion Exchanger
Check Valve	Pump/Driver Assembly
Flow Element	Relief Valve
Filter	Temperature Indicator
Flow Orifice	Temperature Switch
Hand Valve	Wye Strainer

5.18.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the SFPCS components is given in Table 5.18-3, with plausible ARDMs identified by an annotation in the appropriate device type column. [Reference 4, Table 4-2] An annotation indicates that the ARDM applies to at least one subcomponent for the device type listed. 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. Table 5.18-3 also identifies the group to which each ARDM/device type combination belongs. Exceptions are noted where appropriate. Some device types are included in more than one of these groups because of the diversity of materials used in their fabrication. The following groups have been defined for the SFPCS:

Group 1: Device Types or Subcomponents: bolting and supports; vessel shells and covers; hand valve bodies; heat exchanger shell, nozzles, and channel covers (all carbon steel)
ARDMs: crevice corrosion, galvanic corrosion, general corrosion, pitting

Group 2: Device Types or Subcomponents: hand valve diaphragm, lining
ARDMs: rubber degradation, radiation damage (diaphragm only)

Group 3: Device Types or Subcomponents: hand valve seat/disk
ARDMs: wear

Group 4: Device Types or Subcomponents: pump casing
ARDMs: cavitation erosion, erosion corrosion

Following Table 5.18-3 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 5.18-3

POTENTIAL AND PLAUSIBLE ARDMs FOR THE SFPCS

Potential ARDMs	Equipment / Device Types													
	PIPE		FILTER			VALVE			(single-device equipment)					
	-HC	FO	FL	BS	YS	CKV	HV	RV	FE	HX	IX	PMP	TI	TS
Cavitation Erosion												√(4)		
Corrosion Fatigue														
Crevice Corrosion	√(1)		√(1)		√(1)	√(1)	√(1)			√(1)		√(1)		
Erosion Corrosion												√(4)		
Fatigue														
Fouling														
Galvanic Corrosion	√(1)		√(1)		√(1)	√(1)	√(1)			√(1)		√(1)		
General Corrosion	√(1)		√(1)		√(1)	√(1)	√(1)			√(1)	√(1)	√(1)		
Hydrogen Damage														
Intergranular Attack														
Microbiologically-Induced Corrosion														
Particulate Wear Erosion														
Pitting	√(1)		√(1)		√(1)	√(1)	√(1)			√(1)		√(1)		
Radiation Damage							√(2)							
Rubber Degradation							√(2)							
Saline Water Attack														
Selective Leaching														
Stress Corrosion Cracking														
Stress Relaxation														
Thermal Damage														
Thermal Embrittlement														
Wear							√(3)							

Note: Not every subcomponent within the device types listed here may be susceptible to a given ARDM. This is because groups within a device type are not always fabricated from the same materials or subjected to the same environments.

Group 1 - (crevice corrosion, galvanic corrosion, general corrosion, and pitting of bolting and supports, vessel shells and covers, hand valve bodies, heat exchanger shell, nozzles, and channel covers) - Materials and Environment

All of the subcomponents included within this group are composed of some variety of carbon steel. External surfaces of some subcomponents are zinc-plated or are painted. Table 5.18-4 presents a summary of the subcomponents subject to aging, and the associated materials, as derived from the AMR Report. [Reference 4, Attachments 4 and 5 for each device type (Attachment 4 identifies the materials for each subcomponent, and Attachment 5 identifies the susceptible subcomponents)]

Table 5.18-4

GROUP 1 SUBCOMPONENTS AND MATERIALS SUBJECT TO AGING

Equipment Type	Subcomponents and Materials
PIPE	bolting bolts: ASTM* A-193 GR B7 nuts: ASTM A-194 GR 2H
FILTER	SFP filter cover clamp assembly zinc-plated carbon steel ASME* SA-193, GR B7 and SA-105, GR 1
	SFP filter vessel support legs and base ring painted carbon steel
	SFP demineralizer strainer bolting carbon or alloy steel
VALVE	SFP pump discharge check valve cover-to-body bolting studs: ASTM A-193, GR B7 nuts: ASTM A-194, GR 2H
	some hand valve body/bonnet bolting bolts: ASTM A-193, GR B7 nuts: ASTM A-194, GR 2H
HEAT EXCHANGER	heat exchanger shell and nozzles shell: carbon steel, ASME SA-285-C, SA-106 GR B nozzles: ASME SA-181, GR 1
	heat exchanger channel cover carbon steel, ASME SA-515, GR 60
DEMINERALIZER	vessel support (subject to general corrosion only) painted carbon steel
PUMP	casing stud nuts ASTM A-194, GR 2H

* American Society for Testing and Materials
American Society of Mechanical Engineers

The external environment for all items in this group is climate-controlled air in the Auxiliary Building and in the Containment. [Reference 4, Attachment 3s] The Containment atmosphere is applicable only to some subcomponents. Under normal operation, the temperature and humidity in the Auxiliary Building do not exceed 160°F and 70% [Reference 7, Attachment 1, Table 1, page 5 of 14] and, in the Containment, 120°F and 70% [Reference 7, Attachment 1, Table 1, page 13 of 14].

The internal environment for all devices, with the exception of the shell side of the heat exchangers, is controlled-chemistry borated water, with approximately 2500 ppm boron. The shell side of the heat exchangers are exposed to treated demineralized water. [Reference 4, Attachment 3s]

The subcomponents in this group are not normally exposed to borated water because they are all external to the devices, but they may be exposed to it as a result of leakage. The possible effects of boric acid are therefore taken into consideration in this analysis.

Group 1 - (crevice corrosion, galvanic corrosion, general corrosion, and pitting of bolting and supports, vessel shells and covers, hand valve bodies, heat exchanger shell, nozzles, and channel covers) - Aging Mechanism Effects

Crevice corrosion and pitting are related forms of intensive, localized corrosion. Crevice corrosion occurs in crevices such as may exist under bolt heads, within lap joints, or adjacent to weld backing rings. Pitting occurs when corrosion proceeds at one small location at a rate greater than the corrosion of the surrounding area. In either case, the stagnant fluid within the pit or crevice tends to accumulate corrosive chemicals, and thereby to accelerate the local corrosion process. Crevice corrosion can lead to stress corrosion cracking or other material failures, and can also lead to pitting. Pitting can result in complete perforation of the material. [Reference 4, Attachment 7 for Pipe, Filter, Valve, Heat Exchanger, Demineralizer, Pump]

Galvanic corrosion is an accelerated form of corrosion caused by dissimilar metals in contact in a conductive solution. It requires two dissimilar metals in physical or electrical contact and a conducting solution. [Reference 4, Attachment 7 for Pipe, Filter, Valve, Heat Exchanger, Demineralizer, Pump]

General corrosion is a thinning of a metal by the chemical attack of an aggressive environment at its surface. An important concern for pressurized water reactors is boric acid attack upon carbon steels. General corrosion is not a concern for austenitic stainless steel alloys. [Reference 4, Attachment 7 for Pipe, Filter, Valve, Heat Exchanger, Demineralizer, Pump]

Carbon steels are susceptible to all of these forms of corrosion. They are particularly susceptible to significant acceleration of corrosion when exposed to boric acid in the concentrations present in the SFPCS. Due to the potential for leakage of system fluid onto external component surfaces, boric acid corrosion effects were determined to be plausible for the carbon steel and alloy steel bolting components listed in Table 5.18-4. [Reference 4, Attachment 6s for listed components (Code A)]

In heat exchangers, crevice corrosion and pitting can occur in cooler shell-side areas that are not exposed to the general flowstream (such as in areas where internal parts interface with the shell, and in other crevices). Galvanic corrosion may occur to a limited extent at the carbon steel shell to stainless steel tubesheet joint due to the dissimilar materials. These areas may comprise small localized volumes of stagnant solution for which fluid chemistry may deviate from bulk system chemistry. Higher concentrations of impurities may exist in these crevices due to out-of-specification system chemistry during excursions, and due to the stagnant flow conditions of the crevice. The resulting degradation consists of highly localized pits or cracks. General corrosion of the shell-side components can occur if adverse chemistry conditions are present for extended periods. [Reference 4, Attachment 6 for heat exchangers (Code A)]

In general, regardless of the particular corrosion mechanism, the result is a reduction in the integrity of the corroded parts and a resulting increase in the likelihood of mechanical failure. In addition, corrosion can compromise the closeness-of-fit of fitted parts, and result in fluid leakage and an increased likelihood of mechanical wear due to vibration or other relative motion.

If unmanaged, long-term exposure to these corrosion mechanisms could eventually result in loss of the pressure-retaining capability under current licensing basis (CLB) design loading conditions.

Group 1 - (crevice corrosion, galvanic corrosion, general corrosion, and pitting of bolting and supports, vessel shells and covers, hand valve bodies, heat exchanger shell, nozzles, and channel covers) - Methods to Manage Aging Effects

Mitigation**:** Boric acid corrosion can be mitigated by minimizing leakage. The susceptible areas of the SFPCS (i.e., bolted joints) can be routinely observed for signs of borated water leakage, and appropriate corrective action can be initiated as necessary to eliminate leakage, clean spill areas, and assess any corrosion. [Reference 4, Attachment 6 for pipe, check valves, hand valves (Code A) and for heat exchangers and pumps (Code B)]

For heat exchanger internals, the effects of corrosion can be minimized through control of fluid chemistry. [Reference 4, Attachment 6 for heat exchangers (Code A)]

Painting and zinc-plating are used as external coatings to minimize corrosion of carbon steels, but corrosion of painted and zinc-plated carbon steel surfaces has nevertheless been observed. Properly maintained paint and zinc plating can prevent significant corrosion of protected surfaces. [Reference 4, Attachment 6 for filters (Codes A and B), and for demineralizers (Code A)]

Discovery**:** The effects of corrosion are generally detectable by visual techniques.

Corrosion of a painted or zinc-coated carbon steel surface cannot occur without degrading the paint or coating. Confirmation that this paint or coating is intact is an effective method for ensuring that the effects of the plausible ARDMs have not occurred. Since the paint or coating does not contribute to the components' intended functions, degradation of the coating provides an alert condition, which triggers corrective action before corrosion that affects the equipment's ability to perform its intended function can occur. The paint or coating degradation that does occur can be discovered and managed by periodic inspection of the exposed surfaces and by repair of the surfaces, as needed.

The cooler shell-side components of heat exchangers (or representative components from other plant locations) can be subjected to inspection to determine the extent of general and/or localized degradation that may be occurring. [Reference 4, Attachment 6 for heat exchangers (Code A)]

Group 1 - (crevice corrosion, galvanic corrosion, general corrosion, and pitting of bolting and supports, vessel shells and covers, hand valve bodies, heat exchanger shell, nozzles, and channel covers) - Aging Management Program(s)

Mitigation**:**

The CCNPP Boric Acid Corrosion Inspection (BACI) Program, (MN-3-301, Reference 8, described more fully under "Discovery" in this section) can mitigate the effects of boric acid corrosion through timely discovery of leakage of borated water and removal of any boric acid residue that is found. This program requires visual inspection of the components containing boric acid for evidence of leaks, quantification of any leakage indications, and removal of any leakage residue from component surfaces. [Reference 4, Attachment 8]

Maintenance of proper SRW System chemistry will suppress general corrosion, galvanic corrosion, crevice corrosion, and pitting on the shell side of the SFPCS heat exchangers. [Reference 4, Attachment 8]

Calvert Cliffs Procedure CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems," provides for monitoring of the SRW and Component Cooling Water System chemistry to control the concentrations of oxygen, chlorides, and other chemicals and contaminants. Control of the water chemistry prevents a corrosive environment for the shell side of the SFPCS heat exchangers. [Reference 4, Attachment 8]

Calvert Cliffs procedure CP-206 describes the surveillance and specifications for monitoring the SRW System fluid. It lists the parameters to be monitored, the frequency for the monitoring of those parameters, and the target and action levels for the SRW System fluid parameters. The parameters monitored by CP-206 are pH, hydrazine, chloride, dissolved oxygen, dissolved copper, dissolved iron, suspended solids, gamma activity, and tritium activity (normally not a radioactive system). [Reference 9, Attachment 1]

These parameters are currently monitored on a frequency ranging from three times per week to once a month. All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter. Two of the parameters, pH and hydrazine, have action levels associated with them. For pH the current action level is less than 9.0 or greater than 9.8. For hydrazine, the current action level is less than 5 or greater than 25 parts per million (ppm). If any gamma activity or tritium is detected in the SRW System, the procedure currently directs CCNPP personnel to CP-224, "Monitoring Radioactivity in Systems Normally Uncontaminated." CP-206 presents the specific monitoring frequency and target values for each chemistry parameter. [Reference 9, Attachment 1]

Review of SRW operational experience identified no problems related to significant deficiencies in CP-206. In 1996, CP-206 was revised to include monitoring of dissolved iron as a method for discovering any unusual corrosion of carbon steel components.

An internal BGE chemistry summary report for 1996 described the CCNPP Units 1 and 2 Component Cooling/SRW Systems chemistry as excellent. Action levels for all four systems were only exceeded on eight occasions, or approximately 0.7% of the time during the year. Over 70% of the action levels entered were due to major system changes during the 1996 outage. The report included recommendations to determine outage evolutions that can affect the Component Cooling/SRW chemical parameters and take action to prevent chemistry parameters from being exceeded.

Calvert Cliffs procedure CP-206 provides for rapid assessment of off-normal chemistry parameters so that steps can be taken to return them to normal levels.

Discovery:

Discovery of boric acid leakage is ensured by the BACI Program (MN-3-301, Reference 8). [Reference 4, Attachment 8] This program also requires investigation of any leakage that is found. A visual examination of external surfaces is performed for components containing boric acid. [Reference 8]

The Inservice Inspection Program required the establishment of the BACI Program to systematically ensure that boric acid corrosion does not degrade the primary system boundary. [Reference 10, page 23, Section 5.8.A.1.] The program also applies to "valves in systems containing borated water which could leak onto Class 1 Carbon Steel Components," and it identifies other plant areas to be examined. [Reference 8, Section 5.1B] The program controls examination, test methods, and actions to minimize the loss of structural and pressure-retaining integrity of components due to boric acid corrosion. [Reference 10, page 7, Section 3.0.C] The basis for the establishment of the program is Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." [Reference 8, Section 1.1]

The scope of the program is threefold in that it: (a) identifies locations to be examined; (b) provides examination requirements and methods for the detection of leaks; and (c) provides the responsibilities for initiating engineering evaluations and necessary corrective actions. [Reference 8, Section 1.2]

During each refueling outage, inservice inspection personnel perform a walkdown inspection to identify and quantify any leakage found at specific locations inside the Containment and in the Auxiliary Building. The inservice inspection ensures that all components that are the subjects of existing Issue Reports (IRs) where boric acid leakage has been found are examined in accordance with the requirements of this program. A second inspection is performed prior to plant startup (at normal operating pressure and temperature) if leakage was identified and corrective actions were taken. [Reference 8, Sections 5.1 and 5.2] Calvert Cliffs procedure QL-2-100, "Issue Reporting and Assessment," defines requirements for initiating, reviewing and processing IRs, and resolution of issues. Issue Reports are generated to document and resolve process and equipment deficiencies and nonconformances.

Under the BACI Program, the walkdown inspections applicable to the SFPCS are type VT-2 (a type of visual examination described in ASME XI, IWA-2212). The VT-2 visual examinations include the accessible external exposed surfaces of pressure-retaining, non-insulated components; floor areas or equipment surfaces located underneath non-insulated components; vertical surfaces of insulation at the lowest elevation where leakage may be detected, and horizontal surfaces at each insulation joint for insulated components; floor areas and equipment surfaces beneath components and other areas where water may be channeled for insulated components whose external insulation surfaces are inaccessible for direct examination; and for discoloration or residue on any surface for evidence of boric acid accumulation. Any leakage detected is reported on an IR for assessment and corrective action. [Reference 8, Section 5.2]

Issue Reports written in accordance with this program are required to address the removal of the boric acid residue and the inspection of the affected components for general corrosion. If general corrosion is found on a component, the IR is to provide an evaluation of the component for continued service and corrective actions to prevent recurrence. [Reference 8, Section 5.3]

The BACI Program has evolved with regard to boric acid leaks discovered during other types of walkdowns and inspections. The program specifies the minimum qualification level for inspectors evaluating boric acid leaks. Apparent leaks that are discovered during these other walkdowns/inspections are documented in IRs by the individual discovering the leak. These IRs are then routed to the inservice inspection group for closer inspection and evaluation by a qualified inspector. This approach provides for more boric acid leakage inspection coverage while still meeting the minimum qualification requirement.

The corrective actions taken as a result of IRs under this program will ensure that the SFPCS components remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Calvert Cliffs procedure CP-206 provides for the monitoring of SRW System chemistry. This controls galvanic corrosion, crevice corrosion, and pitting on the shell side of the SFPCS heat exchangers, and detects the presence of corrosion products in the SRW. The presence of an abnormal concentration of corrosion products in the SRW would suggest that unexpected corrosion is taking place, and would trigger investigations and corrective actions.

Since the following components in Group 1 are installed in areas that are normally inaccessible due to radiation levels, CCNPP currently plans to include them in an Age-Related Degradation Inspection (ARDI) Program to verify that degradation of the components by general, crevice, or galvanic corrosion or by pitting is not occurring:

- SFP filter cover clamp assembly and filter vessel support legs and base ring;
- body-to-bonnet bolting for stainless steel diaphragm valves not covered by the BACI Program;
- heat exchanger shell and nozzles;
- demineralizer vessel support legs and floor mounting plate (susceptible to general corrosion only); and
- SFP demineralizer wye-strainer bolting.

The program is 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 loading conditions 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.

Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Action Program and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 1 - (crevice corrosion, galvanic corrosion, general corrosion, and pitting of bolting and supports, vessel shells and covers, hand valve bodies, heat exchanger shell, nozzles, and channel covers) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to crevice corrosion, galvanic corrosion, general corrosion, and pitting of the device types addressed in this section:

- These device types contribute to the system pressure boundaries, and their integrity must be maintained under CLB design conditions.
- The construction material for components in this group is carbon steel. External surfaces may be coated with paint or plated with zinc.
- Crevice corrosion, galvanic corrosion, general corrosion, and pitting are plausible ARDMs for this group of components because the components are exposed to boric acid 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.
- The effects of boric acid will be managed by means of the BACI Program, MN-3-301, Reference 8. When boric acid leakage is identified, either through required program inspections or through IRs resulting from other types of walkdowns and inspections, this program will ensure that corrosion induced by boric acid is discovered and that appropriate corrective action is taken.
- Chemistry control in accordance with CP-206, Reference 9, will ensure that the cooling water supplied to the SFPCS heat exchangers is of an appropriate chemistry to minimize corrosion, and will discover any unusual corrosion that may be taking place and ensure that appropriate corrective action is initiated.
- Components not adequately protected under the two programs listed above will be subjected to an ARDI Program. This program will examine a representative sample of the components for degradation, and ensure that appropriate corrective actions are initiated on the basis of the findings.

Therefore, there is a reasonable assurance that the effects of aging will be adequately managed for these components 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 - (rubber degradation of hand valve linings; rubber degradation and radiation damage of hand valve diaphragms) - Materials and Environment

All of the subcomponents included within this group are composed of elastomers. Table 5.18-5 presents a summary of the subcomponents and the associated materials. [Reference 4, Attachments 4 and 5 for each device type (Attachment 4 identifies the materials for each subcomponent, and Attachment 5 identifies the susceptible subcomponents)]

Table 5.18-5

GROUP 2 SUBCOMPONENTS AND MATERIALS

Device Type	Subcomponents and Materials
VALVE	body with rubber liner and seat (for rubber-lined carbon steel valves) diaphragm (for stainless steel diaphragm valves) ethylene propylene terpolymer

The environment for these devices is controlled-chemistry borated water, with approximately 2500 ppm boron. In addition, the diaphragm valves are exposed to an external environment consisting of the Auxiliary Building atmosphere (see the Group 1 discussion for specifications). [Reference 4, Attachment 3s] Radioactive material accumulating in the SFPCS demineralizer vessel during normal plant operations results in high radiation levels in the vicinity of the diaphragm valves. [Reference 1, Section 11.2.2]

Group 2 - (rubber degradation of hand valve linings; rubber degradation and radiation damage of hand valve diaphragms) - Aging Mechanism Effects

When an elastomer ages, the primary mechanisms involved are scission, crosslinking, and changes associated with the compounding ingredients. Scission is the process of breaking molecular bonds, typically due to ozone attack, ultraviolet light, or radiation. Crosslinking is the process of creating molecular bonds between adjacent long-chain molecules, typically due to radiation, oxygen attack, heat, or curing. Scission results in increased elongation, decreased tensile strength, and decreased modulus; crosslinking has the opposite effects (i.e., decreased elongation, increased tensile strength, and increased modulus). The compounding ingredients used in an elastomer/rubber may be affected by evaporation, leaching, or mutation over their service life. Long-term exposure of rubber to water will result in water absorption and swelling, blistering, hardening, and eventual cracking. When utilized as a protective lining, moisture permeation of the rubber produces blisters beneath the lining and initiates corrosion of the lined surface. [Reference 4, Attachment 7 for Valve]

Exposure to gamma radiation can result in degradation of non-metallic material properties, such as tensile strength, hardness, elongation, and compressibility. Material susceptibility is dependent upon strength of the radiation field, duration of exposure, and specific material composition. [Reference 4, Attachment 7 for Valve]

The components in this group are composed of elastomers, which are subject to rubber degradation. The valve diaphragms are also subject to the effects of radiation damage. Failure of a valve body liner would result in exposure of the valve body to the process fluid, which would result in corrosion and reduced wall thickness. Failure of a diaphragm or valve seat would also result in leakage. In either case, the pressure boundary function would eventually be compromised.

Group 2 - (rubber degradation of hand valve linings; rubber degradation and radiation damage of hand valve diaphragms) - Methods to Manage Aging Effects

Mitigation: The degradation of elastomer liners and diaphragms is related solely to time and the environment, and additional shielding of the valve diaphragms from the highly radioactive fluids in the SFPCS demineralizer is impractical. [Reference 4, Attachment 6 for diaphragm valves (Code B)] Therefore, there are no reasonable methods of mitigating the effects of these ARDMs for the subject subcomponents.

Discovery: These subcomponents can be inspected and/or tested as the opportunity arises in future valve seat replacements or other maintenance.

Group 2 - (rubber degradation of hand valve linings; rubber degradation and radiation damage of hand valve diaphragms) - Aging Management Program(s)

Mitigation: There are no programs credited with mitigating the effects of these ARDMs for the subject subcomponents.

Discovery: An ARDI Program, as described in the BGE IPA Methodology, will be implemented to address rubber degradation of the elastomers used in the linings and diaphragms for these valves, as well as radiation damage to the elastomers used in the valve diaphragms. The ARDI Program will include the following elements:

- Identification of the specific valves to be inspected;
- Specification and use of appropriate inspection techniques;
- Methods for interpretation of examination results;
- Requirements for reporting of results and corrective actions if aging concerns are identified;
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation; and
- Methods for resolution of adverse examination findings, including consideration of all design loading conditions required by the CLB and specification of required corrective actions.

The ARDI Program will ensure that aging of elastomers used in valve body linings and diaphragms due to rubber degradation, as well as radiation damage to the elastomers used in the valve diaphragms, is identified and corrected such that the valves will be capable of performing their intended functions under all design conditions required by the CLB.

Group 2 - (rubber degradation of hand valve linings; rubber degradation and radiation damage of hand valve diaphragms) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to rubber degradation in hand valve linings and diaphragms, and radiation damage in hand valve diaphragms:

- The linings and diaphragms of hand valves contribute to the system pressure boundaries. The diaphragms are themselves part of the pressure boundary; the linings protect the valve bodies which are part of the pressure boundary. The integrity of these valves must be maintained under CLB design conditions.
- These components are composed of elastomers.
- Rubber degradation is a plausible ARDM for this group of components. In addition, radiation damage is plausible for the diaphragms in this group. If unmitigated, these ARDMs could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- A new ARDI Program will address the requirements for the inspection and maintenance of elastomers used in valve body linings and in valve diaphragms.

Therefore, there is reasonable assurance that the effects of aging will be adequately managed for these components 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 3 - (wear of hand valve seats and disks) - Materials and Environment

This group consists solely of cast or forged stainless steel (Type 304/316 or CF-3/CF-8) hand valve seats and disks for SFPCS containment isolation hand valves. [Reference 4, Attachments 4 and 5 for each device type (Attachment 4 identifies the materials for each subcomponent, and Attachment 5 identifies the susceptible subcomponents)]

The environment is the process fluid (i.e., controlled-chemistry borated water, approximately 2500 ppm boron). [Reference 4, Attachment 3]

Group 3 - (wear of hand valve seats and disks) - Aging Mechanism Effects

Wear occurs both in components that experience considerable relative motion, and in components that are held under high loads with no motion for long periods. Additionally, impeded relative motion between two surfaces held in intimate contact for extended periods may result from galling/self-welding. [Reference 4, Attachment 7] The seating surfaces of the containment penetration isolation hand valves may be subject to all of these forms of wear. The effect of seating surface wear is leakage through the seat/disk. Excessive seat leakage could prevent the satisfactory performance of the containment pressure boundary function. [Reference 4, Attachment 6 for containment isolation valves (Code B)]

Group 3 - (wear of hand valve seats and disks) - Methods to Manage Aging Effects

Mitigation: Since the valves in this group are actuated very infrequently, wear of the stainless steel seating surfaces would result principally from galling/self-welding or from being held under high loads with no motion for long periods. Valves which operate infrequently can be actuated to prevent sticking.

Discovery: Wear can be discovered by inspecting and testing the valve device types that are susceptible to this ARDM. In addition, local leak rate testing (LLRT) of the containment isolation valves can provide for detection of leakage that could be the result of wear on valve internals.

Group 3 - (wear of hand valve seats and disks) - Aging Management Program(s)

Mitigation: Since more frequent valve operations are not operationally practical, no programs are credited with mitigating wear.

Discovery: Calvert Cliffs procedures STP M-571E-1 and M-571E-2, which cover LLRT for penetrations 59 and 61, are part of the overall CCNPP Containment Leakage Rate Program. [References 11 and 12] 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, Option B, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." 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 13, Section 6.5.6; References 14 and 15]

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 valves that isolate the containment penetration piping for the SFPCS are included in the scope of this program as part of the leakage testing for containment penetrations 59 and 61. [Reference 13]

The LLRT is performed on a performance-based testing schedule in accordance with Option B of 10 CFR Part 50, Appendix J, as implemented by CCNPP Technical Specifications. [References 13, 14, and 15] Local leak rate testing presently includes the following procedural steps:

- Leak rate monitoring test equipment is connected to the appropriate test point.
- The test volume is pressurized to the LLRT Program test pressure, which 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.
- 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 that 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 containment isolation valve that changes the closing characteristic of the valve, an "as left" test must be performed on the penetration to ensure leakage rates are acceptable.

The corrective actions taken as part of the LLRT Program will ensure that the SFPCS containment isolation valves remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Group 3 - (wear of hand valve seats and disks) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the detection and mitigation of wear in regard to the subject valve parts:

- The SFPCS device types described here act as a pressure-retaining boundary for the Containment, and their integrity must be maintained under CLB design conditions.
- Wear is plausible for the valve device types discussed in the materials and environment section above which could lead to the loss of the pressure-retaining boundary function of the SFPCS.
- The CCNPP LLRT Program performs leakage testing on the SFPCS valves listed for this ARDM, and contains acceptance criteria that ensure corrective actions will be taken such that there is a reasonable assurance that the containment pressure boundary function will be maintained.

Therefore, there is a reasonable assurance that the effects of wear will be managed in order to maintain the intended function for the containment isolation hand valve seats and disks under all design loading conditions required by the CLB during the period of extended operation.

Group 4 - (cavitation erosion, erosion corrosion of pump casings) - Materials and Environment

This group consists solely of the SFPCS pump casings and stuffing box extensions. These are composed of ASTM A-296, GR CA-15 with 12% chrome. [Reference 4, Attachment 4 for Pump] NOTE: ASTM standard A-296 has been replaced by A-743 and A-744.

The external environment for these devices is the Auxiliary Building atmosphere (see the Group 1 discussion for specifications). [Reference 4, Attachment 3 for Pump]

The internal environment for these devices is controlled-chemistry borated water, with approximately 2500 ppm boron. [Reference 4, Attachment 3 for Pump]

Group 4 - (cavitation erosion, erosion corrosion of pump casings) - Aging Mechanism Effects

Erosion is a mechanical action of a fluid and/or particulate matter on a metal surface, without the influence of corrosion. Cavitation erosion is localized material erosion caused by formation and collapse of vapor bubbles in close proximity to a metal surface. It can occur only in the presence of fluid (liquid) flow, and also requires pressure fluctuations which temporarily drop the liquid pressure below the corresponding fluid vapor pressure. Erosion corrosion is characterized by an increased rate of movement between a corrosive fluid and the metal surface. Mechanical wear or abrasion can be involved, characterized by grooves, gullies, waves, holes, and valleys on the metal surface. [Reference 4, Attachment 7 for Pump]

The pump casing has experienced in-service loss of material in the area behind the impeller (stuffing box extension), apparently due to erosion corrosion and/or cavitation erosion. [Reference 4, Attachment 6 for Pump (Code A)]

Group 4 - (cavitation erosion, erosion corrosion of pump casings) - Methods to Manage Aging Effects

Mitigation: This ARDM is an unavoidable consequence of the operation of the pump. There is no practicable mechanism for the mitigation of this effect.

Discovery: The effects of cavitation erosion and erosion corrosion can be evaluated by visual inspection and measurement.

Group 4 - (cavitation erosion, erosion corrosion of pump casings) - Aging Management Program(s)

Mitigation: Since there is no practicable method for mitigating cavitation erosion and erosion corrosion, no mitigation program is credited.

Discovery: Calvert Cliffs' Preventive Maintenance Tasks 00672007 and 00672008, "Inspect #11 (#12) Spent Fuel Pool Cooling Pump," automatically schedule and implement Mechanical Preventive Maintenance Checklist MPM67102, "Inspect Spent Fuel Pool Cooling Pump." This checklist directs disassembly and inspection of the pumps, and is currently performed on each pump approximately every four years. [Reference 16] These preventive maintenance tasks will be modified to implement a new maintenance procedure specific to the SFPCS pumps for disassembly, inspection, and re-assembly. The new procedure will explicitly present inspection requirements and acceptance criteria for discovery of material loss from the SFPCS pump casing that may be caused by cavitation erosion and/or erosion corrosion. [Reference 4, Attachment 10]

Any corrective actions that are required are taken in accordance with the CCNPP Corrective Action Program and will ensure that the components will remain capable of performing their intended functions under all CLB conditions.

Group 4 - (cavitation erosion, erosion corrosion of pump casings) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the detection and mitigation of cavitation erosion and erosion corrosion in the SFPCS pump casings:

- The SFPCS pump casings act as a pressure-retaining boundary, and their integrity must be maintained under CLB design conditions.
- Cavitation erosion and erosion corrosion are plausible for the SFPCS pump casings described in the materials and environment section above, and could lead to the loss of the pressure-retaining boundary function of the SFPCS.
- Preventive Maintenance Tasks 00672007 and 00672008 will be modified to provide for periodic disassembly of the pump casings, with specific requirements to detect the effects of cavitation erosion and erosion corrosion on the SFPCS Pump casings. This ensures that corrective actions will be taken such that there is a reasonable assurance that the pressure boundary function will be maintained.

Therefore, there is a reasonable assurance that the effects of cavitation erosion and erosion corrosion will be managed in order to maintain the intended function of the SFPCS pump casings under all design loading conditions required by the CLB during the period of extended operation.

5.18.3 Conclusion

The aging management programs discussed for the SFPCS are listed in Table 5.18-6. 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 SFPCS 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 5.18-6

AGING MANAGEMENT PROGRAMS FOR THE SFPCS

	Program	Credited For
Existing	BACI Program (MN-3-301)	• Management of boric-acid-induced corrosion in SFPCS Group 1 components
Existing	SRW System Chemistry, Specification and Surveillance (CP-206)	• Management of conditions that could lead to corrosion on the shell side of the SFPCS heat exchangers (included in SFPCS Group 1) • Discovery of evidence of corrosion on the shell side of the SFPCS heat exchangers (included in SFPCS Group 1)
Existing	Containment Penetration Leak Rate Testing (STP-M-571E-1/2)	• Discovery of leakage that could be the result of wear of containment isolation valves in SFPCS Group 3
Modified	SFPCS pump housing inspection (Repetitive Tasks 00672007, 00672008, modified to explicitly present inspection requirements)	• Management of cavitation- and flow-related degradation within the SFPCS pump housings (SFPCS Group 4)
New	ARDI Program	• Management of corrosion on components not included in the BACI Program (SFPCS Group 1) • Management of corrosion and coating damage to filter and demineralizer supports. (SFPCS Group 1) • Management of aging of elastomer-based valve linings and diaphragms (SFPCS Group 2)

5.18.4 References

1. CCNPP Updated Final Safety Analysis Report, Revision 19
2. Letter from Mr. D. K. Davis (NRC) to Mr. A. E. Lundvall, Jr. (BGE), dated January 4, 1978, "Amendment Nos. 27 and 12 to Facility Operating License Nos. DPR-53 and DPR-69 for the Calvert Cliffs Nuclear Power Plant Unit Nos. 1 and 2"
3. Letter from J. W. Johnson (MPR Associates) to J. Makar (BGE), "SFP Cooling System Pipe Failures: Recommended Corrective Actions," August 29, 1990
4. CCNPP Aging Management Review Report: Spent Fuel Pool Cooling System (067), Revision 1
5. CCNPP Drawing 60716, Revision 47, "Spent Fuel Pool Cooling, Pool Fill & Drain Systems"
6. Component Level ITLR Screening Results for the Spent Fuel Pool Cooling System, Revision 1
7. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0
8. CCNPP Procedure MN-3-301, "CCNPP Boric Acid Corrosion Inspection Program," Revision 1 Change 0
9. CCNPP Procedure CP-206, "Specifications and Surveillance Component Cooling/Service Water System," Revision 3
10. CCNPP Procedure MN-3-110, "Inservice Inspection of ASME Section XI Components," Revision 2
11. 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
12. CCNPP Surveillance Test Procedure STP-M-571E-2, "Local Leak Rate Test, Penetrations 15, 16, 18, 38, 59, 60, 61" (Unit 2), Revision 1
13. Letter from Mr. A. W. Dromerick (NRC) to Mr. C. H. Cruse (BGE), "Issuance of Amendments for Calvert Cliffs Nuclear Power Plant, Unit 1(TAC No. M92549) and Unit 2 (TAC No. M92550)," dated December 10, 1996 [Amendment Nos. 217/194]
14. 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors"
15. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated November 26, 1996, "Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318 License Amendment Request: Adoption of 10 CFR Part 50, Appendix J, Option B for Types B and C Testing"
16. CCNPP NUCLEIS Database Repetitive Task 00672007 (00672008), "Inspect #11 (#12) Spent Fuel Pool Cooling Pump"

6.1 Cables

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing Cables. Cables have been evaluated as a "commodity" 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 LRA.

6.1.1 Scoping

6.1.1.1 Commodity Cables Scoping

Cables are associated with equipment in almost every plant system. The CCNPP equipment database does not contain specific equipment connection information for individual cables. Instead, a separate Cable and Raceway System (CRS) database contains information on the CCNPP scheduled cables, their service function (power, control, or instrumentation), their materials, and their routing. Correlation of cable schemes to individual raceways, equipment, and rooms is then possible using the information in the CRS database and design drawings. Due to these methods of documenting information on individual cables and the system non-specific nature of plant cabling, the BGE IPA process does not include cables within any of the system Aging Management Reviews (AMRs), but instead evaluates cables as a separate commodity. [Reference 1, Section 2.1]

Commodity Description/Conceptual Boundaries

Cables are within the scope of license renewal because they support various plant electrical components which are required to perform the functions described in §54.4(a)(1), (2), and (3). In general, cables provide the electrical path between electrical components in order to provide: AC or DC power required for component operation, voltage or current signals for component control functions, and voltage and current signals for instrumentation functions.

The population of cables at CCNPP includes scheduled and unscheduled cables in power, control, and instrumentation service. Scheduled cables are defined as those cables that are maintained as line items in the CCNPP CRS database. Unscheduled cables at CCNPP (i.e., those not in the CRS database) include internal panel wiring, equipment pigtails and terminal wiring, field installed jumpers, and some non-safety-related cabling. Cable insulation material types for CCNPP scheduled cables include: silicone rubber, ethylene propylene rubber (EPR), crosslinked polyethylene (XLPE), crosslinked polyolefin (XLPO), mineral, Kapton, polyvinyl chloride, Teflon, and other miscellaneous insulation types. In addition, CCNPP uses Tefzel insulated wiring as the currently approved safety-related internal wiring in the Main Control Boards. [Reference 1, Section 1.1, Table 1-1, Table 1-3; Reference 2, Pages 4-6, 4-7, 4-8, 4-45, 4-46, 4-47; Reference 3]

The conceptual boundary used to evaluate the CCNPP cables includes all site cables in the CRS database (i.e., all CCNPP scheduled cables). Unscheduled cables are drawn from the same reels of cable used for scheduled cables (except for some internal panel wiring that may be single conductor without jacket), and are installed using the same installation standards and practices. Internal panel wiring at CCNPP is not exposed to high temperatures or high radiation levels; therefore, aging which could affect the functionality of the wiring during the period of extended operation is not considered plausible. Therefore, the results of the evaluation of scheduled cables are applicable to all types of CCNPP cabling that could be subject to plausible aging. [Reference 1, Section 1.1]

Operating Experience

The following historical operating experience is included to provide insight in supporting the aging management demonstrations provided in Section 6.1.2 of this report. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, through documented discussions with currently assigned cognizant CCNPP personnel, and through other sources as indicated below.

Calvert Cliffs cable operating experience includes age-related thermal degradation of cables in the Main Steam Isolation Valve rooms. These cables have been replaced as required through routine maintenance practices. In addition, excess heat was identified as a problem for the emergency diesel generator space heater wiring. This wiring has been replaced with high-temperature wiring. Calvert Cliffs has also experienced vibration induced loosening of some motor-operated valve terminations. This problem was resolved by replacement of the susceptible motor-operated valve terminations with bolted splices. Thermal degradation of terminations for continuously run 4kV pump motors has also been observed at CCNPP. Corrective actions for the 4kV motor terminations has included cutting out the degraded portion of the connecting cable and then re-terminating the cable. The aging management for the 4kV motor terminations is discussed further in Section 6.1.2 of the BGE LRA. [Reference 1, Section 4.4]

The NRC performed an Electrical Distribution System Functional Inspection at CCNPP in 1992. The inspection was performed to determine if the Electrical Distribution System was capable of performing its intended safety functions as designed, installed, and configured. Although the Electrical Distribution System Functional Inspection did not focus on cables, they are an integral part of the Electrical Distribution System. The NRC concluded that the CCNPP Electrical Distribution System is capable of performing its intended safety functions. [Reference 4]

There is a vast wealth of industry operating experience related to performance of electrical cables and cable terminations in nuclear power plants. Much of this information can be found in: NRC Information Notices, Bulletins, Circulars, Generic Letters, and Licensee Event Reports; the Institute for Nuclear Power Operations Nuclear Plant Reliability Data System; industry reports; and plant surveys. These sources of information were reviewed by Sandia National Laboratories as part of the preparation of Reference 2. Some of the generic observations/conclusions made in Reference 2 regarding historical performance of electrical cables and terminations include: [Reference 2, Pages 3-53 through 3-55]

- The number of cable and termination failures during normal operating conditions (all voltage classes) that have occurred throughout the industry is extremely low in proportion to the amount of cables and terminations.
- Thermal aging and embrittlement of insulation is one of the most significant aging mechanisms for low-voltage cable. Thermal aging results from ambient temperature effects, ohmic heating (i.e., cable conductor internal heating), and localized heating effects (e.g., hot spots due to proximity to hot piping).

An industry report on the aging of cables concluded that cables are highly reliable under normal plant operating conditions, with no evidence that there is a significant increase in the failure rate due to aging. The most safety-significant aging effects are those that have the potential to lead to common cause failures during accident conditions. Some of the failure mechanisms that might occur include: [Reference 5, Pages 1, 41; Reference 6]

- Degradation of cable jacket and/or insulation that could create electrical paths to adjacent conductors (including other conductors in the same multi-conductor cable) or ground, resulting in electrical failure of the cable; and
- Degradation of the cable insulation that reduces the insulation resistance (IR), which could be of concern for some instrumentation cables.

Scoped Structures and Components and Their Intended Functions

The conceptual boundary (i.e., all cables in the CRS database) includes cables which are covered by the CCNPP Environmental Qualification (EQ) Program (10 CFR 50.49), as well as non-EQ cables. As discussed in Section 7.2.1.1 of the CCNPP IPA Methodology, structures and components subject to the EQ Program are associated with Time-Limited Aging Analyses that are evaluated separately. The EQ cables are evaluated in Section 6.3 of the BGE LRA.

Cables which satisfy either of the following conditions are considered to be within the scope of license renewal: [Reference 1, Section 2.3]

- Any cable associated with a safety-related load or a load whose failure could prevent operation of a safety function; and
- Any cable associated with equipment relied upon for response to the regulated events in §54.4(a)(3) if the plant-specific evaluation for these events requires such cables to supply power to the load as part of the event response. For example, cables supplying power to a load which is turned off during the response to a station blackout would not be included within the scope of license renewal. Cables providing diverse scram or diverse turbine trip signals in accordance with the anticipated transients without scram rule would be within the scope of license renewal.

For the purposes of this evaluation, all scheduled cables were initially assumed to be within the scope of license renewal without prescreening. If a set of non-EQ cables otherwise subject to AMR were identified for which an age-related degradation mechanism (ARDM) was determined to be plausible, then in-scope for license renewal screening was sometimes employed to determine if further evaluation was necessary. Cables were determined to be not within the scope of license renewal and excluded from further evaluation if they met any of the following conditions: [Reference 1, Section 1.1, Page C-38]

- Cable schemes associated with systems having no license renewal functions;
- Cable schemes which are non-safety-related and are associated with systems which do not support any non-safety-related license renewal functions;
- Cable schemes for annunciator circuits which do not support any events regulated under the License Renewal Rule [i.e., 10 CFR 54.5(a)(3)];
- Cable schemes which have been spared (i.e., no longer perform any function); or

- Cable schemes which do not support a license renewal function as determined by specific examination of connection drawings and schematics.

The non-EQ cable types within the scope of license renewal for the cables evaluation are indicated in Table 6.1-1. [Reference 1, Table 1-3; Table 3-6]

The design basis and associated loading conditions for the CCNPP electrical systems (which include components such as cables) are described in UFSAR Section 8.1.1. All cables vital to plant safety are designated as Class 1E so that their integrity is not impaired by the Safe Shutdown Earthquake, high winds, or disturbances in the external electrical system. [Reference 7, Section 8.1.1]

TABLE 6.1-1

NON-EQ CABLE TYPES WITHIN THE SCOPE OF LICENSE RENEWAL FOR THE COMMODITY CABLES EVALUATION

Cable Insulation Material	Power Service Function	Control Service Function	Instrumentation Service Function
Silicone Rubber	4500	7100	11500
EPR/XLPE/XLPO	1400	500	1700
Mineral	100	0	20
Kapton	0	0	20
Miscellaneous	0	2	4

= Approximate number of CCNPP cable schemes

Notes for Table 6.1-1:

1. All polyvinyl chloride and Teflon insulated scheduled cables are associated with cable schemes which do not support any license renewal functions. [Reference 1, Table 1-1]
2. The number of cable schemes shown as within the scope of license renewal in each category is approximate to show the mix of non-EQ cables at CCNPP. Specific numbers of cables are available. [Reference 1, Table 1-3; Table 3-6]
3. The miscellaneous insulation cables shown in the above table consist of (2) vendor supplied turbine supervisory (control) cables of unknown insulation material and (4) fiber optic (instrumentation) cables. These cables are not subjected to high temperatures or radiation which would result in plausible aging. [Reference 1, Section 3.4]
4. All of the Kapton insulated cables are used in fire detection service in the containment. The function of these cables is to provide early detection of elevated temperatures in the cable trays. These cables are part of the "Protectowire" instrumentation system. The Protectowire cables are installed around or on top of the cable trays, and are designed such that the cable insulation melts and the conductors short-circuit if the cable tray temperature at a specific location rises to approximately 280°F. The short-circuit decreases the resistance in the circuit proportional to the

length of wire between the point of the short and the power supply (i.e., can determine the fire location). Degradation of these cables could potentially result in generation of false fire alarms. The function of the Kapton cables is designated as "active" since the cables must change state (i.e., insulation melting and conductors shorting) in order to perform their function. As discussed in Section 5.1 of the CCNPP IPA Methodology, structures and components with active functions are not subject to AMR. [Reference 8]

5. Silicone rubber and mineral insulated cables are not subject to plausible aging. Mineral insulated cables can be degraded by exposure to moisture. However, moisture exposure is a design consideration that is addressed by Raychem sleeving of the termination where deemed necessary. For example, the mineral insulated cabling to the CCNPP Unit 1 pressurizer back-up heaters is sleeved at the pressurizer. Non-EQ cabling is not required to function when exposed to harsh environments induced by design basis accidents. [Reference 1, Sections 3.1.6 and 3.1.7.1]

Passive Intended Functions / Cables Requiring AMR

As discussed above, cables are within the scope of license renewal because they support various plant electrical components which are required to perform the functions described in §54.4(a)(1), (2), and (3). The scoping process for cables did not evaluate specific passive versus active functions for each of the cables within the scope of license renewal. However, the following general passive functions may apply to cables, depending on their service: [Reference 1, Page 1-8]

- Maintenance of dielectric strength - (applies to most power and control cables); and
- Maintenance of adequate IR (for non-coax) or impedance (for coax) - (applies to some instrumentation cables).

Section 7.2.1.2 of the CCNPP IPA Methodology states that cables are passive and long-lived. In addition, Section 5.1.1 of the methodology states that the passive function "prevent or isolate faults in an electrical circuit when such protection or isolation does not involve moving parts or a change in properties or configuration" applies to cable insulation (this function relates directly to the maintenance of dielectric strength). Therefore, all cables within the scope of license renewal (as shown in Table 6.1-1) are also subject to an AMR (except for the Kapton insulated cables discussed in Table 6.1-1, Note 4, which have an active function). [Reference 1, Table 1-3]

6.1.2 Aging Management

The list of potential ARDMs for cables is given in Table 6.1-2, with plausible ARDMs identified by a check mark (✓) in the appropriate column. For efficiency in presenting the results of these evaluations in this report, cable types/ARDM combinations are grouped where there are similar characteristics and the discussion is applicable to all cables within that group. Exceptions are noted where appropriate. Table 6.1-2 also identifies the group assigned to each cable type/ARDM combination. The following groups have been selected: [Reference 1, Section 3.1, Table 4-2]

Group 1 - Includes thermal aging for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing.

Group 2 - Includes thermal aging for EPR/XLPE non-EQ cables in power service, which are routed with maintained spacing.

Group 3 - Includes synergistic radiative and thermal aging for EPR/XLPE non-EQ cables in power service, which are routed inside containment.

Group 4 - Includes thermal aging for EPR non-EQ cables in power service, associated with the Saltwater System and Service Water System 4kV pump motor terminations.

Group 5 - Includes IR reduction for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable IR.

Group 6 - Includes treeing for EPR non-EQ cables in 4kV power service. As explained in the Group 6 Aging Management section below, treeing is a form of voltage-induced degradation that causes hollow microchannels in the cable insulation to grow in a tree-like pattern.

TABLE 6.1-2

POTENTIAL AND PLAUSIBLE ARDMs FOR CABLES

Potential ARDMs	Cable Insulation Materials							Not Plausible
	Silicone Rubber	EPR	XLPE	XLPO	Mineral	Kapton	Miscellaneous	
Mechanical Stress and Installation Damage								x
Electrical Stress								x
Treeing		✓ (6)						
Thermal Aging		✓ (1, 2, 4)	✓ (1, 2)	✓ (1)				
Synergistic Thermal and Radiative Aging (Note 2)		✓ (3)	✓ (3)					
Kapton Specific Aging								x
IR Reduction (Notes 1, 2)		✓ (5)	✓ (5)	✓ (5)				

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

Group	Group Characteristics
1	Power and Control - routed without maintained spacing
2	Power - routed with maintained spacing
3	Power - inside containment
4	Power - associated with the Saltwater System and Service Water System 4kV pump motor terminations
5	Instrumentation - sensitive to reduction in cable IR
6	Power - 4kV service

Notes
1. Insulation Resistance Reduction is actually an aging effect rather than an ARDM.
2. Radiation stress is included in synergistic thermal and radiative aging and IR reduction.

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.

Group 1 (Thermal aging for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing) - Materials and Environment

Group 1 consists of power and control cables with EPR, XLPE, or XLPO insulation. The power and control cables at CCNPP have an insulation temperature rating of 90°C (194°F) or higher. [Reference 1, Page 2-2]

The highest (non-accident) ambient design temperature of any area in the plant that contains cabling is in the Main Steam Penetration Room. This room has a maximum design ambient temperature of 160°F. [Reference 1, Page 2-1]

The Group 1 cables are also subject to ohmic heating, which can cause the cables to be exposed to a temperature environment hotter than the ambient temperature. Ohmic heating of a cable conductor is proportional to the square of the current carried by the conductor. Ohmic heating may be significant for energized power cables since they are designed to carry large currents. Ohmic heating is negligible for control cables since they generally carry small currents. The Group 1 cables are routed without maintained spacing between individual cables within a cable tray. This installation method is also known as "random-lay" or "random-fill." Cables installed in this manner may be tightly packed together, thus not allowing natural air flow around the cables to dissipate heat. Heat generated by an energized power cable conductor can transfer through the insulation of the energized cable and affect other cables (including the control cables) routed within the same raceway. Calvert Cliffs' cable installation practices (based on Insulated Power Cable Engineers Association [IPCEA] standards), include cable ampacity derating factors designed to limit cable operating temperatures to the cable insulation temperature rating of 90°C (194°F). The ampacity derating factors used at CCNPP are based on exposure of in-service cables to a constant ambient temperature of 40°C (104°F). Since the maximum design ambient temperature is 160°F (as discussed above), this raises the possibility that some cable operating temperatures may sometimes exceed the insulation temperature rating of 90°C (194°F). Baltimore Gas and Electric Company has developed a temperature survey program to establish an upper bound on the operating service temperatures for the Group 1 cables. These temperature surveys will determine if the insulation temperature rating is being exceeded (details on the temperature survey program are provided in the "Aging Management Program" section below). [Reference 1, Pages 1-7, 2-2, 3-12, B-15, B-21; Reference 9, Page 962; References 10 through 15]

In addition to the ambient and ohmic heating effects, the temperature environment for cables may potentially be affected by localized heating effects. Localized heating effects could be experienced by cables in close proximity to sources of heat, such as hot piping. [Reference 2, Pages 4-8, 4-9]

Group 1 (Thermal aging for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing) - Aging Mechanism Effects

The Group 1 cables may be subject to thermal stress resulting from ambient, ohmic, and localized heating effects as discussed above. Elevated temperature produces some degree of aging in most organic materials. Organic subcomponents typically used in the construction of power and control cables include the outer cable jacket and the conductor insulation. Thermal aging produces changes in the organic material properties, including reduced elongation, variations in tensile strength, loss of antioxidant, and loss of plasticizer. Visual indications of thermal aging may include embrittlement, cracking, discoloration, and melting of the jacket and insulation. The potential effects to the jacket due to these degradations include reduced mechanical integrity and protection from the environment. The potential effects to the insulation due to these degradations include reduced IR, noise, changes in flammability, and electrical failure. [Reference 2, Section 4.1.1, Table 4-1, Table 4-13; Reference 16, Page 3-2]

Jackets are intended to provide physical protection to the cable insulation during installation and use. The jacket provides no necessary electrical isolation function for power and control service. Therefore, degradation of the jacket is not considered significant in maintaining the passive intended function to prevent or isolate faults in an electrical circuit. Nuclear Regulatory Commission Information Notice 92-81 describes a potential aging concern for electrical cables with bonded Hypalon jackets. Environmental qualification testing for these type of cables resulted in jacket cracking that propagated through the EPR conductor insulation. However, the cracks did not prevent the cables from passing an insulation resistance test that was conducted in a dry environment (cables only failed after being subjected to a loss-of-coolant accident test). Therefore, the issues presented in Information Notice 92-81 are not considered to be an aging concern for non-EQ cables. Hypalon jackets bonded to underlying EPR insulation is in limited use at CCNPP. [Reference 16, Pages 3-8, 3-9, 4-15; Reference 17]

Cable insulation provides the primary electrical isolation between the conductor and the external environment. The electrical isolation provided by the insulation is important for power, control, and instrumentation service. Cable insulation is a dielectric material (i.e., a nonconductor of electricity). A critical characteristic of the insulation that must be maintained in order to provide its isolation function is its dielectric strength (i.e., its ability to withstand electric stress before breakdown or electrical discharge through the insulation occurs). The higher the dielectric strength of a material, the better insulator it is. Therefore, degradation of the insulation (which can result in the electrical failure of the insulation) is considered significant in maintaining the passive intended function to prevent or isolate faults in an electrical circuit. [Reference 1, Pages 1-8, 1-9; Reference 16, Pages 3-6, 3-8; Reference 18, Page 9; Reference 19, Page 460]

For each cable insulation material type, CCNPP has determined a 60-year service limiting temperature. The service limiting temperature is the maximum continuous service temperature for which cable life will be not less than 60 years. The 60-year service limiting temperature was determined based on Arrhenius analysis of database information for cable insulation materials using the methodology of IEEE Standard 101-1987, “IEEE Guide for the Statistical Analysis of Thermal Life Data.” The database (“System 1000” database - currently part of the Equipment Qualification Data Bank managed by NUS Information Services, Inc.) contains information on time to failure versus temperature for many organic materials. The calculation of the 60-year service limiting temperatures included the selection of a data set from System 1000 for each insulation material for insulation properties associated with dielectric failure or retention of elongation. When System 1000 contained more than one set of data, then a conservative selection was made. [Reference 1, Pages 3-11, B-18, B-19]

The Arrhenius model relates the rate of degradation (reaction) to temperature through a mathematical function that uses the materials' activation energy. The activation energy is a measure of the energy required to produce a given type of endothermic reaction within the material. This parameter can be correlated to the rate of degradation; that is, materials with higher activation energies will thermally degrade at a slower rate than those with lower activation energies. [Reference 2, Section 4.1.1.1.2]

For XLPE, BGE used the lowest activation energy associated with the dielectric failure data in System 1000. For XLPO, an activation energy equal to half the difference between the lowest and median values was selected from the available (11) data sets. The data sets were based on 100% retention of elongation. This characteristic provides a high level of margin to dielectric failure since changes in mechanical properties of cable insulation material precede changes in electrical characteristics. Therefore, the selection of a low, but not the lowest, activation energy was considered justifiable. For EPR, the lowest activation energy in the available (20) data sets was 1.05eV. An activation energy of 1.06eV was chosen since this corresponds to Kerite (EPR) material used at CCNPP. The EPR data sets were based on 20% retention of elongation. Similar to the discussion for XLPO above, for EPR the selection of a low, but not the lowest, activation energy was considered justifiable since changes in mechanical properties precede changes in electrical properties. [Reference 1, Page 3-11]

Using the process and data described above, the service limiting temperatures were determined to be 184°F for EPR, 182°F for XLPE, and 189°F for XLPO insulation. [Reference 1, Page 3-11]

If the cable service temperature (i.e., actual operating temperature) is less than the 60-year service limiting temperature for the insulating material, then thermal aging is not plausible (i.e., aging will not progress to functional failure). If the cable service temperature does or might exceed the 60-year service limiting temperature, then thermal aging is considered plausible and the insulation could be subject to significant dielectric degradation during the period of extended operation. [Reference 1, Page 2-2]

A margin of 10°C (18°F) is used when these 60-year service limiting temperatures are applied as an "aging management required" screening criteria. For example, if the service temperature for a XLPE insulated cable exceeds 164°F (i.e., service limiting temperature of 182°F minus the 18°F margin), then aging management is required. The selection of a conservative data set and the use of the 10°C margin introduces sufficient robustness in the screening process to ensure that no cables needing aging management are excluded. [Reference 1, Page 4-3]

Since thermal aging can result in breakdown of the dielectric strength of the insulation, this aging mechanism, if unmanaged, could eventually lead to loss of the passive intended function to prevent or isolate faults in an electrical circuit under current licensing basis (CLB) conditions. Therefore, thermal aging was determined to be a plausible ARDM for which aging effects must be managed for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing, and whose service temperature does or might exceed the 60-year service limiting temperature for the respective insulation material type. [Reference 1, Table 4-2]

Group 1 (Thermal aging for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing) - Methods to Manage Aging

Mitigation: Since the degradation of the Group 1 cables is due to the effects of thermal stress resulting from ambient, ohmic, and localized heating effects, decreasing the service temperatures experienced by the cables could mitigate the thermal aging effects. Decreasing the service temperatures would slow the degradation and could be accomplished by reducing ambient temperatures (e.g., increasing heating, ventilation, and air conditioning system(s) cooling capacity), rerouting the cables through lower ambient temperature areas, reducing the amount and/or time current is carried through the power cables (e.g., replacement of an existing motor with another motor having lower load requirements, or changing procedures to operate a pump for less time), rerouting the cables in trays with maintained spacing, and rerouting the cables away from local heat sources. Of the above methods, only the various cable rerouting options are considered feasible methods of mitigating the thermal aging effects.

Discovery: Since thermal aging was only determined to be plausible for the Group 1 cables whose service temperature does or might exceed the 60-year service limiting temperature for the respective insulation material type, measurement of actual operating service temperatures in the cable raceways could be used to discover if any of the service limiting temperatures are being exceeded. Alternatively, if the temperature rise due to ohmic heating can be calculated, then a calculated cable service temperature (based on a calculated ambient temperature limit and the calculated ohmic heating effect) for a 60-year cable life can be used in lieu of taking actual temperature measurements. The calculated ambient temperature limit would be equal to the service limiting temperature for the respective insulation material minus the temperature increase due to ohmic heating. The calculated cable service temperature would be equal to the ambient temperature limit plus the ohmic heating effect. However, an analytical assessment of the ohmic heat rise for the random-lay trays at CCNPP has not proven to be practical. Therefore, only actual temperature measurements are a feasible method to discover if any of the service limiting temperatures are being exceeded. [Reference 1, Pages 3-12, B-15, B-21]

If any of the service limiting temperatures are being exceeded (as discovered by measurement of the actual operating service temperatures), additional activities (e.g., analysis, monitoring, testing) would need to be performed in order to assess the thermal aging that does occur. These activities would ensure that cables are replaced prior to degradation of the insulation that could compromise the passive intended function (i.e., prevent or isolate faults in an electrical circuit). [Reference 1, Pages 4-1, F-2]

Group 1 (Thermal aging for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing) - Aging Management Program(s)

Mitigation: To mitigate the effects of thermal aging, the Group 1 cables can be rerouted, as deemed appropriate, as a result of the corrective actions taken per the Age-Related Degradation Inspection (ARDI) program described below.

Discovery: To manage the effects of thermal aging for the Group 1 cables, a new plant program will be developed to provide monitoring, testing, or analysis (or an appropriate combination thereof). The program is considered an ARDI program as defined in the CCNPP IPA Methodology (Section 2.0 of the BGE LRA). The purpose of the Cables ARDI program is to determine if plausible aging could potentially progress to cable failure such that ongoing aging management is required to be implemented. [Reference 1, Pages 4-1, 4-2, F-2]

The Cables ARDI program will include the elements listed below. Some of the elements have already been completed and are so noted. [Reference 1, Pages 4-1, 4-2, F-2]

- Ranking all 480V power service cable trays by using a heat transfer model which takes into consideration the circuit loads, ambient temperatures, cable mass, fire barriers, and tray covers. (Completed)
- Identifying cable trays near significant external radiant heat sources (i.e., localized heating effects) such as hot pipes. (Completed)
- Analyzing the results of the tray ranking and external radiant heat sources and selecting thermal survey locations. (Completed)
- Performing a thermal survey of candidate "hot" tray locations and external radiant heat sources to find "bounding" locations for long-term temperature monitoring. (Partially Completed)
- Installing temperature probes at "bounding" locations. (Partially Completed)
- Collecting temperature data over sufficient time to capture peak cable service temperatures (i.e., determine upper bound of service temperatures for the Group 1 cables).
- Comparing peak cable service temperatures against the 60-year service limiting temperature for the applicable insulation materials. The 60-year service limiting temperatures are considered the acceptance criteria for this ARDI.
- If any of the service limiting temperatures are exceeded (i.e., acceptance criteria not met), generate an Issue Report (per Reference 20) and determine the appropriate corrective action (i.e., ongoing aging management). Corrective action may include one or a combination of the following items:
  1. Rerouting cable such that service limiting temperatures will not be exceeded;
  2. Analysis to determine a cable replacement date;
  3. Visual or physical inspection (for detection of embrittlement, cracking, discoloration, and melting);
  4. Pulling cable samples for testing of chemical, mechanical, or electrical properties (e.g., elongation, dielectric strength) and subsequent replacement and repair of the tested cable sections;
  5. Cable condition monitoring (i.e., in-situ non-destructive testing); or
  6. Replacement of cable.

Items 3, 4, and 5 above will include acceptance criteria to trigger cable replacement prior to degradation that would prevent the cable from performing its intended function. If any of the acceptance criteria are not met, an Issue Report would be generated, per Reference 20, to document the degraded condition and the required corrective actions (i.e., cable replacement).

Cable condition monitoring is presently considered an optional approach to ongoing cable management. However, it does not have industry consensus or regulatory acceptance as a means of establishing cable residual life. Baltimore Gas and Electric Company considers condition monitoring to be a viable alternative and will monitor research in this area through Electric Power Research Institute (EPRI) and Nuclear Energy Institute (NEI) to develop this aspect of the aging management program accordingly.

The corrective actions taken as a result of the Cables ARDI program will ensure that the Group 1 cables remain capable of performing their intended function to prevent or isolate faults in an electrical circuit under all CLB conditions.

Group 1 (Thermal aging for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to thermal aging for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing:

- The Group 1 cables provide the passive intended function to prevent or isolate faults in an electrical circuit under CLB conditions.
- Thermal aging is plausible for the Group 1 cables that are subject to service temperatures greater than their service limiting temperatures, causing a breakdown of the cable insulation dielectric strength, which could eventually lead to electrical failure of the insulation and loss of the function to prevent or isolate faults in an electrical circuit under CLB conditions.
- The CCNPP Cables ARDI program will determine if plausible aging could potentially progress to cable failure, such that ongoing aging management is required to be implemented. The program will also contain acceptance criteria that ensure corrective actions will be taken, such that there is reasonable assurance that the prevention or isolation of faults in an electrical circuit function will be maintained.

Therefore, there is reasonable assurance that the effects of thermal aging will be managed in order to maintain the function to prevent or isolate faults in an electrical circuit as provided by the Group 1 cables, consistent with the CLB, during the period of extended operation.

Group 2 (Thermal aging for EPR/XLPE non-EQ cables in power service, which are routed with maintained spacing) - Materials and Environment

Group 2 consists of power cables with EPR or XLPE insulation. The power cables at CCNPP have an insulation temperature rating of 90°C (194°F) or higher. [Reference 1, Page 2-2]

The highest (non-accident) ambient design temperature of any area in the plant that contains cabling is in the Main Steam Penetration Room. This room has a maximum design ambient temperature of 160°F. [Reference 1, Page 2-1]

The Group 2 cables are also subject to ohmic heating effects, which can cause the cables to be exposed to a temperature environment hotter than the ambient temperature. Ohmic heating of a cable conductor is proportional to the square of the current carried by the conductor. Ohmic heating may be significant for energized power cables since they are designed to carry large currents. The Group 2 cables are routed with maintained spacing between individual cables within a cable tray. Cables installed in this manner are separated by a specified percentage of cable diameters, thus allowing natural air flow around the cables to dissipate the heat. Heat generated by an energized power cable conductor can transfer through the insulation of the energized cable and affect other cables routed within the same raceway. Calvert Cliffs' cable installation practices (based on IPCEA standards) include cable ampacity derating factors designed to limit cable operating temperatures to the cable insulation temperature rating of 90°C (194°F). The ampacity derating factors used at CCNPP are based on exposure of in-service cables to a constant ambient temperature of 40°C (104°F). Since the maximum design ambient temperature is 160°F (as discussed above), this raises the possibility that some cable operating temperatures may sometimes exceed the insulation temperature rating of 90°C (194°F). However, BGE has performed analysis to verify that none of the operating temperatures for the Group 2 cables exceed the 90°C insulation rating. [Reference 1, Pages 1-7, 2-2, 3-12, B-15, B-21; Reference 9, Page 962; References 10 through 15]

In addition to the ambient and ohmic heating effects, the temperature environment for cables may potentially be affected by localized heating effects. Localized heating effects could be experienced by cables in close proximity to sources of heat such as hot piping. [Reference 2, Pages 4-8, 4-9]

Group 2 (Thermal aging for EPR/XLPE non-EQ cables in power service, which are routed with maintained spacing) - Aging Mechanism Effects

The Group 2 cables may be subject to thermal stress resulting from ambient, ohmic, and localized heating effects as discussed above. The aging mechanisms, resultant aging effects, and the plausibility concerns for the Group 2 cables are the same as for the Group 1 cables. Therefore, degradation of the cable insulation dielectric strength (which can result in the electrical failure of the insulation) is considered significant in maintaining the passive intended function to prevent or isolate faults in an electrical circuit. [Reference 1, Pages 1-8, 1-9]

As discussed in the Group 1 Aging Mechanism Effects section, the 60-year service limiting temperatures were determined to be 184°F for EPR and 182°F for XLPE insulation. If the cable service temperature (i.e., actual operating temperature) is less than the 60-year service limiting temperature for the insulating material, then thermal aging is not plausible (i.e., aging will not progress to functional failure). If the cable service temperature does or might exceed the 60-year service limiting temperature, then thermal aging is considered plausible and the insulation could be subject to significant dielectric degradation during the period of extended operation. [Reference 1, Pages vii, 2-2, 3-11]

Since thermal aging can result in breakdown of the dielectric strength of the insulation, this aging mechanism, if unmanaged, could eventually lead to loss of the passive intended function to prevent or isolate faults in an electrical circuit under CLB conditions. Therefore, thermal aging was determined to be a plausible ARDM for which aging effects must be managed for EPR/XLPE non-EQ cables in power service, which are routed with maintained spacing, and whose service temperature does or might exceed the 60-year service limiting temperature for the respective insulation material type. [Reference 1, Table 4-2]

Group 2 (Thermal aging for EPR/XLPE non-EQ cables in power service, which are routed with maintained spacing) - Methods to Manage Aging

Mitigation: The feasible methods of mitigating thermal aging for the Group 2 cables are the same as discussed above for the Group 1 cables (i.e., rerouting of cables such that service temperatures are decreased).

Discovery: Since thermal aging was only determined to be plausible for the Group 2 cables whose service temperature does or might exceed the 60-year service limiting temperature for the respective insulation material type, analysis of the cable routing (including calculation of cable operating service temperatures in the cable raceways) could be used to discover if any of the service limiting temperatures are being exceeded. The cable service temperature could be calculated as described in the Group 1, Methods to Manage Aging section above. [Reference 1, Pages 4-2, B-15, B-21]

If any of the service limiting temperatures are being exceeded (as discovered by the cable routing analysis), additional activities (e.g., analysis, monitoring, testing) would need to be performed in order to assess the thermal aging that does occur. These activities would ensure that cables are replaced prior to degradation of the insulation that could compromise the passive intended function (i.e., prevent or isolate faults in an electrical circuit). [Reference 1, Pages 4-1, F-2]

Group 2 (Thermal aging for EPR/XLPE non-EQ cables in power service, which are routed with maintained spacing) - Aging Management Program(s)

Mitigation: To mitigate the effects of thermal aging, the Group 2 cables can be rerouted, as deemed appropriate, as a result of the corrective actions taken per the ARDI program described below.

Discovery: To manage the effects of thermal aging for the Group 2 cables, a new plant program will be developed to provide monitoring, testing, or analysis (or an appropriate combination thereof). The program is considered an ARDI program as defined in the CCNPP IPA Methodology (Section 2.0 of the BGE LRA). The purpose of the Cables ARDI program is to determine if plausible aging could potentially progress to cable failure such that ongoing aging management is required to be implemented. [Reference 1, Pages 4-1, F-2]

The Cables ARDI program will include the following elements: [Reference 1, Pages 4-1, B-22, F-2]

- Performing a routing and ohmic heat rise analysis in order to determine the cable service temperatures. The routing analysis determines the maximum bulk ambient temperature to which the cable is exposed. The ohmic heat rise is calculated using the computational method established by Reference 1 to IPCEA Standard P-46-426.
- Comparing calculated cable service temperatures against the 60-year service limiting temperature for the applicable insulation materials. The 60-year service limiting temperatures are considered the acceptance criteria for this ARDI.
- If any of the service limiting temperatures are exceeded (i.e., acceptance criteria not met), generate an Issue Report (per Reference 20) and determine the appropriate corrective action (i.e., ongoing aging management). Corrective action is the same as for Group 1 and may include one or a combination of the following items:

1. Rerouting cable such that service limiting temperatures will not be exceeded;
2. Analysis to determine a cable replacement date;
3. Visual or physical inspection (for detection of embrittlement, cracking, discoloration, and melting);
4. Pulling cable samples for testing of chemical, mechanical, or electrical properties (e.g., Elongation, dielectric strength) and subsequent replacement and repair of the tested cable sections;
5. Cable condition monitoring (i.e., In-situ non-destructive testing); and
6. Replacement of cable.

Items 3, 4, and 5 above will include acceptance criteria to trigger cable replacement prior to degradation that would prevent the cable from performing its intended function. If any of the acceptance criteria are not met, an Issue Report would be generated, per Reference 20, to document the degraded condition and the required corrective actions (i.e., cable replacement).

Cable condition monitoring is presently considered an optional approach to ongoing cable management. However, it does not have industry consensus or regulatory acceptance as a means of establishing cable residual life. Baltimore Gas and Electric Company considers condition monitoring to be a viable alternative and will monitor research in this area through EPRI and NEI to develop this aspect of the aging management program accordingly.

The corrective actions taken as a result of the Cables ARDI program will ensure that the Group 2 cables remain capable of performing their intended function to prevent or isolate faults in an electrical circuit under all CLB conditions.

Group 2 (Thermal aging for EPR/XLPE non-EQ cables in power service, which are routed with maintained spacing) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to thermal aging for EPR/XLPE non-EQ cables in power service, which are routed with maintained spacing:

- The Group 2 cables provide the passive intended function to prevent or isolate faults in an electrical circuit under CLB conditions.
- Thermal aging is plausible for the Group 2 cables that are subject to service temperatures greater than their service limiting temperatures, causing a breakdown of the cable insulation dielectric strength, which could eventually lead to electrical failure of the insulation and loss of the function to prevent or isolate faults in an electrical circuit under CLB conditions.
- The CCNPP Cables ARDI program will determine if plausible aging could potentially progress to cable failure, such that ongoing aging management is required to be implemented. The program will also contain acceptance criteria that ensure corrective actions will be taken, such that there is reasonable assurance that the prevention or isolation of faults in an electrical circuit function will be maintained.

Therefore, there is reasonable assurance that the effects of thermal aging will be managed in order to maintain the function to prevent or isolate faults in an electrical circuit as provided by the Group 2 cables, consistent with the CLB, during the period of extended operation.

Group 3 (Synergistic radiative and thermal aging for EPR/XLPE non-EQ cables in power service, which are routed inside containment) - Materials and Environment

Group 3 consists of power cables inside containment with EPR or XLPE insulation. The power cables at CCNPP have an insulation temperature rating of 90°C (194°F) or higher. [Reference 1, Page 2-2]

The maximum normal ambient temperature in the containment is 120°F. The normal general background radiation level is 1 rad/hour (although may it be higher in some locations). [Reference 21, Section 5.4.A]

The Group 3 cables may also be subject to ohmic heating and localized heating effects as previously discussed in Groups 1 and 2. [Reference 1, Pages 1-7, 2-2, 3-12, B-15, B-21; Reference 2, Pages 4-8, 4-9]

Group 3 (Synergistic radiative and thermal aging for EPR/XLPE non-EQ cables in power service, which are routed inside containment) - Aging Mechanism Effects

Since the Group 3 cables are located inside containment, they are subject to radiation stress in addition to thermal stress. The lowest radiation dose required to produce a 25% change in elongation for the polymers used in fabricating cables for CCNPP, with the exception of Teflon, is 7E06 rads. [Reference 22, Figure 3-3, Figure 3-7, Page B-175] As noted previously, all Teflon insulated cables are associated with cable schemes which do not support any license renewal functions. Changes in electrical properties lag behind the changes in mechanical properties. Therefore, no observable change in dielectric strength is expected at doses of 7E06 rads or lower. The maximum non-accident dose for CCNPP for 40 years is ≤ 1E06 rads, as determined from radiation data collected over the first twenty years of plant operation. Extrapolating to 60 years results in a maximum non-accident dose of 1.5E06 rads. Comparison of the maximum 60-year non-accident service dose to the 7E06 threshold for the polymers in service at CCNPP, results in the conclusion that the effects of radiation on non-EQ cables at CCNPP over 60 years is considered insignificant. However, EPR or XLPE insulated cables in power service inside containment may be affected by synergistic thermal and radiative aging. Synergistic thermal and radiative aging must be considered when both aging mechanisms are active and at least one may be significant. Both of these cable types are subject to plausible thermal aging when used in power service, therefore, synergistic thermal and radiative aging is plausible for the EPR and XLPE power cables inside containment. [Reference 1, Pages 3-2, 4-4; Reference 2, Page 5-4]

Radiation-induced degradation of organics (e.g., cable jacket and insulation) produces changes in the organic material properties, including reduced elongation and changes in tensile strength. Visible indications of radiative aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation. The potential effects to the jacket due to these degradations include reduced mechanical integrity and reduced protection from the environment. The potential effects to the insulation due to these degradations include reduced IR, changes in flammability, and electrical failure. [Reference 2, Page 4-46, Table 4-13]

The aging mechanism and resultant aging effects for the Group 3 cables relative to thermal aging are the same as for the Group 1 cables.

The functions of the jacket and insulation for the Group 3 cables are the same as for the Group 1 cables. Therefore, degradation of the cable insulation dielectric strength (which can result in the electrical failure of the insulation) is considered significant in maintaining the passive intended function to prevent or isolate faults in an electrical circuit. [Reference 1, Pages 1-8, 1-9]

Since synergistic thermal and radiative aging can result in breakdown of the dielectric strength of the insulation, this aging mechanism, if unmanaged, could eventually lead to loss of the passive intended function to prevent or isolate faults in an electrical circuit under CLB conditions. Therefore, synergistic thermal and radiative aging was determined to be a plausible ARDM for which aging effects must be managed for EPR/XLPE non-EQ cables in power service, which are routed inside containment. [Reference 1, Table 4-2]

Group 3 (Synergistic radiative and thermal aging for EPR/XLPE non-EQ cables in power service, which are routed inside containment) - Methods to Manage Aging

Mitigation: Since all the Group 3 cables are inside containment, there are no feasible means of reducing the cable service temperature or to reduce the effects due to radiation. Therefore, there are no methods deemed necessary to mitigate the effects of synergistic radiative and thermal aging for the Group 3 cables.

Discovery: The effects of synergistic radiative and thermal aging that do occur can be discovered through a combination of analysis, monitoring, and testing. These activities would ensure that cables are replaced prior to degradation of the insulation that could compromise the passive intended function (i.e., prevent or isolate faults in an electrical circuit). [Reference 1, Pages 4-1, F-2]

Group 3 (Synergistic radiative and thermal aging for EPR/XLPE non-EQ cables in power service, which are routed inside containment) - Aging Management Program(s)

Mitigation: Since there are no methods deemed necessary to mitigate the effects of synergistic radiative and thermal aging for the Group 3 cables, there are no programs credited with mitigation of these effects.

Discovery: To manage the effects of synergistic radiative and thermal aging for the Group 3 cables, a new plant program will be developed to provide monitoring, testing, or analysis (or an appropriate combination thereof). The program is considered an ARDI program as defined in the CCNPP IPA Methodology (Section 2.0 of the BGE LRA). The purpose of the Cables ARDI program is to determine if plausible aging could potentially progress to cable failure such that ongoing aging management is required to be implemented. [Reference 1, Pages 4-1, F-2]

The Cables ARDI program will include the following elements as appropriate: [Reference 1, Pages 4-1, F-2]

- Analysis to determine a cable replacement date;
- Visual or physical inspection (for detection of embrittlement, cracking, discoloration, melting, and swelling);

- Pulling cable samples for testing of chemical, mechanical, or electrical properties (e.g., elongation, dielectric strength) and subsequent replacement and repair of the tested cable sections;
- Cable condition monitoring (i.e., In-situ non-destructive testing); and
- Replacement of cable.

Visual or physical inspection, pulling cable samples for testing, and cable condition monitoring will include acceptance criteria to trigger cable replacement prior to degradation that would prevent the cable from performing its intended function. If any of the acceptance criteria are not met, an Issue Report would be generated, per Reference 20, to document the degraded condition and the required corrective actions (i.e., cable replacement).

Cable condition monitoring is presently considered an optional approach to ongoing cable management. However, it does not have industry consensus or regulatory acceptance as a means of establishing cable residual life. Baltimore Gas and Electric Company considers condition monitoring to be a viable alternative and will monitor research in this area through EPRI and NEI to develop this aspect of the aging management program accordingly.

The corrective actions taken as a result of the Cables ARDI program will ensure that the Group 3 cables remain capable of performing their intended function to prevent or isolate faults in an electrical circuit under all CLB conditions.

Group 3 (Synergistic radiative and thermal aging for EPR/XLPE non-EQ cables in power service, which are routed inside containment) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to synergistic radiative and thermal aging for EPR/XLPE non-EQ cables in power service, which are routed inside containment:

- The Group 3 cables provide the passive intended function to prevent or isolate faults in an electrical circuit under CLB conditions.
- Synergistic radiative and thermal aging is plausible for the Group 3 cables, causing a breakdown of the cable insulation dielectric strength, which could eventually lead to electrical failure of the insulation and loss of the function to prevent or isolate faults in an electrical circuit under CLB conditions.
- The CCNPP Cables ARDI program will determine if plausible aging could potentially progress to cable failure, such that ongoing aging management is required to be implemented. The program will also contain acceptance criteria that ensure corrective actions will be taken, such that there is reasonable assurance that the prevention or isolation of faults in an electrical circuit function will be maintained.

Therefore, there is reasonable assurance that the effects of synergistic radiative and thermal aging will be managed in order to maintain the function to prevent or isolate faults in an electrical circuit as provided by the Group 3 cables, consistent with the CLB, during the period of extended operation.

Group 4 (Thermal aging for EPR non-EQ cables in power service, associated with the Saltwater System and Service Water System 4kV pump motor terminations) - Materials and Environment

Group 4 consists of power cables with EPR insulation which are associated with the Saltwater System and Service Water System 4kV pump motor terminations. The power cable for each of the pump motors is routed from the power source, via conduits and trays, to a junction box on the pump motor which contains the motor leads. The power cable is bolt spliced to the motor leads in this junction box. The bolted splice is wrapped with insulating tape. [Reference 23]

The portions of the cables that are subject to aging management (i.e., the motor terminations) are located in the Intake Structure Pump Room (for Saltwater System pump motors) and in the Service Water Pump Room. The cables in these areas are subjected to localized heating effects due to their close proximity to the pump motors. [Reference 7, Figures 1-14, 1-5, 1-30]

The normal maximum temperatures are 104°F in the Intake Structure Pump Room and 113°F in the Service Water Pump Room. [Reference 21, Pages 51, 53, 63]

Group 4 (Thermal aging for EPR non-EQ cables in power service, associated with the Saltwater System and Service Water System 4kV pump motor terminations) - Aging Mechanism Effects

Thermal degradation of organic material (i.e., cable jacket and insulation) is considered plausible for cable terminations on continuously run 4kV motors which are within the scope of license renewal (i.e., thermal degradation is due to heat generated by motor operation). The Saltwater System and Service Water System pump motors are the only continuously run 4kV motors determined to be within the scope of license renewal. The portion subject to thermal aging consists of the cabling in close proximity to the pump motors. [Reference 1, Page 4-5; Reference 2, Table 4-13]

The aging mechanism and resultant aging effects for the Group 4 cables relative to thermal aging are the same as for the Group 1 cables. The functions of the jacket and insulation for the Group 4 cables are the same as for the Group 1 cables. Therefore, degradation of the cable insulation dielectric strength (which can result in the electrical failure of the insulation) is considered significant in maintaining the passive intended function to prevent or isolate faults in an electrical circuit.

Since thermal aging of the insulation can result in breakdown of the dielectric strength of the insulation, this aging mechanism, if unmanaged, could eventually lead to loss of the passive intended function to prevent or isolate faults in an electrical circuit under CLB conditions. Therefore, thermal aging was determined to be a plausible ARDM for which aging effects must be managed for EPR non-EQ cables in power service, associated with the Saltwater System and Service Water System 4kV pump motor terminations. [Reference 1, Pages 4-5, F-2]

Group 4 (Thermal aging for EPR non-EQ cables in power service, associated with the Saltwater System and Service Water System 4kV pump motor terminations) - Methods to Manage Aging

Mitigation: Since the degradation of the Group 4 cables is due to heat generated from pump motor operation, the only feasible means of mitigating the thermal aging effects is by selection of suitable cable materials. Therefore, there are no additional specific methods deemed necessary to mitigate the effects of thermal aging for the Group 4 cables.

Discovery: The effects of thermal aging that do occur can be discovered through visual inspection performed during periodic maintenance to the pump motors. This activity would ensure that cables are replaced prior to degradation of the insulation that could compromise the passive intended function (i.e., prevent or isolate faults in an electrical circuit). [Reference 1, Page F-2]

Group 4 (Thermal aging for EPR non-EQ cables in power service, associated with the Saltwater System and Service Water System 4kV pump motor terminations) - Aging Management Program(s)

Mitigation: Since there are no methods deemed necessary to mitigate the effects of thermal aging for the Group 4 cables, there are no programs credited with mitigation of this effect.

Discovery: To manage the effects of thermal aging for the Group 4 cables, the existing Electrical Preventative Maintenance (EPM) Program will be modified. [Reference 1, Page F-2]

Visual inspection will take place as part of the periodic EPM on the pump motors. The EPM checklists associated with pump motors for the Group 4 cables will be revised to include appropriate inspection criteria. If any of the acceptance criteria are not met, an Issue Report would be generated, per Reference 20, to document the degraded condition and the required corrective actions (i.e., cable replacement). [Reference 24]

The corrective actions taken as a result of the EPM Program will ensure that the Group 4 cables remain capable of performing their intended function to prevent or isolate faults in an electrical circuit under all CLB conditions.

Group 4 (Thermal aging for EPR non-EQ cables in power service, associated with the Saltwater System and Service Water System 4kV pump motor terminations) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to thermal aging for EPR non-EQ cables in power service, associated with the Saltwater System and Service Water System 4kV pump motor terminations:

- The Group 4 cables provide the passive intended function to prevent or isolate faults in an electrical circuit under CLB conditions.
- Thermal aging is plausible for the Group 4 cables, causing a breakdown of the cable insulation dielectric strength, which could eventually lead to electrical failure of the insulation and loss of the function to prevent or isolate faults in an electrical circuit under CLB conditions.
- The CCNPP EPM Program will conduct visual inspections to detect the effects of thermal aging, and will contain acceptance criteria that ensure corrective actions will be taken such that there is reasonable assurance that the prevention or isolation of faults in an electrical circuit function will be maintained.

Therefore, there is reasonable assurance that the effects of thermal aging will be managed in order to maintain the function to prevent or isolate faults in an electrical circuit as provided by the Group 4 cables, consistent with the CLB, during the period of extended operation.

Group 5 (IR reduction for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable IR) - Materials and Environment

Group 5 consists of instrumentation cables with EPR, XLPE, or XLPO insulation. The cable is used in Radiation Monitoring System, power range nuclear instrumentation, and wide range nuclear instrumentation circuits routed throughout the plant (inside and outside of containment). [Reference 1, Pages 3-3 through 3-10]

The highest (non-accident) ambient design temperature of any area in the plant that contains cabling is in the Main Steam Penetration Room. This room has a maximum design ambient temperature of 160°F. [Reference 1, Page 2-1]

The normal general background radiation level inside containment is 1 rad/hour (although may be higher in some locations). There are no design radiation requirements outside containment during normal operating conditions. [Reference 21, Sections 5.4.A, 5.4.C]

Group 5 (IR reduction for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable IR) - Aging Mechanism Effects

The Group 5 cables may be subject to thermal stress due to ambient heating effects. The Group 5 cables inside containment are also subject to radiation stress.

Both the thermal and radiation-induced degradation of the cable insulation can result in reduced IR. Insulation resistance (also called DC resistivity) is a measure of resistance to the transport of electrical charge (or DC) through the insulation. Insulation resistance for cable is typically specified in terms of ohms per 1000 feet of cable length. Unaged cables typically have IR specifications of 10^8 to 10^{11} ohms per 1000 feet. Cable tests (e.g., for EQ of cable under accident conditions) have demonstrated that radiation and thermal aging may result in a decrease in IR of several orders of magnitude. Insulation resistance decreases with increasing temperature and may recover as temperature decreases. [Reference 5, Pages 29, 41; Reference 16, Pages 4-2, 4-3, 4-5; Reference 25, Appendix D]

The reduction in IR causes an increase in leakage currents between conductors, and from individual conductors to ground. Leakage currents are typically negligibly small under normal, non-accident conditions and are more of a concern under harsh conditions (i.e., high temperature, humidity, and radiation). Harsh environmental conditions would only be a concern for EQ cables since they are required to function in a post-accident environment. The IR reduction effect can be a concern for circuits with sensitive, low level signals such as current transmitters, resistance temperature detectors, and thermocouples. It is especially a concern for channels with logarithmic signals such as radiation monitors and neutron monitoring instrumentation. The IR reduction effect contributes to inaccuracies in the instrument loop current signal (e.g., 4-20 mA) such that the measurement of the process variable (e.g., rads/hour) becomes more uncertain. These uncertainties are taken into account when calculating instrument loop setpoints and instrument loop indication uncertainties. For CCNPP, reduction in IR was determined to be plausible for cables associated with Radiation Monitoring System, power range nuclear instrumentation, and wide range nuclear instrumentation circuits. This determination of plausibility is considered conservative since IR reduction effects were calculated to have negligible impact on the operation of radiation monitoring and neutron monitoring instrument loops even during accident conditions. [Reference 1, Page 3-3; Reference 6; Reference 25, Appendix D; Reference 26, Sections 3.7, 3.8, 10.6, 10.7; References 27 and 28; Reference 29, Page 112]

Since thermal and radiation-induced aging can result in reduced IR, these aging mechanisms, if unmanaged, could eventually lead to the loss of the passive function to maintain adequate IR under CLB conditions. Therefore, IR reduction was determined to be a plausible effect which must be managed for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable IR. [Reference 1, Page 4-1]

Group 5 (IR reduction for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable IR) - Methods to Manage Aging

Mitigation: In normal environmental conditions, the leakage currents due to IR reduction will be small enough such that periodic instrument loop calibration will be sufficient to mitigate the IR reduction effects. [Reference 27; Reference 29, Page 112]

Discovery: There are no methods deemed necessary to discover the IR reduction effects since the effects can be mitigated through periodic calibration of the instrument loops.

Group 5 (IR reduction for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable IR) - Aging Management Program(s)

Mitigation: To manage the IR reduction effects on the Group 5 cables, the existing Instrument Calibration Program, MN-1-211, will be used to provide performance monitoring of the affected circuits. [Reference 1, Pages 3-10, 4-1; Reference 30]

The Instrument Calibration Program provides the administrative controls that ensure proper calibrations of instrumentation used for tests, surveillances, and other procedures are performed. The program applies to CCNPP installed process instrumentation. Instrument loops are normally calibrated using a Surveillance Test Procedure or a Preventative Maintenance Task. The Surveillance Test Procedure is a stand alone procedure that ensures instruments important to safety keep the plant parameters in normal bounds or put the plant in a safe condition if those parameters exceed normal bounds. Surveillance Test Procedures are performed at specific intervals to satisfy Technical Specification requirements. The tests assure that the quality of systems and components are maintained, their operation will be within safety limits, and the limiting conditions for operation will be met. Preventative Maintenance Tasks maintain equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimize equipment failure, and extend equipment and plant life. [Reference 30, Sections 1.1, 1.2, 5.2]

Instrument loops are normally calibrated by applying a test input signal at the sensor end of the loop and then observing a desired output signal (based on the instruments input/output scaling relationships such as linear, square root, logarithmic, etc.) at the bistable or indicator end of the loop. Calibration data points are normally chosen such that they span the entire instrument loop range at evenly spaced intervals (e.g., 0%, 25%, 50%, 75%, 100%). Each desired output value has an acceptance band based on the desired output value plus or minus the instrument loop setting tolerance. The setting tolerance is derived from instrument uncertainty calculations, design basis documents, or documented engineering evaluations. When an instrument is found to be out-of-calibration during the performance of a Surveillance Test Procedure, Preventative Maintenance Task, or corrective maintenance activity, BGE determines if the out-of-calibration instrument could effect any surveillance test. If necessary, an Issue Report is initiated (per Reference 20) and the necessary corrective actions are taken. [Reference 30, Section 5.7; Reference 31, Section 3.0.T, Attachment 7]

Since IR reduction causes inaccuracies in the instrument loop current signal, periodic instrument loop calibration to eliminate the inaccuracies (whether due to IR or other effects) is an effective means to mitigate the IR reduction effects.

The Instrument Calibration Program is subject to internal quality assurance audits and external assessments (e.g., NRC inspections). Nuclear Regulatory Commission inspections have noted weaknesses in the program in two general areas. First, there were program inconsistencies that did not permit a readily accessible mechanism to ensure safety-related process instrumentation was scheduled and periodically calibrated. Second, there was no process to evaluate the effect on equipment operability of instrumentation found out-of-calibration. Baltimore Gas and Electric Company has subsequently taken corrective actions to address these items and the NRC concerns with installed safety-related instrumentation calibration have been resolved. [References 32 through 36]

The corrective actions taken as a result of the Instrument Calibration Program will ensure that the Group 5 cables will remain capable of performing their function to maintain adequate IR under all CLB conditions.

Discovery: Since there are no methods deemed necessary to discover the IR reduction effects, there are no programs crediting with discovery of these effects.

Group 5 (IR reduction for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable IR) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to IR reduction for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable IR:

- The Group 5 cables provide the passive intended function to maintain adequate IR under CLB conditions.
- Thermal and radiation-induced aging can result in plausible IR reduction for the Group 5 cables, which could eventually lead to the loss of the passive function to maintain adequate IR under CLB conditions.
- The CCNPP Instrument Calibration Program will periodically calibrate the instrument loops associated with the Group 5 cables to mitigate the IR reduction effects, and contains acceptance criteria that ensures corrective actions will be taken such that there is reasonable assurance that the maintenance of adequate IR function will be maintained.

Therefore, there is reasonable assurance that the IR reduction effects will be managed in order to maintain the maintenance of adequate IR function as provided by the Group 5 cables, consistent with the CLB, during the period of extended operation.

Group 6 (Treeing for EPR non-EQ cables in 4kV power service) - Materials and Environment

Group 6 consists of 4kV power cables with EPR insulation associated with the saltwater pumps, the service water pumps, and the safety-related 4kV feeds from the 4kV unit busses to the 480V unit busses. [Reference 1, Page 3-1]

The Group 6 cables are subjected to the following conditions: [Reference 1, Page 3-1]

- 4kV service voltage;
- Continuously energized; and
- Insulation is subject to electrical stress of 35V/mil or greater.

Group 6 (Treeing for EPR non-EQ cables in 4kV power service) - Aging Mechanism Effects

Treeing is a form of voltage-induced degradation of the cable insulation. Hollow microchannels with a tree-like pattern can initiate from electrical stress concentrations within a polymer, and progressively cause localized polymer decomposition. The stress concentrations may be protrusions on an electrode surface or contaminants within the insulation. Treeing requires insulation exposure to a high electrical field stress. Degradation of the insulation due to treeing can result in an eventual breakdown of the insulation dielectric strength. [Reference 2, Table 4-4; Reference 16, Section 4.7.1]

Treeing is considered plausible if all of the following conditions are met: [Reference 1, Page 3-1]

- Cable is in 4kV service;
- Cable is continuously energized; and
- Cable insulation is subject to electrical stress of 35V/mil or greater.

The function of the insulation for the Group 6 cables is the same as for the Group 1 cables. Therefore, degradation of the cable insulation dielectric strength (which can result in the electrical failure of the insulation) is considered significant in maintaining the passive intended function to prevent or isolate faults in an electrical circuit.

Since degradation of the insulation due to treeing can result in breakdown of the dielectric strength of the insulation, this aging mechanism, if unmanaged, could eventually lead to loss of the passive intended function to prevent or isolate faults in an electrical circuit under CLB conditions. Therefore, treeing was determined to be a plausible ARDM for which aging effects must be managed for EPR non-EQ cables in 4kV power service.

Group 6 (Treeing for EPR non-EQ cables in 4kV power service) - Methods to Manage Aging

Mitigation: Since the degradation of the Group 6 cables is due to operational conditions which cannot be changed, there are no feasible means of mitigating these effects. Therefore, there are no methods deemed necessary to mitigate the effects of treeing for the Group 6 cables.

Discovery: The effects of treeing that do occur can be discovered through a combination of analysis, monitoring, and testing. These activities would ensure that cables are replaced prior to degradation of the insulation that could compromise the passive intended function (i.e., prevent or isolate faults in an electrical circuit). [Reference 1, Pages 4-8, F-2]

Group 6 (Treeing for EPR non-EQ cables in 4kV power service) - Aging Management Program(s)

Mitigation: Since there are no methods deemed necessary to mitigate the effects of treeing for the Group 6 cables, there are no programs credited with mitigation of this effect.

Discovery: To manage the effects of treeing for the Group 6 cables, a new plant program will be developed to provide monitoring, testing, or analysis (or an appropriate combination thereof). The program is considered an ARDI program as defined in the CCNPP IPA Methodology (Section 2.0 of the BGE LRA). The purpose of the Cables ARDI program is to determine if plausible aging could potentially progress to cable failure such that ongoing aging management is required to be implemented. [Reference 1, Page 4-1, Section 4.7, Appendix F]

The Cables ARDI program will include the following elements as appropriate: [Reference 1, Pages 4-1, F-2]

- Analysis to determine a cable replacement date;
- Pulling cable samples for testing of chemical, mechanical, or electrical properties and subsequent replacement and repair of the tested cable sections;
- Cable condition monitoring (i.e., in-situ non-destructive testing); and
- Replacement of cable.

Pulling cable samples for testing and cable condition monitoring will include acceptance criteria to trigger cable replacement prior to degradation that would prevent the cable from performing its intended function. If any of the acceptance criteria are not met, an Issue Report would be generated, per Reference 20, to document the degraded condition and the required corrective actions (i.e., cable replacement).

Cable condition monitoring is presently considered an optional approach to ongoing cable management. However, it does not have industry consensus or regulatory acceptance as a means of establishing cable residual life. Baltimore Gas and Electric Company considers condition monitoring to be a viable alternative and will monitor research in this area through EPRI and NEI to develop this aspect of the aging management program accordingly.

The corrective actions taken as a result of the Cables ARDI program will ensure that the Group 6 cables remain capable of performing their intended function to prevent or isolate faults in an electrical circuit under all CLB conditions.

Group 6 (Treeing for EPR non-EQ cables in 4kV power service) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to treeing for EPR non-EQ cables in 4kV power service:

- The Group 6 cables provide the passive intended function to prevent or isolate faults in an electrical circuit under CLB conditions.
- Treeing is plausible for the Group 6 cables, causing a breakdown of the cable insulation dielectric strength, which could eventually lead to electrical failure of the insulation and loss of the function to prevent or isolate faults in an electrical circuit under CLB conditions.
- The CCNPP Cables ARDI program will determine if plausible aging could potentially progress to cable failure, such that ongoing aging management is required to be implemented. The program will also contain acceptance criteria that ensure corrective actions will be taken, such that there is reasonable assurance that the prevention or isolation of faults in an electrical circuit function will be maintained.

Therefore, there is reasonable assurance that the effects of treeing will be managed in order to maintain the function to prevent or isolate faults in an electrical circuit as provided by the Group 6 cables, consistent with the CLB, during the period of extended operation.

6.1.3 Conclusion

The programs discussed for cables are listed in the following table. 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 cables 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 aging management review.

TABLE 6.1-3

LIST OF AGING MANAGEMENT PROGRAMS FOR CABLES

	Program	Credited For
Existing	Instrument Calibration Program, MN-1-211	Management of the effects of IR reduction for Group 5 (EPR/XLPE/XLPO non-EQ cables in instrumentation service, sensitive to reduction in cable IR).
Modified	EPM Program EPM Checklists EPM04000, EPM04003, EPM05135	Management of the effects of thermal aging for Group 4 (EPR non-EQ cables in power service, associated with Saltwater System and Service Water System 4kV pump motor terminations).
New	Cables ARDI Program	Management of the effects of: - Thermal aging for Group 1 (EPR/XLPE/XLPO non-EQ cables in power and control service, routed without maintained spacing), and Group 2 (EPR/XLPE non-EQ cables in power service, routed with maintained spacing) - Synergistic thermal and radiative aging for Group 3 (EPR/XLPE non-EQ cables in power service, routed inside containment) - Treeing for Group 6 (EPR non-EQ cables in 4kV power service)

6.1.4 References

1. "CCNPP Aging Management Review Report for the Cables & Terminations (Commodity Evaluation)," Revision 2, June 9, 1997
2. Department of Energy Contractor Report SAND96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations," September 1996
3. CCNPP Drawing 61-406-A, Sec. 109.1, Sheet 3, "Control Panel Wiring," Revision 3, October 10, 1995
4. Letter from Mr. M. W. Hodges (NRC) to Mr. G. C. Creel (BGE), dated June 5, 1992, Transmittal of Inspection Report 50-317/92-80, 50-318/92-80 (Electrical Distribution System Functional Inspection)
5. NUREG/CR-5461, "Aging of Cables, Connections, and Electrical Penetration Assemblies Used in Nuclear Power Plants," July 1990
6. NRC Information Notice 93-33, "Potential Deficiency of Certain Class 1E Instrumentation and Control Cables," April 28, 1993
7. CCNPP Updated Final Safety Analysis Report, Revision 20
8. Letter from Mr. D. H. Jaffe (NRC) to Mr. A. E. Lundvall, Jr. (BGE), dated December 9, 1985, Transmittal of License Amendments 109 and 92
9. IEEE Paper 70 TP 557-PWR, "Ampacities for Cables in Randomly Filled Trays," submitted September 18, 1969 by J. Stolpe
10. CCNPP Drawing 61406SEC001A-SH0012, "Design and Construction Standards - Cable Derating," Revision 2, April 10, 1991
11. CCNPP Drawing 61406SEC001A-SH0013, "Design and Construction Standards - Cable Derating," Revision 2, April 10, 1991
12. CCNPP Drawing 61406SEC001A-SH0014, "Design and Construction Standards - Cable Derating," Revision 2, April 10, 1991
13. CCNPP Drawing 61406SEC001A-SH0015, "Design and Construction Standards - Cable Derating," Revision 3, April 10, 1991
14. CCNPP Drawing 61406SEC001A-SH0016, "Design and Construction Standards - Cable Derating," Revision 2, April 10, 1991
15. CCNPP Drawing 61406SEC001A-SH0017, "Design and Construction Standards - Cable Derating," Revision 2, April 10, 1991
16. EPRI Report TR-103841, "Low-Voltage Environmentally-Qualified Cable License Renewal Industry Report," Revision 1, July 1994
17. NRC Information Notice 92-81, "Potential Deficiency of Electrical Cables with Bonded Hypalon Jackets," December 11, 1992
18. Engineered Materials Handbook, Volume 1, "Composites," ASM International, Copyright 1987

19. Engineered Materials Handbook, Volume 2, "Engineering Plastics," ASM International, Copyright 1989
20. CCNPP Administrative Procedure QL-2-100, "Issue Reporting and Assessment," Revision 4, January 2, 1996
21. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0, November 8, 1995
22. EPRI Report NP-4172SP,"Radiation Data for Design and Qualification of Nuclear Plant Equipment, August 1985
23. CCNPP Drawing 61-406-A Sec. VII, Sheet 15, "Kerite 4KV SR/EQ Motor Termination," Revision 4, January 18, 1991
24. CCNPP Nucleis Database, Electrical Preventative Maintenance Checklists EPM04000, EPM04003, and EPM05135
25. Instrument Society of America Recommended Practice ISA-RP67.04 - Part II, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation," September 1994
26. CCNPP Calculation I-93-87, "Insulation Resistance Degradation Uncertainty Effects," Revision 2, March 8, 1995
27. NRC Information Notice 92-12, "Effects of Cable Leakage Currents on Instrument Settings and Indications," February 10, 1992
28. Title 10 Code of Federal Regulations Part 21 Notification by GA Technologies Inc., "Defect in Ion Chamber Signal Coaxial Cable," February 23, 1987
29. CCNPP Engineering Standard ES-028, "Instrument Loop Uncertainty and Setpoint Methodology," Revision 0, October 17, 1995
30. CCNPP Administrative Procedure MN-1-211, "Instrument Calibration Program," Revision 1, January 17, 1996
31. CCNPP Engineering Standard ES-026, "Instrument Calibration Data Development," Revision 0, November 8, 1995
32. Letter from Mr. E. C. Wenzinger (NRC) to Mr. J. A. Tiernan (BGE), dated June 6, 1986, Transmittal of NRC Inspection Report 50-317/86-07, 50-318/86-07
33. Letter from Mr. J. A. Tiernan (BGE) to Mr. E. C. Wenzinger (NRC), dated July 17, 1986, Response to NRC Inspection Report 50-317/86-07, 50-318/86-07
34. Letter from Mr. G. C. Creel (BGE) to NRC Document Control Desk, dated June 21, 1989, Response to NRC Inspection Report 50-317/89-200, 50-318/89-200 (Special Team Inspection)
35. Letter from Mr. C. J. Cowgill (NRC) to Mr. G. C. Creel (BGE), dated June 6, 1986, Transmittal of NRC Inspection Report 50-317/91-14, 50-318/91-14
36. Letter from Mr. C. J. Cowgill (NRC) to Mr. G. C. Creel (BGE), dated May 13, 1992, Transmittal of NRC Inspection Report 50-317/92-12, 50-318/92-12

6.2 Electrical Commodities

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing Electrical Commodities (ECs), which have been 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 LRA.

6.2.1 Scoping

6.2.1.1 Electrical Commodities Scoping

Electrical components are associated with most plant systems. The scoping process, performed separately for each system within the scope of license renewal, identified passive electrical structural enclosures/supports (e.g., panels, racks, etc.) from 26 systems that were included in the Electrical Commodities Evaluation (ECE). Since the component materials and environments are common to numerous systems, it was determined that a commodity evaluation approach would be more efficient rather than evaluating these electrical commodities (ECs) in each system aging management review (AMR). [Reference 1, Sections 1.1]

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

Commodity Description/Conceptual Boundaries

Electrical commodities are within the scope of license renewal because they support and protect various plant electrical components that are required to perform the functions described in 10 CFR 54.4(a)(1), (2), and (3). As discussed in Section 5.0 of the CCNPP IPA Methodology, system components are assigned to the scope of the ECE during the system pre-evaluation process. As a result of that process, several types of passive, long-lived electrical components were considered electrical commodities. These components typically were either conductive equipment (such as distribution buses) or panels/cabinets, which support and/or protect safety-related electrical equipment and terminal blocks. Cables were excluded from this evaluation and have been addressed in the Cables Commodity Evaluation in Section 6.1 of the BGE LRA. The ECE is composed of the following structural enclosures for electrical equipment, which provide support and/or protection of the electrical equipment within them: [Reference 1, Section 1.2.2]

- Miscellaneous panels;
- Motor control center (MCC) cabinets;
- Switchgear/disconnect cabinets;
- Bus cabinets;
- Circuit breaker cabinets;
- Local control stations panels;
- Battery terminals and charger cabinets; and
- Inverter cabinets.

The supporting cabinets and panels of the identified equipment above are evaluated in this report along with terminal blocks and other structural subcomponents of these enclosures. Most of the supporting panels and cabinets covered by this report are identified by the name of the equipment they support because they do not have their own unique equipment identifiers. The panels are included here as a device type because some of the panels do have unique equipment identifiers. Terminal blocks attached to the cabinets are used for the termination of electrical connections. These blocks are considered to be part of the cabinets or panels that house them and are included in this evaluation. They are phenolic material subject to the effect of electrical stressors.

Electrical commodities are assigned to a number of systems in the CCNPP equipment database because they are functionally related to the system components. In all cases, the passive intended function of such electrical commodities equipment is to provide structural support to active system components contained in this equipment, and/or to ensure electrical continuity of power, control, or instrumentation signals. The conceptual boundaries for the ECs includes panels and the enclosures/supports (i.e., cabinets, etc.) for MCCs, switchgears, buses, disconnect switches/links, local control stations, batteries, chargers, and inverters for the systems shown in Table 6.2-1. The CCNPP system numbers and the applicable BGE LRA Sections for the systems are also shown in the table. [Reference 1, Section 3.0]

The design basis and associated loading conditions for the CCNPP electrical systems (which include ECs) are described in Updated Final Safety Analysis Report Section 8.1.1. All ECs vital to plant safety are designated as Class 1E so that their integrity is not impaired by a Safe Shutdown Earthquake, high winds, or disturbances in the external electrical system. [Reference 2, Section 8.1.1]

Operating Experience

The following historical operating experience is included to provide insight in supporting the aging management demonstrations provided in Section 6.2.2 of this report.

The ECs are usually not subject to extreme conditions or excessive loads; however, some CCNPP ECs are subject to corrosive environments. For example, there have been EC components that have been rusted and corroded due to exposure to saltwater spray. [Reference 3] Other instances of corrosion have occurred in the Nos. 11A and B traveling screen control panels. Though these panels are not within the scope of license renewal, they are made of materials and exposed to environments similar to panels within the scope of license renewal addressed in this report. The legs of these panels were corroded due to exposure to the atmosphere and were replaced with stainless steel support legs.

The cathodic protection system panels for the intake structure baffle walls experienced corrosion, and have been replaced with new, upgraded panels made of fiber reinforced plastic. Though the cathodic protection system baffle walls are not within the scope license renewal, they are made of materials and exposed to environments similar to panels within the scope of license renewal addressed in this report.

Any panel onsite that is either outside or subject to salty air or high humidity could be subject to external corrosion, and corrosion product buildup on contacts or terminations if panel door and penetration seals leak.

The discovery of these anomalies and the actions taken subsequent to discovery demonstrates that CCNPP inspects and maintains the ECs subject to harsh environments to ensure that these components remain capable of performing their intended function(s) under current licensing basis (CLB) conditions.

TABLE 6.2-1

SYSTEMS CONTAINING ELECTRICAL PANELS WITHIN THE SCOPE OF THE ELECTRICAL COMMODITIES EVALUATION

System Number	System Name	BGE LRA Section
002	Electrical 125 VDC Distribution	-
004	Electrical 4 kV Transformers and Buses	-
005	Electrical 480V Transformers and Buses	-
006	Electrical 480V MCCs	-
011	Service Water	5.17
012	Saltwater	5.16
013	Fire Protection	5.10
017	Instrument AC (alternating current)	-
018	Vital Instrument AC	-
019	Compressed Air	5.4
020	Data Acquisition	-
024	Emergency Diesel Generators	5.8
030	Control Room Heating, Ventilation, and Air Conditioning (HVAC)	5.11.C
032	Auxiliary Building and Radwaste Heating and Ventilation	5.11.A
036	Auxiliary Feedwater	5.1
038	Nuclear Steam Supply System Sampling	5.13
048	Engineered Safety Feature Actuation	-
052	Safety Injection	5.15
058	Reactor Protective	-
060	Containment Heating and Ventilation	5.11.B
062	Control Boards	-
073	Hydrogen Recombiners	-
074	Nitrogen and Hydrogen Gas	-
078	Nuclear Instrumentation	-
079	Radiation Monitoring	5.14
094	Plant Computer	-
097	Lighting and Power Receptacle	-
103	Diesel Generator Building HVAC	5.11C

Scoped Structures and Components and Their Intended Functions

The conceptual boundaries for the ECs include the panels and enclosures/supports (i.e., cabinets, etc.) for MCCs, circuit breakers, switchgear, buses, local control stations, disconnect switch/links, battery terminals, chargers, and inverters as described above for the systems shown in Table 6.2-1. All of these panels and enclosures/supports perform passive intended functions and are subject to AMR. Active electrical devices are explicitly excluded from AMR based on §54.21(a)(1)(i). Based on the discussion in Section 4.1.1 of the CCNPP IPA Methodology, ECs that perform the following passive intended functions are within the scope of license renewal based on §54.4(a)(1) and §54.4(a)(2): [Reference 1, Section 1.2.3, 3.1, 3.2]

- To maintain electrical continuity and/or provide protection of the electrical system; and
- To provide seismic integrity and/or protection of safety-related components.

Based on the above, the EC components that support passive functions and that are long-lived are subject to AMR. The EC enclosure device types that are subject to an AMR are listed in Table 6.2-2. [Reference 1, Sections 3, Table 3-1] The device types in Table 6.2-2 are used to identify the panels and cabinets (subject to AMR in the ECE) that might not have a unique equipment identification number in the equipment database.

The aging of non-metallics used in electrical cabinets is discussed below. Non-metallic subcomponents in electrical cabinets and panels fall into one of three categories.

Subcomponent Category 1: Subcomponent of Active Device - Excluded from AMR

The first category includes subcomponents of active electrical devices such as teflon-coated sleeve bearings, polyester glass arc chutes, and polyester glass bus stand-off insulators used in 480 VAC circuit breakers. Active devices are excluded from the requirement for an AMR.

Subcomponent Category 2: Conductor Insulation - Subject to AMR

The second category includes the organic insulation of wiring or buswork. For example, crosslinked polyethylene insulated wiring is used in the 4 kV switchgear cabinets, 480 VAC load centers, and 480 VAC MCCs. The internal operating temperatures for insulated connections in 4 kV switchgear cabinets and 480 VAC load centers is limited to 70 Centigrade (C) based on an ambient temperature of 40C per American National Standards Institute/Institute of Electrical and Electronic Engineers C37.20.2 - 1987. This is more than 10C below the 60-year service limiting temperatures for polyolefin and ethylene propylene rubber materials. Therefore, thermal aging is not plausible for the wiring contained in the 4 kV switchgear cabinets or the 480 VAC load centers. Internal operating temperatures in 480 VAC MCCs can approach 60-year service limits for polyolefin insulated wiring. Therefore, thermal aging is plausible for polyolefin insulated wiring in 480 VAC MCCs and will require aging management. This wiring will be included in the cables aging management program discussed in Section 6.1, Cables, of the BGE LRA. Organically insulated control panel wiring is not subject to plausible thermal aging since operating temperatures in this service are well below 60-year service limiting temperatures for any organic insulating material, except polyvinyl chloride (PVC), which is not used in this service. This category of subcomponents subject to aging applies to the 480 VAC MCCs of Group 5.

The bus splices in 4 kV switchgear cabinets are insulated with PVC boots. The operating temperature of the PVC boots is within 5C of ambient. However, PVC is sensitive to thermal aging even at relatively low temperatures. Failure of air conditioning for an extended period of time could impact these boots. Therefore, thermal aging is plausible for the PVC boots in 4 kV switchgear cabinets and will require aging management. The aging of buswork insulation applies to the 4 kV switchgear cabinets in Group 3. These boots will be included in the cables aging management program discussed in Section 6.1, Cables, of the BGE LRA.

Subcomponent Category 3: Subcomponent of Panel - Subject to AMR

The third category includes subcomponents of the housing/cabinet such as insulating stand-off supports. Such subcomponents provide structural support for buswork and active ungrounded devices contained in the housing/cabinets. These subcomponents are subject to plausible aging if certain elastomers are used. They are not subject to plausible aging if a thermoset or thermoplastic material is used. For example, polyester-glass is used to support and insulate the buswork in the 4 kV switchgear cabinets, 480 VAC load centers, and 480 VAC MCCs. However, polyester-glass is not subject to plausible aging. Elastomers, other than silicone rubber, used to insulate and support ungrounded devices are subject to plausible embrittlement and loss of insulation resistance due to thermal aging. Such aging could result in failure of the support under seismic loading or short circuit forces. The critical characteristic is the loss of flexibility since changes in mechanical properties typically precede changes in electrical properties for insulating elastomers. The 125 VDC chargers, inverters, and power distribution panels of Group 3 and Group 7 will be examined to explicitly identify any such elastomeric insulating supports. These supports will be explicitly included in the Age-Related Degradation Inspection (ARDI) Program or the existing "clean and inspect" Preventive Maintenance (PM) Procedure. Then, the PM or ARDI will be adjusted to monitor the support for the discovery of loss of flexibility. There are other non-metallic subcomponents of the panels that do not have a license renewal function. These subcomponents include dust shields and wiring penetration sleeves.

Terminal blocks are also considered to be subcomponents of the housing/cabinets. They are hard plastic, typically phenolic material, and are not subject to plausible thermal aging due to exposure to normal ambient temperatures. However, they are subject to electrical stress. The plausible aging identified with this stressor is the ohmic heating effects brought about by increased termination resistance associated with loosened connections. This aging effect and the management of it is addressed explicitly in this report. All groups of panels contain terminal blocks subject to electrical stressor aging.

TABLE 6.2-2

DEVICE TYPE WITHIN THE SCOPE OF LICENSE RENEWAL FOR THE ELECTRICAL COMMODITIES EVALUATION

Device Type	Component Supported and/or Protected	Typical Associated EC for Support/Protection
BATT	Batteries	Terminals
BKR	Circuit Breakers	Cabinet
BUS	Electrical Buses	Cabinet
CHGR	Chargers	Cabinet
DISC	Disconnect Switch/Links	Cabinet
INV	Inverters	Cabinet
MCC	MCCs	Cabinet
NA	4 kV Local Control Stations	Panel
NB	480V Local Control Stations	Panel
ND	125/250 VDC Local Control Stations	Panel
PNL	Panel	Panels

6.2.2 Aging Management

The potential age-related degradation mechanisms (ARDMs) for the EC components are listed in Table 6.2-3. The plausible ARDMs are identified in the table by a check mark (✓) in the appropriate column. The device types listed in Table 6.2-3 are those previously identified in Table 6.2-2 as passive and long-lived. For efficiency in presenting the results of these evaluations in this report, the components here are grouped together based on device types. [Reference 1, Section 4.4] The groups addressed are:

- Group 1 - Battery Terminals/Charger and Inverter Cabinets (electrical stressors, general corrosion, and wear);
- Group 2 - Breaker Cabinets (electrical stressors, wear, and fatigue);
- Group 3 - Bus Cabinets (electrical stressors, wear, and fatigue);
- Group 4 - Disconnect Cabinets (electrical stressors, wear, and fatigue);
- Group 5 - MCC Panels (electrical stressors, wear, fatigue, and dynamic loading);
- Group 6 - 4 kV, 480 VAC, and 125/250 VDC Local Control Station Panels (electrical stressors, wear, fatigue, and general corrosion); and
- Group 7 - Miscellaneous Panels (electrical stressors, wear, fatigue, and dynamic loading).

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

The clean and inspect PM procedures (as opposed to testing PMs) cover most of the electrical panels at CCNPP from 4 kV down to 125 VDC. However, some of the lower voltage electrical panels are not covered by clean and inspect PMs even if they are subject to testing PMs. These electrical panels will be subject to an ARDI Program to inspect for signs of age-related degradation.

TABLE 6.2-3

POTENTIAL PLAUSIBLE ARDMs

Potential ARDMs	Enclosures for Support and/or Protection of Electrical Commodities Device Types										
	BATT terminal	BKR cabinet	BUS cabinet	CHGR cabinet	DISC cabinet	INV cabinet	MCC panel	NA panel	NB panel	ND panel	PNL
Corrosion Fatigue											
Crevice Corrosion											
Dynamic Loading (1)							✓(5)				✓(7)
Electrical Stressors (2)		✓(2)	✓(3)	✓(1)	✓(4)	✓(1)	✓(5)	✓(6)	✓(6)	✓(6)	✓(7)
Erosion Corrosion											
Fatigue (1)		✓(2)	✓(3)		✓(4)		✓(5)		✓(6)		✓(7)
Fretting											
General Corrosion	✓(1)								✓(6)		
Hydrogen Damage											
Intergranular Attack											
Microbiologically-Induced Corrosion											
Neutron Embrittlement											

Oxidation											
Pitting											
Saline Water Attack											
Shrinkage/Creep											
Stress Corrosion Cracking											
Thermal Embrittlement											
Uniform Attack											
Wear		✓(2)	✓(3)	✓(1)	✓(4)	✓(1)	✓(5)	✓(6)	✓(6)	✓(6)	✓(7)

Note 1: Dynamic loading and fatigue are plausible for some but not all components associated with the indicated device type. Reference 1 contains the detail for the plausibility of these aging mechanisms for each individual component.

Note 2: Electrical stressors applies to phenolic terminal blocks.

Group 1 (battery terminals/charger and inverter cabinets) - Materials and Environment

As Table 6.2-3 shows, the battery terminals are subject to corrosion, while the charger and inverter cabinets and associated terminal blocks are susceptible to the effects of electrical stressors and wear. This group consists of the components for the 125 VDC Electrical Distribution System. The battery terminals are made of aluminum, lead, and copper, while the charger and inverter cabinets are constructed from carbon steel. [Reference 1, Attachment 1, BATT-01, CHGR-01, INV-01, Attachments 2, 5]

The environment that the battery terminals/charger and inverter cabinets experience is that of a mild controlled atmosphere within the CCNPP Auxiliary Building. The ECs in this group are subject to operational and maintenance activities. Terminal blocks attached to the cabinets are used for the termination of electrical connections. These blocks are considered to be part of the cabinets that house them and are included in this evaluation. They are phenolic material subject to the effects of electrical stressors. The battery terminals are subject to the potentially corrosive environment of battery acid. [Reference 1, BATT-01, CHGR-01, INV-01, Attachments 5, 6]

Group 1 (battery terminals/charger and inverter cabinets) - Aging Mechanism Effects

Electrical stressors (e.g., local ohmic heating) occur most commonly as a result of loose or improper terminations, which result in the degradation of organic materials and terminal block hardware. Loose terminations can occur as a result of the operation of panel components, as well as non-seismic vibration produced externally to the electrical components, which causes connections and terminals to loosen. Degradation of organic material can occur as ohmic heating and elevated ambient temperatures cause terminal blocks to degrade. Terminal blocks are generally made of organic material that may lose its mechanical integrity (e.g., cracking and embrittlement may cause loss of support and insulating capabilities). [Reference 1, Attachment 7s] The terminal blocks are subject to the above conditions and are, therefore, susceptible to the aging effects of electrical stressors.

Wear results from relative motion between two surfaces and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). Cabinet components, such as door hinges and circuit breaker racking mechanisms and other sliding parts, can wear from repeated openings for maintenance and testing. [Reference 1, Attachments 6, 7] Therefore, wear was determined to be plausible for the charger and inverter cabinets for which aging effects must be managed during the period of extended operation.

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface by an aggressive environment. The consequences of the damage are the loss of load carrying cross-sectional area of the metal. General corrosion requires an aggressive environment. An important concern for pressurized water reactors is the attack of boric acid on carbon steels. Borated water has been observed to leak from piping, valves, storage tanks, etc., and fall on other steel components and attack the component from the outside. In addition, systems that contain saltwater can also leak and corrode carbon steel components. Acid leakage from station batteries can result in the corrosion of battery terminals. Therefore, general corrosion was determined to be plausible for the 125 VDC battery terminals. [Reference 1, NB-01, Attachments 6, 7]

If unmanaged, these ARDMs could eventually result in the loss of seismic support capability and electrical continuity under CLB design loading conditions.

Group 1 (battery terminals/charger and inverter cabinets) - Methods to Manage Aging

Mitigation: There are no feasible ways of preventing electrical stressors on the terminal blocks in battery charger and inverter cabinets other than through proper installation and maintenance. There are also no feasible ways of preventing wear on cabinet components other than not operating the associated equipment; therefore, there are no practical means of preventing wear from occurring. In addition, there are also no feasible ways of preventing general corrosion of battery terminals other than proper maintenance.

Discovery: The effects of these ARDMs are detectable by visual techniques. Inclusion of the battery racks, charger and inverter cabinets in regular maintenance/overhaul inspections of these components under maintenance/overhaul/inspection repetitive tasks would result in the discovery of signs of these ARDMs.

Group 1 (battery terminals/charger and inverter cabinets) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited with the mitigation of electrical stressors, general corrosion, or wear on the battery terminals/charger and inverter cabinets and associated terminal blocks.

Discovery: The CCNPP PM Program is credited for the discovery of electrical stressors, general corrosion, and wear of the battery terminals/charger and inverter cabinets and associated terminal blocks. This program is described below.

Calvert Cliffs PM Program

The CCNPP PM 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. [Reference 4, Section 1.1]

The program is governed by CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," and covers all PM activities for nuclear power plant structures and equipment within the plant, including the ECE structural components (i.e., panels, etc.) within the scope of license renewal. Guidelines drawn from industry experience and utility best practices were used in the development and enhancement of this program.

The PM Program includes periodic inspection of specific components through various maintenance activities. These activities provide an effective means to discover and manage the age-related degradation effects on these components. The program requires that an Issue Report be initiated according to CCNPP Procedure QL-2-100, "Issue Reporting and Assessment," for deficiencies noted during performance of PM tasks. Corrective actions are taken to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions. [Reference 4, Section 5.2.B.1.f]

The PM Program has had numerous levels of management review, all the way down to the specific implementation procedures. Specific responsibilities are assigned for evaluating and upgrading the PM Program and for initiating program improvements based on system performance. Issue Reports are initiated according to CCNPP Procedure QL-2-100 to request changes to the program that could improve or correct plant reliability and performance. Changes to the PM Program that require Issue Reports included changes to the PM task scope, frequency, process changes, results from operating experience reviews, as well as other types of changes. [Reference 4, Sections 5.1.A and 5.4] The PM Program also has undergone periodic evaluation by the NRC as part of their routine licensee assessment activities. [Reference 5]

Under the PM Program, electrical stressors and wear (and fatigue, dynamic loading, and general corrosion for other groups in this report) of the EC components are managed through existing PM. [Reference 1, Attachment 1] The following repetitive tasks will be modified to inspect for these ARDMs and include additional specified components where they are not currently included in the PM task.

The following CCNPP PM repetitive tasks are credited with the discovery of the effects of general corrosion on the indicated 125 VDC battery terminals. These repetitive tasks reference other procedures to test and inspect the batteries and their terminals. Each of these repetitive tasks is currently performed every 12 weeks: [Reference 1, Attachment 1; References 6 through 9]

- Calvert Cliffs Repetitive Task 10020008, "1 BATT11;"
- Calvert Cliffs Repetitive Task 10020009, "1 BATT12;"
- Calvert Cliffs Repetitive Task 20020008, "2 BATT22;" and
- Calvert Cliffs Repetitive Task 20020009, "2 BATT21."

The following repetitive tasks are credited for discovery of electrical stressors and wear on the battery charger cabinets. The repetitive tasks direct the user to clean, inspect, and calibrate the chargers. These repetitive tasks are currently performed every 96 weeks. [Reference 1, Tables 5-1, 5-2, 5-3; References 10 and 11]

- Calvert Cliffs Repetitive Task 10020006, "BATTERY CHARGER 11;"
- Calvert Cliffs Repetitive Task 10020007, "BATTERY CHARGER 12;"
- Calvert Cliffs Repetitive Task 10020015, "BATTERY CHARGER 23;"
- Calvert Cliffs Repetitive Task 10020016, "BATTERY CHARGER 24;"
- Calvert Cliffs Repetitive Task 20020002, "BATTERY CHARGER 21;"
- Calvert Cliffs Repetitive Task 20020003, "BATTERY CHARGER 22;"
- Calvert Cliffs Repetitive Task 20020014, "BATTERY CHARGER 13;" and,
- Calvert Cliffs Repetitive Task 20020015, "BATTERY CHARGER 14."

The following repetitive tasks will discover wear and electrical stressors on the inverter cabinets. These Electrical PMs (EPMs) direct the user to inspect the inverter cabinets and calibrate the meters. These repetitive tasks are currently performed every 96 weeks. [Reference 1, Table 5-1, Table 5-3, References 12 through 19]

- Calvert Cliffs Repetitive Task 10180013, "Inverter 14;"
- Calvert Cliffs Repetitive Task 10180012, "Inverter 13;"
- Calvert Cliffs Repetitive Task 20180011, "Inverter 22;"
- Calvert Cliffs Repetitive Task 20180012, "Inverter 23;"
- Calvert Cliffs Repetitive Task 20180013, "Inverter 24;"
- Calvert Cliffs Repetitive Task 10180010, "Inverter 11;"
- Calvert Cliffs Repetitive Task 20180010, "Inverter 21;" and,
- Calvert Cliffs Repetitive Task 10180011, "Inverter 12."

Any corrective actions that are required during these inspections are performed in accordance with the CCNPP Corrective Actions Program, and will ensure that the battery terminals/charger and inverter cabinets will remain capable of performing their intended function under all CLB conditions.

Group 1 (battery terminals/charger and inverter cabinets) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the 125 VDC battery terminals, charger and inverter cabinets:

- The 125 VDC battery terminals, charger and inverter cabinets, and associated terminal blocks, have the intended functions of maintaining the seismic integrity and/or protection of safety-related components and electrical continuity under CLB design conditions.
- Electrical stressors, general corrosion, and wear are plausible for the 125 VDC battery terminals, charger and inverter cabinets, and associated terminal blocks, which could lead to loss of seismic integrity and/or protection of safety-related components and electrical continuity under CLB design conditions.
- The CCNPP PM Program will provide for the discovery of the aging effects of electrical stressors, wear, and general corrosion that may be of concern for the 125 VDC battery terminals, charger and inverter cabinets using repetitive tasks. The repetitive tasks will be modified to include these ARDMs where they are not presently included, and additional specified components where they are not presently inspected. Inspections will be performed and appropriate corrective action will be taken where any of these ARDMs are discovered.

Therefore, there is reasonable assurance that the effects of these ARDMs on the 125 VDC battery terminals, charger and inverter cabinets will be adequately managed to maintain their intended function under all design loadings required by the CLB during the period of extended operation.

Group 2 (breaker cabinets) - Materials and Environment

As Table 6.2-3 shows, breaker cabinets and associated terminal blocks are susceptible to the effects of electrical stressors, fatigue, and wear. This group consists of the Reactor Protective System (RPS) trip switchgear cabinets, which are made of carbon steel. [Reference 1, Attachment 1, BKR-01, Attachments 2, 5]

The environment that the RPS trip switchgear cabinets experience is that of a mild controlled atmosphere within the CCNPP Auxiliary Building. These switchgear cabinets are subject to operational and maintenance activities. Terminal blocks attached to the cabinets are used for the termination of electrical connections. These blocks are considered to be part of the cabinets that house them and are included in this evaluation. They are phenolic material subject to the effects of electrical stressors. [Reference 1, BKR-01, Attachments 5, 6]

Group 2 (breaker cabinets) - Aging Mechanism Effects

The effects of electrical stressors and wear were previously discussed in Group 1 (battery terminals/charger and inverter cabinets) under the Aging Mechanisms Effect section. The RPS trip switchgear cabinets are subject to the conditions described in the Group 1 Aging Mechanism Effects section and are, therefore, susceptible to the aging effects of these ARDMs.

Fatigue damage results from progressive, localized structural change in materials subjected to fluctuating stresses and strains. Associated failures may occur at either high or low cycles in response to various kinds of loads (e.g., mechanical or vibrational loads, thermal loads, or pressure cycles). Fatigue cracks initiate and propagate in regions of stress concentration that intensify strain. The fatigue life of a component is a function of several variables, such as stress level, stress state, cyclic wave form, environment, and the metallurgical condition of the material. Failure occurs when the endurance limit number of cycles (for a given load amplitude) is exceeded. All materials are susceptible (with varying endurance limits) when subjected to cyclic loading. [Reference 1, Attachment 7s]

Fatigue typically occurs in switchgear cabinets from low-level vibrational loading of electrical equipment (e.g., relays, contactors, transformers, etc.) induced by AC hum or from mechanical operation. Mechanical stresses can cause housing welds to crack. [Reference 1, Attachments 6, 7] Therefore, fatigue was also determined to be plausible for the RPS trip switchgear cabinets for which aging effects must be managed during the period of extended operation.

If unmanaged, these ARDMs could eventually result in the loss of seismic support capability under CLB design loading conditions.

Group 2 (breaker cabinets) - Methods to Manage Aging

Mitigation: There are no feasible ways of preventing electrical stressors on the terminal blocks in the RPS trip switchgear cabinets other than through proper installation and maintenance. There are also no feasible ways of preventing fatigue and wear on the RPS trip switchgear cabinets other than not operating the contained equipment; therefore, there are no practical means to prevent fatigue or wear from occurring.

Discovery: The effects of these ARDMs are detectable by visual techniques. Inclusion of the RPS trip switchgear cabinets and associated terminal blocks in a regular maintenance/overhaul inspection of these components would provide for the discovery of these ARDMs.

Group 2 (breaker cabinets) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited with the mitigation of electrical stressors, fatigue or wear on the RPS trip switchgear cabinets and associated terminal blocks.

Discovery: The CCNPP PM Program is credited with the discovery of these ARDMs on the RPS trip switchgear and associated terminal blocks. Refer to the previous discussion of the CCNPP PM Program in Group 1 (battery terminals, charger and inverter cabinets) under Aging Management Programs. The EPM below will be modified to include these ARDMs, where they are not presently included, and additional specified components, where they are not presently inspected.

Calvert Cliffs EPM58500, “Reactor Trip Circuit Breaker Inspection,” is the particular PM checklist credited for the discovery of electrical stressors, fatigue, and wear. The PM checklist directs the user to other procedures (e.g., field test and evaluation procedures) in performing the necessary inspections to reveal the presence of electrical stressors, fatigue, and wear on the RPS cabinets. This checklist is currently performed every 48 weeks. [Reference 1, BRK-01, Attachments, 1, 8, Reference 20]

Any corrective actions that are required will be performed in accordance with the CCNPP Corrective Actions Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions. [Reference 1, BKR-01, Attachments 1, 8]

Group 2 (breaker cabinets) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the RPS trip switchgear cabinets and associated terminal blocks:

- The RPS trip switchgear cabinets and associated terminal blocks, have intended functions of maintaining the seismic integrity and/or protection of safety-related components under CLB design conditions.
- Electrical stressors, fatigue, and wear are plausible for the carbon steel RPS cabinets and associated terminal blocks, which could lead to loss of seismic integrity and/or protection of safety-related equipment under CLB design conditions.
- The CCNPP PM Program will provide for the discovery of electrical stressors, fatigue, and wear that may be of concern for the RPS trip switchgear cabinets and associated terminal blocks. This EPM will be modified to include these ARDMs where they are not presently included.

Therefore, there is reasonable assurance that the effects of these ARDMs on the RPS trip switchgear cabinets will be adequately managed to maintain their intended function under all design loadings required by the CLB during the period of extended operation.

Group 3 (bus cabinets) - Materials and Environment

As Table 6.2-3 shows, the bus cabinets' terminal blocks are susceptible to the effects of electrical stressors, and the bus cabinets are susceptible to fatigue and wear. The 125 VDC distribution bus cabinets and associated terminal blocks are susceptible to wear and electrical stressors while the 480V and 4 kV bus cabinets and associated terminal blocks are susceptible to all three ARDMs. The bus cabinets are made of carbon steel. [Reference 1, BUS-01, Attachments 1, 5, 6]

The environment that the bus cabinets and associated terminal blocks experience is that of a mild controlled atmosphere within the CCNPP buildings. However, at operating voltages of 480V and above, AC hum can produce exposure to low-level vibration. There are also routine maintenance and/or modifications performed on these bus cabinets, which requires manipulation of the bus cabinet subcomponents. Terminal blocks attached to the cabinets are used for the termination of electrical connections. These blocks are considered to be part of the cabinets that house them and are included in this evaluation. They are phenolic material subject to the effect of electrical stressors. [Reference 1, BUS-01, Attachments 5, 6]

Group 3 (bus cabinets) - Aging Mechanism Effects

The effects of electrical stressors and wear were previously discussed in Group 1 (battery terminals/charger and inverter cabinets) and fatigue was previously discussed in Group 2 (breakers) under the Aging Mechanisms Effects sections.

The bus cabinets are subject to the conditions described in the Groups 1 and 2 Aging Mechanism Effects sections and are, therefore, susceptible to the aging effects of these ARDMs. If unmanaged, these ARDMs could eventually result in the loss of seismic support capability and maintenance of electrical continuity under CLB design loading conditions

Group 3 (bus cabinets) - Methods to Manage Aging

Mitigation: There are no feasible ways of preventing electrical stressors on the bus cabinets' terminal blocks other than through proper installation and maintenance. There are also no feasible ways of preventing fatigue and wear on the bus cabinets, which must be opened for maintenance, other than not operating the contained equipment; therefore, there are no practical means to prevent fatigue or wear from occurring.

Discovery: The effects of these ARDMs are detectable by visual techniques. Regular maintenance/overhaul inspections of these components under maintenance/overhaul/inspection repetitive tasks would discover signs of these ARDMs. [Reference 1, BUS-01, Attachments 1, 8]

Group 3 (bus cabinets) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited with the mitigation of electrical stressors, fatigue, or wear on the bus cabinets and associated terminal blocks.

Discovery: The CCNPP PM Program is credited with the discovery of these ARDMs on the 125 VDC, 480 VAC, and 4 kV bus cabinets and associated terminal blocks. Refer to the previous discussion of the

CCNPP PM Program in Group 1 (battery terminals, charger and inverter cabinets) under Aging Management Programs.

The following CCNPP PM repetitive tasks are credited with the discovery of the effects of electrical stressors and wear on the indicated 125 VDC bus cabinets and associated terminal blocks. These repetitive tasks call for the user to inspect and clean the bus and cabinet. Each of these repetitive tasks is currently performed every 10 years: [References 21 through 24]

- Calvert Cliffs Repetitive Task 10020004, "Inspect DC Bus 11 Disconnects;"
- Calvert Cliffs Repetitive Task 10020005, "Inspect DC Bus 12 Disconnects;"
- Calvert Cliffs Repetitive Task 20020006, "Inspect DC Bus 21 Disconnects;" and
- Calvert Cliffs Repetitive Task 20020007, "Inspect DC Bus 22 Disconnects."

The following summarizes the corresponding checklists or PMs that will manage ARDMs for the 480 VAC and 4 kV bus cabinets. The PM checklists or repetitive tasks will be modified to include these ARDMs where they are not presently included, and additional specified components where they are not presently inspected.

Calvert Cliffs EPM05900, "480V Load Center and Transformers Cleaning and Inspection," is credited with the discovery of effects of electrical stressors, fatigue, and wear on the 480V bus cabinets and associated terminal blocks. This EPM requires the cleaning and inspection of the load center bus enclosure, transformer, and buswork. This checklist is currently performed every eight weeks. [Reference 1, Table 5-3, 05BUS-01, Attachment 1, Reference 25]

The following CCNPP PM repetitive tasks are credited with the discovery of the effects of electrical stressors, fatigue, and wear on the indicated 4 kV bus cabinets and associated terminal blocks. These repetitive tasks call for the user to clean, inspect, and test the buses and cabinets. Each of these repetitive tasks is currently performed every 10 years:. [Reference 1, Table 5-1, Attachment 1; References 26 through 29]

- Calvert Cliffs Repetitive Task 10040016, "4 kV Bus 11;"
- Calvert Cliffs Repetitive Task 10040018, "4 kV Bus 14;"
- Calvert Cliffs Repetitive Task 20040016, "4 kV Bus 21;" and
- Calvert Cliffs Repetitive Task 20040018, "4 kV Bus 24."

Any corrective actions that are required will be performed in accordance with the CCNPP Corrective Actions Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 3 (bus cabinets) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the bus cabinets:

- The 125 VDC, 480 VAC, and 4 kV bus cabinets and associated terminal blocks have the intended functions of maintaining the seismic integrity and/or protection of safety-related components and maintenance of electrical continuity under CLB design conditions.
- Electrical stressors and wear are plausible for the 125 VDC bus cabinets and associated terminal blocks, and these two ARDMs, plus fatigue, are plausible for the 480 VAC/4 kV bus cabinets. These ARDMs could lead to a loss of seismic integrity and/or protection of safety-related components and loss of electrical continuity under CLB design conditions.
- The CCNPP PM Program will provide for the discovery of any effects due to electrical stressors and wear on the 125 VDC bus cabinets, and electrical stressors, fatigue, and wear on the 4 kV and 480 VAC bus cabinets and associated terminal blocks through the use of EPMs and repetitive tasks. These EPMs and repetitive tasks will be modified to include these ARDMs where they are not presently included, and additional specified components where they are not presently inspected.

Therefore, there is reasonable assurance that the effects of electrical stressors, fatigue, and wear on the 125 VDC, 480 VAC, and 4 kV bus cabinets and associated terminal blocks will be adequately managed to maintain their intended functions under all design loadings required by the CLB during the period of extended operation.

Group 4 (disconnect cabinets) - Materials and Environment

Table 6.2-3 shows that the disconnect cabinets' terminal blocks are susceptible to the effects of electrical stressors, and the disconnect cabinets are susceptible to fatigue and wear. This group also contains contactor panels and associated terminal blocks, which are susceptible to electrical stressors, fatigue, and wear. The contactor panels and disconnect cabinets are made of carbon steel. [Reference 1, DISC-01/02, Attachments 1, 5, 6]

The environment that these device types experience is that of a mild controlled atmosphere within the Auxiliary Building. Terminal blocks attached to the cabinets are used for the termination of electrical connections. These blocks are considered to be part of the cabinets that house them and are included in this evaluation. They are phenolic material subject to the effects of electrical stressors. [Reference 1, DISC-01/02, Attachments 1, 3]

Group 4 (disconnect cabinets) - Aging Mechanism Effects

The effects of electrical stressors and wear were previously discussed in Group 1 (battery terminals/charger and inverter cabinets) and fatigue was discussed in Group 2 (breaker cabinets) under the Aging Mechanisms Effect section.

The contactor panels and disconnect cabinets and associated terminal blocks are subject to the conditions described in the Groups 1 and 2 Aging Mechanisms Effect sections and are, therefore, susceptible to the aging effects of these ARDMs. If unmanaged, these ARDMs could eventually result in the loss of seismic support capability under CLB design loading conditions

Group 4 (disconnect cabinets) - Methods to Manage Aging

Mitigation: There are no feasible ways of preventing electrical stressors on the contactor panels and disconnect cabinets' terminal blocks other than through proper installation and maintenance. There are also no feasible ways of preventing fatigue and wear on the contactor panels and disconnect cabinets, that must be opened for maintenance, other than not operating the contained equipment; therefore, there are no practical means to prevent fatigue or wear from occurring.

Discovery: A program of regular maintenance and inspection would discover indications of fatigue in the housing welds, indications of wear in fasteners or portions of contactor panels/disconnect cabinets that are held together for long periods of time, and indications of electrical stressors in terminal blocks before these ARDMs prevent the EC components from performing their passive intended functions. [Reference 1, DISC-01/02, Attachments 1, 8]

Group 4 (disconnect cabinets) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited with the mitigation of electrical stressors, fatigue, and wear on the contactor panels and disconnect cabinets and associated terminal blocks.

Discovery: The CCNPP PM Program is credited with the discovery of these ARDMs on the disconnect cabinets and associated terminal blocks. Refer to the previous discussion of the CCNPP PM Program in Group 1 (battery terminals, charger and inverter cabinets) under Aging Management Programs. The following EPM and repetitive task will be modified to include these ARDMs, where they are not presently included, and additional specified components, where they are not presently inspected.

Calvert Cliffs EPM60601, "Third Train Containment Filter Motor and Control Inspection," is the particular PM checklist credited for the discovery of these ARDMs. The PM checklist directs the user to other procedures (e.g., field test and evaluation procedures) in performing the necessary inspections to reveal the presence of electrical stressors, fatigue, and wear on the cabinets. The checklist presently directs the user to look for wear and discoloration on the stationary cubicle stabs. This checklist is currently performed every 96 weeks. [Reference 1, DISC-01, Attachments, 1, 8, Reference 30]

Calvert Cliffs Repetitive Task 20320008, "21 Switchgear HVAC Unit Motor and Breaker Inspection," is credited for the discovery of all three ARDMs on the contactor panel and associated terminal blocks for the switchgear room air conditioning compressor cabinets. The repetitive task calls for the user to inspect for dust, discoloration, and signs of overheating. It also directs the user to other procedures and checklists to perform the inspection and testing of the contactor panels. This repetitive task is currently performed every two years. [Reference 1, Table 5-1, Reference 31]

Any corrective actions that are required will be performed in accordance with the CCNPP Corrective Actions Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 4 (disconnect cabinets) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the contactor panels and disconnect cabinets:

- The contactor panels and disconnect cabinets and associated terminal blocks have the intended functions of maintaining the seismic integrity and/or protection of safety-related components and maintenance of electrical continuity under CLB design conditions.
- Electrical stressors, fatigue, and wear are plausible for the carbon steel contactor panels and disconnect cabinets and associated terminal blocks, which could lead to loss of seismic integrity and/or protection of safety-related equipment or loss of electrical continuity under CLB design conditions..
- The CCNPP PM Program will provide for the discovery of the effects of electrical stressors, fatigue, and wear on the contactor panels and disconnect cabinets and associated terminal blocks through the use of EPMs and repetitive tasks. These EPMs and repetitive tasks will be modified to include these ARDMs where they are not presently included, and additional specified components where they are not presently inspected.

Therefore, there is reasonable assurance that the effects of electrical stressors, fatigue, and wear on the contactor panels and disconnect cabinets and associated terminal blocks will be adequately managed to maintain their intended function under all design loadings required by the CLB during the period of extended operation

Group 5 (MCC panels) - Materials and Environment

Table 6.2-3 shows that the MCC panels' terminal blocks are susceptible to the effects of electrical stressors, and the MCC panels are susceptible to fatigue, wear, and dynamic loading. The MCC panels in this group include the emergency diesel generator (EDG) MCC and engine auxiliary MCC panels, and other 480 VAC MCC panels. Only the EDG engine auxiliary MCC panels are susceptible to dynamic loading. The EDG MCC, engine auxiliary MCC, and other MCC panels are made of carbon steel. [Reference 1, MCC-01/02, Attachments 1, 5, 6]

The environment that these device types experience is that of a mild controlled/ventilated atmosphere within the Auxiliary and Turbine Buildings. The EDG engine auxiliary MCCs are located near the EDGs. In this location there is exposure to high-level vibration from the operation of the EDGs. There is also routine maintenance performed on these device types, which requires manipulation of the their subcomponents. Terminal blocks attached to the panels are used for the termination of electrical connections. These blocks are considered to be part of the panels that house them and are included in this evaluation. They are phenolic material subject to the effects of electrical stressors. [Reference 1, MCC-01/02, Attachments 5, 6]

Group 5 (MCC panels) - Aging Mechanism Effects

The effects of electrical stressors and wear were previously discussed in Group 1 (battery terminals, charger and inverter cabinets) and fatigue was discussed in Group 2 (breaker cabinets) under the Aging Mechanisms Effect section.

The EDG MCC, engine auxiliary MCC, and other MCC panels and associated terminal blocks are subject to the conditions described in the Groups 1 and 2 Aging Mechanisms Effect sections and are, therefore, susceptible to the aging effects of these ARDMs. If unmanaged, these ARDMs could eventually result in the loss of seismic support under CLB design loading conditions.

Dynamic loading is only plausible for the EDG engine auxiliary MCC panels. Power plant components and structures are designed to accommodate loads that are expected in service. Experience has shown that while expected loads have been properly treated, dynamic loads not explicitly considered during design have occurred in service, causing material degradation and component failure. Although dynamic loading occurs through phenomena such as water hammer and unstable fluid flow, switchgears are typically not located near the sources of these loads. Components can be subjected to loading due to vibration from equipment such as compressors, diesel generators, and large pumps, as well as vibration from seismic loading. The expected effects of dynamic loading include failure of welds, and failure or degradation of fasteners, hardware, and supports. [Reference 1, MCC-02, Attachments 6, 7]

Since the EDG auxiliary MCC panels are located near the EDGs, which produce vibration, they are considered to be susceptible to dynamic loading. If unmanaged, these plausible ARDMs could eventually result in the loss of seismic support capability under CLB design loading conditions

Group 5 (MCC panels) - Methods to Manage Aging

Mitigation: There are no feasible ways of preventing electrical stressors on the these MCC panels' terminal blocks other than through proper installation and maintenance. There are also no feasible ways of preventing fatigue and wear on the MCC panels other than not operating the contained equipment; therefore, there are no means to prevent fatigue or wear from occurring. In addition, there are no feasible ways of preventing dynamic loading on the EDG engine auxiliary MCC panels other than not running the EDGs. The EDGs must be periodically operated to ensure that they are capable of performing their design function; therefore, there are no means to prevent dynamic loading from occurring.

Discovery: A program of regular maintenance and inspection for the EDG MCC panel, and associated terminal blocks, could discover indications of fatigue in the panel housing welds, indications of wear in fasteners or portions of the MCC panels that are held together for long periods of time, and indications of electrical stressors and dynamic loading before these ARDMs prevent the EDG MCC panels from performing their passive intended function. [Reference 1, MCC-01/02, Attachments 1, 8]

The effects of these ARDMs, as described above, are detectable by visual techniques. Inclusion of EDG engine auxiliary MCC panel and associated terminal blocks in an inspection program that inspects a sample of representative equipment for the signs of these ARDMs during the period of extended operation would provide for the discovery of these ARDMs in the EDG MCC panels. [Reference 1, MCC-02, Attachments 1, 8]

If unmanaged, these ARDMs could eventually result in the loss of seismic support capability under CLB design loading conditions

Group 5 (MCC panels) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited with the mitigation of electrical stressors, fatigue, and wear on the EDG MCC panel and associated terminal blocks and the mitigation of these three ARDMs and dynamic loading on the EDG engine auxiliary MCC panels.

Discovery: The CCNPP PM Program is credited with the discovery of these ARDMs on the MCC panel and associated terminal blocks. Refer to the previous discussion of the CCNPP PM Program in Group 1 (battery terminals, charger and inverter cabinets) under Aging Management Programs.

The PM checklists below are credited for the discovery of the electrical stressors, fatigue, and wear on the EDG MCC panels. The PM checklists direct the user to other procedures (e.g., field tests and evaluation procedures) in performing the necessary inspections to reveal the presence of electrical stressors, fatigue, and wear. These EPMs will be modified to include these ARDMs where they are not presently included, and additional specified components where they are not presently inspected. These checklists are currently performed every six years. [Reference 1, Table 5-3, MCC-01, and Attachments 2, 8, References 32, 33, and 34]

- EPM06093, "Check MCC 2AG Feeder Breakers;"
- EPM06047, "Check MCC 1BG;" and
- EPM06049, "Check MCC 2BG."

Additionally, the following PM checklists are credited with the discovery of electrical stressors, fatigue, and wear on the indicated safety-related 480 VAC MCC panels and their associated terminal blocks. These checklists direct the users in the use of field tests and evaluation procedures for these panels. Each of these checklists is also to be modified in the same manner discussed above and is currently performed every six years. [References 35 through 38]

- EPM06067, "Check MCC 104R and Feeder Breaker;"
- EPM06038, "Check MCC 114R and Feeder Breaker;"
- EPM06051, "Check MCC 204R and Feeder Breaker;" and
- EPM06039, "Check MCC 214R and Feeder Breaker."

A review of maintenance history has yielded no age-related failures of the equipment in this group. Therefore, the ARDI Program will provide for the discovery of the effects of electrical stressors, fatigue, wear, and dynamic loading on the EDG engine auxiliary MCC panel and associated terminal blocks. This program will examine representative samples of susceptible cabinets for signs of these ARDMs. The inspections will determine whether further action is needed and will be performed prior to the period of extended operation. [Reference 1, Attachment 8s] The ARDI Program is defined in the CCNPP IPA Methodology presented in Section 2.0 of this application.

The elements of the ARDI Program will include: [Reference 1, MCC-02, Attachments 1, 2, 8]

- Determination of the examination sample size based on plausible aging effects and device types;
- Identification of a sample of the device type population for inspection prior to the period of extended operation based on plausible ARDMs and the consequences of the loss of device type intended functions;
- 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.

Any corrective actions that are required will be performed in accordance with the CCNPP Corrective Actions Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 5 (MCC panels) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the EDG MCC and engine auxiliary MCC panel and associated terminal blocks:

- These MCC panels and associated terminal blocks have an intended function of maintaining the seismic integrity and/or protection of safety-related components under CLB design conditions.
- Electrical stressors are plausible for the MCC panels' terminal blocks, while fatigue, and wear are plausible for the EDG and safety-related 480 VAC MCC carbon steel panels. Wear, fatigue, and dynamic loading are plausible for the EDG engine auxiliary MCC carbon steel panels. This susceptibility could lead to a loss of seismic integrity and/or protection of safety-related equipment.
- The CCNPP PM Program will provide for the discovery of the effects of electrical stressors, fatigue, and wear on the EDG MCC and safety-related 480 VAC MCC panels and associated terminal blocks through the use of EPMs. These EPMs will be modified to assign additional specified components to the inspection/cleaning activities and to develop checklists for these other specified components. These PMs will also be modified to include these ARDMs where they are not presently included.
- The CCNPP ARDI Program will provide for the discovery of the effects of electrical stressors, fatigue, wear, and dynamic loading that may be of concern for the EDG engine auxiliary MCC panel and associated terminal blocks. Inspections will be performed and appropriate corrective action will be taken if these ARDMs are discovered.

Therefore, there is reasonable assurance that the effects of electrical stressors, fatigue, wear, and dynamic loading on the EDG MCC panels and engine auxiliary MCC panels will be adequately managed in order to maintain their intended function under all design loadings required by the CLB during the period of extended operation.

Group 6 (local control station panels) - Materials and Environment

Table 6.2-3 shows that the 125/250 VDC, 480 VAC, and 4 kV local control station panels and associated terminal blocks are susceptible to the effects of electrical stressors, fatigue, and wear. In addition to these ARDMs, the 480 VAC boric acid pump control panels and saltwater air compressor (SWAC) local control station panels are also susceptible to the effects of general corrosion. All of the enclosures for these device types are constructed of carbon steel. [Reference 1, Attachment 1, NA, NB, ND, Attachments 5, 6]

The environment that these device types experience is that of a mild controlled atmosphere within the CCNPP Auxiliary Building. Terminal blocks attached to the cabinets are used for the termination of electrical connections. These blocks are considered to be part of the panels that house them and are included in this evaluation. They are phenolic material subject to the effects of electrical stressors. The boric acid pump and SWAC local control stations are located in regions with piping that contains either borated water or saltwater. [Reference 1, NB-01, Attachments 6, 7; Reference 1, MCC-02, PNL-01, Attachment 6]

Group 6 (local control station panels) - Aging Mechanism Effects

The effects of electrical stressors, wear, and general corrosion were previously discussed in Group 1 (battery terminals, charger and inverter cabinets) and fatigue was discussed in Group 2 (breaker cabinets) under the Aging Mechanisms Effects sections.

The local control station panels are subject to the conditions described in the Group 1 Aging Mechanisms Effects section and are, therefore, susceptible to the aging effects of these ARDMs. If unmanaged, these ARDMs could eventually result in the loss of seismic support capability under CLB design loading conditions.

General corrosion is plausible for the boric acid pump control panels and SWAC local control station panels. If unmanaged, general corrosion could eventually result in the loss of seismic support capability under CLB design loading conditions. [Reference 1, NB-01]

Group 6 (local control station panels) - Methods to Manage Aging

Mitigation: There are no feasible ways of preventing electrical stressors on the these local control station panels other than through proper installation and maintenance. There are also no feasible ways of preventing fatigue and wear on the local control station panels other than not operating the contained equipment; therefore, there are no practical means to prevent fatigue or wear from occurring.

Discovery: A program of regular maintenance and inspection for the local control panel and associated terminal blocks would discover indications of fatigue in the housing welds, indications of wear in fasteners or portions of disconnect cabinets that are held together for long periods of time, and indications of electrical stressors and general corrosion before these ARDMs prevent the local control stations from performing their passive intended function. [Reference 1, NA-01, NB-01, ND-01, Attachments 1, 8]

Inclusion in a program that examines a representative sample of susceptible local control panels for signs of these ARDMs could provide for the discovery of these ARDMs on these control panels.

Group 6 (local control station panels) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited with the mitigation of electrical stressors, fatigue, wear, and general corrosion on the local control station panel and associated terminal blocks.

Discovery: The CCNPP PM Program is credited for the discovery of electrical stressors, fatigue, and wear on the local control station panels and associated terminal blocks. Refer to the previous discussion of the CCNPP PM Program in Group 1 (battery terminals, charger and inverter cabinets) under Aging Management Programs. The following repetitive tasks and checklists will be modified to include these ARDMs where they are not presently included, and additional specified components, where they are not presently inspected. The various checklists and repetitive tasks credited here are listed in the following groups:

4 kV Panels

Calvert Cliffs EPM04003, "Third Train 4 kV Breaker, Disconnect Switch, Relays, Meter, and Motor," is credited for the discovery of wear on the 4 kV panels and electrical stressors on some of these 4 kV panels' terminal blocks. The PM checklist directs the user to other procedures (e.g., field test and evaluation procedures) in performing the necessary inspections to reveal the presence of electrical stressors and wear. This checklist is currently performed every two years. [Reference 1, Table 5-1, Reference 39]

The PM Program uses repetitive tasks to discover the effects of electrical stressors and wear on local control station panels and associated terminal blocks. The repetitive tasks credited for discovery of these ARDMs are: [Reference 1, Tables 5-1, 5-2, 5-3]

- CCNPP Repetitive Tasks 10120003, "Inspect 13 Salt Water Pump Motor, Normal Feed Breaker, Disconnect Switches, Calibrate Meters and Relays," and 20120003, "Inspect 23 Salt Water Pump Motor, Normal Feed Breaker, Disconnect Switches, Calibrate Meters and Relays," are both credited for the discovery of electrical stressors and wear on the saltwater cooling pump panel and associated terminal blocks. The PM checklist directs the user to perform inspections and to use other procedures (e.g., field test and evaluation procedures) in performing the necessary steps to reveal the presence of electrical stressors and wear. These repetitive tasks are currently performed every three years. [Reference 1, Table 5-3, NA-01, Attachments 1, 2, 8, References 40 and 41]
- CCNPP Repetitive Tasks 10520005, "Inspect 13 HPSI Pump Motor, Normal Feed Breaker, Disconnect Switches, Calibrate Meters and Relays," and 20520001, "Inspect 23 HPSI Pump Motor, Normal Feed Breaker, Disconnect Switches, Calibrate Meters and Relays," are both credited for the discovery of electrical stressors and wear on the high pressure safety injection pumps panel and associated terminal blocks. The PM checklist directs the user to perform inspections and to use other procedures (e.g., field test and evaluation procedures) in performing the necessary steps to reveal the presence of electrical stressors and wear. These repetitive tasks are currently performed every 96 weeks. [Reference 1, Table 5-3, NA-01, Attachments 1, 2, 8, References 42 and 43]

480 VAC Local Control Stations

A review of maintenance history has yielded no age-related failures of the equipment in this group. Therefore, the ARDI Program is credited with the discovery of electrical stressors, fatigue, wear, and general corrosion on the SWAC local control station panels and boric acid pump local control panels and associated terminal blocks. The ARDI Program was previously described in Group 2 (breaker cabinets) under Aging Management Programs.

EPM30701, "CR/CSR Smoke Removal Damper Control Panel 1C108 Inspection," is credited with the discovery of electrical stressors, fatigue, and wear on the Control Room HVAC compressor panel and associated terminal blocks, and an ARDI (as described above) for the same ARDMs on its heater panel and associated terminal blocks. The PM checklist directs the user to clean and inspect these panels to reveal the presence of ARDMs. This checklist is currently performed every 44 weeks. [Reference 1, Table 5-1, NB-01, Attachments 1, 2, 8, Reference 44]

EPM60600, "Containment Cooler Fan MTR/BKR/Controller Inspection," is credited with the discovery of electrical stressors, fatigue, and wear on the containment cooling fan local control station panel and associated terminal blocks. The PM checklist directs the user to perform inspections and to use other procedures (e.g., field test and evaluation procedures) in performing the necessary steps to reveal the presence of these ARDMs. This checklist is currently performed every 96 weeks. [Reference 1, Table 5-1, NB-01, Attachments 1, 2, 8, Reference 45]

Any corrective actions that are required will be performed in accordance with the CCNPP Corrective Actions Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

125/250 VDC Local Control Stations

A review of maintenance history has yielded no age-related failures of the equipment in this group. Therefore, the ARDI Program will provide for the discovery of the effects of electrical stressors and wear on the 125/250 VDC blowdown heat exchanger isolation and Auxiliary Feedwater Pump local control panel and associated terminal blocks if they are present. The ARDI Program was previously described in Group 5 (MCC panels) under Aging Management Programs. [Reference 1, ND-01, Attachments 1, 2, 8]

Any corrective actions that are required will be performed in accordance with the CCNPP Corrective Actions Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 6 (local control station panels) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to electrical stressors, fatigue, wear, and general corrosion on the local control station panels susceptible to these ARDMs:

- The 4 kV, 480 VAC, and 125/250 VDC local control station panels' terminal blocks are susceptible to electrical stressors. These local control station panels are susceptible to fatigue, wear, and general corrosion and have an intended function of maintaining the seismic integrity and/or protection of safety-related components under CLB design conditions.
- The CCNPP PM Program will provide for the discovery of the effects of electrical stressors, fatigue, and wear on the 4 kV and 480 VAC local control station panel and associated terminal blocks through the use of repetitive tasks and EPMs. The repetitive tasks will provide for the discovery of electrical stressors and wear on the 4 kV local control station panel and associated

terminal blocks, while the EPMs will provide for the discovery of electrical stressors, fatigue, and wear on the 480 VAC local control station panel and associated terminal blocks. These repetitive tasks and checklists will be modified to include these ARDMs where they are not presently included, and additional specified components where they are not presently inspected.

- The CCNPP ARDI Program will provide for the discovery of the effects of electrical stressors and/or wear that may be of concern for the 125/250 VDC local control station panels and electrical stressors, fatigue, wear, and general corrosion on the 480 VAC SWAC local control station panels and boric acid pump local control panels. The 480 VAC Control Room HVAC compressor crankcase heater panel and associated terminal blocks are subject to electrical stressors, fatigue, and wear. Inspections will be performed and appropriate corrective action will be taken if these ARDMs are discovered.

Therefore, there is reasonable assurance that the effects of electrical stressors, fatigue, wear, and general corrosion on the 4 kV, 480 VAC, and 125/250 VDC local control station panel and associated terminal blocks will be adequately managed to maintain the intended function of these components under all design loadings required by the CLB during the period of extended operation.

Group 7 (miscellaneous panels) - Materials and Environment

As Table 6.2-3 shows, the miscellaneous panels' terminal blocks are susceptible to the effects of electrical stressors, while the panels are susceptible to fatigue and wear. In addition, the EDG control panels in this group are also susceptible to dynamic loading. The panel enclosures in this group are made of carbon steel. [Reference 1, PNL-01/02/03, Attachments 1, 5, 6]

The environment that these device types experience is that of a mild controlled or ventilated atmosphere within the CCNPP buildings. In some locations, there is exposure to high-level vibration from the operation of the EDGs. There is also routine maintenance performed on these device type, which requires manipulation of their subcomponents. Terminal blocks attached to the cabinets are used for the termination of electrical connections. These blocks are considered to be part of the panels that house them and are included in this evaluation. They are phenolic material subject to the effects of electrical stressors.[Reference 1, PNL-01/02/03, Attachments 5, 6]

Group 7 (miscellaneous panels) - Aging Mechanism Effects

The effects of electrical stressors and wear were previously discussed in Group 1 (battery terminals, charger and inverter cabinets), fatigue was discussed in Group 2 (breaker cabinets), and dynamic loading was discussed in Group 5 (MCC panels) under the Aging Mechanisms Effects sections.

The panels are subject to the conditions described in the Groups 1 and 2 Aging Mechanism Effects sections and are, therefore, susceptible to the aging effects of these ARDMs. If unmanaged, these ARDMs could eventually result in the loss of seismic support capability under CLB design loading conditions

Group 7 (miscellaneous panels) - Methods to Manage Aging

Mitigation: There are no feasible ways of preventing electrical stressors on the panels' terminal blocks other than through proper installation and maintenance. There are also no feasible ways of preventing fatigue and wear on the panels other than not operating the contained equipment; therefore, there are no practical means to prevent fatigue or wear from occurring. In addition, there are no feasible ways of preventing dynamic loading on some of the panels (e.g., EDG control panels) other than not running the EDGs. The EDGs must be periodically operated to ensure that they are capable of performing their design function. Therefore, there is no practical means to prevent dynamic loading from occurring.

Discovery: A program of regular maintenance and inspection for the panels would discover indications of fatigue in the housing welds, indications of wear in fasteners or portions of panels that are held together for long periods of time, indications of electrical stressors, and indications of dynamic loading (e.g., fasteners) before these ARDMs prevent the panels from performing their passive intended function. [Reference 1, PNL-01/02, Attachments 1, 8]

Inclusion in a program that examines a representative sample of susceptible panels for signs of these ARDMs could provide for the discovery of these ARDMs on these panels.

Group 7 (miscellaneous panels) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited with the mitigation of electrical stressors, fatigue, wear, and dynamic loading on the miscellaneous system panel and associated terminal blocks.

Discovery: The CCNPP PM Program is credited with the discovery of these ARDMs on the panel and associated terminal blocks for the plant systems previously listed in the scoping section. Refer to the previous discussion of the CCNPP PM Program in Group 1 (battery terminals, charger and inverter cabinets) under Aging Management Programs. The PM Program utilizes both EPMs and Instrument PMs (IPMs) to discover the effects of electrical stressors, fatigue, and wear on miscellaneous system panel and associated terminal blocks. These EPMs and IPMs will be modified to include these ARDMs where they are not presently included, and additional specified components where they are not presently inspected. Currently, 55% of the panels in this group are covered by PMs, while the remaining panels will be subject to an ARDI Program. The following are the EPMs and IPMs credited for discovery of these ARDMs: [Reference 1, Tables 5-1, 5-2, 5-3, PNL-01/02/03, References 46 through 55]

- EPM02800, “Clean and Inspect 125 VDC Distribution Panels,” will provide for the discovery of wear and electrical stressors on the 125 VDC Electrical Distribution Panel and associated terminal blocks. This checklist is currently performed every 10 years.
- EPM18800, “Clean and Inspect 120V Vital Instrument AC Distribution Panels,” will provide for the discovery of wear and electrical stressors on the 120V Vital Instrument Distribution Panel and associated terminal blocks. This checklist is currently performed every four years.
- EPM32601, “Check SWGR RM HVAC Breakers & Motors,” will provide for the discovery of electrical stressors, fatigue, and wear on the 11/12 and 21/22 switchgear room AC control cabinets and associated terminal blocks. This checklist is currently performed every two years.
- EPM73601, “H2 Recombiner Power Supply and Feeder BKR Inspection,” will provide for the discovery of wear and electrical stressors on the 11, 12, 21 and 22 hydrogen recombiner power supply cabinets and associated terminal blocks. This checklist is currently performed every 96 weeks.

- IPM12104, "Clean and Inspect NSR DAS Fans, Filters, and Printers," will provide for the discovery of electrical stressors and wear on the data acquisition computer panel and associated terminal blocks. This checklist is currently performed every 24 weeks.
- IPM12103, "Clean and Inspect SR DAS Fans and Filters," will provide for the discovery of electrical stressors and wear on the data acquisition computer panel and associated terminal blocks. This checklist is currently performed every 24 weeks.
- IPM13000, "Clean and Inspect Unit 1 ESFAS Cabinet Filters," will provide for the discovery of electrical stressors and wear on the Unit 1 Engineered Safety Features Actuation System (ESFAS) cabinets and associated terminal blocks. This checklist is currently performed every 12 weeks.
- IPM13001, "Clean and Inspect Unit 2 ESFAS Cabinet Filters," will provide for the discovery of electrical stressors and wear on the Unit 2 ESFAS cabinets. This checklist is currently performed every 12 weeks.
- IPM13118, "Clean and Inspect Control RM Panels/Cabinets and Vacuum RVLMS Filters," (RVLMS is Reactor Vessel Level Monitoring System) will provide for the discovery of electrical stressors and wear on the Unit 1 RPS cabinets, Control Room panels, and Nuclear Instrumentation Control Room panels and associated terminal blocks. This checklist is currently performed every two years.
- IPM13119, "Clean and Inspect Control RM Panels/Cabinets and Vacuum RVLMS Filters," will provide for the discovery of electrical stressors and wear on the Unit 2 RPS cabinets, Control Room panels, and Nuclear Instrument Control Room panels and associated terminal blocks. This checklist is currently performed every two years.

The PM Program uses repetitive tasks to discover the effects of electrical stressors and wear on miscellaneous system panel and associated terminal blocks. These repetitive tasks will be modified to include these ARDMs where they are not presently included, and additional specified components where they are not presently inspected. The following repetitive tasks are credited for discovery of electrical stressors and wear for the indicated DG local control panels and plant computer panels. Each of these repetitive tasks is currently performed every five years: [Reference 1, Tables 5-1, 5-2, 5-3, References 56 through 60]

- Repetitive Task 10240015, "1B DG Local Control Panel;"
- Repetitive Task 20240007, "2B DG Local Control Panel;"
- Repetitive Task 10945001, "SSS CPU A PNL (Gould 9750);"
- Repetitive Task, 20945001 "SSS CPU B PNL (Gould 9750);" and
- Repetitive Task 20240009, "2A DG Local Control Panel."

A review of maintenance history has yielded no age-related failures of the equipment in this group. Therefore, the ARDI Program will provide for the discovery of the effects of electrical stressors, fatigue, wear, and dynamic loading on the remainder of the miscellaneous panels and associated terminal blocks. The ARDI Program was previously described in Group 5 (MCC panels) under Aging Management Programs. [Reference 1, PNL-01/02/03, Attachments 1, 2, 8]

Any corrective actions that are required will be performed in accordance with the CCNPP Corrective Actions Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 7 (miscellaneous panels) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to electrical stressors, fatigue, and wear on the miscellaneous panels susceptible to these ARDMs:

- The CCNPP miscellaneous system panels' terminal blocks are susceptible to electrical stressors. The miscellaneous panels are susceptible to fatigue, wear, and dynamic loading, and have the intended functions of maintaining the seismic integrity and/or protection of safety-related components and electrical continuity under CLB design conditions.
- The CCNPP PM Program will provide for the discovery of the effects of electrical stressors, fatigue, wear, and dynamic loading on the miscellaneous system panel and associated terminal blocks through the use of repetitive tasks, EPMs and IPMs. The repetitive tasks and IPMs will discover electrical stressors and wear of the panel and associated terminal blocks, while the EPMs will discover electrical stressors, fatigue, and wear of the panel and associated terminal blocks. These repetitive tasks and checklists will be modified to include these ARDMs where they are not presently included, and additional specified components where they are not presently inspected.
- The CCNPP ARDI Program will provide for the discovery of the effects of electrical stressors, fatigue, wear, and dynamic loading that may be of concern for the miscellaneous system panels and associated terminal blocks. Inspections will be performed and appropriate corrective action will be taken if these ARDMs are discovered.

Therefore, there is reasonable assurance that the effects of these ARDMs on the miscellaneous system panels will be adequately managed to maintain their intended functions under all design loadings required by the CLB during the period of extended operation.

6.2.3 Conclusion

The programs discussed for ECE are listed in the following table. 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 ECE 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 aging management review.

TABLE 6.2-4

LIST OF AGING MANAGEMENT PROGRAMS FOR ECE

	Program	Credited For
Modified	Repetitive Task 10020008, "1 BATT11"	Discovery of general corrosion on the 125 VDC Battery 11 terminals (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10020009, "1 BATT12"	Discovery of general corrosion on the 125 VDC Battery 12 terminals (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20020008, "2 BATT22"	Discovery of general corrosion on the 125 VDC Battery 22 terminals (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20020009, "2 BATT21"	Discovery of general corrosion on the 125 VDC Battery 21 terminals (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20040016, "4 kV Bus 21"	Discovery of the effects of electrical stressors, fatigue, and wear of 4 kV Bus 21 cabinets (Group 3). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20040018, "4 kV Bus 24"	Discovery of the effects of electrical stressors, fatigue, and wear of 4 kV Bus 24 cabinets (Group 3). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10040016, "4kV Bus 11"	Discovery of the effects of electrical stressors, fatigue, and wear of 4 kV Bus 11 cabinets (Group 3). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.

TABLE 6.2-4

LIST OF AGING MANAGEMENT PROGRAMS FOR ECE

	Program	Credited For
Modified	Repetitive Task 10040018, "4kV Bus 14"	Discovery of the effects of electrical stressors, fatigue, and wear of 4 kV Bus 14 cabinets (Group 3). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10240015, "1B DG Local Control Panel"	Discovery of the effects of electrical stressors and wear of the 1B EDG local control panel (Group 7). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20240007, "2B DG Local Control Panel"	Discovery of the effects of electrical stressors and wear of the 2B EDG local control panel (Group 7). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20240009, "2A DG Local Control Panel"	Discovery of the effects of electrical stressors and wear of the 2A EDG local control panel (Group 7). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20320008, "2 HVAC/A SWGR Room A/C Compressor"	Discovery of the effects of electrical stressors, fatigue and wear of the 21 and 22 switchgear room A/C compressor contactor panels (Group 4). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10120003, "Inspect 13 Salt Water Pump Motor, Normal Feed Breaker, Disconnect Switches, Calibrate Meters and Relays"	Discovery of the effects of electrical stressors and wear on the saltwater cooling pump panels (Group 6). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.

TABLE 6.2-4

LIST OF AGING MANAGEMENT PROGRAMS FOR ECE

	Program	Credited For
Modified	Repetitive Task 20120003, "Inspect 23 Salt Water Pump Motor, Normal Feed Breaker, Disconnect Switches, Calibrate Meters and Relays"	Discovery of the effects of electrical stressors and wear on the saltwater cooling pump panels (Group 6). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10520005, "1 SI HPSI Pump 13 Motor"	Discovery of the effects of electrical stressors and wear of the 13 HPSI Pump disconnect panels (Group 6). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20520001, "23 SI HPSI Pump Motor"	Discovery of the effects of electrical stressors and wear of the 23 HPSI Pump disconnect panels (Group 6). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10945001, "SSS CPU A Panel (Gould 9750)"	Discovery of the effects of electrical stressors and wear of the plant computer panels (Group 7). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20945001, "SSS CPU B Panel (Gould 9750)"	Discovery of the effects of electrical stressors and wear of the plant computer panels (Group 7). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Tasks 10020006, "Battery Charger 11" 10020007, "Battery Charger 12" 10020015, "Battery Charger 23" 10020016, "Battery Charger 24"	Discovery of the effects of electrical stressors and wear on the 125 VDC Battery Charger cabinets 11, 12, 23, and 24 (Group 1). These repetitive tasks will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.

TABLE 6.2-4

LIST OF AGING MANAGEMENT PROGRAMS FOR ECE

	Program	Credited For
Modified	Repetitive Tasks 20020002, "Battery Charger 21" 20020003, "Battery Charger 22" 20020014, "Battery Charger 13" 20020015, "Battery Charger 14"	Discovery of the effects of electrical stressors and wear on the 125 VDC Battery Charger cabinets 13, 14, 21, and 22 (Group 1). These repetitive tasks will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10180013, "Inverter 14"	Discovery of the effects of electrical stressors and wear on Inverter 14 cabinet (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10180012, "Inverter 13"	Discovery of the effects of electrical stressors and wear on Inverter 13 cabinet (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20180011, "Inverter 22"	Discovery of the effects of electrical stressors and wear on Inverter 22 cabinet (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20180012, "Inverter 23"	Discovery of the effects of electrical stressors and wear on Inverter 23 cabinet (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20180013, "Inverter 24"	Discovery of the effects of electrical stressors and wear on Inverter 24 cabinet (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10180010, "Inverter 11"	Discovery of the effects of electrical stressors and wear on Inverter 11 cabinet (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.

TABLE 6.2-4

LIST OF AGING MANAGEMENT PROGRAMS FOR ECE

	Program	Credited For
Modified	Repetitive Task 20180010, "Inverter 21"	Discovery of the effects of electrical stressors and wear on Inverter 21 cabinet (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10180011, "Inverter 12"	Discovery of the effects of electrical stressors and wear on Inverter 12 cabinet (Group 1). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10020004, "Inspect DC Bus 11 Disconnects"	Discovery of the effects of electrical stressors and wear of the 125 VDC bus 11 disconnect cabinets (Group 3). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 10020005, "Inspect DC Bus 12 Disconnects"	Discovery of the effects of electrical stressors and wear of the 125 VDC bus 12 disconnect cabinets (Group 3). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20020006, "Inspect DC Bus 21 Disconnects"	Discovery of the effects of electrical stressors and wear of the 125 VDC bus 21 disconnect cabinets (Group 3). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	Repetitive Task 20020007, "Inspect DC Bus 22 Disconnects"	Discovery of the effects of electrical stressors and wear of the 125 VDC bus 22 disconnect cabinets (Group 3). This repetitive task will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.

TABLE 6.2-4

LIST OF AGING MANAGEMENT PROGRAMS FOR ECE

	Program	Credited For
Modified	EPM04003, "Third Train 4 kV Breaker, Disconnect Switch, Relays, Meter, and Motor"	Discovery of the effects of wear and electrical stressors on the 13 and 23 Service Water Pump, Saltwater Pump, and HPSI Pump disconnect panels (Group 6). This PM will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	EPM06067, "Check MCC 104R and Feeder Breaker" EPM06038, "Check MCC 114R and Feeder Breaker" EPM06051, "Check MCC 204R and Feeder Breaker" EPM06039, "Check MCC 214R and Feeder Breaker"	Discovery of the effects of electrical stressors, fatigue, and wear on the safety-related 480 V MCC panels (Group 5). These PMs will be modified to include these ARDMs where they are not presently included, and additional specified components where they are not presently inspected.
Modified	EPM06049, "Check MCC 2BG"	Discovery of the effects of electrical stressors, fatigue, and wear on the EDG MCC 21G panel (Group 5). This PM will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	EPM06093, "Check MCC 2AG and Feeder Breaker"	Discovery of the effects of electrical stressors, fatigue, and wear on the EDG MCC panels 11G (Group 5). This PM will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	EPM60600, "Containment Cooler Fan MTR/BKR/Controller Inspection"	Discovery of the effects of electrical stressors, fatigue, and wear on the Containment Cooling Fan local control station panels (Group 6). This PM will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	EPM60601, "Third Train Containment Filter Motor and Control Inspection"	Discovery of the effects of electrical stressors, fatigue, and wear on the Containment Cooler disconnect cabinets (Group 4). This PM will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.

TABLE 6.2-4

LIST OF AGING MANAGEMENT PROGRAMS FOR ECE

	Program	Credited For
Modified	EPM73601, "H2 Recombiner Power Supply and Feeder BKR Inspection"	Discovery of the effects of electrical stressors and wear on the Hydrogen Recombiner power supply cabinets (Group 7). This PM will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	IPM12104, "Clean and Inspect NSR DAS Fans, Filters, and Printers"	Discover of the effects of electrical stressors and wear on the Data Acquisition computer panels (Group 7). This PM will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	IPM12103, "Clean and Inspect SR DAS Fans and Filters"	Discover of the effects of electrical stressors and wear on the Data Acquisition computer panels (Group 7). This PM will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	IPM13000 "Clean/Inspect Unit 1 ESFAS Cabinets"	Discover of the effects of electrical stressors and wear on the Unit 1 ESFAS cabinets(Group 7). This PM will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	IPM13001, "Clean and Inspect Unit 2 ESFAS Cabinet Filters"	Discover of the effects of electrical stressors and wear on the Unit 2 ESFAS cabinets (Group 7). This PM will be modified to include these ARDMs where they are not presently included and additional specified components where they are not presently inspected.
Modified	EPM02800, "Clean and Inspect 125 VDC Distribution Panels"	Discovery of the effects of electrical stressors and wear on the 125 VDC Electrical Distribution Panels. This PM will be modified to include these ARDMs, where they are not presently included, and any additional specified components where they are not presently inspected (Group 7).

TABLE 6.2-4

LIST OF AGING MANAGEMENT PROGRAMS FOR ECE

	Program	Credited For
Modified	EPM05900, "480V Load Center and Transformer Cleaning and Inspection"	Discovery of the effects of electrical stressors, fatigue and wear on the 480V Bus cabinets. This PM will be modified to include these ARDMs, where they are not presently included, and any additional specified components where they are not presently inspected (Group 3).
Modified	EPM06047, "Check MCC 1BG"	Discovery of the effects of electrical stressors, fatigue, and wear on the EDG MCC panel 12G. This PM will be modified to include these ARDMs, where they are not presently included, and any additional specified components where they are not presently inspected (Group 5).
Modified	EPM18800, "Clean and Inspect 120V Instrument AC Distribution Panels"	Discovery of the effects of electrical stressors and wear on the Service Water distribution panels. This PM will be modified to include these ARDMs, where they are not presently included, and any additional specified components where they are not presently inspected (Group 7).
Modified	EPM30701, "CR/CSR Smoke Removal Damper Control Panel 1C108 Inspection"	Discovery of the effects of electrical stressors and wear on the Control Room HVAC compressor. This will be modified to include these ARDMs, where they are not presently included, and any additional specified components where they are not presently inspected (Group 6).
Modified	EPM32601, "Check Switchgear Room HVAC Breakers and Motors"	Discovery of the effects of electrical stressors, fatigue, and wear on the 11/12 and 21/22 switchgear room AC compressor contactor cabinets. This PM will be modified to include these ARDMs, where they are not presently included, and any additional specified components where they are not presently inspected (Group 7).
Modified	IPM13118, "Clean and Inspect Control Room Panels/Cabinets and Vacuum RVLMS Filters"	Discovery of the effects of electrical stressors and wear on the Unit 1 RPS cabinets, Control Room panels, and Nuclear Instrumentation Control Room panels. This PM will be modified to include these ARDMs, where they are not presently included, and any additional specified components where they are not presently inspected (Group 7).

TABLE 6.2-4

LIST OF AGING MANAGEMENT PROGRAMS FOR ECE

	Program	Credited For
Modified	IPM13119, "Clean and Inspect Control Room Panels/Cabinets and Vacuum RVLMS Filters"	Discovery of the effects of electrical stressors and wear on the Unit 2 RPS cabinets, Control Room panels, and Nuclear Instrumentation Control Room panels. This PM will be modified to include these ARDMs, where they are not presently included, and any additional specified components where they are not presently inspected (Group 7).
Modified	EPM58500, "Reactor Trip Circuit Breaker Inspection"	Discovery of the effects of electrical stressors, fatigue, and wear on the RPS switchgear cabinets (Group 2). This PM will be modified to include these ARDMs, where they are not presently included.
New	CCNPP ARDI Program	Discovery of the effects electrical stressors, fatigue, wear, and dynamic loading on the EDG auxiliary MCC panels (Group 5); electrical stressors and/or wear for 125/250 VDC local control station panels and electrical stressors, fatigue, wear, and general corrosion on the SWAC and Boric Acid Pump local control panels (Group 6); and electrical stressors, fatigue, wear, and dynamic loading on miscellaneous panels (Group 7).

6.2.4 References

1. "CCNPP Aging Management Review Report for the Electrical Commodities, Volumes 1 and 2" Revision 1, July 23, 1997
2. Calvert Cliffs Nuclear Power Plant, Updated Final Safety Analysis Report, Revision 20
3. Letter from Mr. G. C. Creel (BGE) to Mr. T. T. Martin (NRC), dated May 29, 1990, "Unit 1 Startup Assessment"
4. CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," Revision 5, September 27, 1996
5. Letter from Mr. R. W. Cooper II (NRC) to Mr. C. H. Cruse (BGE), dated May 31, 1996, "Calvert Cliffs Plant Performance Review Results"
6. CCNPP Repetitive Task 10020008, "1 Battery 11"
7. CCNPP Repetitive Task 10020009, "1 Battery 12"
8. CCNPP Repetitive Task 20020008, "2 Battery 22"
9. CCNPP Repetitive Task 20020009, "2 Battery 21"
10. CCNPP Repetitive Tasks 10020006, "Battery Charger 11;" 1002007, "Battery Charger 12;" 10020015, "Battery Charger 23;" 10020016, "Battery Charger 24"
11. CCNPP Repetitive Tasks 20020002, "Battery Charger 21;" 2002003, "Battery Charger 22;" 20020014, "Battery Charger 13;" 20020015, "Battery Charger 14"
12. CCNPP Repetitive Task 10180013, "Inverter 14"
13. CCNPP Repetitive Task 10180012, "Inverter 13"
14. CCNPP Repetitive Task 20180011, "Inverter 22"
15. CCNPP Repetitive Task 20180012, "Inverter 23"
16. CCNPP Repetitive Task 20180013, "Inverter 24"
17. CCNPP Repetitive Task 10180010, "Inverter 11"
18. CCNPP Repetitive Task 20180010, "Inverter 21"
19. CCNPP Repetitive Task 10180011, "Inverter 12"
20 CCNPP EPM 58500 Checklist Sheet, "Reactor Trip Circuit Breaker Inspection," Revision 0, April 8, 1993
21. CCNPP Repetitive Task 10020004, "Inspect DC Bus 11 Disconnects"
22. CCNPP Repetitive Task 10020005, "Inspect DC Bus 12 Disconnects"
23. CCNPP Repetitive Task 20020006 "Inspect DC Bus 21 Disconnects"
24. CCNPP Repetitive Task 20020007 "Inspect DC Bus 22 Disconnects"
25. CCNPP EPM05900 Checklist Sheet, "480V Load Center and Transformer Cleaning and Inspection," Revision 0, September 3, 1994
26. CCNPP Repetitive Task 10040016, "4 kV Bus 11"

27. CCNPP Repetitive Task 10040018, "4 kV Bus 14"
28. CCNPP Repetitive Task 20040016, "4 kV Bus 21"
29. CCNPP Repetitive Task 20040018, "4 kV Bus 24"
30. CCNPP EPM60601 Checklist Sheet, "Third Train Containment Filter Motor and Control Inspection" Revision 0, June 8, 1994
31. CCNPP Repetitive Task 20320008, "21 Switchgear HVAC Unit Motor and Breaker Inspection"
32. CCNPP EPM06093 Checklist Sheet, "Check MCC 2AG Feeder Breakers," Revision 1, August 14, 1997
33. CCNPP EPM06047 Checklist Sheet, "Check MCC 1BG," Revision 0, August 14, 1997
34. CCNPP EPM06049 Checklist Sheet, "Check MCC 2BG," Revision 0, August 14, 1997
35. CCNPP EPM06067 Checklist Sheet, "Check MCC 104R and Feeder Breaker," Revision 0, January 8, 1992
36. CCNPP EPM06038 Check List Sheet, "Check MCC 114R and Feeder Breaker," Revision 0, February 3, 1992
37. CCNPP EPM06051 Checklist Sheet, "Check MCC204R and Feeder Breaker," Revision 0, January 3, 1992
38. CCNPP EPM06039 Checklist Sheet, "Check MCC214R and Feeder Breaker," Revision 0, January 3, 1992
39. CCNPP EPM04003 Checklist Sheet, "Third Train 4 V Breaker, Disconnect Switch, Relays, Meter, and Motor" Revision 0, March 20, 1993
40. CCNPP Repetitive Task 10120003, "Inspect 13 Salt Water Pump Motor, Normal Feeder Breaker, Disconnect Switches, Calibrate Meters and Relays"
41. CCNPP Repetitive Task 20120003, "Inspect 23 Salt Water Pump Motor, Normal Feeder Breaker, Disconnect Switches, Calibrate Meters and Relays"
42. CCNPP Repetitive Task 10520005, "Inspect 13 HPSI Pump Motor, Normal Feeder Breaker, Disconnect Switches, Calibrate Meters and Relays"
43. CCNPP Repetitive Task 20520001, "Inspect 23 HPSI Pump Motor, Normal Feeder Breaker, Disconnect Switches, Calibrate Meters and Relays"
44. CCNPP EPM30701 Checklist Sheet, "CR/CSR Smoke Removal Damper Control Panel 1C108 Inspection," Revision 0, January 6, 1993
45. CCNPP EPM60600 Checklist Sheet, "Containment Fan Motor/Breaker/Controller Inspection," Revision 0, July 30, 1994
46. CCNPP EPM02800 Checklist Sheet, "Clean and Inspect 125 VDC Distribution Panels," Revision 0, March 2, 1992
47. CCNPP EPM18800 Checklist Sheet, "Clean and Inspect 120V Vital Instrument AC Distribution Panels," Revision 0, March 2, 1992
48. CCNPP EPM32601 Checklist Sheet, "Check Switchgear Room HVAC Breakers and Motors," Revision 0, January 3, 1992

49. CCNPP EPM73601 Checklist Sheet, “H2 Recombiner Power Supply and Feeder Breaker Inspection,” Revision 0, April 16, 1996
50. CCNPP IPM12104 Checklist Sheet, “Clean and Inspect NSR DAS Fans, Filters, and Printers,” Revision 0, February 15, 1992
51. CCNPP IPM12103 Checklist Sheet, “Clean and Inspect SR DAS Fans, Filters,” Revision 0, February 15, 1992
52. CCNPP IPM13000 Checklist Sheet, “Clean and Inspect Unit 1 ESFAS Cabinet Filters,” Revision 0, November 8, 1991
53. CCNPP IPM13001 Checklist Sheet, “Clean and Inspect Unit 2 ESFAS Cabinet Filters,” Revision 0, November 8, 1991
54. CCNPP IPM13118 Checklist Sheet, “Clean and Inspect Control Room Panels/Cabinets and Vacuum RVLMS Filters,” Revision 0, July 8, 1996
55. CCNPP IPM13119 Checklist Sheet, “Clean and Inspect Control Room Panels/Cabinets and Vacuum RVLMS Filters,” Revision 0, July 8, 1996
56. CCNPP Repetitive Task 10240015, “1B DG Local Control Panel”
57. CCNPP Repetitive Task 20240007 “2B DG Local Control Panel”
58. CCNPP Repetitive Task 10945001, “SSS CPU A Panel (Gould 9750)”
59. CCNPP Repetitive Task 20945001, “SSS CPU B Panel (Gould 9750)”
60. CCNPP Repetitive Task 20020009, “2A DG Local Control Panel”

6.3 Environmentally Qualified Equipment

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Environmentally Qualified (EQ) Equipment. The EQ Equipment has been 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.

Because this section of the BGE LRA provides justification for the aging management afforded by a plant program, the Environmental Qualification (also used as EQ) Program, instead of the techniques utilized for the aging management of a plant system, its approach will differ from the template employed to generate the other BGE LRA sections. It provides three things: (1) a discussion of the program, and the devices included in the program, that indicates how the program provides effective aging management of those passive, long-lived EQ devices that require aging management review (AMR) for license renewal; (2) a discussion of the program and its function as a Time Limited Aging Analysis (TLAA) for license renewal for all long-lived EQ devices; and (3) a discussion of the program with regard to accelerated aging issues in Generic Safety Issue (GSI) 168, "Environmental Qualification of Electrical Equipment." This section of the BGE LRA is provided to specifically address the EQ provision (10 CFR 50.49) of 10 CFR 54.4(a)(3).

6.3.1 Scoping

Title 10 CFR 50.49 requires that the aging of EQ equipment be addressed such that required Design Basis Event (DBE) functionality is ensured if the equipment is exposed to postulated harsh environmental conditions at any time up to and including the end of the equipment's qualified life. The CCNPP EQ Program addresses the effects of aging to ensure that the required electrical equipment EQ functionality is maintained, as required, by analytically determining the qualified life of the program equipment and determining the maintenance required to maintain qualification. The program is also referred to as the CCNPP 50.49 Program. [Reference 1, Section 1.3]

The License Renewal Rule (10 CFR Part 54) requires that the effects of aging of passive, long-lived equipment be managed. During the component level scoping process, described in Section 4.0 of the CCNPP IPA Methodology, the performance of safety-related functions under harsh environmental accident conditions was identified and associated with EQ components designated as SR-5049 on the Calvert Cliffs Quality List (Q-List). During the scoping process to determine structures and components subject to AMR, any structures or components (including those designated as SR-5049) that are replaced at intervals shorter than 40 years, are excluded from further AMR. Those EQ devices with qualified lives greater than or equal to 40 years were included on the list of structures or components subject to AMR, in accordance with 10 CFR 54.4(a)(3), and have been designated for evaluation under this section of the BGE LRA. [Reference 1, Section 1.3]

In this regard, an EQ device may have intended functions in the scope of license renewal that are not managed by the EQ Program. For example, a normally open solenoid valve (SV) may have an EQ function of closure under DBE conditions, and a pressure-retaining license renewal function. The functionality of the operator portion of the valve would be ensured by the EQ Program. Any plausible aging, which could affect the pressure-retaining function, could be managed by the EQ Program (e.g., if the entire SV is replaced at 40 years), or it could be managed by means other than the EQ Program. This section of the BGE LRA addresses the effects of aging on passive, long-lived EQ equipment, whether managed by the

CCNPP 50.49 Program or some other means. Where addressed by other means, those means are identified. [Reference 1, Section 1.3]

6.3.1.1 System Level Scoping

Since the EQ Program is not specific to any particular system and applies, in fact, to many systems, the system level scoping considerations normally addressed are not applicable in this case. [Reference 1, Section 2.0]

6.3.1.2 Component Level Scoping

The equipment which satisfies 10 CFR 50.49(b)(1) and (b)(2) is classified as safety-related and further designated as Class 1E on the Calvert Cliffs Q-List. The equipment which satisfies 10 CFR 50.49(b)(3) was identified in the CCNPP response to NRC Inspection and Enforcement Bulletin (IEB) 79-01B. This equipment is classified as safety-related and further designated as PAM1 or PAM2 on the CCNPP Q-List. Electrical equipment which is required to perform a safety-related function, after being subjected to, or while exposed to, harsh environmental conditions induced by DBEs, is further designated as 5049 on the Q-List. [Reference 1, Section 1.2.2]

Device Types Subject to AMR

Table 6.3-1 contains a summary of those EQ device types that are within the scope of license renewal and includes the applicable abbreviation of each device type. [Reference 1, Table 2-1]

TABLE 6.3-1
SUMMARY OF EQ DEVICE TYPES WITHIN SCOPE OF LICENSING RENEWAL

Cables (CBL)	Core Exit Thermocouple System (RI)
Current/Pneumatic Transducer (I/P)	Seal (SEAL)
Junction Box (WRNMS)	Solenoid Valve (SV)
Level Transmitter (LT)	Terminal Block (TB)
Motors (M, MA, MB)	Temperature Element (TE)
Valve Motor Operator (MOVOP)	Reactor Vessel Level Monitoring System In-Core Assembly (TP)
Neutron Flux Monitoring Instrument Assembly (NE)	
Containment Penetration Assembly (PEN)	Temperature Switch (TS)
Pressure Transmitter (PT)	Vibration Element (VE)
Hydrogen Recombiner (RCMB)	Vibration Signal Transmitter (VT)
Flow Transmitter (FT)	Pressure Switch (PS)
Radiation Element (RE)	Position Switch (ZS)

As seen from this table, EQ equipment includes motor-operated valve operators; however, the associated valve bodies are given their own unique equipment identifiers and are not identified as EQ equipment. In those cases, evaluation of aging mechanisms applicable to the valve body, disc, and seat is under the appropriate equipment group containing these valves and included in the applicable system section of the BGE LRA. When the valve and the operator are a single unit (SVs), and the unique equipment identifier is designated as EQ, then aging of the valve body, internals, and operator are addressed in this section of the BGE LRA. [Reference 1, Section 4.2.2]

After identification of long-lived, passive components, consideration must be given to the aging of these components in their normal service environment. Plausible aging mechanisms are identified from a list of potential age-related degradation mechanisms (ARDMs) based on operating environmental conditions and the presence of material in the component, which is known to be susceptible to the effects of one or more of the potential aging mechanisms. [Reference 1, Section 4.1]

6.3.2 The Aging Management Function of the EQ Program

Section 6.3.2.1 presents the evaluation of the ARDMs for the various EQ device types. Section 6.3.2.2 discusses the CCNPP 50.49 Program that manages these ARDMs. Section 6.3.2.3 provides the operating history and design basis of the program. Section 6.3.2.4 discusses the methods utilized to effectively manage the effects of aging. Section 6.3.2.5 provides a conclusion regarding the effectiveness of aging management of EQ device types at CCNPP.

6.3.2.1 ARDM Evaluation

Of the EQ device types listed in Table 6.3-1, only eight were determined to be subject to AMR. The remaining device types were determined to be active either in the individual system pre-evaluation tasks or in the Instrument Lines Commodity Evaluation. These eight device types subject to AMR are presented in Table 6.3-2 with the ARDMs that could potentially affect them. ARDMs that were evaluated for a device type but were determined to be not plausible have been marked as not plausible using the symbol (×) in the device type's column. Age-related degradation mechanisms that have been determined to be plausible for a device type have been marked with a check mark (✓) in the device type's column. These ARDMs are based on aging from exposure to normal service. [Reference 1, Table 4-1, Section 4.2.3]

TABLE 6.3-2
POTENTIAL AND PLAUSIBLE ARDMS FOR EQ DEVICE TYPES

	EQ DEVICE TYPES SUBJECT TO AMR							
POTENTIAL ARDMS	**CBL**	**PEN**	**SEAL**	**SV**	**TB**	**TP**	**RI**	**WRNMS**
Cavitation Erosion				×				
Corrosion Fatigue				×				
Crevice Corrosion		×		✓		✓	✓	
Erosion Corrosion				×				
Fatigue		×		×				
Fouling				×				
Galvanic Corrosion				×				
General Corrosion		✓		×	×			
Hydrogen Damage		×		×				
Intergranular Attack		×		×				
Kapton Unique Aging				✓				
Microbiologically-Induced Corrosion		×		×				
Oxidation		×		×				
Particulate Wear Erosion				×				
Pitting		×		✓		✓	✓	
Radiation Damage	✓	✓	✓	✓	✓	✓	✓	✓
Rubber Degradation				×				
Selective Leaching				×				
Stress Corrosion Cracking		×		×				
Stress Relaxation		×		×				
Thermal Damage	✓	✓	✓	✓	✓	✓	✓	✓
Thermal Embrittlement		×		×				
Wear				×				

Passive Intended Functions

For the eight EQ device types having plausible ARDMs, Table 6.3-3 identifies their intended functions. Active device types and short-lived device types (requiring periodic replacement of device or device wear parts) are not subject to AMR. The intended functions for each of the device types subject to AMR are included in Table 6.3-3. Active functions are included for information. The passive functions are identified as EQ and non-EQ. [Reference 1, Sections 3.0, 4.0]

TABLE 6.3-3
INTENDED FUNCTIONS FOR DEVICE TYPES REQUIRING AMR

DEVICE TYPE	INTENDED FUNCTION
CBL	Provide electrical continuity for the execution of safety-related functions under harsh environmental conditions associated with a DBE occurring at the end of the plant's licensed life (Passive-EQ).
WRNMS	(1) Provide indication of reactor core neutron flux levels (Active). (2) Provide electrical continuity for the execution of safety-related functions under harsh environmental conditions associated with a DBE occurring at the end of the plant's licensed life (Passive-EQ).
PEN (EPA)	(1) Provide electrical continuity for the execution of safety-related functions under harsh environmental conditions associated with a DBE occurring at the end of the plant's licensed life (Passive-EQ). (2) Provide a containment pressure boundary function to prevent the release of fission products in the event of a DBE occurring at the end of the plant's licensed life (Passive-non-EQ).
RI (CETX)	(1) Provide indication of reactor core exit temperatures (Active). (2) Provide pressure seal at the reactor vessel (Passive-non-EQ). (3) Provide electrical continuity for the execution of safety-related functions under harsh environmental conditions associated with a DBE occurring at the end of the plant's licensed life (Passive-EQ).
SEAL	Prevent moisture intrusion into splices, terminations, conduits, and equipment housings, under accident conditions, to protect cables and equipment relied upon to execute safety-related functions, under harsh environmental conditions, associated with a DBE occurring at the end of the plant's licensed life (Passive-EQ).
SV	(1) Open/close control of venting, sampling, and instrument air (IA) flow paths to support the execution of safety-related functions (Active). (2) Maintain system pressure boundary to support safety-related functions (Passive-non-EQ).
TB	Provide electrical continuity for the execution of safety-related functions under harsh environmental conditions associated with a DBE occurring at the end of the plant's licensed life (Passive-EQ).
TP (RVLMS)	(1) Provide indication of water level in the reactor vessel (Active). (2) Provide pressure seal at reactor vessel (Passive-non-EQ). (3) Provide electrical continuity for the execution of safety-related functions under harsh environmental conditions associated with a DBE occurring at the end of the plant's licensed life (Passive-EQ).

For each of the device types in Table 6.3-3, the following discussions describe the aging management programs in place for each of the plausible ARDMs. Each EQ device type is analyzed in detail in the CCNPP 50.49 Program EQ Files (EQFs). The EQFs for each device type requiring AMR are identified in the following discussions.

Cables (CBL)

The cables subject to AMR (EQFs CBL001, 003, 008, 009, 010, 011, 013, 018, 019, 024, 027, 031, 035, 037, 038, 039, 041, 043, 045, and 046) are susceptible only to radiation and thermal damage. These aging mechanisms affect organic material and are addressed by the CCNPP 50.49 Program to ensure electrical safety-related functionality throughout the component's qualified life. [Reference 1, Tables 4-1 and 4-3]

WRNMS

The Wide Range Nuclear Monitoring System (WRNMS) is susceptible only to radiation and thermal damage, and these ARDMs are managed by the CCNPP 50.49 Program. [Reference 1, Table 4-10]

Penetrations (PEN)

Penetrations are deemed to be susceptible to radiation, thermal damage, and general corrosion, as indicated in Table 6.3-4, for the various penetration types that are subject to AMR. The aging management programs, other than the CCNPP 50.49 Program, and ARDMs indicated in this table by an (*), are addressed in Section 3.3, Structures (under Containment Systems), of the BGE LRA within the discussions for non-EQ and mechanical penetrations. The ARDMs and their managing programs are equivalent. [Reference 1, Table 4-4]

TABLE 6.3-4
AGING MANAGEMENT PROGRAMS FOR PLAUSIBLE PENETRATION (PEN) ARDMS

APPLICABLE EQFS	AGING MECHANISMS	PLAUSIBLE	AGING MECHANISM PROGRAM
EPA004 - Types 2A, 2B, 2C, 2D, 3A, 3C, & 3E	Radiation Damage	No	N/A
	Thermal Damage	No	
	General Corrosion*	Yes	PEG-7*, MN-3-100*, QL-2-100*
EPA004 - Type 3D	Radiation Damage	Yes	CCNPP 50.49 Program
	Thermal Damage	Yes	
	General Corrosion*	Yes	PEG-7*, MN-3-100*, QL-2-100*
EPA010 - Types 2A, 2B, 4A, 4B	Radiation Damage	Yes	CCNPP 50.49 Program
	Thermal Damage	Yes	
	General Corrosion*	Yes	PEG-7*, MN-3-100*, QL-2-100*

Seals (SEAL)

The seals subject to AMR (SEAL01, 02, 04, 06, 08, 09, 10, 11, 12, 13, 14, 15, and 16) are susceptible only to radiation and thermal damage, and these ARDMs are managed by the CCNPP 50.49 Program. [Reference 1, Table 4-5]

Solenoid Valves (SV)

Solenoid valves are susceptible to radiation and thermal damage, crevice corrosion, pitting, and Kapton unique aging (Kapton undergoes accelerated aging when under sufficient mechanical stress in a hot and wet environment), as indicated in Table 6.3-5, for the various SV types that are subject to AMR. The aging management programs and ARDMs indicated in this table by an (*), are addressed in Section 5.13, NSSS Sampling, of the BGE LRA for equivalent SVs. [Reference 1, Table 4-7]

TABLE 6.3-5
AGING MANAGEMENT PROGRAMS FOR PLAUSIBLE SV ARDMS

APPLICABLE EQFS	AGING MECHANISMS	PLAUSIBLE	AGING MECHANISM PROGRAM
SV0026 Target Rock 79 UU-001-1 Reactor Coolant System Vent Service	Radiation Damage	Yes	CCNPP 50.49 Program
	Thermal Damage	Yes	
	Crevice Corrosion, Pitting	No, corrosion of 316SS prevented by low oxygen content of Reactor Coolant System	N/A
SV0029 Valcor V526-5295-xxx Post-Accident Monitoring Service	Radiation Damage	Yes	CCNPP 50.49 Program
	Thermal Damage	Yes	
	Crevice Corrosion*, Pitting*	Yes	Chemistry Control Program* (wetted valves only); Age-Related Degradation Inspection*
	Kapton unique aging	Yes	CCNPP 50.49 Program
SV0034 ASCO NP(L) 8316 A65E IA Service	Radiation Damage	Yes	CCNPP 50.49 Program
	Thermal Damage	Yes	
	Crevice Corrosion, Pitting	No	N/A
SV0038 ASCO NP(L) 8320 IA Service	Radiation Damage	Yes	CCNPP 50.49 Program
	Thermal Damage	Yes	
	Crevice Corrosion, Pitting	No	N/A
SV0038 ASCO (L) 206-381 IA Service	Radiation Damage	Yes	CCNPP 50.49 Program
	Thermal Damage	Yes	
	Crevice Corrosion, Pitting	No	N/A

Terminal Blocks (TB)

The terminal blocks subject to AMR (EQFs TB0001, 0003, 0004, 0005, and 0008) are susceptible only to radiation and thermal damage and these ARDMs are managed by the CCNPP 50.49 Program. The general corrosion ARDM is not plausible since all terminal blocks inside containment are installed in a gasketed junction box with a weephole, and the normal Auxiliary Building environment (temperature and humidity controlled) does not promote corrosion of termination hardware. [Reference 1, Table 4-6]

Reactor Vessel Level Monitoring System Thermocouple Probes (TP)

The Reactor Vessel Level Monitoring system (EQF RVLMSX) is susceptible to four ARDMs as shown in Table 6.3-2. Radiation and thermal damage are managed by the CCNPP 50.49 Program. The crevice corrosion and pitting ARDMs are addressed by Section 4.2, Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System of the BGE LRA. [Reference 1, Table 4-9]

Core Exit Thermocouple System (RI)

The Core Exit Thermocouple System (EQF CETX01) is susceptible to four ARDMs as shown in Table 6.3-2. Radiation and thermal damage are managed by the CCNPP 50.49 Program. The crevice corrosion and pitting ARDMs are addressed by Section 4.2, Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System of the BGE LRA. [Reference 1, Table 4-11]

6.3.2.2 CCNPP 50.49 Program Overview

The control of EQ equipment at Calvert Cliffs is administered under a program designated as the Calvert Cliffs 50.49 Program. The equipment encompassed by this program is all electrical equipment, which satisfies the criteria specified in 10 CFR 50.49(b), and must function while exposed to potentially harsh environmental conditions associated with DBEs. All such equipment is referred to as being EQ. The program manages the following: [Reference 1, Sections 1.1, 1.2.1]

- Qualification of all EQ equipment; and
- Aging of organic subparts to provide reasonable assurance that all EQ equipment will function when subjected to postulated harsh environmental conditions during its qualified life.

Engineering procedures are in place to ensure the program is administered in accordance with 10 CFR 50.49 requirements and BGE quality assurance procedures. As required by 10 CFR 50.49, the aging of EQ equipment is addressed to ensure that, when exposed to harsh environmental conditions, the equipment will perform its intended function as required. The EQ Program at CCNPP is based on the following regulatory requirements: [Reference 1, Section 1.2.1]

- Division of Operating Reactors (DOR) Guidelines as transmitted by NRC IEB 79-01B
- NUREG-0588, Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment
- 10 CFR 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The CCNPP 50.49 Program has the following elements: [Reference 1, Section 1.2.1]

- Identification of the equipment that is required to be EQ per 10 CFR 50.49(b);
- Establishment of documentation that substantiates EQ equipment is EQ;
- Establishment of a maintenance and surveillance program to ensure that qualification is maintained on a continuing basis; and
- Establishment of procedures to describe the requirements and process for development and control of the EQ Program documentation.

Each of these elements is discussed further below.

Identification of Equipment within the Scope of the EQ Program

The equipment which satisfies 10 CFR 50.49(b)(1) and (b)(2) is classified as safety-related and further designated as Class 1E on the Calvert Cliffs Q-List. The equipment which satisfies 10 CFR 50.49(b)(3) was identified in the CCNPP response to NRC IEB 79-01B. This equipment is classified as safety-related and further designated as PAM1 or PAM2 on the CCNPP Q-List. Electrical equipment which is required to perform a safety-related function, after being subjected to, or while exposed to, harsh environmental conditions induced by DBEs, is further designated as 5049 on the Q-List. Selection criteria are outlined in Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation" [Reference 2]. The Q-List and classification process is controlled under EN-1-100, "Engineering Service Process Overview" [Reference 3]. [Reference 1, Section 1.2.2]

Substantiation of EQ

The CCNPP 50.49 Program considers exposure to harsh environmental conditions, i.e., temperature, pressure, humidity (steam), chemical and demineralized water sprays, radiation and submergence, imposed as a result of a DBE. The DBEs include a Loss-of-Coolant Accident (LOCA) or Main Steam Line Break inside containment, or a High Energy Line Break (HELB) outside containment as described in the Updated Final Safety Analysis Report (UFSAR). The specific parameters (limiting conditions) are based upon UFSAR Chapters 14 and 10A. Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions used at CCNPP," [Reference 4] provides the following information: [Reference 1, Section 1.2.3]

- Identification and bases for all DBEs applicable to the EQ Program;
- Identification of harsh and mild environmental areas;
- Environmental profiles for postulated accident conditions; and
- Identification of normal and accident environmental service parameters.

The equipment within the scope of the CCNPP 50.49 Program is qualified by evidence from type tests, analyses, or by any combination of these methods to substantiate that the equipment is capable of meeting, during its qualified life, the required performance as specified in the design basis. The qualification evidence and analysis for a given device type is contained in the EQF for that device type. [Reference 1, Section 1.2.3]

Each item of EQ equipment at CCNPP is qualified either to the DOR Guidelines, NUREG-0588, or 10 CFR 50.49. Note that equipment qualified to the requirements of the DOR Guidelines or NUREG-0588 will not necessarily be replaced during the period of extended operation.

Program Maintenance and Surveillance

Qualification Maintenance Requirement Sheets (QMRS) are developed by the Plant Engineering Section, based on input from the EQFs, to ensure that specific EQ-related installation and maintenance requirements are identified. The QMRS identify the following: [Reference 1, Section 1.2.4]

- Installation requirements to ensure that equipment is installed in accordance with EQ requirements, including sealing and torquing requirements;
- Requirements for EQ electrical connections; and
- Maintenance requirements and frequencies necessary to maintain the EQ of the equipment; e.g., the replacement of 'short-lived' parts such as O-rings.

Each EQ component has an associated QMRS, and NUCLEIS/NORMS, the site nuclear equipment technical database, is utilized to link EQ components to the applicable QMRS.

The "Preventive Maintenance Program," MN-1-102, [Reference 5] is utilized to ensure that the required EQ-related maintenance and replacement intervals are adhered to. Preventive maintenance tasks are created, per MN-1-102, to control these repetitive activities. The use of QMRS is integrated into the maintenance order planning process, which is controlled by MN-1-200, "Maintenance Order Planning." [Reference 6] Corrective maintenance under Rover Maintenance, as outlined in MN-1-101, "Control of Maintenance Activities" [Reference 7], also utilizes the QMRS to ensure EQ components are maintained in accordance with EQ requirements.

Administration of the Program

Calvert Cliffs Engineering Procedure EN-1-103, "Control of 10 CFR 50.49 Environmental Qualification of Electrical Equipment," [Reference 8] Engineering Standards ES-014 [Reference 4] and ES-024, "10 CFR 50.49 Environmental Qualification Program," [Reference 9] are in place to ensure that the CCNPP 50.49 Program is administered in accordance with 10 CFR 50.49 and BGE quality assurance procedures. [Reference 1, Section 1.2.5]

Integration of EQ into the design change process has been an evolving activity. Currently, EN-1-100 controls the design change process. Within the EN-1-100 process, cross-disciplinary 'specialty' design inputs are required to be considered, as outlined in Engineering Standard ES-020, "Specialty Input Screens for the Engineering Service Process." [Reference 10] As part of this specialty design input, EQ is a consideration for all changes. On changes which require EQ input, EQ documentation (EQFs) are prepared/revised by the Design Engineering Section, Electrical Engineering Unit to support the change. The preparation of this EQ documentation is controlled by EN-1-103 and ES-024. Each EQ component has an associated EQF. NUCLEIS/NORMS is utilized to link EQ components to applicable EQ Files. The temporary alteration process, MD-1-100, "Temporary Alterations," [Reference 11] also contains EQ-related specialty design input, similar to EN-1-100, to ensure continued EQ compliance, even with temporary plant changes

When EQ-related deficiencies or nonconformances are identified, an Issue Report is initiated, per QL-2-100, "Issue Reporting and Assessment." [Reference 12] The QL-2-100 process ensures that equipment operability, with the EQ deficiency or nonconformance, is evaluated and determined. The corrective actions to resolve the deficiency or nonconformance are also established and completed in accordance with QL-2-100.

6.3.2.3 Program Operating Experience and Design Basis

The design basis for the EQ Program is NRC IEB 79-01B, applicable generic letters, and 10 CFR 50.49. Calvert Cliffs UFSAR Section 7.12 [Reference 13] provides an overview of the program design basis requirements.

Design Basis

Nuclear Regulatory Commission IEB 79-01B, issued on January 14, 1980, along with Supplements 1, 2, and 3, issued on February 29, September 30, and October 24, 1980, respectively, and NRC Generic Letters 81-05, 81-15, and 82-09 are the EQ Program design basis for:

- Identifying and environmentally qualifying safety-related electrical equipment required to function, while exposed to postulated harsh environment accident conditions, to bring the plant to its licensed 'safe shutdown' condition. Applicable safety-related electrical equipment relied upon, in emergency procedures, to mitigate the postulated accidents and applicable Three Mile Island Action Plan (NUREG-0737) equipment are also to be identified. (Accident conditions were defined in IEB 79-01B as being the result LOCA/HELB inside containment, including areas outside containment where fluids are recirculated to accomplish long-term cooling following a LOCA, and HELB outside containment.)
- Establishing the normal and accident environmental conditions for identified safety-related components.
- Establishing the requirements to be met for EQ of identified safety-related components.

  Note: Nuclear Regulatory Commission IEB 79-01B, Supplement 2, specified that all operating reactors, as of May 23, 1980, must be evaluated against the DOR guidelines. In cases where the DOR guidelines did not provide sufficient detail, NUREG-0588 was to be used.

10 CFR 50.49, issued January 21, 1983 (effective date of February 22, 1983), is the EQ Program design basis for:

- Identifying and environmentally qualifying 'important to safety' electrical equipment required to function while exposed to harsh environmental conditions during and following all applicable DBEs.

  Note: 10 CFR 50.49 expanded the scope of electrical equipment to be included in the EQ Program. Previously, IEB 79-01B required only safety-related electrical equipment be considered. 10 CFR 50.49 also expanded the number of events/accidents to be considered when determining harsh environmental conditions. Previously, IEB 79-01B required only that LOCA/HELB inside containment, and HELB outside containment be considered.

- Identifying and environmentally qualifying certain post-accident monitoring equipment.

  Note: 10 CFR 50.49 provides guidance, in a footnote, on which post-accident monitoring equipment is to be considered. The footnote states, “Specific guidance concerning the types of variables to be monitored is provided in Revision 2 of Regulatory Guide 1.97.”

- Establishing the requirements to be met for qualifying replacement EQ equipment installed subsequent to February 22, 1983.

  Notes: Operating reactors were not required to requalify electrical equipment important to safety in accordance with the provisions of 10 CFR 50.49 if the NRC had previously required qualification of that equipment in accordance with the requirements established in the DOR Guidelines or NUREG-0588.

  10 CFR 50.49 stipulates that replacement equipment must be qualified to the provisions of 10 CFR 50.49 unless there are ‘sound reasons’ to the contrary. NRC Regulatory Guide 1.89, Revision 1, provides these sound reasons. If they are met, then qualification of the replacement equipment to the DOR Guidelines, or NUREG-0588, as applicable, is acceptable. This remains unchanged by the process of license renewal.

Background

In response to IEB 79-01B, CCNPP made various submittals of EQ documentation to the NRC. This documentation was reviewed by the NRC and Safety Evaluation Reports were issued on May 28, 1981, December 16, 1982, and November 20, 1984, concluding that the CCNPP 50.49 Program complies with the requirements of IEB 79-01B and 10 CFR 50.49. These NRC Safety Evaluation Reports were supplemented by various NRC EQ inspections on June 18-20, 1980, October 27-29, 1980, October 15-19, 1984, September 9-13, 1985, March 23-27, 1987, May 11-15, 1987 and February 27-March 3, 1989. These NRC inspections were focused on the detailed implementation of the CCNPP 50.49 Program, as discussed in the various NRC Safety Evaluation Reports, to ensure compliance with IEB 79-01B and 10 CFR 50.49.

In response to 10 CFR 50.49(g), CCNPP submitted its list of electric equipment important to safety, within the scope of 10 CFR 50.49(b), that had already been qualified and had yet to be qualified in its May 10, 1983 letter to the NRC.

Note: NRC submittal requirements were imposed on CCNPP via an NRC letter to BGE dated March 25,1983. These submittal requirements were: 1) to specifically indicate whether previous submittals made in response to IEB 79-01B complied with paragraphs (a) and (b) of 10 CFR 50.49; and 2) to describe in the submittal the methods used to identify the equipment covered by paragraph (b)2 of 10 CFR 50.49, and establish any qualification programs not previously described for such equipment. Both of these submittal requirements were met in BGE’s May 10, 1983 and August 24, 1983 letters to the NRC.

Additional NRC submittal requirements were imposed on CCNPP via NRC letter to BGE, dated May 31, 1984, requiring:

- BGE certification that in performing the review of the methodology to identify equipment within the scope of 10 CFR 50.49(b)(2), CCNPP had performed the 'NRC specified' steps identified in their letter.
- BGE certification that all DBEs which could potentially result in a harsh environment, including flooding outside containment, were addressed in identifying safety-related electrical equipment within the scope of 10 CFR 50.49(1).
- BGE certification that the electrical equipment within the scope of 10 CFR 50.49(b)(3) was all Regulatory Guide 1.97, Category 1 and 2 equipment, or that justification had been provided for any such equipment not included in the EQ Program.

This submittal requirement was met in BGE's July 9, 1984 letter to the NRC.

Nuclear Regulatory Commission Safety Evaluation Report, dated November 20, 1984, concluded that the various submittals made by BGE, in response to the requirements of 10 CFR 50.49(g) and associated NRC letters, were acceptable.

Operating Experience

Over the history of the program, EQ-related issues/problems have been identified by both the NRC and by BGE and its contractors as a result of audits, assessments, and day-to-day plant operation. They have been documented in Nonconformance Reports, Issue Reports, and Program Deficiency Reports as part of CCNPP's deficiency identification and corrective action program.

In each case, the appropriate corrective action was taken as required.

Since the completion of the NRC EQ audits that have been conducted, EQ equipment qualified to the requirements of the DOR guidelines has been replaced with EQ equipment qualified to 10 CFR 50.49. The Facility Change Requests and Minor Change Request that have replaced EQ equipment are as follows:

- Facility Change Request 89-0067 - Replace GE processes Model CR151 terminal blocks on main steam isolation valves (MSIVs)
- Minor Change Request 91-012-030-00 - Replace Johnson Controls Model P-7221 switches on Emergency Core Cooling System pump room temperature controls
- Facility Change Request 83-1031 - Replace Rosemount Model 104-1713-1 resistance temperature detectors on primary loops

Baltimore Gas and Electric Company is a member of the Nuclear Utility Group on Equipment Qualification (NUGEQ). This industry group is comprised of the majority of nuclear utilities in the United States as well as Canada. This group is a working group comprised of technical personnel from each utility who are responsible for the EQ Programs at their plant. This group has, since the early 1980s, provided both technical and licensing support to its members specifically related to the EQ issue as it evolved. Collectively, the group represents the largest collection of EQ experts with the most extensive industry knowledge base in the country. Industry EQ problems and issues are typically addressed by this group, with each member utility benefiting from this knowledge base.

6.3.2.4 Aging Effects Management Methodology [Reference 1, Section 4.3]

The continued functionality of passive, long-lived EQ devices is assured through the following design features, new activities, and on-going activities:

Design Features Credited in Aging Evaluation:

- Where feasible, use of materials that are insensitive to aging mechanisms;
- Location of in-containment terminal blocks above flood level;
- Enclosure of in-containment terminal blocks to prevent spray impingement; and
- Provision of weep holes in the in-containment terminal block enclosures to provide for drainage.

New Activities:

- Age-related degradation inspection of EQF SV0029 (Valcor) SVs called for in Section 5.13, NSSS Sampling System, of the BGE LRA.

On-going Activities:

- Continued administration of the CCNPP 50.49 Program in accordance with 10 CFR 50.49;
- Pressure monitoring and local leak rate testing of penetrations;
- System walkdowns per procedures PEG-7, "Plant Engineering Section System Walkdowns" [Reference 14]; and the Protective Coating Program per procedure MN-3-100, "Painting and Other Protective Coatings," [Reference 15] as applicable to penetrations;
- Keeping instrument air dry and clean to prevent the corrosion of SVs;
- The QL-2-100 Issue Reporting Program [Reference 12] to report and track the resolution of identified problems;
- The continued monitoring of NRC and industry efforts through organizations such as NUGEQ and Nuclear Energy Institute (NEI) to further investigate issues associated with EQ equipment; and
- Membership in one of the available EQ equipment databases.

The CCNPP 50.49 Program addresses the aging of EQ equipment by qualification in accordance with 10 CFR 50.49, and the execution of the required maintenance and/or condition monitoring deemed necessary to maintain the EQ of the equipment. Maintenance includes replacement before the equipment reaches the end of its qualified life. The EQF for each device contains a summary of the results of the qualification process and copies of the relevant documentation. Two of the end products of the qualification process are the determination of the qualified life for the device being evaluated and the maintenance required to maintain the device's qualification. The process is controlled by EN-1-103. [Reference 8]

Each EQF also contains the qualification criteria and criteria justification for the device covered, the identification of the qualification source (10 CFR 50.49, NUREG-0588, or the DOR Guidelines), other standards that are met in the qualification process (such as Institute of Electrical and Electronic Engineers IEEE-323-1974), the qualification methodology used, and the justification for the use of that methodology.

Acceptable methodologies, include testing, analysis, or analysis, derived from partial test data. Performance characteristics are also identified and verified as part of the qualification process to ensure that performance requirements are met. Anomalies are evaluated for impact on the qualification. The accident and normal service environmental conditions used in the qualification of equipment are documented in ES-014. [Reference 4]

The identification of materials susceptible to significant thermal and/or radiological degradation and aging ensures that the limiting subparts of the device drive the qualification process. Arrhenius accelerated pre-aging activation energies, and their source, as well as radiation thresholds, and their source, are identified for use in the qualification process. Synergistic effects are evaluated as applicable based on the best currently available information. Operational stressors are identified and incorporated into the qualification process as needed. Accident service conditions are compared to qualification conditions and margins are identified and evaluated. Note that thermal aging is not required for DOR Guideline qualified equipment.

Installation and interface requirements ensure that the equipment qualification is valid for the equipment installed in the plant. Maintenance requirements ensure that the qualification is maintained throughout the qualified life, and that replacement is performed prior to reaching the end of the equipment's qualified life. Maintenance can include a variety of activities; e.g., replacement of gaskets, or other short-lived subparts, greasing of bearings, etc. Condition monitoring requirements ensure that degradation, which could lead to premature failure if not addressed, is detected. Such degradation would be documented in an Issue Report as a condition adverse to quality/safety and addressed by QL-2-100. [Reference 12]

6.3.2.5 Conclusion for the Aging Management Function of the EQ Program

As a regulatory based and monitored program, the CCNPP 50.49 Program has regulatory approval of its implementation, management, evaluation methodologies, surveillance provisions, and documentation as discussed in Section 6.3.2.3 of the BGE LRA. Based on this and the previous discussion, BGE concludes that the CCNPP 50.49 Program adequately addresses and manages the aging (thermal, radiological, and operational stressors) of EQ devices, which could prevent them from performing their required harsh environment safety functions during their qualified lives, in such a way that the intended functions of these devices will be maintained during the period of extended operation consistent with the current licensing basis (CLB) under all design loading conditions.

6.3.3 The TLAA Function of the EQ Program [Reference 1, Section 5.1]

The CCNPP 50.49 Program is identified as a TLAA for the purposes of License Renewal. The TLAA aspect of EQ encompasses all long-lived EQ equipment whether active or passive. At CCNPP, each EQF for a long-lived component documents a TLAA.

To grant license renewal, 10 CFR 54.29 requires that the NRC find that "Actions have been identified and have or will be taken with respect to the matters identified in Paragraphs (a)(1) and (a)(2) of this section, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB in order to comply with this paragraph are in accord with the Act and the Commission's regulations." The matter identified in (a)(2) is "time-limited aging analyses that have been identified to require review under 10CFR54.21(c)." Whenever the Commission must find that actions "will be taken" rather than "have been taken," the NRC staff has indicated that the following information should be provided to support this finding:

- Details concerning the methodology which will be used for TLAA evaluation;
- Acceptance criteria that will be used to judge the adequacy of the component, consistent with the CLB, when the TLAA evaluation is performed;
- Corrective actions that CCNPP could perform to provide reasonable assurance that the EQ equipment will perform its intended function when called upon or will not be outside of its design basis, established by the plant's CLB; and
- Identification of when the completed TLAA evaluation will be submitted to the NRC to ensure that the necessary evaluation will be performed before any EQ components would not be able to perform their intended functions consistent with the CLB.

Each of these requirements is discussed in detail in the following sections. The information contained in these discussions supports the conclusion that the effects of aging of EQ equipment at CCNPP are being, and will continue to be, managed during the period of extended plant operation. The intent of the above NRC requirements is, therefore, being met.

<u>Methodology for Extending Component Qualified Life</u> [Reference 1, Section 5.2]

Environmentally qualified equipment is replaced with qualified new equipment prior to the end of its qualified life. Preventive maintenance is scheduled to initiate and execute these replacements. Qualified life re-evaluations are an ongoing activity, and consider actual normal operating conditions as compared to design maximums. Qualified lives are adjusted up or down accordingly. The following describes the steps currently taken when re-evaluation of the qualified life (in accordance with 10 CFR 50.49, ES-024 [Reference 9], and engineering oversight procedures) is considered technically viable and economically desirable:

- Review original qualified life bases including assumptions, margin/uncertainty, and margin/uncertainty sensitivity factors;
- Establish margin/uncertainty limits for qualified life;
- Review available aged specimen test data for impact on and validation of margin/uncertainty;
- Review any condition monitoring data for impact on and validation of margin/uncertainty to the degree allowed by regulations;
- Adjust qualified life based on consideration of analytical and test data, condition monitoring data, and refurbishment without violating the qualification margin/uncertainty limits established under the second bullet above; and
- Establish new replacement dates for qualified equipment and establish continuing condition monitoring requirements as appropriate in accordance with plant and 10 CFR 50.49 program procedures.

In the re-evaluation of existing EQFs to determine if the qualification will support use of the devices during the period of extended operation, required qualification margins must be maintained and aging must be analyzed in a conservative manner. Excessive conservatisms in the qualification process to support use in the extended period are available, however. For example, devices that are exposed to temperatures well below the maximum normal design value may be re-evaluated using a bounding value that envelopes the maximum temperatures experienced instead of the maximum design temperature. There is no need to maintain the excess conservatism that exists in the current qualification just because that maximum design temperature was used as the basis for the current qualified life. This concept holds for all equipment qualification parameters, including temperature, pressure, radiation, voltage, currents, and cycling. Required margins must be maintained, so the re-evaluations will in no way change the current qualification envelope for any qualification parameter. They will just be re-evaluated using a lower maximum temperature, referring to the example, to eliminate excessive conservatism while maintaining the current parameter qualification envelopes. The end result of this approach will be an increased qualified life for the device. [Reference 16]

Baltimore Gas and Electric Company participates in and monitors industry developments and data gathering activities relative to EQ of electrical equipment. When information relative to equipment qualification comes to light as a result of these or other activities, BGE evaluates its applicability to CCNPP for incorporation into the EQ Program. The current programs and groups that BGE participates in are described below. Its participation in these programs demonstrates its commitment to quality and safety. [Reference 1, Section 5.2 and Appendix E]

- If an internal safety or quality issue arises, an Issue Report is generated. This initiates BGE's corrective action process. The report is investigated and dispositioned in accordance with plant procedures.
- If an external safety or quality issue arises, BGE will address the concern through its Industry Operating Experience Review Program or its Nuclear Regulatory Matters Unit. Baltimore Gas and Electric Company may be notified of externally generated issues by the NRC (e.g., Information Notices), by manufacturer's or users (e.g., Part 21 notifications), by Institute for Nuclear Power Operations (e.g., Bulletins), or by industry groups (NUGEQ).
- BGE is a member of the Electric Power Research Institute (EPRI), which performs research for the industry in areas of concern to maintain the viability of economical and safe power production. A program currently underway is assessing the aging and condition monitoring of cables in nuclear power plants. Programs of this type change from year to year in support of industry efforts to stay focused on the areas that will yield the maximum economic benefit to BGE.
- BGE is a member of NUGEQ, the industry group that follows industry EQ developments. They identify issues, comment on regulatory concerns, and occasionally generate position papers relative to pertinent issues.

Acceptance Criteria for Judging Adequacy of Components

Re-evaluation, as discussed above, and/or replacement at or before the end of qualified life are acceptable methods for dispositioning a TLAA that determines that a component's qualified life falls short of the end of the period of extended operation. If the re-evaluated qualified life falls short of the end of the period of extended plant operation, then the component will be scheduled for replacement at or before the end of its qualified life. These are the same actions currently taken for the short-lived EQ components under the EQ Program. [Reference 1, Section 5.3]

Note: A portion of the EQ equipment in the plant has a qualified life of 40 years. Some of this equipment has been installed within the last 6 to 16 years. Consequently, the qualified life of the equipment will exceed the current licensed life of the plant, but will not exceed the plant's licensed life with a 20-year period of extended operation. Any new EQ equipment installed today with a qualified life of 40 years would have a qualified life which exceeded the licensed life of the plant, including a 20-year period of extended operation.

Corrective Actions if EQ Component Qualified Life Falls Short of Period of Extended Operation [Reference 1, Section 5.4]

If re-evaluation of an EQ device's qualified life to achieve an effective "plant" life of 60 years cannot be accomplished, then corrective action is required. The only corrective action currently taken by the CCNPP 50.49 Program is replacement with new equipment, qualified in accordance with 10 CFR 50.49, prior to the end of the EQ equipment's qualified life. This same corrective action will be used during the period of extended operation.

An alternative approach to replacement would be to develop reasonable assurance, through condition monitoring, that the EQ equipment's actual age is less than its established qualified life which can be conservative. 10 CFR 50.49 allows such an approach as part of "ongoing qualification;" however, such an alternative approach does not currently exist at CCNPP. In addition, such an alternative does not presently have industry consensus nor regulatory acceptance. As discussed above, CCNPP continues to follow industry and regulatory developments and will keep this option open within the context of complying with regulatory requirements.

Timing of Resolution

Calvert Cliffs typically reassesses the qualified life of EQ equipment, according to existing procedures, sufficiently in advance of the end of qualified life to determine if a revised qualified life can be established, or if equipment replacement is necessary, to maintain EQ functional continuity. This reassessment is performed now under the current EQ Program and will continue to be performed during the period of extended plant operation. [Reference 1, Section 5.5]

Conclusion of the Effectiveness of the TLAA Function of the EQ Program

During the period of extended operation, EQFs will provide the TLAAs for EQ equipment, and will be maintained and controlled under the current EQ Program in the same manner they are maintained and controlled under the CLB in accordance with 10 CFR 50.49. Adjustments will be made in accordance with any new regulatory requirements. When deemed necessary, CCNPP will make changes to the program within the bounds of the then existing regulatory requirements

6.3.4 EQ GSI

According to the BGE IPA methodology and the Statements of Consideration to the License Renewal Rule (60FR22484), there are three options available to resolve issues associated with license renewal which are also the subject of a GSI. Those three options are listed in Sections 6.3.5 and 8.3.2 of the BGE IPA methodology as follows: [Reference 1, Section 6.1]

- If the issue is resolved before BGE LRA (LRA) submittal, the applicant can incorporate the resolution into the LRA;
- An applicant can justify that the CLB will be maintained until a point when one or more reasonable options would be available to adequately manage the effects of aging; or
- An applicant could develop a plant-specific program that incorporates a resolution to the aging issue.

The following issue is identified as Issue 168 of the NRC Task Action Plan. Its description is taken directly from the plan as follows: [Reference 1, Section 6.2]

> "As discussed in SECY-93-049, the staff reviewed significant license renewal issues and found that several related to environmental qualification (EQ). A key aspect of these issues was whether the licensing bases, particularly for older plants whose licensing bases differ from newer plants, should be reassessed or enhanced in connection with license renewal or whether they should be reassessed for the current licensing term. The staff concluded that differences in EQ requirements constituted a potential generic issue which should be evaluated for backfit independent of license renewal.
>
> During the staff's development of an interoffice action plan to address upgrading EQ requirements for older plants during the current licensing term, the staff evaluated the technical adequacy of EQ requirements. As part of this evaluation, the staff reviewed tests of qualified cables performed by SNL *[Sandia National Laboratory]*, under contract with the NRC. The purpose of these tests was to determine the effects of aging on cable products used in nuclear power plants. After accelerated aging, some of the environmentally-qualified cables either failed or exhibited marginal insulation resistance during accident testing, indicating the qualification of some electric cables may have been non-conservative. Although the SNL tests may have been more severe than required by NRC regulations, the test results raised questions with respect to the EQ and accident performance capability of certain artificially-aged cables. Depending on the application, the failure of these cables during or following DBEs could affect the performance of safety functions in nuclear power plants."

As noted in the above description, the focus of this GSI is cables. The adequacy of DOR Guideline qualified equipment has been confirmed in the November 15, 1996 Report to the NRC on Status of the EQ Task Action Plan (WITS 9300107) quoted below:

> "While the staff recognizes that the methodology and requirements imposed on licensees differ according to the original licensing requirements of the plant, the staff concluded that actions taken by the Nuclear Regulatory Commission (NRC) and licensees since the implementation of the EQ rule and the margins inherent in the qualification process itself ensure an acceptable level of safety independent of which qualification requirement was implemented. . . . based on the results of the EQ-TAP *[task action plan]* to date, the staff does not believe there is a significant safety concern that requires immediate regulatory action."

This is reinforced by the following quote from the same report:

> ". . . the staff has concluded that the differences between older and newer EQ requirements do not constitute a significant safety issue, and that adequate margin exists in the qualification process for both older and newer plants to ensure public health and safety . . . "

As of this writing, the major unresolved issues may be categorized as follows: [Reference 1, Section 6.2]

- Issues associated with using accelerated aging to simulate advanced natural aging;
- Issues associated with failure mechanisms of special cables; and
- Issues associated with the efficacy of cable condition monitoring techniques.

The third of these issues (i.e., condition monitoring) addresses a staff position stated in the aforementioned report and quoted below:

> "The staff believes, however, that because of uncertainties in predicting age-related degradation, condition monitoring (i.e., an inservice inspection program) provides the simplest and most effective approach to assuring environmental qualification for the license renewal term. . . . The staff is currently sponsoring research to investigate whether certain condition monitoring techniques can be used successfully to predict the condition of nuclear power plant cables that are within the scope of 10 CFR 50.49."

These major issues are addressed in the following sections. Relative to these discussions, in accordance with the Statements of Consideration and the BGE IPA methodology, BGE will, therefore, maintain its CLB relative to EQ until such time that reasonable options are available to adequately manage the effects of aging. The resolution of this aspect of the GSI applies to the TLAA issue, as well. Environmental qualification of equipment within the scope of the CCNPP 50.49 Program will continue on the basis of the CLB until such time that reasonable options to address this aspect of the GSI are available or until the GSI is considered closed by the NRC. [Reference 1, Section 6.2.1]

Issues Associated with the Accelerated Aging Qualification Process

The principle in question is the use of accelerated aging of equipment to predict its performance when it is aged naturally. With this approach, the equipment is artificially aged by exposing it to temperatures in excess of the normal service temperature. Using Arrhenius methodology, the equipment can be quickly aged to a 40- or 60-year life condition before subjecting it to functional testing under accident conditions. The methodology assumes that thermal aging is the only significant aging mechanism. [Reference 1, Section 6.2.1]

The NRC plans additional research into the area of accelerated versus natural aging. There have been several meetings about the GSI between the NRC and the industry in which BGE has participated. There were originally 43 issues to be addressed during the performance of this research. Through these meetings, the number has been reduced to 19 and there has been a consensus that further reductions are needed to assure cost-effectiveness for the issues that are ultimately addressed. It will, however, be several years before the research is performed and a disposition can be determined. [Reference 1, Section 6.2.1]

Baltimore Gas and Electric Company will continue to meet its CLB relative to EQ, including accelerated aging at elevated temperatures. If data from current or future research activities on naturally-aged cable specimens reveals conclusively that artificially-aged specimens are not conservatively aged prior to LOCA testing, then appropriate adjustments will have to be made to the qualification of relevant cables. Baltimore Gas and Electric Company will continue to follow industry and regulatory developments relative to the issue and will respond to any new regulatory requirements that arise from the resolution of this aspect of the GSI. [Reference 1, Section 6.2.1; Reference 17]

Issues Associated with the Failure Mechanisms of Special Cables [Reference 1, Section 6.2.2]

Explicit identification of failure modes is only needed if failure modes exist which could occur without violation of the established acceptance criteria. An acceptable criteria which is directly linked to critical cable electrical characteristics, or to a known precursor to electrical property changes, precludes the need to explicitly determine cable failure modes.

The EQ of equipment by BGE includes identification of the equipment's safety function and the acceptance criteria for meeting the intended safety function. The acceptance criteria for cables is directly linked to critical cable electrical characteristics or to a known precursor to electrical property changes. Therefore, BGE's practices under the CLB negate the need to specifically identify potential failure modes. Research in this area will continue to be monitored through EPRI and NEI. Baltimore Gas and Electric Company will respond to any new regulatory requirements that arise from the resolution of this aspect of the GSI.

Issues Associated with Condition Monitoring Techniques

The NRC plans to conduct research regarding cable condition monitoring to determine the effectiveness, reliability, and applicability of such techniques relative to the prediction of current cable condition and/or accident survivability. Condition monitoring does not currently have industry consensus or regulatory acceptance as a means of establishing cable residual life. Baltimore Gas and Electric Company will continue to monitor research in this area through EPRI and NEI and will respond to any new regulatory requirements arising from the resolution of this aspect of the GSI. To the extent that regulatory acceptance and economic and technical considerations support it, BGE will consider using condition monitoring when extended life margins warrant reinforcement of analytical results. [Reference 1, Section 6.2.3]

Conclusions of EQ GSI

With regard to this GSI, BGE is opting for the second of the approaches discussed at the beginning of this section, in that it will continue to manage the effects of aging in accordance with the CLB, modified as appropriate to address regulatory changes. The current 40-year equipment lives are, therefore, adequate until the period of extended operation because, under the CLB, EQ equipment is qualified for 40 years using the currently acceptable techniques for calculating such lives.

6.3.5 Conclusions

Calvert Cliffs is a DOR Guidelines plant. This section of the BGE LRA does not change our CLB relative to EQ. Baltimore Gas and Electric Company has DOR Guideline, NUREG-0588, and 10 CFR 50.49 qualified equipment. Calvert Cliffs will continue to function in the period of extended operation as it does today relative to EQ, except as required by changes to regulatory requirements. Equipment that must be replaced due to the approaching end of its qualified life will be replaced in accordance with regulatory constraints associated with 10 CFR 50.49

As a regulatory based and monitored program, the CCNPP 50.49 Program has regulatory approval of its implementation, management, evaluation methodologies, surveillance provisions, and documentation as discussed in Section 6.3.2.3 of the BGE LRA. Based on this and the discussion provided in the balance of Section 6.3.2, BGE concludes that the CCNPP 50.49 Program adequately addresses and manages the aging (thermal, radiological, and operational stressors) of EQ devices, which could prevent them from performing their required harsh environment safety functions during their qualified lives, in such a way that the intended functions of these devices will be maintained during the period of extended operation consistent with the CLB under all design loading conditions.

During the period of extended operation, EQFs will provide the TLAAs for EQ equipment and will be maintained and controlled under the current EQ Program in the same manner they are maintained and controlled under the CLB, in accordance with 10 CFR 50.49. Adjustments will be made in accordance with any new regulatory requirements. When deemed necessary, CCNPP will make changes to the program within the bounds of the then existing regulatory requirements.

With regard to GSI 168, BGE is opting for the provision by which it is allowed to provide justification that the CLB will be maintained until a point when one or more reasonable options will be available to adequately manage the effects of cable aging.

The program analyses/assessments, corrective actions, and confirmation/documentation process for license renewal are in accordance with QL-2, “Corrective Action Program.” QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

6.3.6 References

1. CCNPP Aging Management Review Report for the EQ System, Revision 0, November 1996
2. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation, Revision 1, August 27, 1996
3. CCNPP Administrative Procedure EN-1-100, "Engineering Service Process Overview," Revision 7, March 17, 1997
4. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions Used at CCNPP," Revision 0, November 8, 1995
5. CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," Revision 5, September 27, 1996
6. CCNPP Administrative Procedure MN-1-200, "Maintenance Order Planning," Revision 13, May 9, 1997
7. CCNPP Administrative Procedure MN-1-101, "Control of Maintenance Activities," Revision 14, May 10, 1997
8. CCNPP Administrative Procedure EN-1-103, "Control of 10 CFR 50.49 Environmental Qualification of Electrical Equipment," Revision 0, March 22, 1995
9. CCNPP Engineering Standard ES-024, "10 CFR 50.49 Environmental Qualification Program," Revision 2, September 2, 1996
10. CCNPP Engineering Standard ES-020, "Specialty Input Screens for the Engineering Service Process," Revision 2, April 25, 1997
11. CCNPP Administrative Procedure MD-1-100, "Temporary Alterations," Revision 5, July 17, 1996
12. CCNPP Administrative Procedure QL-2-100, "Issue Reporting and Assessment," Revision 5, March 3, 1997
13. CCNPP UFSAR Section 7.12, "Environmental Qualification of Electrical Equipment Important to Safety"
14. CCNPP Plant Engineering Section Guideline PEG-7, "Plant Engineering Section System Walkdowns," Revision 4, November 30, 1995
15. CCNPP Administrative Procedure MN-3-100, "Painting and Other Protective Coatings," Revision 4, March 10, 1997
16. Electric Power Research Institute TR-104063, "Evaluation of Environmental Qualification Options and Costs for Electrical Equipment for a License Renewal Period for CCNPP," October, 1994
17. CCNPP Aging Management Review Report for the Cables and Terminations (Commodity Evaluation), Revision 1, November, 1996

6.4 Instrument Lines

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing instrument lines. Instrument lines have been evaluated as a “commodity” 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 LRA.

6.4.1 Scoping

6.4.1.1 Instrument Lines Commodity Scoping

For the purposes of this commodity evaluation, an “instrument line” is generally defined as the components located downstream of the process root valve. The “root valve” is the first hand valve off of the main process line or vessel. The root valve provides a point of isolation between the process and the instrument that senses the process. Sometimes piping class considerations require that two root valves be utilized in series to provide double isolation. In such cases, the instrument line begins at the exit of the valve most removed from the process. Both root valves and the connecting piping, fittings, drain/vent valves, etc., between the root valves, are considered part of the process line. [Reference 1, Section 2.3.1.a and Figure 8-F3]

An instrument line may include the following components: [Reference 2, Section 5.3.2]

- Small bore piping (i.e., 2-inch diameter and smaller), tubing, and fittings from the root valve to the instrument;
- Hand valves that are part of the instrument lines (e.g., transmitter equalization, vent, drain, and isolation valves); and
- Any other components associated with the instrument line that contribute substantially to maintaining the pressure-retaining boundary function of the instrument line (e.g., connected instruments and supports for the small bore piping and tubing).

For clarification purposes, an "instrument line" could include tubing and small bore piping that is required for operation of system components (e.g., compressed air lines to air-operated valves) as well as lines for monitoring of the process conditions (e.g., tubing to a pressure indicator).

Instrument lines (i.e., small bore piping, tubing, fittings, valves, and connected instruments) were originally excluded from the CCNPP IPA on the basis that manual actuation of root isolation valves could be credited for maintenance of the system pressure boundary in the event of leakage from an instrument line. Subsequent to the development of this approach, the final version of 10 CFR Part 54 was issued. Section V.3 of the Statements of Consideration for the final License Renewal Rule state that it is not appropriate to generically credit operator action (e.g., manual component isolation), exclusively as adequate aging management for portions of systems that would otherwise require an aging management review (AMR). Therefore, BGE added instrument lines to the IPA as components to be evaluated for AMR. [Reference 3, Section 1.0]

Instrument lines are associated with most plant systems. They perform the same passive function (i.e., maintenance of the system pressure boundary) and are constructed of the same basic materials regardless of the system with which they are associated. For these reasons, it was determined that a commodity evaluation approach would be more efficient than evaluating the instrument lines as part of each system AMR. [Reference 2, Sections 5.3.2 and 7.1.2]

Conceptual Boundaries

As discussed in Section 5.0 of the CCNPP IPA Methodology, system components are assigned to the scope of the instrument lines commodity evaluation during the system pre-evaluation process. The system pre-evaluation includes steps to determine which instrument lines in the system pressure boundary are isolable from the rest of the system pressure boundary using installed root valves. Isolable instrument lines that are connected to portions of the system that perform the pressure boundary passive intended function are assigned to the scope of the Instrument Lines Commodity Evaluation (ILCE).

Since some of the small bore piping and tubing do not have equipment number identifiers in the CCNPP equipment database, the pre-evaluation identifies the root valves and all the components within the isolable instrument lines (e.g., instruments, instrument hand valves) as a means to identify the instrument lines that are in scope for the ILCE. The root valves are normally included within the scope of the system evaluation and not within the scope of the ILCE. [Reference 4, Section 5.2.B.10]

There are also some instrument lines that do not have root valves. Therefore, the system pre-evaluation includes steps to identify any pressure transmitters, pressure indicators, pressure differential transmitters, or similar instruments that have a pressure boundary passive function but are not included within an isolable instrument line. For these instruments, the pre-evaluation determines whether the instrument and its associated components (e.g., tubing, instrument valves) should be included in the ILCE or remain in the system evaluation. [Reference 4, Section 5.2.C.1]

Supports for tubing are also included in the ILCE. Supports for small bore piping and for the instruments connected to the instrument lines are included in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA. Instrument line supports interface with the structure to which they are attached (e.g., wall). At this interface, if anchor bolts are used, there is an overlap between the evaluations of site structures in Sections 3.3A through 3.3E of the BGE LRA and in the ILCE.

The systems for which the pre-evaluation process identified instrument lines within the scope of the ILCE are shown in Table 6.4-1. The CCNPP system numbers and the applicable BGE LRA sections for the systems are also shown in the table. [Reference 3, Section 3.0]

Based on the above, the scope of the ILCE generally includes the instrument lines and associated components (i.e., small bore piping, tubing, tubing supports, fittings, valves, and connected instruments) for the systems shown in Table 6.4-1. However, some of the valves and connected instruments may be scoped in the respective system evaluation. For example, the Nuclear Steam Supply System Sampling evaluation includes the instrument line valves and instruments. Only the Nuclear Steam Supply System Sampling small bore piping and tubing are included in the ILCE. The specific boundaries for each system with the ILCE can be found in the Scoping section of each of the BGE LRA sections referenced in Table 6.4-1.

TABLE 6.4-1

SYSTEMS CONTAINING INSTRUMENT LINES WITHIN THE SCOPE OF THE ILCE

System Number	System Name	BGE LRA Section
011	Service Water	5.17
012	Saltwater	5.16
013	Fire Protection	5.10
015	Component Cooling	5.3
019	Compressed Air	5.4
023	Diesel Fuel Oil	5.7
024	Emergency Diesel Generators	5.8
030	Control Room Heating, Ventilation, and Air Conditioning	5.11.C
032	Auxiliary Building and Radwaste Heating and Ventilation	5.11.A
036	Auxiliary Feedwater	5.1
038	Nuclear Steam Supply System Sampling	5.13
041	Chemical and Volume Control	5.2
045	Feedwater	5.9
052	Safety Injection	5.15
060	Containment Heating and Ventilation	5.11.B
061	Containment Spray	5.6
064	Reactor Coolant	4.1
067	Spent Fuel Pool Cooling	5.18
069	Waste Gas	See Note 1
071	Liquid Waste	See Note 1
077/079	Radiation Monitoring	5.14
083	Main Steam	5.12

Notes for Table 6.4-1

1. The instrument lines and associated components for the Waste Gas and Liquid Waste Systems were included in the pre-evaluation for the Containment Isolation Group of systems. The Containment Isolation Group is discussed in BGE LRA Section 5.5. [Reference 3, Section 3.0 and Appendix A; Reference 5, Attachment 4A]

Operating Experience

Representative historical operating experience pertinent to aging is included to provide insight in supporting the aging management demonstrations provided in Section 6.4.2 of this report. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, through documented discussions with currently assigned cognizant CCNPP personnel, and through other sources as indicated below.

An internal review was performed by BGE in 1996 of CCNPP tubing failures for the period of 1989 through 1995. Approximately 400 maintenance orders (MOs) associated with tubing failures were reviewed. The MOs were generated to resolve the following general types of tubing issues:

- Approximately 93% of the MOs were written for tubing and fitting leaks/failures due to improper maintenance or installation practices;
- Approximately 5% of the MOs were written for tubing abuse; and
- Approximately 1% of the MOs were written for vibration problems.

A breakdown of the tubing failures by year is provided in Table 6.4-2.

TABLE 6.4-2

HISTORY OF TUBING FAILURES AT CCNPP - 1989 THROUGH 1995

Year	Non-Safety Related Tubing/Fitting Failures	Safety-Related Tubing/Fitting Failures	Total Tubing/Fitting Failures
1995	79	3	82
1994	53	3	56
1993	72	5	77
1992	84	9	93
1991	64	0	64
1990	17	0	17
1989	4	0	4
TOTAL	373	20	393

There are approximately 100,000 fittings in the plant (average 10 fittings per instrument and approximately 10,000 instruments for both units). Based on the MOs for 1989 through 1995, the failure rate for all tubing/fittings is 0.056% per year (i.e., [393 failures / 7 years] / 100,000 fittings).

From the information contained in the MOs, the probable root causes of the tubing/fitting failures are as follows:

- **Improper maintenance practices:** loose fitting, improper seating of ferrule, improper make-up of fitting, mixing fitting parts, too much torque applied, damaged tubing fitting, fitting not properly retightenend, dirt entered fitting/ferrules while tubing disconnected;
- **Improper installation practices:** unsupported tubing span, missing support or tube tray clips, missing support hardware; and
- **Tubing abuse:** tubing kinked, bent, crimped, or damaged due to external force (e.g., tubing stepped on).

Based on the information provided by the BGE internal review of tubing failures at CCNPP, it can be concluded that tubing/fitting failures are predominately due to root causes other than age-related degradation. The only tubing failure issue identified that could be construed as age-related was vibration, which accounted for approximately 1% of the tubing failures that were reviewed. Some of these vibration problems may have been due to improper maintenance or installation practices (e.g., loose fittings or missing supports). Vibration problems that are due to causes other than improper maintenance or installation practices are typically resolved by design changes (e.g., strengthening/addition of supports or use of flexible tubing). Therefore, vibration problems are considered the result of installation inadequacies and not the result of normal aging mechanisms.

Based on lessons learned from past tubing failures at CCNPP, corrective actions have been taken to minimize tubing failures for new or modified tubing installations. These actions include the recent development of a technical procedure for proper installation and inspection of compression fittings. This procedure replaced guidelines that relied more on "skill of the craft" for compression fitting installation rather than specific requirements. The procedure includes acceptance criteria to ensure that the fittings are adequately tightened and also provides specific instructions for disconnecting and reconnecting fittings on existing tubing. Other corrective actions taken include training of plant personnel in the use of the new procedure and training to stress the importance of adequate follow-through on lessons learned from industry and site operating experience. [Reference 6]

Scoped Structures and Components and Their Intended Functions

As discussed above, instrument lines all perform the passive intended function of maintaining the system pressure boundary. Based on the discussion in Section 4.1.1 of the CCNPP IPA Methodology, instrument lines that maintain the Reactor Coolant System pressure boundary, maintain radiological boundaries to prevent exceeding 10 CFR Part 100 limits, or maintain safety system boundaries to limit system leakage, are within the scope of license renewal based on §54.4(a)(1) and §54.4(a)(2).

All of the instruments included in the ILCE perform the passive intended function of maintaining pressure boundary in their respective systems and would normally be subject to AMR. However, some instruments also perform active functions (in addition to their pressure boundary function) and are excluded from AMR based on §54.21(a)(1)(i). Pressure transmitters, pressure indicators, and water level indicators are examples of “active” instruments, which perform their intended functions with moving parts or with a change in configuration, and are explicitly excluded from AMR based on §54.21(a)(1)(i). As stated in the NRC Final Safety Evaluation for the CCNPP IPA Methodology, “. . . the pressure retaining boundary of “active” instrumentation may be excluded from an AMR because functional degradation resulting from the effects of aging on active functions is more readily determinable, and existing programs and requirements are expected to directly detect the effects of aging.” For example, aging effects on the diaphragm of a pressure transmitter will affect the analog output of the transmitter (i.e., active function) prior to loss of the transmitter passive pressure boundary function. Surveillance testing or calibration of the transmitter will detect the aging effects on the diaphragm. [Reference 2, Section 7.1.2; Reference 3, Section 2.0; Reference 7, Section 3.7.2]

Other instruments included in the scope of for the ILCE (in addition to pressure transmitters, pressure indicators, and water level indicators) also have active functions and, depending on certain characteristics, may be excluded from AMR. In order to be excluded, age-related degradation of the active function must directly correlate to age-related degradation of the passive pressure boundary function. Instruments that sense pressure as their means of measuring the process have internal subcomponents such as diaphragms, seals, and mechanical linkages to convert the pressure input to an analog output signal (e.g., 4 to 20 milliamps), to provide a digital contact output, or to provide local indication (e.g., meter movement). The conversion of the process pressure to a monitorable output signal or indication would be considered the active function for these pressure sensing instruments. Detrimental effects of aging on the pressure-conversion active function are readily determinable, and existing programs and requirements (such as surveillance testing of response time or calibration of the instrument) are expected to directly detect the effects of aging.

Based on the above, instruments that have one or more of the following characteristics may be excluded from AMR:

- Instruments that sense pressure and have an analog output signal;
- Instruments that sense pressure and have a digital output signal; or
- Instruments that sense pressure and provide local indication by a moving part (e.g., meter movement).

Therefore, examples of other types of instruments (in addition to pressure transmitters, pressure indicators, and water level indicators) that may also be excluded from AMR include:

- Flow transmitters;
- Level transmitters;
- Differential pressure transmitters;
- Level switches;
- Pressure switches; and
- Differential pressure indicators.

Instruments included in the scope of the ILCE that are subject to AMR would include non-pressure sensing instruments such as level sight glasses.

Based on the above, the ILCE components subject to AMR are as follows: [Reference 3, Sections 2.0, 3.0, and 4.0]

- Small bore piping, tubing, and fittings;
- Hand valves;
- Non-pressure sensing instruments; and
- Supports for instrument line tubing.

6.4.2 Aging Management

For efficiency in presenting the results of the aging management evaluations for this report, the ILCE components subject to AMR are grouped as follows:

Group 1 - Includes instrument line pressure boundary components (i.e., small bore piping, tubing, fittings, hand valves, and non-pressure sensing instruments).

Group 2 - Includes instrument line supports.

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.

Group 1 (instrument line pressure boundary components) - Materials and Environment

Group 1 includes the following instrument line pressure boundary components: small bore piping, tubing, fittings, hand valves, and non-pressure sensing instruments.

Instrument tubing at CCNPP is made up of three different materials: carbon steel, stainless steel, and copper. In general, steels are used in liquid systems and copper is used in air applications. Steels are also used in some air applications and copper is used in some oil applications. Liquid systems with more aggressive environments or high purity water primarily use stainless steel instead of carbon steel. Tubing fittings and valves are selected based on the type of tubing: carbon steel for carbon steel tubing, stainless steel for stainless steel tubing, and brass or bronze for copper tubing. Materials for small bore piping and the associated valves and fittings are determined based on the respective piping class. [Reference 1; Reference 3, Section 3.0; Reference 8]

The instrument line pressure boundary components are subjected to internal and external environmental conditions similar to those for the main process line components in their respective systems.

Group 1 (instrument line pressure boundary components) - Aging Mechanism Effects

The small bore piping, tubing, fittings, hand valves, and non-pressure sensing instruments are constructed of materials similar to those for the main process line components in the systems in which they are installed. In addition, they are exposed to internal and external environmental conditions similar to those for the main process line components in their respective systems. For these reasons, any plausible age-related degradation mechanism (ARDM) applicable to the main process line pressure boundary components in a specific system is also considered applicable for the instrument line pressure boundary components in that system. The specific ARDMs are addressed for each of the systems containing instrument lines within the scope of the ILCE per the BGE LRA sections shown in Table 6.4-1. [Reference 3, Section 3.0]

Due to the smaller inside diameter and thinner walls of instrument lines (relative to process piping), and other design considerations such as use of compression fittings, the following potential ARDMs are addressed for instrument line pressure boundary components, since they may not be considered plausible for the system main process line components:

- Fouling;
- Fretting; and
- High cycle fatigue.

Fouling refers to the accumulation of deposits on the inside of components that increases resistance to fluid flow (e.g., long-term accumulation of corrosion products). This ARDM could eventually cause instrument line blockage. However, this ARDM has no impact on the pressure boundary passive intended function. [Reference 3, Section 3.0; Reference 9, Attachment 7 for Pipe]

Fretting is a wear phenomenon that occurs due to small vibratory or sliding motions. For instrument lines, fretting can occur at the tubing/compression fitting interface or at the tubing/tubing support interface. Improperly installed fittings or inadequate support can allow the tubing to vibrate, which could eventually cause loss of tubing material and eventually cause tubing failure. As discussed in the Operating Experience section above, vibration problems are due to installation inadequacies (e.g., improper maintenance or installation practices or design problems) and are not considered the result of normal aging mechanisms. These types of failures typically occur soon after tubing installation or modification. Strict compliance with CCNPP's Instrument and Tubing Installation specification (Reference 1) ensures that failures due to fretting are minimized. [Reference 3, Section 3.0; Reference 9, Attachment 7 for Pipe]

High cycle fatigue occurs when the component cyclic stresses (including modifying factors such as stress concentrations, surface conditions, and plating) exceed the material fatigue strength for the number of cycles. Improperly installed fittings or inadequate support can allow the tubing to vibrate, which could eventually result in fatigue cracking of the instrument line. As discussed in the Operating Experience section above, vibration problems are due to installation inadequacies (e.g., improper maintenance or installation practices or design problems) and are not considered the result of normal aging mechanisms. These types of failures typically occur soon after tubing installation or modification. Strict compliance with CCNPP's Instrument and Tubing Installation specification (Reference 1) ensures that failures due to high cycle fatigue are minimized. [Reference 3, Section 3.0; Reference 9, Attachment 7 for Pipe]

Based on the above, the "instrument line specific" potential ARDMs (i.e., fouling, fretting, and high cycle fatigue) are not considered plausible aging mechanisms. Only the plausible ARDMs applicable to the pressure boundary components in the systems shown in Table 6.4-1 are considered applicable for the instrument line pressure boundary components in those systems.

The plausible ARDMs applicable to the main process line pressure boundary components, if unmanaged, could eventually result in effects such that the instrument line pressure boundary components may not be able to perform their pressure boundary function under CLB conditions. Therefore, the effects of these ARDMs must be managed for the instrument line pressure boundary components.

Group 1 (instrument line pressure boundary components) - Methods to Manage Aging

Since the instrument line pressure boundary components are subject to the same plausible ARDMs as the main process line pressure boundary components in their respective systems, the methods to manage aging of the instrument line components would be the same as for these main process line components. Some of the ARDMs can be mitigated by minimizing the exposure of the components to an aggressive environment. This can sometimes be accomplished by methods that control the environment (e.g., maintaining process fluid chemistry or maintaining dry air in the Instrument Air System). For ARDMs that cannot be mitigated or to provide additional assurance that degradation is not occurring, discovery methods such as visual inspections can be used.

Group 1 (instrument line pressure boundary components) - Aging Management Program(s)

As discussed above, there are similarities between instrument line pressure boundary components and the main process line pressure boundary components with respect to materials, internal and external environments, plausible ARDMs, and methods to manage aging. Therefore, the aging management programs applicable to the main process line pressure boundary components, for the systems shown in

Table 6.4-1, would also be effective in managing aging for the instrument line pressure boundary components. For example, if a system credits a chemistry program to mitigate crevice corrosion and pitting in a main process line, the chemistry program would directly apply to the connected instrument lines due to the common fluid. Discovery programs such as the Age-Related Degradation Inspection (ARDI) Program that are credited for specific main process line pressure boundary components, bound the aging management for the instrument line pressure boundary components. The results of these inspections (including the associated corrective actions) provide the means to discover age-related degradation for the instrument line pressure boundary components, as discussed below. [Reference 3, Section 3.0]

All of the CCNPP aging management programs require that corrective actions be taken if any actual or suspected conditions adverse to quality are identified (e.g., chemistry parameters out of acceptable range, age-related degradation discovered). Conditions adverse to quality are documented on Issue Reports in accordance with the CCNPP Corrective Actions Program. Issue Reports are required to identify the extent of the issue, including the suspected boundary of the problem. In addition, Issue Reports are required to indicate if the problem could have generic implications or affect the operability of other associated equipment and systems. Corrective actions are taken as required as part of the Issue Report resolution process. [Reference 10, Section 1.2.A; Reference 11, Section 5.5.A, Attachment 1]

Based on the above, if conditions adverse to quality are identified in a main process line, then the boundary of the problem and generic implications would be investigated. The scope of the investigation would be expanded to include the associated instrument lines, if applicable. For example, age-related degradation discovered in a main process line during a visual inspection would cause an Issue Report to be initiated. Generic implications and the boundary of the degradation would be identified as part of the Issue Report process (i.e., other components or systems may also be experiencing degradation due to the same root cause). As a result of the investigation, the scope of the visual inspections may need to be expanded to the instrument lines in order to determine the full extent of the degradation in the system. [Reference 3, Section 3.0]

To provide further assurance that aging for the instrument line pressure boundary components is managed, the ARDI Program will provide guidance regarding the expansion of scope from the main process lines to the instrument lines if conditions adverse to quality are found. Age-related degradation in the main process lines is expected to occur prior to age-related degradation of the instrument lines, since the main process lines are typically exposed to more aggressive environments. The fluid temperature in instrument lines generally decreases to near ambient room temperature within several feet of the main process line connection. Therefore, corrosion rates (which typically increase with temperature) are expected to be lower in the instrument lines than the main process lines. In addition, instrument lines lack flow. Therefore, degradation from flow-dependent ARDMs such as erosion corrosion is not expected in the instrument lines. [Reference 1, Figure 8-F6; Reference 3, Section 3.0; Reference 12, pages 21 and 76]

The corrective actions taken as a result of conditions adverse to quality identified for the main process line pressure boundary components (during aging management program activities) will ensure that the instrument line pressure boundary components will remain capable of performing their pressure boundary function under all CLB conditions during the period of extended operation.

Group 1 (instrument line pressure boundary components) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the instrument line pressure boundary components:

- The instrument line pressure boundary components (i.e., small bore piping, tubing, fittings, hand valves, and non-pressure sensing instruments) have the passive intended function of maintaining the system pressure boundary under CLB conditions.
- The ARDMs applicable to the main process line pressure boundary components are also applicable to the instrument line pressure boundary components. These ARDMs, if unmanaged, could eventually result in effects such that the instrument line pressure boundary components may not be able to perform their pressure boundary function under CLB conditions.
- The aging management programs applicable to the main process line pressure boundary components, for the systems shown in Table 6.4-1, provide the means to mitigate and/or discover age-related degradation for the instrument line pressure boundary components.
- To provide further assurance that aging for the instrument line pressure boundary components is managed, the ARDI Program will provide guidance regarding the expansion of scope from the main process lines to the instrument lines if conditions adverse to quality are found.
- Corrective actions taken as a result of conditions adverse to quality identified for the main process line pressure boundary components (during aging management program activities) will ensure that the instrument line pressure boundary components will remain capable of performing their pressure boundary function.

Therefore, there is reasonable assurance that the effects of the applicable ARDMs will be managed for the instrument line pressure boundary components such that they will be capable of performing their pressure boundary function**,** consistent with the CLB, during the period of extended operation.

Group 2 (instrument line supports) - Materials and Environment

Group 2 consists of supports for instrument line tubing.

The materials of construction for instrument line supports include: carbon steel, stainless steel, brass, bronze, aluminum, and elastomers. [Reference 3, Section 4.0]

The plant environmental conditions are as follows: [Reference 13, Sections 5.4.A and 5.4.C]

Inside Containment:

- The maximum design ambient air temperature is 120°F for normal conditions.
- The design ambient air relative humidity during normal plant operation is 50% at 120°F and 14.7 psia.

In other buildings:

- Ambient temperatures are controlled by plant ventilation systems, as specified in Updated Final Safety Analysis Report Chapter 9. The plant ventilation systems are designed to provide minimum (winter) and maximum (summer) building air temperatures, as specified in Updated Final Safety Analysis Report Table 9-18. Certain areas are maintained by safety-related ventilation systems.

The remaining areas are ventilated by non-safety-related ventilation systems and are maintained at or below the maximum design temperatures.

- There are no design humidity requirements for the plant areas outside containment.

Outdoors:

- Instrument line supports located outdoors are subject to the site environmental conditions described in Updated Final Safety Analysis Report Chapter 2.0.

Commonly used subcomponent parts for instrument line supports include: [Reference 1]

- Structural steel (E.G., Plates, Channel);
- Clamps (typically constructed of carbon steel, stainless steel brass, or aluminum);
- Nuts, bolts, and washers (typically constructed of carbon or stainless steel); and
- Elastomer tubing tray filler material (used to secure tubing within tubing tray).

Group 2 (instrument line supports) - Aging Mechanism Effects

Instrument line supports are subject to general corrosion and elastomer hardening. General corrosion is only plausible for the carbon steel subcomponents of the supports (e.g., structural steel, clamps, nuts, bolts, and washers). Elastomer hardening is only plausible for the elastomer subcomponents of the supports (i.e., elastomer tubing tray filler material). [Reference 3, Section 4.0]

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The consequences of the damage are loss of load carrying cross-sectional area. General corrosion requires an aggressive environment and materials susceptible to that environment. Uncoated carbon steel components will corrode in moist environments. General corrosion is plausible for the carbon steel subcomponents of the instrument line supports due to normal humidity levels in the plant and due to potential leakage of water from components in the vicinity of the supports. The effects of general corrosion on the instrument line supports would be a loss of support material and reduction in the support strength if the ARDM were allowed to progress unmanaged. Exposed carbon steel surfaces at CCNPP are covered with a protective coating in accordance with Reference 14. However, during the plausibility determination, no credit was taken for the protective coating applied to these instrument line support subcomponents. [Reference 9, Attachment 7s; Reference 15; Pages 2-3 and 2-10]

Extended exposure to light, heat, oxygen, ozone, water, or radiation can cause scission or crosslinking of the polymer chains forming elastomer materials. Chain scission (the breaking of chemical bonds) lowers the elastomer tensile strength and elastic modulus. Crosslinking (undesirable linking of adjacent polymer strings at susceptible sites) causes elastomers to become more brittle and promotes surface cracking. Elastomer hardening is plausible for the tubing tray filler material due to normal plant environmental conditions. Elastomer hardening of this instrument line support subcomponent could allow excessive movement of tubing within the tubing trays if the ARDM were allowed to progress unmanaged. [Reference 15, Page 2-4]

These aging mechanisms, if unmanaged, could eventually result in insufficient support being afforded to the instrument lines such that the instrument lines may not be able to perform their pressure boundary function under CLB conditions. Therefore, general corrosion and elastomer hardening were determined to be plausible ARDMs for which the aging effects must be managed for the instrument line supports.

Group 2 (instrument line supports) - Methods to Manage Aging

Mitigation:

To mitigate the effects of general corrosion, the conditions on the external surfaces of the carbon steel subcomponents of the instrument line supports must be controlled. Preventing direct and prolonged contact between the carbon steel surfaces and moisture is an effective mitigation technique for general corrosion. Therefore, to mitigate general corrosion, protective coatings ensure that the carbon steel subcomponents are not in contact with a moist, aggressive environment for extended periods of time. In addition, plant activities that identify conditions such as degraded paint or leaking water can be used to mitigate the effects of general corrosion.

Since elastomer hardening is affected by exposure to environmental conditions that are not feasible to control (e.g., light, heat, oxygen, ozone, water, radiation), there are no practical means to mitigate its effects.

Discovery:

The effects of general corrosion are detectable by inspection. The external surfaces of the carbon steel subcomponents of the supports are covered by a protective coating, and observing that significant degradation has not occurred to this coating is an effective method to ensure that corrosion has not affected the intended function of the support. Coatings degrade slowly over time, allowing visual detection during normal operations. Since the coating does not contribute to the intended function of the supports, observing the coating for degradation provides an alert condition that triggers corrective action prior to degradation that affects the support's ability to perform its intended function. The degradation of the protective coating, or any actual corrosion that does occur, can be discovered and monitored by periodically inspecting the supports and by carrying out corrective action as necessary.

The effects of elastomer hardening are detectable by inspection. The inspection would need to examine the tubing tray filler material for signs of surface cracking and could also include a hands-on examination to detect brittleness. If significant degradation is found, appropriate corrective action (e.g., replacement of tubing tray filler material) can be taken to ensure that the instrument line support continues to perform its intended function.

Group 2 (instrument line supports) - Aging Management Program(s)

Mitigation:

The external surfaces of the carbon steel subcomponents of the supports are covered by a protective coating that mitigates the effects of general corrosion. The discovery programs discussed below ensure that the protective coatings are maintained and that plant housekeeping conditions are such that general corrosion is mitigated (e.g., discovery of water leakage).

There are no CCNPP programs credited with mitigation of elastomer hardening for the instrument line supports.

Discovery:

To verify that no significant general corrosion or elastomer hardening is occurring on the instrument line supports, a new plant program will be developed to provide inspections of representative supports. The program is considered an ARDI Program as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA). The program details are provided below. [Reference 3, Section 4.0]

ARDI Program

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.

Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Actions Program and will ensure that the instrument line supports remain capable of performing their passive intended function under all CLB conditions.

In addition to the ARDI Program, ongoing plant activities are credited with managing general corrosion either by discovery of corrosion or by discovery of poor housekeeping conditions that could eventually lead to general corrosion (e.g., degraded paint or leaking water). The CCNPP procedures for Structure and System Walkdowns, Control of Shift Activities, and Ownership of Plant Operating Spaces govern these ongoing activities. The programs are discussed below.

Structure and System Walkdowns

Calvert Cliffs Administrative Procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of general corrosion (or conditions that could allow general corrosion to progress) for the instrument line supports by performance of visual inspections during plant walkdowns. The purpose of the program is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. [Reference 16, Section 1.1]

Under this program, responsible personnel perform periodic walkdowns of their assigned structures and systems. Walkdowns may also be performed as required for reasons such as: material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when the system is initially pressurized, energized, or placed in service); and as required for plant modifications. [Reference 16, Section 5.1]

One of the objectives of the program is to assess the condition of the CCNPP structures, systems, and components such that any degraded condition will be identified, documented, and corrective actions taken before the degradation proceeds to failure of the structures, systems, and components to perform their intended functions. Conditions adverse to quality are documented and resolved by the CCNPP Corrective Actions Program. [Reference 16, Sections 5.1.C, 5.2.A.1, and 5.2.A.5]

The program provides guidance for specific types of degradation or conditions to inspect for when performing the walkdowns. Inspection items related to aging management include the following: [Reference 16, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion or vibration;
- Effects that may have been caused by ARDMs such as damaged supports; concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, or inadequate support of components (e.g., missing, detached , or loose fasteners and clamps).

Specifically for walkdowns of mechanical systems, the program inspects for proper installation of instrumentation, leaking fittings, and missing components on tubing supports. [Reference 16, Attachment 1]

This program promotes familiarity of the systems by the responsible personnel and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance alone. The program has been improved over time, based on past experience, to provide guidance on specific activities to be included in the scope of the walkdowns.

The corrective actions taken as a result of this program will ensure that the instrument line supports remain capable of performing their passive intended function under all CLB conditions.

Control of Shift Activities

Calvert Cliffs Administrative Procedure NO-1-200, "Control of Shift Activities," provides for discovery of conditions that could allow general corrosion to progress for the instrument line supports by performance of visual inspections during plant operator rounds. The purpose of the program is to ensure that shift operations are conducted in a safe and reliable manner and within the scope of the operator's license, procedures, and applicable regulatory requirements. [Reference 17, Section 1.1]

Under this program, plant operators inspect accessible operating spaces each shift. The containment is also inspected once per shift when the plant is shutdown and the containment is open for normal access. Conditions adverse to quality that are identified during the operator rounds are documented and resolved by the CCNPP Corrective Actions Program. [Reference 17, Section 5.8.B]

The program provides guidance for specific conditions to inspect for when performing the walkdowns. Inspection items related to aging management include the following: [Reference 17, Section 5.8.B]

- Items related to specific ARDMs such as vibration;
- Effects that may have been caused by ARDMs such as damaged piping and instrument tubing, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as leakage of fluids.

Operator rounds have been historically effective in identifying plant deficiencies. The documented guidance and expectations have been improved over the years as a result of lessons learned and the site emphasis on continual quality improvement.

The corrective actions taken as a result of this program will ensure that the instrument line supports remain capable of performing their passive intended function under all CLB conditions.

Ownership of Plant Operating Spaces

Calvert Cliffs Administrative Procedure NO-1-107, "Ownership of Plant Operating Spaces," provides for discovery of general corrosion (or conditions that could allow general corrosion to progress) for the instrument line supports by performance of visual inspections on plant operating areas. The purpose of the program is to provide requirements and guidance on personnel accountability for the correction of housekeeping, material, and radiological deficiencies. The individual responsibilities stated in the procedure are carried out in order to establish a program that will improve the housekeeping and material condition of the plant operating areas on a long-term basis. [Reference 18, Section 1.1]

Under this program, owners are identified within each space and provide a point of contact for any individual who finds deficiencies or any concern with the space. The responsible individuals are required to periodically inspect their assigned space(s) for housekeeping/cleanliness, material condition, and radiological protection deficiencies. Conditions adverse to quality that are identified are documented and resolved by the CCNPP Corrective Actions Program. [Reference 18, Sections 4.4, 5.1, and 5.2]

The program provides guidance for types of deficiencies to look for when performing the inspections. Inspection items related to aging management include the following: [Reference 18, Attachment 2]]

- Items related to specific ARDMs such as corrosion;
- Effects that may have been caused by ARDMs such as loose lines/pipes, loose fasteners, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as unbracketed lines/pipe, missing fasteners, inadequate paint, or leakage of fluids.

The corrective actions taken as a result of this program will ensure that the instrument line supports remain capable of performing their passive intended function under all CLB conditions.

Group 2 (instrument line supports) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the instrument line supports:

- The instrument line supports have the passive intended function of maintaining the system pressure boundary under CLB conditions.
- General corrosion and elastomer hardening were determined to be plausible ARDMs for the instrument line supports. These ARDMs, if unmanaged, could eventually result in insufficient support being afforded to the instrument lines such that the instrument lines may not be able to perform their pressure boundary function under CLB conditions.
- General corrosion is mitigated by applying protective coatings to the instrument line supports, periodically examining the supports for degradation of that coating or conditions that could accelerate degradation, and by maintaining the coatings.
- The ARDI Program will conduct inspections of representative instrument line supports to discover the effects of general corrosion and elastomer hardening, and will contain acceptance criteria that ensure corrective actions will be taken such that there is reasonable assurance that the supports remain capable of performing their passive intended function under all CLB conditions.
- Ongoing plant activities (Structure and System Walkdowns, Control of Shift Activities, and Ownership of Plant Operating Spaces) provide for the discovery of general corrosion (or conditions that could allow general corrosion to progress) for the instrument line supports by performance of visual inspections. Corrective actions will be taken such that there is reasonable assurance that the supports remain capable of performing their passive intended function under all CLB conditions.

Therefore, there is reasonable assurance that the effects of general corrosion and elastomer hardening will be managed for the instrument line supports such that the instrument lines will be capable of performing their pressure boundary function**,** consistent with the CLB, during the period of extended operation.

6.4.3 Conclusion

The programs discussed for instrument lines are listed in the following table. 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 instrument lines 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 6.4-3

LIST OF AGING MANAGEMENT PROGRAMS FOR INSTRUMENT LINES

	Program	Credited For
Existing	Structure and System Walkdowns (MN-1-319) Control of Shift Activities (NO-1-200) Ownership of Plant Operating Spaces (NO-1-107)	Discovery of the effects of general corrosion for the instrument line supports (Group 2).
New	ARDI Program	Providing guidance for expansion of scope from the main process lines to the instrument lines if conditions adverse to quality are found (Group 1). Discovery of the effects of general corrosion and elastomer hardening for the instrument line supports (Group 2).

6.4.4 References

1. CCNPP Drawing 92401, "Instrument and Tubing Installation," Revision 18, July 31, 1996
2. "CCNPP Integrated Plant Assessment Methodology," Revision 1, January 11, 1996
3. "CCNPP Aging Management Review Report for the Instrument Line Commodity," Revision 1, August 4, 1997
4. CCNPP Administrative Procedure EN-1-304, "Component Pre-Evaluation," Revision 2, April 9, 1997
5. "CCNPP Component Pre-Evaluation for the Containment Isolation Group (013, 029, 037, 051, 053, 069, 071)," Revision 0, March 19, 1997
6. CCNPP Technical Procedure TUBE-01, "Fabrication and Installation of Parker CPI and Swagelok Compression Fittings," Revision 1, October 1, 1997
7. Letter from Mr. D. M. Crutchfield (NRC) to Mr. C. H. Cruse (BGE), dated April 4, 1996, "Final Safety Evaluation (FSE) Concerning Baltimore Gas & Electric Company Report Entitled, "Integrated Plant Assessment Methodology"
8. CCNPP Drawing 92767, "M-600 Piping Class Sheets," Revision 1, April 20, 1994
9. "CCNPP Aging Management Review Report for the Saltwater System," Revision 4, February 11, 1997
10. CCNPP Directive QL-2, "Corrective Actions Program," Revision 2, January 2, 1996
11. CCNPP Administrative Procedure QL-2-100, "Issue Reporting and Assessment," Revision 5, March 3, 1997
12. "Corrosion Engineering," Second Edition, M. G. Fontana and N. D. Greene, McGraw-Hill Book Company, Copyright 1978
13. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0, November 8, 1995
14. CCNPP Technical Requirements Document TRD-A-1000, "BGE Coating Application Performance Standard," Revision 14, September 29, 1997
15. "CCNPP Aging Management Review Report for Component Supports," Revision 3, February 4, 1997
16. CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns," Revision 0, September 16, 1997
17. CCNPP Administrative Procedure NO-1-200, "Control of Shift Activities," Revision 11, March 31, 1997
18. CCNPP Administrative Procedure NO-1-107, "Ownership of Plant Operating Spaces," Revision 3, September 30, 1997

ATTACHMENT (1)

APPENDIX B

UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPLEMENT

1.0 INTRODUCTION

This supplement to the Calvert Cliffs Nuclear Power Plant (CCNPP) Updated Final Safety Analysis Report (UFSAR) provides information required by 10 CFR 54.21(d) to accompany the License Renewal Application (LRA) filed by Baltimore Gas and Electric Company (BGE). Part 54.21(d) requires the UFSAR supplement to contain ". . . a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation . . ."

Section 2.0 presents a summary description of the programs and activities that BGE credited for managing the effects of aging. Section 3.0 summarizes the evaluation of Time-Limited Aging Analyses (TLAAs).

2.0 AGING MANAGEMENT PROGRAMS AND ACTIVITIES

This section summarizes the activities that the BGE Integrated Plant Assessment (IPA) credited to demonstrate that intended function(s) will be adequately maintained during the period of extended operation.

The individual activities credited for aging management are associated with programs implemented through the BGE Nuclear Procedures Hierarchy. The hierarchy consists of Nuclear Program Policies, Nuclear Program Directives, Administrative Procedures, and Technical Procedures. Each program consists of a directive and the administrative procedure(s) necessary to support the directive. Directives assign responsibilities and state management requirements and regulatory commitments for each program area supporting the Nuclear Program Policies. Administrative procedures specify the processes used for compliance with the Nuclear Program Directive and the actions necessary to implement the program. Technical procedures are written to operate, maintain, test or protect systems and related equipment, and are controlled by administrative procedures.

Summary descriptions of the programs credited for aging management are presented in the subsections listed in Table B-1. Each of these programs and the associated activities credited for aging management for the period of extended operation are controlled by site procedures. Changes to these programs and activities in the areas of methods, acceptance criteria, and frequency of performance, as they pertain to aging management for license renewal, are required to be reviewed prior to implementation to ensure that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis.

TABLE B-1
LISTING OF AGING MANAGEMENT PROGRAM SUMMARIES

Directive Areas	Program Summary Descriptions
2.1 Design Authority	2.1.1 Engineering Service Process Overview 2.1.2 Design Change and Modification Implementation 2.1.3 Control of 10 CFR 50.49 Environmental Qualification of Electrical Equipment 2.1.4 Implementation of Fatigue Monitoring
2.2 Testing Program	2.2.1 Coordination of Testing 2.2.2 ASME Pump and Valve Testing 2.2.3 Surveillance Testing 2.2.4 Containment Leakage Rate Testing Program
2.3 Chemistry Program	
2.4 Maintenance Program	2.4.1 Preventive Maintenance Program 2.4.2 Load Handling 2.4.3 Instrumentation Calibration Program 2.4.4 Structure and System Walkdowns
2.5 Pressure Boundary Codes and Special Processes Program	2.5.1 Painting and Other Protective Coatings 2.5.2 Materials Testing and Evaluation 2.5.3 Inservice Inspection of ASME Section XI Components 2.5.4 Erosion/Corrosion Monitoring of Secondary Piping 2.5.5 Control of the Comprehensive Reactor Vessel Surveillance Program 2.5.6 Boric Acid Corrosion Inspection Program 2.5.7 Control of the Alloy 600 Program Plan
2.6 Nuclear Operations Program	2.6.1 Conduct of Operations 2.6.2 Ownership of Plant Operating Spaces 2.6.3 Control of Shift Activities 2.6.4 Calvert Cliffs Operating Manual 2.6.5 Operations Section Performance Evaluations
2.7 Fire Protection Program	
2.8 Nuclear Safety Program	2.8.1 Use of Operating Experience and the Nuclear Hotline

2.1 DESIGN AUTHORITY

A design authority directive describes requirements and responsibilities for establishing and maintaining the CCNPP design bases, and controlling design output documents to accurately reflect the design bases. This directive also establishes technical standards and criteria for the performance of design and engineering activities, including generation of drawings, calculations, specifications, and other items.

2.1.1 Engineering Service Process Overview

An engineering service process provides controls for initiating and performing engineering services at CCNPP. Engineering products that are credited for managing the aging of many components within the scope of license renewal are prepared, issued, and controlled through this process. The process also ensures that the design requirements of other programs credited for aging management are incorporated into engineering products.

Initial development or implementation of several new programs and additional activities credited for management of aging in the BGE LRA require engineering services. Completion of the following engineering activities will ensure that aging is adequately managed for the affected system(s), structure(s), and commodity group(s) during the period of extended operation:

- Fatigue analysis activities - Calvert Cliffs will complete an engineering review of Combustion Engineering Owners Group task reports related to NRC Generic Letter 88-08 to address the impact of thermal stratification on fatigue calculations for the Safety Injection System. (Reference 1) Additionally, an analysis will be performed to address low cycle fatigue for components subject to gamma heating in the Reactor Vessel Internals (RVI) System. (Reference 2)
- Development of an age-related degradation inspection (ARDI) program - The elements of an ARDI program are described in the CCNPP IPA Methodology. This program will provide for discovery of various age-related degradation mechanisms (ARDMs) by one-time inspection of representative component(s) in the affected system(s) using examination techniques determined to be effective for detecting progress of plausible ARDM(s) or for confirming the effectiveness of programs credited for mitigation of the ARDM(s). The BGE LRA identified components in the system(s) and commodity group(s) listed in Table B-2 for which an ARDI program provides reasonable assurance that aging will be managed during the period of extended operation.
- Development of a caulking and sealant inspection program for certain caulking and sealant not subject to existing inspection programs - This program will provide for the discovery of the effects of weathering and elastomer degradation by identification, inspection, and maintenance of caulking and sealants. The program will include baseline inspections and periodic follow-on inspections at appropriate intervals, depending upon the environment at the installed location. The BGE LRA identified caulking, sealants, and expansion joints in the Turbine Building Structure, Intake Structure, and the Auxiliary Building and Safety-Related Diesel Generator Building Structures, as well as tank perimeter seals in the AFW and Diesel Fuel Oil (DFO) Systems, for which this program will provide reasonable assurance that aging will be managed during the period of extended operation. (References 3 through 7)

- Development of an additional baseline walkdowns program - This program will provide for discovery of ARDMs affecting components in the Component Supports commodity group that are not subject to existing inspection programs. (Reference 8) The walkdown scope will include visual examinations conducted on a sampling basis for corrosion and loose bolts, and will be documented using means such as field notes and photographs. If the baseline walkdowns reveal no significant effects, follow-on activities for aging management of these supports will be implemented through a structure and system walkdowns program; refer to Subsection 2.4.4, below. If an active mechanism is found during the additional baseline walkdowns for the sampled components, the inspection scope would be expanded to determine the extent of the degradation. This activity will provide reasonable assurance that aging of component supports will be managed during the period of extended operation.

The conclusions of the engineering activities summarized above may result in detailed inspections, at various intervals, revised or new preventive maintenance tasks, or additional corrective actions to repair deficiencies.

TABLE B-2
SYSTEMS AND COMMODITY GROUPS INCLUDED IN ARDI PROGRAMS

➢ Auxiliary Feedwater (AFW) System	(Reference 6)	➢ Instrument Lines	(Reference 23)
➢ Auxiliary Building Heating and Ventilating (H&V) System	(Reference 9)	➢ Liquid Waste System	(Reference 19)
➢ Cables	(Reference 10)	➢ Main Steam System	(Reference 18)
➢ Component Cooling (CC) System	(Reference 11)	➢ Nitrogen and Hydrogen System	(Reference 18)
➢ Component Supports	(Reference 8)	➢ Nuclear Steam Supply Systems (NSSS) Sampling System	(Reference 24)
➢ Compressed Air System	(Reference 12)	➢ Plant Drains System	(Reference 19)
➢ Condensate System	(Reference 13)	➢ Plant Heating System	(Reference 19)
➢ Containment H&V System	(Reference 14)	➢ Plant Water System	(Reference 19)
➢ Containment Spray System	(Reference 15)	➢ Radiation Monitoring System	(Reference 25)
➢ Control Room Heating, Ventilating, and Air Conditioning (HVAC) System	(Reference 16)	➢ RVI System	(Reference 2)
➢ Chemical and Volume Control System (CVCS)	(References 17 and 18)	➢ Safety Injection System	(Reference 1)
➢ Demineralized (DI) Water and Condensate Storage System	(Reference 19)	➢ Saltwater System	(Reference 26)
➢ Emergency Diesel Generator (EDG) System	(Reference 20)	➢ Spent Fuel Pool (SFP) Cooling System	(Reference 27)
➢ Electrical Commodities	(Reference 21)	➢ Service Water (SRW) System	(Reference 28)
➢ Extraction Steam System	(Reference 18)	➢ Steam Generator Blowdown System	(Reference 18)
➢ Feedwater System	(References 18 and 22)	➢ Waste Gas System	(Reference 19)
➢ Fire Protection System	(Reference 19)		

2.1.2 Design Change and Modification Implementation

A design change and modification implementation process has been established to develop and implement approved plant modifications using the maintenance order process at CCNPP. This process provides a comprehensive administrative support system for plant configuration control related to modification maintenance order planning and processing. Two plant modifications formed the basis for IPA conclusions regarding certain components requiring aging management review. Implementation of the following modifications is necessary to ensure that aging is adequately managed for the affected system(s) and commodity group(s) during the period of extended operation:

- Calvert Cliffs will replace the Control Room air handling unit supports; the new supports will incorporate spring isolators, thereby eliminating elastomer degradation for the Control Room HVAC air handler supports as a plausible ARDM in the Component Supports commodity group; (Reference 8) and
- Calvert Cliffs will replace the heat trace originally installed in the CVCS with a different type of heat trace; this modification will remove the corrosive adhesive associated with the original heat tracing, thereby eliminating stress corrosion cracking (SCC) for stainless steel components as a plausible ARDM in the CVCS. (Reference 17)

2.1.3 Control of 10 CFR 50.49 Environmental Qualification of Electrical Equipment

An environmental qualification (EQ) program manages the qualification of electrical equipment important to safety at CCNPP as required by 10 CFR 50.49, and is credited for managing the aging of organic subcomponents for EQ components within the scope of license renewal. A discussion of this program is presented in Section 7.12 of the UFSAR. This program provides for management of aging effects by performing periodic preventive maintenance and replacement activities. The BGE LRA identified device types within the EQ commodity group for which this program provides reasonable assurance that aging will be managed during the period of extended operation. (Reference 29)

2.1.4 Implementation of Fatigue Monitoring

A fatigue monitoring program has been established to monitor and track thermal fatigue usage for limiting components of the NSSS and the steam generators. This program manages low cycle thermal fatigue through periodic collection and review of thermal transient data for critical locations. Actual numbers of critical transient cycles are compared to design allowable values, and calculated cumulative usage factors are compared to piping code requirements. Corrective action is initiated well in advance of exceeding established limits. Since the limiting components represent the most bounding locations for critical thermal transients, tracking fatigue usage for these components ensures that fatigue usage for all remaining components in the associated systems will also remain below their allowable limits.

The BGE LRA identified components in the CVCS and Safety Injection System for which this program provides reasonable assurance that aging will be managed during the period of extended operation. (References 17 and 1, respectively) The BGE LRA also identified program modifications that will ensure aging is managed during the period of extended operation for certain additional components in the following system(s):

- Feedwater System; (Reference 22)
- NSSS Sampling System; (Reference 24)

- Reactor Coolant System (RCS); (Reference 30) and
- Reactor Pressure Vessels (RPVs) and Control Element Drive Mechanisms (CEDMs)/Electrical System. (Reference 31)

2.2 TESTING PROGRAM

A testing program directive establishes the requirements and responsibilities for implementing various testing programs at CCNPP, including surveillance testing required by Technical Specifications (except as noted below), and inservice testing (IST) of pumps and valves included in the CCNPP IST Program Plan. This directive also establishes the responsibilities for coordinating various testing activities at CCNPP to ensure testing performed is adequate and to comply with requirements of the operating license. Certain testing activities are implemented under other programs as discussed in the subsections noted below:

- Samples obtained for chemical and radiochemical analysis implemented under the Chemistry Program - refer to Subsection 2.3;
- Troubleshooting and post-maintenance testing implemented under the Maintenance Program - refer to Subsection 2.4;
- Pressure testing and inservice inspections (ISIs) implemented under the Pressure Boundary Codes and Special Processes Program - refer to Subsection 2.5;
- Post-maintenance operability testing, surveillance testing, and performance evaluations implemented under the Nuclear Operations Program - refer to Subsection 2.6; and
- Performance evaluations implemented under the Fire Protection Program - refer to Subsection 2.7.

2.2.1 Coordination of Testing

The administrative requirements for coordination of testing have been established to ensure a comprehensive and integrated approach to testing activities. Processes are provided for planning and execution of surveillance tests, post-maintenance tests, engineering tests, and other tests used to satisfy requirements during refueling outages, during modifications to plant systems, structures, and components, or during complex testing evolutions. Activities directed by this procedure are credited for managing the aging of some components within the scope of license renewal. Certain engineering test procedures developed under this process provide for discovery of aging effects by performing periodic inspection and testing. The BGE LRA identified program modifications that will ensure aging is managed during the period of extended operation for the neutron-absorbing materials used in the SFP storage racks, part of the Auxiliary Building Structure. (Reference 5)

2.2.2 ASME Pump and Valve Testing

A pump and valve IST program has been established to implement IST in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, as required by 10 CFR 50.55a(f). This program is credited for managing the aging of certain valves identified in the CCNPP IST Program Plan that are within the scope of license renewal. This program provides for discovery of aging effects by verifying adequate seat tightness through leakage rate testing or approved alternate methods. The BGE LRA identified components in the Compressed Air System and the Safety Injection System for which this program provides reasonable assurance that aging will be managed during the period of extended operation. (References 12 and 1, respectively)

2.2.3 Surveillance Testing

A surveillance testing program has been established to implement certain surveillance requirements specified by CCNPP Technical Specifications and is credited for managing the aging of certain components within the scope of license renewal. Discussions of surveillance testing activities associated with RCS leakage monitoring, safety-related snubbers, and containment tendons are presented in Sections 4.3.4, 5.3.2, and 5.5.2.2 of the UFSAR, respectively. Surveillance test procedures provide for discovery of aging effects by performing periodic inspection, testing, or engineering activities. Certain steps in applicable procedures also provide for mitigation of aging effects by performing periodic testing and other activities.

The BGE LRA identified components in the following system(s), structure(s), and commodity group(s) for which this program provides reasonable assurance that aging will be managed during the period of extended operation:

- Component Supports; (Reference 8)
- Containment Structure; (Reference 32)
- EDG System; (Reference 20) and
- RCS. (Reference 30)

2.2.4 Containment Leakage Rate Testing Program

A containment leakage rate testing program performs leakage testing of the Containment on a performance-based testing schedule in accordance with Option B of 10 CFR Part 50, Appendix J, as implemented by CCNPP Technical Specifications. A discussion of this program is presented in Section 5.5.2.1 of the UFSAR. Certain testing performed under this program provides for detecting valve seat leakage that could be an indication of aging. The applicable surveillance test procedures contain acceptance criteria and ensure corrective actions will be taken such that there is reasonable assurance that intended functions will be maintained.

The BGE LRA identified certain components in the following system(s) for which this program provides reasonable assurance that aging will be managed during the period of extended operation:

- CVCS (Reference 17)
- CC System (Reference 11)
- Compressed Air System (Reference 12)
- Containment H&V System (Reference 14)
- Containment Spray System (Reference 15)
- DI Water and Condensate Storage System (Reference 19)
- Fire Protection System (Reference 19)
- Liquid Waste System (Reference 19)
- NSSS Sampling System (Reference 24)
- Plant Drains System (Reference 19)
- Plant Heating System (Reference 19)

- Plant Water System (Reference 19)
- Radiation Monitoring System (Reference 25)
- Safety Injection System (Reference 1)
- SFP Cooling System (Reference 27)
- Waste Gas System (Reference 19)

2.3 CHEMISTRY PROGRAM

A 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. This program is implemented through a series of procedures that provide for monitoring, maintaining, and/or controlling chemistry in plant systems. Certain activities directed by these procedures are credited with mitigation of aging effects by performing periodic measurement and evaluation of chemistry parameters in process and supporting fluid systems. For certain fluid systems, activities include treatment with additives to aid in the prevention and control of corrosion mechanisms. Other portions of these procedures are credited with discovery of certain aging effects through measurement and evaluation of additional chemistry parameters in supporting systems. When the value of a measured parameter approaches or goes beyond predetermined warning limits, appropriate corrective actions are initiated as prescribed by the applicable procedure.

The BGE LRA identified components in the following system(s) for which this program provides reasonable assurance that aging will be managed during the period of extended operation:

- AFW System (Reference 6)
- CVCS (Reference 17)
- CC System (Reference 11)
- Containment H&V System (Reference 14)
- Containment Spray System (Reference 15)
- DFO System (Reference 7)
- EDG System (Reference 20)
- Extraction Steam System (Reference 18)
- Feedwater System (Reference 22)
- Main Steam System (Reference 18)
- Nitrogen and Hydrogen System (Reference 18)
- NSSS Sampling System (Reference 24)
- RCS (Reference 30)
- Safety Injection System (Reference 1)
- Saltwater System (Reference 26)

- SRW System (Reference 28)
- SFP Cooling System (Reference 27)
- Steam Generator Blowdown System (Reference 18)

2.4 MAINTENANCE PROGRAM

A maintenance program directive establishes requirements and responsibilities for a program that provides for equipment reliability by ensuring plant structures, systems, and components are adequately maintained and can perform their intended functions. This program also provides a process for preventive and prompt corrective maintenance of plant structures, systems, and components. Elements of this process include: proper maintenance of facilities; corrective and preventive maintenance; planning and coordinating maintenance activities; data collection and analysis; post-maintenance testing; and housekeeping and cleanliness control.

2.4.1 Preventive Maintenance Program

A preventive maintenance program covers all preventive maintenance activities for nuclear power plant structures and equipment within the plant and is credited for managing the aging of many components within the scope of license renewal. Preventive maintenance encompasses a variety of maintenance actions taken to extend equipment life and maintain equipment within design operating conditions. These include periodic maintenance actions (accomplished on a routine basis) and certain other activities (which may be initiated in response to predictive or periodic maintenance results, vendor recommendations, or experience) that are performed prior to equipment failure. Individual tasks controlled under this program provide for discovery of aging effects by performing periodic maintenance activities. Several activities governed by this program also provide for mitigation of aging effects by performing visual inspections and additional periodic tasks.

The BGE LRA identified components in the following system(s) and commodity group(s) for which this program provides reasonable assurance that aging will be managed during the period of extended operation:

- AFW System (Reference 6)
- Cables (Reference 10)
- CC System (Reference 11)
- Compressed Air System (Reference 12)
- Containment H&V System (Reference 14)
- Containment Structure (Reference 32)
- Control Room HVAC System (Reference 16)
- CVCS (Reference 17)
- Extraction Steam System (Reference 18)
- Fuel Handling Equipment (FHE) and Other Heavy Load Handling Cranes (HLHC) (Reference 33)
- Main Steam System (Reference 18)
- Nitrogen and Hydrogen System (Reference 18)

- NSSS Sampling System (Reference 24)
- RCS (Reference 30)
- RPVs and CEDMs/Electrical System (Reference 31)
- Saltwater System (Reference 26)
- SRW System (Reference 28)
- Steam Generator Blowdown System (Reference 18)

The BGE LRA also identified program modifications that will ensure aging is managed during the period of extended operation for certain additional components in the following system(s), structure(s), and commodity group(s):

- Cables (Reference 10)
- Component Supports (Reference 8)
- EDG System (Reference 20)
- Electrical Commodities (Reference 21)
- Feedwater System (Reference 20)
- FHE and HLHC (Reference 33)
- Intake Structure (Reference 4)
- RPVs and CEDMs/Electrical System (Reference 31)
- Saltwater System (Reference 26)
- SFP Cooling System (Reference 27)
- SRW System (Reference 28)

Implementation of several new programs credited for management of aging in the BGE LRA require development of maintenance activities under this program. Accordingly, the following maintenance activities will ensure that aging is adequately managed for the affected system(s) during the period of extended operation:

- Develop programs to visually inspect protective wrapping/coatings applied to the external surface of buried pipe, to address aging effects for the AFW and DFO Systems; and (References 6 and 7)
- Develop a tank internal inspection program to visually inspect and perform coating measurements, to address aging effects for the DFO System. (Reference 7)

2.4.2 Load Handling

A load handling procedure establishes the requirements and assigns responsibilities for activities involving load handling at CCNPP and is credited for managing the aging of certain components in the FHE and HLHC commodity group. (Reference 33) Control of heavy loads at CCNPP is discussed in Section 5.7 of the UFSAR. Certain steps of this procedure provide for discovery of aging effects by performing periodic visual inspection and non-destructive examination. When degraded conditions that would affect the handling capacity of the equipment are identified, corrective actions are taken to repair the deficiency prior to further use. These activities provide reasonable assurance that aging of FHE and HLHC will be managed during the period of extended operation.

2.4.3 Instrumentation Calibration Program

An instrument calibration program has been established to ensure that installed process instruments used to record data in tests, surveillances, and other procedures are properly calibrated. This program is credited for managing the aging of certain cables within the scope of license renewal. This program provides for mitigation of insulation resistance reduction effects by performing periodic calibration of instrument loops. When an instrument is found to be out-of-calibration, the user is directed to determine whether the out-of-calibration instrument could effect any surveillance test. The BGE LRA identified components in the Cables commodity group for which this program provides reasonable assurance that aging will be managed during the period of extended operation. (Reference 10)

2.4.4 Structure and System Walkdowns

A structure and system walkdowns program has been established to standardize the general intent and method of reporting walkdown results and is credited for managing the aging of many systems, structures, and components within the scope of license renewal. This program meets the requirements for evaluating structure and system material condition in accordance with the Maintenance Rule at CCNPP, and replaces the previous CCNPP plant evaluation guideline for system walkdowns. Walkdown activities provide for discovery and mitigation of aging effects.

The BGE LRA identified components in the following system(s) and commodity group(s) for which this program (or the guidelines that were its predecessor) provides reasonable assurance that aging will be managed during the period of extended operation:

- AFW System (References 6 and 13)
- Component Supports (Reference 8)
- CC System (Reference 11)
- Compressed Air System (References 12 and 13)
- Condensate System (Reference 13)
- Containment H&V System (Reference 14)
- DI Water and Condensate Storage System (Reference 13)
- DFO System (Reference 7)
- Instrument Lines (Reference 23)
- Liquid Waste System (Reference 13)
- Main Steam System (Reference 13)
- Plant Drains System (Reference 13)
- Plant Heating System (Reference 13)
- SRW System (Reference 13)
- Well and Pretreated Water System (Reference 13)

The BGE LRA also identified program modifications that will ensure aging is managed during the period of extended operation for certain additional components in the following system(s) and structure(s):

- Auxiliary Building and Safety-Related Diesel Generator Building Structures; (Reference 5)
- Auxiliary Building H&V System; (Reference 9)
- Containment Structure; (Reference 32)
- Control Room HVAC System; (Reference 16)
- Intake Structure; (Reference 4)
- Miscellaneous Tank and Valve Enclosures; (Reference 34)
- Safety Injection System; and (Reference 1)
- Turbine Building Structure. (Reference 3)

2.5 PRESSURE BOUNDARY CODES AND SPECIAL PROCESSES PROGRAM

A pressure boundary codes and special processes program directive covers activities performed on items within the scope of the ASME Boiler and Pressure Vessel Code Section XI, Division I, items covered by the Maryland Boiler and Pressure Vessel Safety Act and amendments, and piping that complies with design requirements of the American National Standards Institute Power Piping Code B31 series standards. This program also applies to application of certain special processes to items covered by the pressure boundary codes above and any other plant equipment where controls to ensure quality and safety would be deemed prudent.

2.5.1 Painting and Other Protective Coatings

A protective coatings program has been established to control painting and protective coatings activities performed inside Containment to ensure they comply with applicable regulatory guidance and industry standards. This program provides for discovery of corrosion by performing periodic walkdown inspections. This program provides reasonable assurance that aging of steel components inside Containment will be managed during the period of extended operation.

2.5.2 Materials Testing and Evaluation

The requirements for materials testing and evaluation have been established to: control testing performed to determine material properties and conditions; and provide a process for determining the significance of examination or test results. These processes are credited for managing aging of several components within the scope of license renewal. Implementation of several new programs and additional activities credited for management of aging in the BGE LRA require materials evaluations. Accordingly, completion of the following analyses will ensure that aging is adequately managed for the affected system(s), structure(s), and commodity group(s) during the period of extended operation:

- Evaluation of cast austenitic stainless steel, consisting of delta ferrite calculations and/or replacement alternatives, to address thermal embrittlement for components in the RCS and the RVI System; (References 30 and 31, respectively)
- Analysis of SCC of control element assembly shroud bolts, to address SCC for components of the RVI System; (Reference 31)
- Analysis of stress relaxation, to address certain components of the RVI System; and (Reference 31)

- Engineering review of SCC of the refueling water tank penetrations, to address SCC for components in the Safety Injection System. (Reference 1)

2.5.3 Inservice Inspection of ASME Section XI Components

An ISI program has been established to control the methods and actions for ensuring the structural and pressure-retaining integrity of nuclear power plant components subject to the inspection or examination requirements of Section XI of the ASME Boiler and Pressure Vessel Code. A discussion of ISI activities associated with the steam generator tubes is presented in Section 4.1.3.2 of the UFSAR. This program provides for discovery of aging effects by performing periodic examinations using non-destructive techniques. Examinations may require, as applicable, determination of structural integrity, measurement of clearances, detection of physical displacements, structural adequacy of supporting elements, connections between load-carrying structural members, and tightness of bolting. This program also addresses evaluation of examination results with referral to ASME Section XI for acceptance standards. When abnormal conditions are identified, the ASME Code provides requirements for the timely correction of deficiencies.

The BGE LRA identified components in the following system(s) and commodity group(s) for which this program provides reasonable assurance that aging will be managed during the period of extended operation:

- RCS; (Reference 30)
- RPVs and CEDMs/Electrical System; and (Reference 31)
- Component Supports. (Reference 8)

The BGE LRA also identified program modifications that will ensure the discovery and management of additional aging effects during the period of extended operation for certain components of the RVI System by visual examination. (Reference 31)

2.5.4 Erosion/Corrosion Monitoring of Secondary Piping

An erosion/corrosion program has been established to provide early detection and prevention of pipe wall thinning that could lead to ruptures in high energy piping and is credited for managing the aging of certain secondary system piping within the scope of license renewal. A discussion of this program is presented in Section 10.2.4 of the UFSAR. This program provides for periodic collection and review of wall thickness data for predetermined locations and inspection points that could indicate erosion corrosion. These data are used in conjunction with a predictive model and industry experience to determine additional inspection points, to revise inspection program priorities, or to estimate the time remaining before wall thickness reaches the minimum allowable for a particular inspection point. Examination results are analyzed to determine the need to replace components, and corrective actions are initiated as appropriate.

The BGE LRA identified components in the following system(s) for which this program provides reasonable assurance that aging will be managed during the period of extended operation:

- Feedwater System; (Reference 22)
- Main Steam System; and (Reference 18)
- Steam Generator Blowdown System. (Reference 18)

2.5.5 Control of the Comprehensive Reactor Vessel Surveillance Program

A comprehensive reactor vessel surveillance program has been established to periodically tabulate and review the information needed to monitor RPV embrittlement to meet the requirements of 10 CFR Part 50, Appendix H. Test coupons of representative RPV materials are installed at locations where their accumulated neutron exposure is higher than that of the RPVs themselves. A discussion of the RPV surveillance materials is presented in Section 4.1.5.2 of the UFSAR. Monitoring of these coupons allows the embrittlement to be predicted through the current license period and the period of extended operation. This program also provides for evaluation and incorporation of other research results, such as applicable coupon surveillance data obtained from other power plants. The results to date demonstrate that CCNPP RPVs will remain well within established regulatory limits through the period of extended operation. (Reference 31)

2.5.6 Boric Acid Corrosion Inspection Program

A boric acid corrosion inspection program is credited for managing the aging of components where leakage of boric acid may cause degradation of the system pressure boundary. A discussion of this program is presented in Section 4.1.5.7 of the UFSAR. This program provides for discovery of aging effects by performing periodic visual examinations. These inspections also provide for mitigation of boric acid corrosion effects through discovery of leakage and removal of boric acid residue that is found. Where boric acid leakage (or evidence of prior leakage) is detected, engineering evaluations and other corrective actions are initiated as necessary. The BGE LRA identified components in the following system(s) and commodity group(s) for which this program provides reasonable assurance that aging will be managed during the period of extended operation:

- CVCS (References 13 and 17)
- Containment Spray System (Reference 15)
- NSSS Sampling System (Reference 24)
- Plant Drains System (Reference 19)
- RCS (Reference 30)
- RPVs and CEDMs/Electrical System (Reference 31)
- Safety Injection System (Reference 1)
- SFP Cooling System (Reference 27)

The BGE LRA also identified program modifications that will ensure aging is managed during the period of extended operation for: (a) the reactor vessel cooling shroud anchorage to the reactor vessel head; and (b) all reactor vessel cooling shroud structural support members in the FHE and HLHC commodity group. (Reference 33)

2.5.7 Control of the Alloy 600 Program Plan

An Alloy 600 program has been established to address nuclear safety concerns and economic impacts associated with primary water SCC of Alloy 600 pressure boundary components, and is credited for managing the aging of applicable pressure boundary components in the RCS and RPVs and CEDMs/Electrical System, including the RPV and pressurizer. (References 30 and 31, respectively) This program defines aging management alternatives and provides the process for considering susceptibility, safety, and economics in selecting from these alternatives. It also includes measures for monitoring industry experience and making appropriate adjustments based on this experience. The program schedules augmented inspections, repairs, or replacement of susceptible components, as necessary. The BGE LRA identified program modifications that will include all Alloy 600 components in the RPVs and CEDMs/Electrical System, as well as nozzle thermal sleeves in the RCS, within the scope of the Alloy 600 program, in addition to the pressure boundary components that are within the scope of the existing program. These activities provide reasonable assurance that aging of applicable RCS and RPVs and CEDMs/Electrical System components will be managed during the period of extended operation.

2.6 NUCLEAR OPERATIONS PROGRAM

A nuclear operations program directive controls activities directly related to the safe and reliable operation of CCNPP, including: plant operations in all operational modes; plant equipment operation that ensures public safety, personnel safety, and prevents equipment damage; and operability testing of equipment and systems.

2.6.1 Conduct of Operations

The requirements for interactions of shift operating personnel with other BGE personnel and their contractors address the controls and basic standards for conduct of daily shift operations. For certain system(s) and component(s) within the scope of license renewal, system parameters during performance of passive intended functions are bounded by normal system operating parameters. In such system(s), performance and condition monitoring activities implemented by this program during normal operation provide for discovery of aging effects through visual inspection and assessment of degraded conditions. This program requires that operators thoroughly assess degraded equipment conditions to ensure personnel and affected equipment safety while completing corrective actions.

The BGE LRA identified components in the following system(s) for which these activities provide reasonable assurance that aging will be managed during the period of extended operation: (Reference 13)

- AFW System
- CC System
- Compressed Air System
- Condensate System
- DI Water & Condensate Storage System
- Liquid Waste System
- Main Steam System
- Plant Drains System
- Plant Heating System
- SRW System
- Well and Pretreated Water System

2.6.2 Ownership of Plant Operating Spaces

Requirements and guidance for personnel accountability for the correction of housekeeping, material, and radiological deficiencies have been established to improve the housekeeping and material condition of the plant operating areas on a long-term basis. This program is credited for managing the aging of certain commodity groups within the scope of license renewal. Under this program, specified areas of the plant are each assigned to an individual owner who provides a point of contact for any individual who finds deficiencies or any concern with the space. The responsible individuals are also required to periodically inspect their assigned space(s) for housekeeping/cleanliness, material condition, and radiological protection deficiencies. Visual inspection of assigned spaces required by this program provides for discovery of degraded conditions that could be indications of several ARDMs. The BGE LRA identified components in the Component Supports and Instrument Lines commodity groups for which this program provides reasonable assurance that aging will be managed during the period of extended operation. (References 8 and 23)

2.6.3 Control of Shift Activities

Responsibilities assigned to watchstanders for control of shift activities have been established to ensure that shift operations are conducted in a safe and reliable manner and within the scope of the operator's license, procedures, and applicable regulatory requirements. The processes described by this program are credited for managing the aging of certain commodity groups within the scope of license renewal. Visual inspection of operating spaces each shift during plant operator rounds provides for discovery of degraded conditions that could be indications of several ARDMs. The BGE LRA identified components in the Component Supports and Instrument Lines commodity groups for which this program provides reasonable assurance that aging will be managed during the period of extended operation. (References 8 and 23)

2.6.4 Calvert Cliffs Operating Manual

An operating manual establishes the requirements for implementing and using various procedures as approved, preplanned methods of conducting operations, and is credited for managing the aging of certain components within the scope of license renewal. Visual inspection of equipment prior to use in accordance with applicable operating instructions provides for discovery of aging effects. In many cases, activities performed under this program invoke operating instructions to accomplish similar inspections. (For a summary description of the performance evaluation program, refer to Subsection 2.6.5, below). The BGE LRA identified components in the FHE and HLHC commodity group for which this program provides reasonable assurance that aging will be managed during the period of extended operation. (Reference 33)

2.6.5 Operations Section Performance Evaluations

A performance evaluation program has been established to perform periodic checks and obtain readings to determine equipment performance, as determined by manufacturers' recommendations, system engineers' recommendations, and operating needs. Certain activities controlled under this program provide for discovery and mitigation of aging effects by performing periodic checks of system performance. The BGE LRA identified certain components within the following system(s), structure(s), and commodity group(s) for which this program provides reasonable assurance that aging will be managed during the period of extended operation:

- Auxiliary Building (SFP liner); (Reference 5)
- FHE and HLHC; and (Reference 33)
- DFO System. (Reference 7)

2.7 FIRE PROTECTION PROGRAM

A CCNPP fire protection program directive provides the necessary controls to protect the health and safety of CCNPP workers and the general public, satisfy NRC and insurer requirements, meet applicable State of Maryland codes and standards, and safeguard BGE assets by preventing fires and minimizing the consequences of any fire that may occur. A discussion of this program is presented in Section 9.9 of the UFSAR. This program is credited for managing the aging of certain components within the scope of license renewal. Various performance and/or condition monitoring activities implemented by this program provide for discovery of aging effects on structural component types (e.g., caulking, sealants, and expansion joints that function as fire barriers), as well as pressure-retaining components (e.g., piping, spoolpieces, and valves), by performing periodic inspections and functional testing. The BGE LRA identified components in the following system(s) and structure(s) for which this program provides reasonable assurance that aging will be managed during the period of extended operation:

- AFW System; (Reference 13)
- Auxiliary Building and adjacent rooms; (Reference 5)
- DFO System; (Reference 13)
- Fire Protection System; (Reference 13)
- Intake Structure; (Reference 4)
- Nitrogen and Hydrogen System; (Reference 13)
- Plant Drains System; and (Reference 13)
- Turbine Building Structure. (Reference 3)

2.8 NUCLEAR SAFETY PROGRAM

A nuclear safety program directive establishes concepts and expectations for performance of activities at or in support of CCNPP. Each program developed under the Nuclear Procedures Hierarchy incorporates appropriate nuclear safety program concepts and expectations such that personnel are able to recognize and apply the concepts and expectations.

2.8.1 Use of Operating Experience

Use of operating experience is credited for managing the aging of certain components within the scope of license renewal. This program directs continual reviews of industry operating experience for potential nuclear safety issues, which may include incidents attributed to aging of systems, structures, and components within the scope of license renewal. If reports indicate that the industry is experiencing age-related degradation of components, appropriate actions will be taken to determine applicability to CCNPP and correct deficiencies as necessary. The BGE LRA identified components in the RCS for which this program provides reasonable assurance that aging will be managed during the period of extended operation. (Reference 30)

3.0 TIME-LIMITED AGING ANALYSES

This section presents a summary description of the evaluation of TLAAs. The evaluation details were discussed in the TLAA chapter of the BGE LRA.

A list of 14 TLAAs was developed by screening relevant calculations and analyses contained or incorporated by reference in the current licensing basis against the TLAA definition presented in 10 CFR 54.3. These analyses were evaluated in accordance with the process defined by the CCNPP IPA Methodology and the associated NRC Safety Evaluation Report, and the following results were obtained:

- One TLAA, the existing fatigue analysis for main steam piping to the turbine-driven AFW pumps, is valid for the period of extended operation.
- The following six TLAAs have been (or will be) extended such that they are valid for the period of extended operation:
  - Heatup and cooldown curves in the plant's Technical Specifications, which will continue to be updated either as required by 10 CFR Part 50, Appendices G and H, to assure the operational

limits remain valid at the current cumulative neutron fluence levels, or on an as-needed basis to provide appropriate operational flexibility;

- Low temperature overpressure protection power-operated relief valve pressure setpoint curves in the plant's Technical Specifications, which will continue to be updated as described above;
- Pressurized thermal shock analyses, which have been projected to the end of the period of extended operation;
- Containment liner plate fatigue analyses, which will be reviewed and/or reanalyzed to accommodate the projected number and severity of thermal cycles to the end of the period of extended operation;
- Normalized tendon lift-off force curves in the plant's Technical Specifications, which will be extended to accommodate the acceptable tendon prestress through the period of extended operation; and
- The criticality analysis for the SFP, which is currently being updated to accommodate the projected loss of boron carbide due to degradation of Carborundum sheets through the period of extended operation.

- The remaining seven TLAAs involve systems, structures, and components for which the IPA demonstrates that the effects of aging will be adequately managed for the period of extended operation. The EQ program described in Subsection 2.1.3, above, manages aging effects for equipment addressed by qualified life calculations in the EQ files. The fatigue monitoring program described in Subsection 2.1.4 above, manages thermal aging effects for equipment in the NSSS that is addressed in the following TLAAs:
  - Reactor vessel fatigue analyses;
  - RCS piping fatigue analyses;
  - Steam generator fatigue analyses;
  - Pressurizer fatigue analyses;
  - Pressurizer auxiliary spray line fatigue analyses; and
  - Pressurizer surge line fatigue analyses, including thermal stratification effects.

Baltimore Gas and Electric Company found no exemptions granted pursuant to 10 CFR 50.12 and in effect that were based on a TLAA.

4.0 References

1. BGE LRA Section 5.15
2. BGE LRA Section 4.3
3. BGE LRA Section 3.3B
4. BGE LRA Section 3.3C
5. BGE LRA Section 3.3E
6. BGE LRA Section 5.1
7. BGE LRA Section 5.7
8. BGE LRA Section 3.1
9. BGE LRA Section 5.11A
10. BGE LRA Section 6.1
11. BGE LRA Section 5.3
12. BGE LRA Section 5.4
13. BGE LRA Section 5.10
14. BGE LRA Section 5.11B
15. BGE LRA Section 5.6
16. BGE LRA Section 5.11C
17. BGE LRA Section 5.2
18. BGE LRA Section 5.12
19. BGE LRA Section 5.5
20. BGE LRA Section 5.8
21. BGE LRA Section 6.2
22. BGE LRA Section 5.9
23. BGE LRA Section 6.4
24. BGE LRA Section 5.13
25. BGE LRA Section 5.14
26. BGE LRA Section 5.16
27. BGE LRA Section 5.18
28. BGE LRA Section 5.17
29. BGE LRA Section 6.3
30. BGE LRA Section 4.1
31. BGE LRA Section 4.2
32. BGE LRA Section 3.3A
33. BGE LRA Section 3.2
34. BGE LRA Section 3.3D