Wolf Creek Generating Station
Audit Questions & Answers Database

Question No AMPA001 LRA Sec 1-B.2.1.22
Audit Question What inspection techniques are to be utilized to detect degradations such as cracking, hardening, and loss of strength as stated in the description of this AMP in the License Renewal Application (LRA)?
Final Response

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program uses visual inspection for detection of aging effects. Visual inspections of internal surfaces of plant components will be performed during the conduct of periodic maintenance, predictive maintenance, surveillance testing and corrective maintenance. Inspections will determine if cracking, loss of strength – hardening, or loss of material aging effects are occurring. Stainless steel exposed to diesel exhaust will be inspected for cracking. Other stainless steel components in the scope of the Internal Inspection program do not meet the 1400 F threshold temperature for cracking. HVAC flexible connectors will be inspected to ensure they are free from hardening - loss of strength. Piping and piping components will be inspected for loss of material. Loss of strength - Hardening is only applicable to Elastomers in the HVAC systems. Physical manipulation during visual inspection of elastomers could be used to verify the absence of hardening or loss of strength. The AMP will provide procedural guidance and training required for personnel performing visual inspections.

Staff Evaluation

The staff finds the applicant's response acceptable because the applicant clarified that detection of hardening and loss of strength is only applicable to the elastomers in the HVAC systems. The applicant also indicated that the inspection technique to be utilized is visual inspection, which is consistent with the GALL AMP XI.M38 recommendations. Furthermore, physical manipulation during visual inspection of elastomers could be used to verify the absence of hardening or loss of strength. The staff noted, through reviewing AMR Sections 3.2 and 3.3 Table 2 line items, that the applicant credited this AMP in managing aging effect of hardening and loss of strength in elastomer components exposed to ventilation atmosphere internal environment.

Question No AMPA002 LRA Sec 2-B.2.1.22
Audit Question It is observed that WCGS has credited the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for inspection of internal surfaces of steel, brass and aluminum piping, ducting and components. What is the minimum size of the piping and ducting covered under this AMP? Are there any special techniques planned to be used to detect corrosion of the nonferrous materials?
Final Response

The program plan procedure will specify what, if any exclusions will exist for small bore piping and ducting covered by the AMP. The program plan procedure has not been completed, however, currently there is no preset minimum piping or ducting size excluded from the program. Specific exclusions will depend upon many factors including constraints associated with inspection equipment (e.g. borescope size). All piping and ductwork currently in the scope of the program is identified, (see AMP applicability list). Piping currently in scope for the program is as small as ¼" though most of the piping is 1" or greater. Ducting currently in scope for the

program ranges in size from 10" to 45" and only includes carbon steel (non-galvanized) ductwork. Visual Inspection is used exclusively for detection of aging effects in ferrous and non-ferrous materials. Visual inspection techniques utilized are the same regardless of whether the material is ferrous or non-ferrous, though industry experience will be utilized whenever possible to enhance detection of corrosion for nonferrous materials.

Staff Evaluation

The staff finds the applicant's response acceptable because it includes details of the program plan procedure for the new internal surfaces inspection program and confirms that the industry experience will be used to enhance detection of corrosion for nonferrous materials.

Question No AMPA003 LRA Sec 3-B.2.1.6

Audit Question The flow accelerated corrosion program described in the GALL Report relies on EPRI guidelines provided in NSAC 202L, Revision 2. WCGS's Flow Accelerated Corrosion Program is based on NSAC 202L, Revision 3. Provide justifications as to how the Revision 3 guidelines are either equivalent or more stringent than those in Revision 2.

Final Response

As indicated in NSAC 202L, Revision 3, the new revision of EPRI guidelines incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that became available since Revision 2 was published. The updated recommendations are intended to refine and enhance those of previous revisions without contradictions to ensure continuity of existing plant FAC programs.

The WCGS FAC program takes exception to the following NUREG-1801 XI.M17 program elements based on using guidance of NSAC 202L, Revision 3 instead of Revision 2. The sections of NSAC 202L associated with these program elements were reviewed to show that Revision 3 guidelines are equivalent to those in Revision 2:

Element (1), Scoping of Program – The differences of section 4.2, Identifying Susceptible Systems, between Revision 2 and Revision 3 are mostly editorial. The guidance of prioritizing the system for evaluation in section 4.2.3 of Revision 2 is addressed in section 4.9 of Revision 3 by applying safety factors in ranking the risks. Section 4.4, Selecting and Scheduling Components for Inspection, of Revision 2 was re-organized in Revision 3. Sample selection for modeled lines and non-modeled lines of Revision 2 was enhanced with more clarification and more details in Revision 3, Guidance for using plant experience and industry experience in selecting inspection locations were added in Revision 3. The basis for sample expansion was clarified in Revision 3.

Instead of dividing into selection of initial inspection and follow-up inspections in Revision 2, the guidance in Revision 3 is provided for a given outage including the recommendations for locations of re-inspection. It is more compatible to the schedule of the implementation of FAC program of the industry.

Element (4), Detection of Aging Effects – Clarification of the inspection techniques of UT and RT was added in section 4.5.1 of Revision 3. There are no changes of the guidance for UT grid.

Appendix B was added in Revision 3 to provide guidance for inspection of vessels and tanks. The guidance for inspection of small-bore piping in Appendix A of Revision 2 and 3 are essentially identical. The guidance for inspection of valves, orifices, and equipment nozzles were enhanced in section 4.5.2 of Revision 3. Also, section 4.5.4 was added for use of RT to inspect large-bore piping, section 4.5.5 for inspection of turbine cross-around piping, and section 4.5.6 for inspection of valves.

Staff Evaluation

The staff finds the applicant's response acceptable because Revision 3 of the EPRI Document NSAC 202L does not contradict Revision 2 and the later revision incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that became available after the prior revision was issued. The staff also verified the scope statement in NSAC 202L, Revision 3 during the audit and found that the changes were acceptable.

Question No AMPA004 LRA Sec 4-B.2.1.6

Audit Question Describe situations which demonstrate effectiveness of the Flow Accelerated Corrosion Program at WCGS. Include actual data (i.e., measured wall thickness, nominal pipe thickness, minimum acceptable thickness, etc.) and details of the corrective actions taken when degradation or wall thinning was observed during flow accelerated corrosion inspections. Describe how effective were these corrective actions in eliminating or controlling the wall thinning problem.

Final Response

Wolf Creek uses the guidance provided in EPRI NSAC 202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program", which is utilized throughout the industry. This document has proven to provide input to effective programs. In addition, the components that are replaced in the Wolf Creek FAC program are normally replaced with FAC-resistant material; no failures have been identified with the FAC-resistant material.

In August 1999, the Callaway pipe break occurred. Using our program, within the same month we inspected the identical location at Wolf Creek. Wall thinning was identified; the affected piping was replaced like-for-like two days later. Additional inspections were added to the next refueling outage (RF 11) inspection scope as a result of finding wall thinning. The entire pipeline was replaced with chrome-moly pipe in RF12. Re-inspection of replaced chrome-moly pipe is scheduled. (Ref PIRs 1999-2958, 2000-2032)

Review of the work orders from 1995 showed that there has been no reported FAC-related leak or rupture at WCGS. Most of the work orders identified the degradation of wall thinning during the inspection by the FAC program. There was no case where the wall thickness was found to violate the minimum acceptable thickness. There were cases where the initial acceptable thickness determined in accordance with the program guidelines (Reference: AI 23H-002) were reached and more rigorous analyses were performed to justify continued service. Problems identified during implementation of the program activities were not significant and adequate corrective actions were taken to prevent recurrence.

For previous refueling outages RF13 and RF14, 75 to 80 locations of large-bore systems were selected for inspection, including 25-30 locations of initial inspection. An inspection location included the subject component (such as an elbow) and its adjacent area (such as upstream and downstream piping). For small-bore systems, 40 to 50 inspections were selected for previous outages, including 20-30 locations of initial inspection. The replacements for each outage are scheduled on proactive basis, determined by the projected remaining service life based on FAC analyses and by programmatic strategy based on industry experience and cost comparison to further inspections. The selection of FAC-resistance material is chrome-moly alloy P22 (2.25% Cr and 1.00% Mo) for most of the replacements.

Staff Evaluation

The staff finds the applicant response acceptable because the applicant has provided several examples that demonstrate the effectiveness of its Flow Accelerated Corrosion Program. The staff also reviewed a sampling of the documentation listed in applicant's response and verified the effectiveness of the program during the site audit.

Question No AMPA005 LRA Sec 5-B.2.1.6

Audit Question Clarify if there have been any modifications and/or improvements to the Flow Accelerated Corrosion Program since its implementation. Describe the specific reasons (i.e., lessons learned, operating experience, industry experience) for these modifications and/or improvements. Explain how these changes made the program more effective with respect to the management of aging.

Final Response

The improvements of the FAC program since its implementation are:

i. EPRI CHECWORKS software has been improved to better predict wear.
Ii. FAC Manager software was purchased about 3-4 years ago and is used to monitor (track, trend, and manage) inspection information.
Iii. NSAC 202L has been issued to provide program guidelines to the industry to provide consistent effectiveness.
Iv. WCGS has increased participation in EPRI CHUG (CHECWORKS Users Group) to better review and respond to issues within the industry.

Staff Evaluation

The intent of this question was to establish how the plant and industry experience is used by the applicant to improve and enhance its aging management program. The staff finds the applicant's response satisfactory because the applicant has provided a list of improvements to its Flow Accelerated Corrosion Program. These improvements are based on the plant and industry experience, and are in accordance with GALL Report recommendations.

Question No AMPA006 LRA Sec 6-B.2.1.6

Audit Question Explain how would the sample size be adjusted to address the detected degradation if the thickness measurements during flow accelerated corrosion inspection indicated degradation or wall thinning beyond the predicted minimum wall thickness. Actual wall thickness data collected

during flow accelerated corrosion inspections should be available for review during audit.

Final Response

The guidance for expanded sample inspection is provided in the procedure AI 23H-002, Rev. 2,

Section 6.5.8. The expanded sample should include, if not recently inspected,
(1) any component within two pipe diameters downstream or within two pipe diameters upstream if the subject component is an expander or expanding elbow,
(2) the two highest ranked components from the CHECWORK wear rate prediction from the train containing the piping component displaying the significant wear, and
(3) Corresponding components of similar geometry in sister train displaying significant wear.

If inspection of the expanded sample detects additional components with significant FAC wear, the sample should be further expanded to include components of the aforementioned items (1) and (2). If additional significant wear is detected, the sample expansion should continue per above until no additional components with significant wear are detected.

Summaries of FAC Inspection Results for the following refueling outages are provided in Section 2 of Program Evaluation Report (PER) for AMP B2.1.6, FAC Program:

(1) RF10 - WCNOC-126
(2) RF11 - WCNOC-147
(3) RF12 - WCNOC-152
(4) RF13 - WCNOC-155

Staff Evaluation

The staff finds that applicant's response acceptable because the applicant has provided a section of its procedure which contains the guidance and criteria for determination of the expanded sample size for inspection of components under its Flow Accelerated Corrosion Program.

Question No AMPA007 LRA Sec 7-B.2.1.6
Audit Question WCGS document AI 23H 002, Revision 2, Page 34, "Guidelines for Implementation of the Flow Accelerated Corrosion Program," includes a flow diagram for the evaluation process. The diagram shows that if "Tmeas" is not greater than "Tminacc", there are two logic steps to follow which state "Generate WR to document nonconformance". Please explain the purpose of these two steps and the difference between the two of them.

Final Response

The two logic steps are duplicate and identical actions. The second logic box is not needed.

Staff Evaluation

The staff finds the applicant's response acceptable because the response is consistent with the staff's observation pertaining to the duplication of a logic step in the logic diagram on page 34 of the applicant's document AI 23H 002, Revision 2, "Guidelines for Implementation of the Flow Accelerated Corrosion Program."

Question No AMPA008 LRA Sec 8-B.2.1.6

Audit Question PIR No. 20002032 states: "After a detailed review of the CHECWORKS model predicted wear rates and estimating the as measured wear rates, significant discrepancies in the predicted vs measured wear rate results were identified." In similar PIR documents that predicted wear rates the actual wear was estimated at:

- 77% higher for the elbow on line AF 417 GBD 6
-263% higher for the elbow on line AF 032 GBD 6

(a) Explain if the Flow Accelerated Corrosion Program management team performed evaluation and root cause analyses to establish why the CHECWORKS predicted wear rates were different from the actual wear rates from the two cases quoted.

(b) Explain if the modeling verified that similar problems did not exist at other locations. Explain what corrective actions were taken to assure that the future predictions were realistic and consistent with the actual wear.

Final Response

(a) Evaluation of the model was performed to determine why the CHECWORKS predicted wear rates were different from the actual wear rate. The possible cause could be due to backing rings installed during construction. Other locations were reviewed to verify consistency of the CHECWORKS results with the field-measured data, with no apparent deficiencies in the model identified.

(b) An EPRI person was bought on site to review the FAC model in August-September of 1999. The objective of the review was to recommend additional inspection locations and to look for improvements to CHECWORKS FAC model. There were no major findings with the model that affect the predicted wear during the review. In 2006, Wolf Creek contracted CSI Technologies to upgrade to CHECWORKS version SFA 2.1 program, at that time the model was reviewed. At that same time the system susceptibility evaluation and susceptible non-modeled components were revised.

Staff Evaluation

The staff finds the applicant's response acceptable because the response describes the actions taken by WCGS in response to the erroneous metal wear rates predicted by the CHECWORKS model. The staff finds these actions appropriate and acceptable. However, the staff asked a follow-up question (Question No. AMPA137) to establish if any erroneous predictions were detected by the applicant after the necessary actions had been taken to address the previous

problem. The follow-up response confirmed that no erroneous predictions were experienced after the corrective actions were taken.

Question No AMPA009 LRA Sec 9-B.2.1.6

Audit Question

PIR No. 1999 2958 documents that radiography inspections were performed on high pressure feed water piping as a result of a pipe break at another nuclear power plant. The PIR states: "Wall thickness measurements at the location were estimated between 0.100 to 0.120 inches (Nominal of 0.280 in.). The critical wall thickness based on hoop stresses had been calculated at 0.109 inch. The identified piping was replaced."

(a) Explain what is the definition of critical wall thickness in the Flow Accelerated Corrosion Program. The estimated thickness value of 0.100 inch is less than the calculated critical thickness reported in the PIR. Explain what is the significance of critical thickness in the implementation of this program.

(b) Clarify if the subject piping was part of the Flow Accelerated Corrosion Program or if the radiography was performed because of the failure of similar piping at the other nuclear plant.

(c) Clarify if the affected piping was replaced with piping made from the same material or with a corrosion resistant material. The PIR talks about wall thinning at the extrados of the 45 degree elbow. Clarify if this fitting was also replaced.

(d) Clarify how long was this piping in operation before the thickness loss was detected. Clarify if this piping was inspected earlier; if yes, show the dates and the inspection result. Explain what were the results of the engineering evaluations as referenced in the PIR and the corrective actions taken.

Final Response

(a) Critical wall thickness is not a standard term used. "Tmin acceptable" is the design minimum acceptable wall thickness of the component. The method for determining the design minimum acceptable wall thickness of components inspected for wall thinning in the FAC Program shall be consistent with the ANSI B31.1, ASME Section III or VIII as applicable, Engineering Design Guides and Calculation procedure. Refer to AI 23H-002 Section 6.6.

(b) The line that failed was within the scope of the FAC program, but the subject location was not ranked to be inspected. Other components within that line were inspected prior to the failure.

(c) The components with low thickness readings, including the 45-degree elbow, were replaced with like-for-like immediately (1999). During RF12 (2002) the line was replaced with chrome-moly pipe.

(d) This piping was installed as part of the original construction and was placed in service in

1984. Selected piping segments downstream of the control valve and the first elbow were inspected in RF4 – results were acceptable.

In addition to the examination of the location equivalent to Callaway's rupture location, piping components potentially susceptible to similar type of degradation contributing to the Callaway failure were selected for additional inspections to detect any unexpected pipe wall thinning.

EPRI/WCGS joint effort evaluations were performed to identify the areas for improvements to the CHECWORKS FAC prediction model.

The detail review of the CHECWORKS model was performed per PIR 2000-2032. The results of the review are summarized in the response to AMP Audit Question #AMPA008 (#B.2.1.6-6). No apparent deficiencies in the model were identified.

The results of the inspections for additional locations and the recommended corrective actions

are provided in PIR 2000-2032. All subsequent inspections and/or replacements in the affected components are tracked/trended and implemented under the WCGS FAC program. The piping associated with the Callaway rupture has been replaced with FAC resistant material.

Staff Evaluation

The staff finds the applicant's response acceptable because the applicant has clarified that the minimum acceptable wall thickness for the components inspected for wall thinning in the FAC Program was consistent with the applicable ANSI or ASME code. The response also includes other clarifications asked in parts b, c and d of the question.

Question No AMPA010 LRA Sec 10-B.2.1.30

Audit Question The operating experience described in LRA Section B.2.1.30, states that "One gasket degradation has been noted. The gasket was installed in 1989, exhibited an increasing leakage trend since 1993 and was replaced in 1997."

Clarify which gasket is being discussed and what was the gasket material. Clarify if the replacement gasket was of the same material. Clarify how frequently has the gasket been inspected after its replacement and show the inspection results.

Final Response

The gasket being discussed is for equipment hatch ZX01. The gasket material is an elastomer known as EPDM (Ethylene Propylene Diene Monomer rubber). The manufacturer is Presray Corporation. EPDM grade E-603 (ref: Work Package 111933, Bill of Materials). The original and replacement gaskets were made of the same material. The ZX01 equipment hatch is tested every refueling outage. The leakage acceptance criteria for the equipment hatch seal is 4,200 sccm. LLRT data for equipment hatch ZX01 from 10/04/1997 failure date to present:

LLRT Date	Component	Leakage(sccm)	Error(sccm)
11/6/2006	ZX-01	20	3.7
5/11/2005	ZX-01	120	20

11/27/2003	ZX-01	0	4
04/23/2002	ZX-01	170	20
10/27/2000	ZX-01	0	4
05/03/1999	ZX-01	40	3.7
04/03/1999	ZX-01	20	3.7
11/20/1997	ZX-01	20	3.88
10/04/1997	ZX-01	6200	230

Staff Evaluation

The staff finds the applicant's response acceptable because the applicant has identified the degraded gasket as the one for equipment hatch ZX01. The applicant's response also includes the information on the gasket material and its performance after the replacement in 1997. The leakage rates for the replacement gasket measured during the eight subsequent LLRT's are significantly lower than the acceptance criteria for this gasket.

Question No AMPA011 LRA Sec 11-B.2.1.30

Audit Question Explain if the containment leakage test program require a local leak rate testing after the maintenance work or repair activities are performed on the containment boundary components (i.e., isolation valves, penetration seals, gaskets etc.) Explain how are the "as found" leakage rates applied if they exceeded the administrative leakage limits.

Final Response

Type B & C as-found testing is performed prior to any repair, modification, or adjustment activity, if the activity would affect the penetration/valve leak tightness.

Type B & C as-left testing is performed after any repair, modification, or adjustment activity, if the activity would affect the penetration/valve leak tightness.

The as-found leakage rates, determined on a minimum pathway leakage rate basis, for all newly tested penetrations/valves is summed with the as-left minimum pathway leakage rate for all other penetrations and valves subject to Type B and C tests to calculate the overall Type B & C leakage rate. For Type B or C tests that are not acceptable, the testing frequency shall be set to the initial test frequency (30 months or less). A cause determination in accordance with AP 28A-001, Performance Improvement Request shall be performed and corrective actions identified to eliminate the identified failure cause and prevent recurrence.

For the purpose of the Inservice Testing Program, which utilizes the Containment Leakage Rate Testing Program to satisfy category A isolation valve leakage test, a maximum allowable leakage rate of 10,000 sccm or the administrative limit, whichever is larger is specified for any single component/penetration. If this maximum allowable leakage rate is exceeded, repair or replacement shall be initiated in accordance with AP 16C-005, MPAC Work Request.

(ref: AP 29E-001, Program Plan for Containment Leakage Measurement, Section 6.2, 6.7.2, 6.8.4 & 6.8.6)

Staff Evaluation

The staff finds the applicant response acceptable because the applicant has adequately described the as-found and as-left test results that are applicable to Type B & C testing.

Question No AMPA012 LRA Sec 12-B.2.1.30
Audit Question Clarify what are the test intervals for Type A, B and C tests for the leak rate test program. Explain how is the test interval for the Type A test adjusted if the leakage rate testing yields unacceptable results.

Final Response

Type A test interval frequency is every ten years. If Type A test performance is unacceptable, the cause will be identified and corrective actions taken to restore satisfactory performance. A subsequent Type A test must be performed within 48 months following the unsuccessful test. If the subsequent test is successful, the frequency may be returned to 10 years. (ref: WCGS-AMP-B2.1.30, Section 3.5 and 3.7)

Type B & C are conducted at various intervals for the many different penetrations depending upon various factors for individual containment isolation components. These factors include past component performance, maintenance history, service environment, design and safety significance. For penetrations that demonstrate acceptable performance, the Type B test interval can be extended to a maximum of 120 months. For containment isolation valves that demonstrate acceptable performance, the Type C test interval can be extended to a maximum of 60 months. Containment purge and vent valves are tested at a periodicity of not greater than 3 months. Current Type B & C test frequencies are shown below:

Description	Component	Frequency
Personnel Air Lock (barrel)	ZX-003,L003	RF
Emergency Air Lock(barrel)	ZX-002,L001	RF
Emergency Air Lock (door seal)	ZX-02	RF
Equipment Hatch	ZX-001,L002	RF
Ctmt Recirc Sump/RHR B Sample	EJHV0024	3RF
Ctmt Recirc Sump/RHR B Sample	EJHV0026	3RF
Ctmt Recirc Sump/RHR A Sample	EJHV0023	3RF
Ctmt Recirc Sump/RHR A Sample	EJHV0025	3RF
Fuel Transfer Tube	Flange	RF
Loop B Seal Water Injection	BBHV8351B	3RF
Loop B Seal Water Injection	BBV0148	3RF
CVCS Letdown	BGHV8152	3RF
CVCS Letdown	BGHV8160	3RF
Seal Water Return	BGHV8100	3RF
Seal Water Return	BGHV8112	3RF
Seal Water Return	BGV0135	3RF
RX Makeup Water	BL8046	3RF
RX Makeup Water	BLHV8047	3RF
RX Coolant Drain TK Discharge	HBHV7136	3RF
RX Coolant Drain TK Discharge	HBHV7176	3RF
ESW To B & D Ctmt Coolers	EFHV0032/EFHV0034	2RF

ESW From B & D Ctmt Coolers	EFHV0046/EFHV0050	RF - Change after RF17
Instrument Air	KAFV0029	3RF
Instrument Air	KAV0218	3RF
Instrument Air	KAV0204	3RF
Ctmt Sump Discharge	LFFV0095	3RF
Ctmt Sump Discharge	LFFV0096	3RF
ILRT Pressurization Line	Flange	6RF
ISI Penetration	Flange	6RF
Loop C Seal Water Injection	BBHV8351C	3RF
Loop C Seal Water Injection	BBV0178	3RF
Loop D Seal Water Injection	BBHV8351D	3RF
Loop D Seal Water Injection	BBV0208	3RF
Loop A Seal Water Injection	BBHV8351A	3RF
Loop A Seal Water Injection	BBV0118	3RF
Aux Steam Decon	HDV0016	3RF
Aux Steam Decon	HDV0017	3RF
RX Coolant Drain TK N2 Supply	HBHV7126	3RF
RX Coolant Drain TK N2 Supply	HBHV7150	3RF
Accumulator N2 Supply	EPHV8880	3RF
Accumulator N2 Supply	EPV0046	3RF
ILRT PS (003-HBB-1")	Flange	6 RF
ILRT PS (005-HBB-1")	Flange	6 RF
Fuel Pool Cooling/Cleanup Supply	ECV0083	3RF
Fuel Pool Cooling/Cleanup Supply	ECV0084	3RF
Fuel Pool Cooling/Cleanup Return	ECV0087	3RF
Fuel Pool Cooling/Cleanup Return	ECV0088	3RF
Fuel Pool Cooling/Cleanup Skimmer	ECV0095	3RF
Fuel Pool Cooling/Cleanup Skimmer	ECV0096	3RF
H2 Analyzer Return	GSHV0008	3RF
H2 Analyzer Return	GSHV0009	3RF
CTMT Atmosphere Monitor Return	GSHV0038	3RF
CTMT Atmosphere Monitor Return	GSHV0039	3RF
RX Drain TK Sample	SJHV0131/SJHV0132	3RF
RX Drain TK Sample	SJV0111	3RF
Accumulator Fill From SI	EMHV8888	3RF
Accumulator Fill From SI	EMV0006	3RF
Pressurizer Relief TK N2 Supply	BBHV8026	3RF
Pressurizer Relief TK N2 Supply	BBHV8027	3RF
Service Air Supply	KAV0039	2RF
Service Air Supply	KAV0118	2RF
Pressurizer Liquid Sample	SJHV0128	3RF
Pressurizer Liquid Sample	SJHV0129/SJHV0130	3RF
Hydrogen Purge	GSHV0020/GSHV0021	RF
Fire Protection	KCHV0253	RF
Fire Protection	KCV0478	2RF
ISI Penetration	Flange	6RF
Pressurizer Liquid Sample	SJHV0012	3RF
Pressurizer Liquid Sample	SJHV0013	3RF
ESW To A & C Ctmt Coolers	EFHV0031/EFHV0033	3RF
ESW From A & C Ctmt Coolers	EFHV0045/EFHV0049	2RF

CCW Supply	EGHV0058/EGHV0127	3RF
CCW Supply	EGV0204	3RF
CCW Return	EGHV0059/EGHV0131	3RF
CCW Return	EGHV0060/EGHV0130	3RF
CCW TB Return	EGHV0061/EGHV0133	3RF
CCW TB Return	EGHV0062/EGHV0132	3RF
Steam Generator Drain	BMV0045	3RF
Steam Generator Drain	BMV0046	3RF
CVCS Charging	BG8381	3RF
CVCS Charging	BGHV8105	3RF
ECCS Test	EMHV8871	3RF
ECCS Test	EMHV8964	3RF
RX Coolant Loop A Hot Leg Sample	SJHV0005	3RF
RX Coolant Loop A Hot Leg Sample	SJHV0006/SJHV0127	3RF
Accumulator Liquid Sample	SJHV0018	RF
Accumulator Liquid Sample	SJHV0019	3RF
H2 Analyzer Return	GSHV0017	3RF
H2 Analyzer Return	GSHV0018	3RF
CTMT Atmosphere Monitor Return	GSHV0033	3RF
CTMT Atmosphere Monitor Return	GSHV0034	3RF
Breathing Air	KBV0001	3RF
Breathing Air	KBV0002	3RF
H2 Analyzer Sample	GSHV0003	3RF
H2 Analyzer Sample	GSHV0004	3RF
H2 Analyzer Sample	GSHV0005	3RF
CTMT Atmosphere Monitor Sample	GSHV0036	3RF
CTMT Atmosphere Monitor Sample	GSHV0037	3RF
H2 Analyzer Sample	GSHV0012	3RF
H2 Analyzer Sample	GSHV0013	3RF
H2 Analyzer Sample	GSHV0014	3RF
CTMT Atmosphere Monitor Sample	GSHV0031	3RF
CTMT Atmosphere Monitor Sample	GSHV0032	3RF
Fiber Optics	PEFO	6RF
Shutdown Purge Exhaust	GTHZ0008	92 days
Shutdown Purge Exhaust	GTHZ0009	92 days
Shutdown Purge Supply	GTHZ0006	92 days
Shutdown Purge Supply	GTHZ0007	92 days
Mini Purge Exhaust	GTHZ0011	92 days
Mini Purge Exhaust	GTHZ0012	92 days
Mini Purge Supply	GTHZ0004	92 days
Mini Purge Supply	GTHZ0005	92 days
South Electrical Penetrations	PES	6RF
North Electrical Penetrations	PEN	6RF

Staff Evaluation

The staff finds the applicant's response acceptable because the response provides maximum test intervals applicable to Type A, B and C tests for leak rate test program and also explains how the test interval for Type A test is adjusted if the testing yields unsatisfactory results.

Question No AMPA013 LRA Sec 13-B.2.1.20

Audit Question External Surfaces Monitoring Program is credited for aging management of elastomer seals and flex connectors for hardening and loss of strength. The applicant referenced GALL AMP XI.M36 which is used to monitor external steel surfaces for loss of material and leakage by visual inspection. Since the elastomers can deteriorate and loose strength without showing a change in the visual appearance, clarify what inspection techniques are used in the External Surfaces Monitoring Program to detect hardening and loss of strength of elastomers.

Final Response

Visual inspections are the primary program method for detecting external corrosion or material aging degradation, such as cracking of elastomers resulting from hardening or loss of strength. Physical manipulation during the visual inspection can also be used to verify the absence of hardening or loss of strength for elastomers. (Element 4)

Staff Evaluation

The staff finds the applicant's response acceptable because the response explains that for the inspection of elastomers, physical manipulation will be used in conjunction with visual inspections to verify absence of hardening or loss of strength.

Question No AMPA014 LRA Sec 14-B.2.1.20

Audit Question The External Surfaces Monitoring Program is credited for aging management of tube sides of several heat exchangers (e.g., HX Nos. 131, 142, 145 and 148). Clarify what type of heat exchangers are these. Clarify if the tube bundles are exposed to the indoor air such that they are accessible for surface inspections.

Final Response

There are forty-two heat exchanger tube side components that credit External Surfaces Monitoring for aging management. Thirty-eight of those components are heat exchanger heads (e.g. Hx Nos 131, 142, 145, & 148) that are described as heat exchanger tube side components only because they contain the tube side fluid. The heat exchanger heads are exposed to plant indoor air externally. The other four components are containment cooler manifolds that are described as heat exchanger tube side components only because they contain the tube side fluid. The containment cooler manifolds are exposed to plant indoor air externally.

The tube bundles related to these forty-two components are not exposed to plant indoor air and are not managed by the External Surfaces Monitoring Program.

Staff Evaluation

The staff finds the applicant's response acceptable because the response includes adequate explanation to clarify that Hx Nos. 131, 142, 145 and 148 are not tubes but are heat exchanger heads which are classified as tube side components in the terminology utilized in the applicant's LRA.

Question No AMPA015 LRA Sec 15-B.2.1.20

Audit Question Clarify if there are any components covered by the External Surfaces Monitoring Program that are not accessible during both plant operations and refueling outages. If yes, explain how the applicant will ensure proper inspection of these components. Also, discuss how the components covered by insulation are inspected under this AMP.

Final Response

There are no components that have been specifically identified as being inaccessible during both plant operations and refueling outages, however, the External Surfaces Monitoring Program has provisions for any such cases. (The External Surfaces Monitoring Program has not been credited for any components that are either submerged or encased in concrete.) Components that are inaccessible during both plant operations and refueling outages are evaluated to ensure that they have been/will be inspected at frequencies that provide reasonable assurance that the effects of aging will be managed such that the applicable intended functions will be maintained during the period of extended operation. (Element 4).

The program provides clarification for areas, or portions of systems or components, that are difficult to access or are exempted from walkdown inspections based on physical (insulated, shielded, etc.) or environmental constraints (radiation levels, etc.). Exempted areas, or exempted portions of systems or components are to be documented on the walkdown inspection checklist, and an evaluation performed to determine that prior to the next refueling cycle, there is reasonable assurance that the effects of aging are managed such that applicable components will perform their intended function (Element 1).

Staff Evaluation

The staff finds the applicant's response acceptable because the response adequately clarifies that currently there are no components identified as inaccessible during plant operation and refueling outages. The response also states that the WCGS program has a provision for evaluation and /or inspection of such components.

Question No AMPA016 LRA Sec 16-B.2.1.20

Audit Question PIR No. 20032733 reports a condition where the essential service water supply piping to the motor driven auxiliary feedwater pump B had not been coated after its installation and external corrosion was evident on the welds, heat affected zones, and valve EF V362. Clarify if the corrosion observed was severe enough to warrant evaluation of wall thinning. Describe what corrective actions were taken to assure that similar problems were avoided in the future.

Final Response

The corrosion was evaluated as minor surface rust. No additional evaluation was undertaken. The components were determined to have been on the maintenance backlog for the coating. The components were prepped and coated; no further corrective actions were taken.

Staff Evaluation

The staff finds the applicant's response satisfactory because the response provides adequate explanation as to how the condition reported in PIR 20032733 was evaluated and what corrective actions were taken.

Question No AMPA017 LRA Sec 17-B.2.1.20

Audit Question The External Surfaces Monitoring Program operating experience discusses several work orders. The problem descriptions included in WO 01 224361-000, WO 01 226813-000, WO 95 107292-000, WO 98 129513-001, and WO 99 208339-000 are incomplete. Provide the complete problem descriptions for these work orders.

Final Response

WO 01-224361-000
Pipe Flange bolts need to be checked and at least one replaced due to rust. It appears that the bolts are rusted due to leakage or condensation. The flange gasket is not leaking at this time. This was written up in 1997, WR#97-126320-002, but it has either rusted again since, or was not replaced at that time.

WO 01-226813-000
A ESW outlet line EF-223-HBC-30 downstream of EFV108 near the wall penetration, the exterior coating has failed and surface rust is evident. The loose paint and exterior corrosion should be removed from the pipe and QC should perform a visual examination prior to application of the coating. Note to QC: UT Activity number 03101 grid markings will be impacted by this activity.

WO 95-107292-000
Screen requires refurbishment due to corrosion of steel parts. Removal of screen from well is needed. Reference eng dispo 04410-92, rev 0 and rev 1 by Sathi (11-10-95) fef01b

WO 98-129513-00
1WS01PA, Service Water Pump "A" needs packing adjustment to minimize leakage. Water spill in the pump house is degrading the supports for the heat trace panel and cable due to the standing water. Leak off piping needs replacement. Fin Team - adjust the packing and make a new task to replace the piping and sent to Maintenance Shop.

WO 99-208339-000
During the performance of STS MT-011 it was noted that the forward load pin and paddle on a PSA 1 snubber attached to hanger BM18-R513 has moderate to heavy rust build up. This should be cleaned so that it doesn't affect the spherical bearing. CWA notify Robin Rumas when the rust is removed so QC can complete STS MT-11.

Staff Evaluation

The staff asked the applicant to provide the complete problem descriptions for the work orders discussed in the operating experience database. The staff finds the applicant's response acceptable because the response includes complete problem descriptions and the

corresponding corrective actions taken by the applicant for each work order identified in the staff's question.

Question No AMPA018 LRA Sec 18-B.2.1.4
Audit Question Explain how the vessel head is inspected for evidence of boric acid.

Final Response

AMP B2.1.4 Element 4 states that "locating small leaks" is identified through walkdowns of systems containing reactor coolant or treated borated water, formalized inspections of reactor coolant and treated borated water systems, and reactor coolant system leak rate monitoring.

AMP B2.1.4 Element 4 also identifies that reactor vessel head examinations are conducted as follows:

(1) Reactor coolant pressure boundary integrity walkdowns are performed by Level II or Level III VT-2 certified personnel using the examination techniques of QCP-20-520, Pressure Test Examination. Attachment G of STN PE-040D documents reactor head inspection results. Any evidence that boron leakage from above vessel may have penetrated the mirror insulation SHALL require a head bare metal inspection for the potentially affected areas of the vessel head, and require cleanup of head and mirror insulation.

(2) Additional inspections that are NRC commitments for RPV closure head inspections have been implemented per NRC Order EA-03-009. (See AMP B2.1.5, Nickel-Alloy Penetration Nozzles Welded to the Upper Vessel Closure Heads of PWRs). This includes bare metal visual examination of the head surface, performed every third refueling or five years, whichever occurs first. Attachment C of STN PE-40E documents reactor head examination results.

Staff Evaluation

The staff finds that the response is acceptable because the proper inspections of the reactor vessel head have been completed in response to the Bulletins.

Question No AMPA019 LRA Sec 19-B.2.1.4
Audit Question Clarify if there are plans to replace the vessel head.

Final Response

Wolf Creek has initiated a project to purchase a reactor vessel head forging as a risk management tool against the increasing world demand for ultra heavy forgings. The decision to finish machining the forging and initiate a project to replace the existing reactor vessel head will be made at a later date.

Staff Evaluation

The information answered the question about plans to replace the reactor vessel head. There are no immediate plans to replace the head since there are no indication of cracks in the vessel nozzles at this time based on bare metal vessel inspections. The applicants has plans to

purchase the forging for the head as a precaution, because purchases of adequate forgings are long lead time items.

Question No AMPA020 LRA Sec 20-B.2.1.4

Audit Question Discuss how the applicant responded to the NRC's orders and bulletins listed below. Explain how these responses have been used to update the component list locations and visual inspections within the scope of the Boric Acid Corrosion Program.

· NRC Bulletin 2002-01, dated March 29 and May 16, 2002
· NRC RAI on Bulletin 2002 01, dated January 17, 2003
· NRC Bulletin 2003-02, dated September 19, 2003
· NRC Order EA 03 009, dated March 3, April 11, and April 18, 2003
· NRC Bulletin 2004-01, dated May 28, 2004

Final Response

Wolf Creek responses to the referenced NRC generic communications are contained in the letters referenced below. Copies of the Wolf Creek letters are available on site for review or in ADAMS.

NRC Bulletin 2002-01
"Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity"

1. WCNOC Letter ET 02-0018 dated April 03, 2002
   Response to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity"
2. WCNOC Letter ET 02-0021 dated May 16, 2002
   60 day response to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity"
3. WCNOC Letter ET 03-0007 dated January 31, 2003
   Response to Request for Additional Information for NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity"

NRC EA-03-009
"Issuance of First Revised Order (EA-03-0009) Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors"

1. WCNOC Letter WM 04-0001 dated January 22, 2004
   60 Day Report for NRC Order EA-03-009, "Issuance of First Revised Order (EA-03-0009) Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors"
2. WCNOC Letter WM 04-0004 dated March 04, 2004
   Response to NRC Order, "Issuance of First Revised Order (EA-03-0009) Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors"
3. WCNOC Letter WM 06-0051 dated December 20, 2006
   60-Day Report for NRC Order EA-03-009, "Issuance of First Revised Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors"

4. Note: additional letters relative to the Wolf Creek relaxation request are noted in the response to question A057

NRC Bulletin 2003-02
"Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Pressure Boundary Integrity"

1. WCNOC Letter WM 03-0044 dated September 19, 2003
   Response to NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and reactor Pressure Boundary Integrity"
2. WCNOC Letter WM 04-0002 dated January 22, 2004
   60 day Report to NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and reactor Pressure Boundary Integrity"
3. NRC Letter 05-00051 dated January 20, 2005
   Wolf Creek Generating Station - Response to NRC Bulletin 2003-02, "Leakage From

   Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity"

NRC Bulletin 2004-01
"Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at PWRs"

1. WCNOC Letter ET 05-0015 dated July 14, 2005
60 Day Report for NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at PWRs
2. WCNOC Letter WO 04-0039 dated July 27, 2004
60 Day Response to NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at PWRs"

Changes to the Wolf Creek Boric Acid Corrosion Control Program as a result of the referenced NRC Generic Communications:

AP 16F-001 Boric Acid Corrosion Control Program
Revision 2 was approved December18, 2000 – no change
Revision 3 was approved May 5, 2005 and was a major revision that included the changes noted below.
Revision 4 was approved October 14, 2005 (current revision – no change)
Revision 3 changes:
1. As part of this revision two additional AIs were prepared:
   - AI 16F-001 Evaluation of Boric Acid Leakage
   - AI 16F-002 Boric Acid Leakage Management
2. Section 6.0 was revised to identify the main elements (8) of the program and on a programmatic level, describe how the elements are to be fulfilled. Revisions also described ties to other processes and procedures which are integral to the ability of the BACC Program to meet the objectives of the program.
3. Attachment A was added to provide guidance on leakage
4. Attachment B was added to clarify/capture frequency of program inspections/examinations (references NRC Bulletin 2002-01 & NRC Order EA-03-009 inspections)

STN PE-040D RCS Pressure Boundary Integrity Walkdown
Revision 1 was approved July 17, 2001 – no change
Revision 2 was approved May 22, 2003 is the current revision and includes the following changes:

1. Added new sections to examine the vessel safe-end nozzles, vessel sides and bottom penetrations.
2. Added Attachment I for Reactor Vessel Loop Safe-Ends Inspection results and Attachment J for Reactor Vessel Sides and Bottom Head Inspection Results
3. Revised Attachment G, Containment - Reactor Cavity Inspection Results to note that any evidence of boron leakage from above vessel may have penetrated the mirror insulation shall require a head bare metal inspection of the potentially affected areas.
4. Attachment K added to identify components/locations containing Alloy 600 materials which have been shown to be susceptible to PWSCC.

Staff Evaluation

The staff finds that the response is acceptable because the proper inspections of the reactor vessel head have been completed in response to the Bulletins.

Question No AMPA021 LRA Sec 21-B.2.1.7
Audit Question Clarify if WCGS has bolting expert in accordance with EPRI recommendations.
Final Response

EPRI TR-104213 December 1995, Bolted Joint Maintenance & Application Guide section 1.9 recommends providing an on-site bolting coordinator, empowered to implement a program to eliminate failures. EPRI TR-104213 identifies a bolting coordinator as an individual who has the technical ability and authority to focus on both programmatic issues and day-to-day resolution of problems. Wolf Creek mechanical design engineering provides the functions of the bolting coordinator consistent with guidance of EPRI TR-104213.

Staff Evaluation

The EPRI Guidance is only a guidance. Rather than designating an individual bolting expert, WCGS designates an entire department. Since this accomplishes the same objective, the staff finds this to be acceptable.

Question No AMPA022 LRA Sec 22-B.2.1.7
Audit Question Clarify if WCGS has ever purchased counterfeit bolting. Clarify if WCGS has a procedure to identify counterfeit bolting. Explain what has WCGS done in response to NRC Information Notice No. 89 59, “Suppliers of Potentially Misrepresented Fasteners.”
Final Response

NRC Information Notice No. 89 59 and the supplements were reviewed for applicability under the WCGS Industry Technical Information Program (ITIP). It was concluded that WCGS did not have any fasteners supplied by the vendors listed in this Notice that had involvement in counterfeit bolts/fasteners.

Procedure AP 24D-003, “Receipt Inspections”, Attachment B, provides guidance to identify items that may be substandard, misrepresented, or supplied with fraudulent documentation. If an item exhibits such indications, it directs to procedure AP 24H-003, “Commodity Discrepancies”, for further investigations and corrective actions.

Staff Evaluation

The staff finds that the response is acceptable because it shows that the applicant reviewed the Information Notice and supplements, and determined that they did not have any fasteners supplied by vendors identified in the Information Notice and supplements. The applicant also has a program in place identify items that may be substandard, misrepresented, or supplied with fraudulent documentation. The applicant also has a procedure to implement a corrective action program if suspect items are identified.

Question No AMPA023 LRA Sec 23-B.2.1.7
Audit Question Describe the maintenance procedures used to check bolt torque and the uniformity of gasket compression. Provide the frequency for the maintenance activity.

Final Response

In accordance with plant procedures on bolting installations, proper bolting practice to provide leak tight pressure retaining joints includes pre-assembly inspection and cleaning requirements, use of specific bolting torquing patterns, increased application of torque through multiple passes, and verification of uniformity of the gasket compression. Post-bolting inspections include verifying contact between the fastener and flange and proper flange alignment. Guidance for proper preload is provided with desired torque values to ensure adequate gasket stress for leak tightness.

Procedures used are:

- MPM M711Q-02, “Primary Manway Removal/Installation using HYDRA-TIGHT,” Sections 7.6, 7.7, 7.8, 7.9.
- MPM M711Q-03, “Handhole Cover and Instrument Opening Cover Removal/Installation,” Section 7.2.
- MPM M711Q-04, “Steam Generator Secondary Manway Removal/Installation,” Section 7.2.
- MPM M711Q-06, “Primary Manway Removal/Installation using NES/TENTEC,” Sections 7.6, 7.7, 7.8, 7.9.
- MPM M712Q-04, “Reactor Coolant Pump Internal Replacement,” Sections 7.10, 7.11, 7.12.
- MPM M713Q-01, “Pressurizer Manway Cover Removal/Installation,” Section 7.2.
- MPM BB-001, “Pressurizer Code Safety Valve Removal and Installation,” Section 7.3, and
- MGM MOOP-08, “Torque Guideline for Bolted Connections,” Section 7.0.

These activities are performed when there are opportunities of removal and installation of the subject components for maintenance or scheduled inspections.

Staff Evaluation

The staff finds that the applicant’s response acceptable because the applicant has qualified procedures for torquing bolts and for assuring uniformity of gasket compression.

Question No AMPA024 LRA Sec 24-B.2.1.8
Audit Question Clarify how many tubes are plugged in each steam generator.

Final Response

The following is the status of Steam Generator tube plugging at the completion of the fourteenth Steam Generator Tube Inspection completed during Refueling Outage 15 (October 2006).
A Steam Generator: 35 tubes plugged (0.62% total percentage plugged)
B Steam Generator: 35 tubes plugged (0.62% total percentage plugged)
C Steam Generator: 20 tubes plugged (0.36% total percentage plugged)
D Steam Generator: 114 tubes plugged (2.03% total percentage plugged)
Note: an additional 3 plugs are installed in A Steam Generator cold leg only, due to tube sheet drilling errors during manufacturing. No tubes are installed in those locations.

Reference: ET 07-0005 "Results of the Fourteenth Steam Generator Tube Inservice Inspection"

Staff Evaluation

The staff finds this response acceptable because the applicant supplied the information requested.

Question No AMPA025 LRA Sec 25-B.2.1.8
Audit Question Discuss if WCGS has plans to replace the existing steam generators.
Final Response

The current economic model for the steam generators does not recommend replacement. This model is updated as conditions change. Wolf Creek has no plans to replace our steam generators.

Staff Evaluation

The staff finds this response acceptable because the applicant indicated that a small percentage of tubes in the steam generator are plugged and replacement of the steam generators is not being considered.

Question No AMPA026 LRA Sec 26-N/A
Audit Question Clarify which Regulatory Guide 1.54 (i.e., Revision 0 or Revision 1) is WCGS committed to.

Final Response

USAR Appendix 3A states that WCGS is committed to Rev. 0 of RG 1.54 as described in Table 6.1-2.

Staff Evaluation

The staff requested clarification on which revision of Regulatory Guide 1.54 WCGS is committed to use. WCGS responded they are using Revision 0.

Question No AMPA027 LRA Sec 27-N/A
Audit Question Clarify if coating inspections are performed at WCGS. If yes, explain what is the basis for these coating inspections.

Final Response

WCGS did not credit NUREG-1801 XI.S8 for aging management.

Staff Evaluation

This question was withdrawn and a new question (AMPA123) was generated.

Question No AMPA028 LRA Sec 28-N/A
Audit Question Explain what consideration does WCGS have for transport of coatings to the sump screens.

Final Response
WCGS did not credit NUREG-1801 XI.S8 for aging management.

Staff Evaluation

This question was withdrawn and a new question (AMPA123) was generated.

Question No AMPA029 LRA Sec 29-N/A
Audit Question Clarify which aging management program will be used to manage the effects of aging of coatings during the period of extended operation.

Final Response

WCGS did not credit NUREG-1801 XI.S8 for aging management.

Staff Evaluation

This question was withdrawn and a new question (AMPA123) was generated.

Question No AMPA030 LRA Sec 30-N/A
Audit Question ASME Code Section XI, IWE 3510.2, "Visual Examination of Coated and Noncoated Areas," states that "The condition of the inspected area is acceptable if there is no evidence of damage or degradation which exceeds the visual acceptance criteria specified by the Owner." Explain what is the acceptance criteria for coated surfaces.

Final Response

Detailed visual examination acceptance criteria identifies the following conditions as rejectable for coated surfaces:

- Cracking
- Flaking
- Blistering
- Peeling
- Discoloration
- Deformation
- Other signs of distress

All rejectable indications require initiation of an Non-Conformance Report (NCR) and evaluation in accordance with the WCGS corrective action process.

Staff Evaluation

This question was withdrawn and a new question (AMPA123) was generated.

Question No AMPA031 LRA Sec 31-B.2.1.18
Audit Question Clarify which materials are included in the Buried Piping and Tanks Inspection Program. The LRA mentions steel, stainless steel, and ductile iron, clarify if there are any other materials. Clarify which materials are coated and which are not. Explain what types of coatings are used for each type of material.

Final Response

The materials included in the buried piping and tanks inspection program include steel, stainless steel, ductile iron and gray cast iron.

The following coatings are used:

Stainless steel coatings: None

Steel, ductile iron and gray cast iron coatings: Coal tar enamel (pipe), Coal tar epoxy (steel tanks)

Staff Evaluation

This was a request for information and the information was provided.

Question No AMPA032 LRA Sec 32-B.2.1.18
Audit Question Clarify if WCGS has buried tanks and, if so, what is the material of construction.

Final Response

The emergency fuel oil storage tanks (carbon steel) are the only tanks in the scope of the buried piping and tanks inspection AMP.

Staff Evaluation

This was a request for information and the information was provided.

Question No AMPA033 LRA Sec 33-B.2.1.18

Audit Question The LRA states that leaks have been observed in buried piping. Clarify where these leaks have been observed and what corrective actions have been taken. Clarify what is the current frequency of buried piping inspections.

Final Response

In 1987 the Engineering Study for Galvanic Corrosion on Underground Piping at WCGS discovered corrosion on multiple runs of buried piping that are in the scope of license renewal in the Fire Protection System and the Auxiliary Feedwater System. The corrosion discovered in the Fire Protection System piping was characterized as galvanic corrosion. Pitting was found on carbon steel piping that was directly connected to ductile iron piping. The study postulated that the corrosion in the Auxiliary Feedwater System was either due to stray current from the Fuel Oil System or galvanic corrosion due to the carbon steel piping becoming a sacrificial anode.

Since the completion of the 1987 study, there have been four occurrences of leakage due to corrosion of the external surface of buried components at Wolf Creek. Three of these leaks occurred in buried portions of the non-essential Service Water System, which are not within the scope of license renewal. An additional leak was discovered in Fire Protection System (KC) outside the Diesel Generator Building in 1997. Subsequent excavation in 1998 discovered loss of material due to pitting corrosion. The Fire Protection System corrosion resulted from a break in the protective coating.

The Borated Refueling Water System and the Auxiliary Feedwater System have only short runs of pipe between pipe tunnels and buildings. The 1987 Engineering Study provides the only known documentation of corrosion related failure in the Auxiliary Feedwater System. In this case pitting corrosion was discovered on excavated carbon steel piping. This section of piping was then replaced from the condensate storage tank to the power block. There have been no documented external corrosion related failures of the Borated Refueling Water System.

The Emergency Fuel Oil System has only short runs of pipe from between the below grade fuel oil storage tank and the Diesel Generator Building. There have been no documented external corrosion related failures of the Emergency Fuel Oil System piping.

The Essential Service Water System has multiple long runs of carbon steel piping. There are no documented external aging failures of the buried Essential Service Water System piping.

The Fire Protection System has four recorded discoveries of pitting corrosion, with two of these resulting in leakage. Three of these discoveries were made during the 1987 Engineering Study with one leakage among that group. The last recorded leakage occurred in 1997 outside of the Diesel Generator Building with pitting corrosion, due to a break in the protective coating. WCGS has no current buried piping inspection procedures. However, work control procedures require evaluation/repair of degraded conditions that are discovered.

Staff Evaluation

The staff asked for information on leaks that have been observed in buried piping. The applicant provided the information requested. The staff also asked about the frequency of

buried pipe and tanks inspections. The applicant replied that since this is a new program, the frequency has not been established at this time.

Question No AMPA034 LRA Sec 34-B.2.1.19
Audit Question Clarify if there are any socket welds identified as high safety significant locations as part of the RI-ISI program. If so, clarify how many are there. The EPRI Topical report specifies that high safety significant locations be volumetrically examined. Explain how socket welds will be examined if they are in a high safety significant location.

Final Response

There are no socket welds identified as high safety significant locations as part of the RI-ISI program.

Staff Evaluation

The staff finds this response acceptable because there are no socket welds identified with high safety significance as part of the RI-ISI Program.

Question No AMPA035 LRA Sec 35-B.2.1.27
Audit Question Clarify if there have been any containment liner plate inspection results since 1996. If not, explain why. If yes, the results should be made available during the audit.

Final Response

The following Owner's Activity Reports document the containment liner plate inspections since 1996.

Containment Inservice Inspection Program First Interval, First Period 2002
Findings:

- There were no components containing flaws or relevant conditions that required an evaluation to determine acceptability for continued service.
- There were no Class MC components that required repairs, replacements, or corrective measures for continued service.

Containment Inservice Inspection Program First Interval, Second Period 2006
Findings:

- A general visual exam found localized pitting in the liner floor of the incore tunnel sump.
- A detailed visual exam was performed to determine the magnitude and extent of degradation to the incore tunnel sump liner. Pitting was the only degradation found. It is believed that the pitting resulted from nearby welding, which damaged the coating. An evaluation performed by design engineering determined that the remaining wall thickness is sufficient and that recoating the pitted area with a qualified coating will stop further degradation. The pitted areas have been recoated with a qualified coating. The incore tunnel sump liner was found to be acceptable for continued service, and the areas containing the pitting were identified for reexamination during

the next inspection period.
- The WCGS corrective action program addressed programmatic concerns. Applicable procedures were reviewed and revised as necessary to ensure compliance with IWE requirements and to establish acceptance criteria for pitting of the containment liner plate.

Containment Inservice Inspection Program First Interval, Third Period 2007
Findings:
- There were no containment liner plate components containing flaws or relevant conditions that required an evaluation to determine acceptability for continued service.
- There were no repairs, replacements, or corrective measures performed on any Class MC or CC items during the period of this report that were required due to an item containing a flaw or relevant condition that exceeded acceptance criteria.

Staff Evaluation

The staff finds this response acceptable because the applicant supplied the information requested.

The staff interviewed the applicant's technical staff to confirm that the operating experience did not reveal any degradation not bounded by industry experience. In addition, the staff notes that the corrective action program, which captures internal and external plant operating experience issues, will ensure that operating experience is reviewed and incorporated in the future, so that the effects of aging are adequately managed.

Question No AMPA036 LRA Sec 36-B.2.1.27
Audit Question The ASME Section XI, Subsection IWE Program operating experience describes degradation found in the in core instrument tunnel sump in 2002 and 2003. Discuss all preventive maintenance and corrective actions taken for each type of degradation found. Final Response

A detailed visual exam was performed to determine the magnitude and extent of degradation to the incore tunnel sump liner. Pitting was the only degradation found. It is believed that the pitting resulted from nearby welding, which damaged the coating. An evaluation performed by design engineering determined that the remaining wall thickness is sufficient and that recoating the pitted area with a qualified coating will stop further degradation. The pitted areas have been recoated with a qualified coating. The incore tunnel sump liner was found to be acceptable for continued service, and the areas containing the pitting were identified for reexamination during the next inspection period.

The WCGS corrective action program addressed programmatic concerns. Applicable procedures were reviewed and revised as necessary to ensure compliance with IWE requirements and to establish acceptance criteria for pitting of the containment liner plate.

Staff Evaluation

The staff finds the applicant’s response acceptable because the response includes complete problem descriptions and the corresponding appropriate corrective actions taken by the applicant.

Question No AMPA037 LRA Sec 37-B.2.1.28
Audit Question The LRA and its commitment list references ASME Code Section XI, 2003 Edition, which does not exist. Clarify this inconsistency.

Final Response

LRA Section B2.1.28 and LRA Commitment number 15 for ASME Section XI, Subsection IWL (RCMS 2006-212) will be amended to read, "ASME Code Section XI, 2001 Edition with 2002 and 2003 addenda."

Staff Evaluation

The staff finds the applicant's response acceptable because in the letter dated May 25, 2007, Commitment # 15 was revised and read: 2001 Edition with 2002, and 2003 addenda.

Question No AMPA038 LRA Sec 38-B.2.1.28
Audit Question The LRA states that in 2005, a 20-year tendon surveillance found some excessive grease void volumes. Explain in detail your surveillance results and justify your conclusions.

Final Response

During the twentieth year surveillance of the post-tensioning system, four tendons were found to accept greater than 10% of the tendon duct volume of grease when refilled after testing, with the highest being 17.4%.

These conditions were evaluated by design engineering and found not to be significant conditions. The apparent cause of these excess voids was determined to be an elevated initial filling temperature along with a short soak time, resulting in increased shrinkage. Examination of the tendons found no deterioration. The engineers also consulted a study conducted at Callaway Nuclear Station, addressing a similar condition with their unbonded tendons. The essential criterion for the operability of the sheathing filler material is to prevent corrosion of both the tendon wires and the anchorage components. The material used at the Callaway Plant, and at WCGS, accomplishes this by a characteristic which gives the filler material an affinity to adhere to steel surfaces, its ability to emulsify any moisture in the system nullifying its rusting ability, and by its resistance to moisture, mild acids, and alkalis. In addition, protection is afforded by each tendon wire being individually pre-coated prior to installation. Therefore, no further action was recommended.

Staff Evaluation

The staff finds the applicant's response acceptable because the material used at WCGS has the affinity to adhere to steel surfaces and are resistant to moisture, mild acids, and alkalies. The staff also reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to confirm that the operating experience did not reveal any degradation not bounded by industry experience. In addition, the staff finds that the corrective action program, which captures internal and external plant operating experience issues, will ensure that

operating experience is reviewed and incorporated in the future so the effects of aging are adequately managed.

Question No AMPA039 LRA Sec 39-B.2.1.31

Audit Question Provide details on the operating experience relating to the degradation found in 2002-2003. Explain how does this compare to the 1998 established baseline. Include the acceptance criteria for cracking, deterioration, missing anchor bolts, anchor bolts pop outs, and the presence of water. Clarify if a scope expansion was required due to unacceptable conditions identified. Identify any additional inspections scheduled for the next inspection period.

Final Response

Based on the 1998 baseline inspections, several masonry walls in the Control Building and Turbine Building had aging effects classified as "Acceptable With Degradation." Subsequent inspections that took place between 2002 and 2003 are summarized as follows:

A masonry wall in the control building had cracks visible on both sides. The cracks were repaired with grout, but the joint was moving enough to re-crack the repair. The wall is located in an area not subject to weather or a threat to water exposure. Design engineering evaluated this condition and determined that there had been no change in the described conditions since the previous inspection, and the described condition is not indicative of any structural concern. This item was re-categorized as “Acceptable With Minor Degradation,” and will be re-inspected during the next scheduled inspection.

Several masonry walls in the turbine building were observed to have minor cracks categorized as "Acceptable With Degradation." In most cases during the 5-year re-inspection, the conditions had stabilized from the baseline observation resulting in a downgraded category. In the north wall of the southeast turbine building truck bay, a previous attempt had been made to repair the crack and was not accessible from the opposite side due to a building column. No leakage is involved that could lead to corrosion. The latest inspection reveals that the length and size of crack continues to increase. Design engineering has evaluated this wall and determined that it will still perform its intended functions.

A support angle attached to a masonry wall was found to be missing an anchor bolt. The angle supports the building’s metal siding and is not a seismic support for the wall. This situation was evaluated by design engineering, who determined that no further action was required due to the redundancy of the design.

Several pop outs around anchor bolts or through-bolts were identified. All of these were determined to have occurred during construction, and not as a result of aging. Design engineering evaluated all of the cases and determined that the damage did not prevent any of the components from performing their intended functions. None were found to have increased degradation during subsequent inspections.

No operating experience pertaining to the presence of water in masonry walls was found.

No scope expansion was required. All items that remain classified as "Acceptable with Degradation" will be inspected again during the next inspection period. No cases of "Major degradation" were found.

Staff Evaluation

The staff finds the applicant's response acceptable because the applicant has provided a reasonable action and an satisfactory engineering evaluation which were based on the plant and industry experience.

Question No AMPA040 LRA Sec 40-B.2.1.32

Audit Question The Structures Monitoring Program operating experience describes that degradations were addressed (e.g., minor degradation, corrosion on a hanger in the essential service water system, corrosion on a steel column, etc.) Discuss the above categories, the assessment performed, future monitoring recommended, and any corrective actions taken to prevent reoccurrences.

Final Response

The WCGS Structures Monitoring Program identifies each structural component in-scope for license renewal and its inspection attributes. All conditions of degradation are identified, assessed, and categorized in accordance with ACI 201.1R, and ACI 349.3R. Specific limits for each type of degradation are provided in applicable WCGS procedures. The Structures Monitoring Program also specifies actions to be taken for each category of degradation. These actions may include future monitoring, further assessment, or corrective action. For the two examples cited in the question, the affected areas have been cleaned and re-coated.

Staff Evaluation

The staff finds the applicant response acceptable because appropriate corrective actions were taken and complied with.

Question No AMPA041 LRA Sec 41-B.2.1.32

Audit Question Provide the following information about the aging management of inaccessible concrete:

(a) Submit the dates and results (at specific locations, not averages or ranges) of all past groundwater monitoring tests.

(b) Discuss why the groundwater is non aggressive, and/or aggressive, if applicable.

(c) Clarify if the Structures Monitoring Program will continue to perform the groundwater monitoring and inspect all inaccessible areas that may be exposed by excavation, whether the environment is considered aggressive or not.

(d) Clarify if the Structures Monitoring Program will inspect any inaccessible areas that are exposed to the same environment which has caused significant concrete degradation in accessible areas.

Final Response

(a)
Groundwater monitoring tests conducted monthly at WCGS from June 2005 to May 2006 show the groundwater and soil to have pH values between 7.0 and 8.7, chloride solutions ranging from 5.0 ppm to 41.2 ppm, and sulfate solutions from 30 ppm to 717 ppm. These tests were conducted at five different locations on-site.

The sulfate concentration of 717 ppm was from a well located north of the circulating water screenhouse. This well showed sulfate levels that were consistently higher than any other sample location. There are no external sources in the vicinity that could account for the elevated levels of sulfate at that location. Therefore, they are judged to exist as part of the natural environment. It should also be noted that the maximum level of sulfate concentration of 717 ppm is less than half of the limit of 1500 ppm as specified in NUREG 1801, Item II.A1-4.

(b)
Question withdrawn by NRC.

(c)
The structures monitoring program will be enhanced to monitor groundwater for pH, sulfates, and chlorides. Two samples of groundwater will be tested every five years.

For inaccessible areas opportunistic inspections will be performed, if practical, whenever the area becomes accessible as a result of refueling outages, power curtailments, maintenance activities, excavations, etc.

(d)
Evaluation of inaccessible areas provides justification for their adequacy, which might include site-specific characteristics, accessible areas subject to similar conditions, industry experience, industry guidance and previous inspections of similar areas. The responsible-in-charge engineer initiates activities necessary to enable an inspection of any inaccessible areas that the evaluation can not provide reasonable assurance that the inaccessible components would be able to continue to perform their intended functions.

LRA Sections A1.32 and B.2.1.32 and LRA Commitment Number 17 for Structures Monitoring Program (RCMS 2006-214) will be enhanced to monitor groundwater for pH, sulfates, and chlorides. Two samples of groundwater will be tested every five years.

Staff Evaluation

The applicant stated in the letter dated May 25, 2007, Commitment No. 17 that the ground water will be monitored for pH, sulfates, and chlorides, with two samples for every five years.

Question No AMPA042 LRA Sec 42-B.2.1.32

Audit Question Provide detailed operating experience for the degradation found in 2002/2003. Clarify if a scope expansion was required due to unacceptable conditions identified. Identify any additional inspections scheduled for the next inspection period.

Final Response

All concrete structures and components that are in-scope for license renewal, and covered by the Structures Monitoring Program, are inspected and compared to acceptance criteria that are in accordance with ACI 201.1R and ACI 349.3R. Specific limits for each type of degradation are provided in applicable WCGS procedures.

During the five-year reinspection in 2002/2003, only four items were identified to have increased aging effects. Two of those items previously categorized as “Acceptable with degradation” are not within the scope of license renewal. Two items that were previously categorized as “Acceptable with minor degradation” were noted to have increased aging effects and reclassified as “Acceptable with degradation”. One was corrosion on an ESW hanger in the

communications corridor, and the other was corrosion on a steel column in the turbine building. Five new items categorized as “Acceptable with degradation” were reported during the 2002/2003 inspection. Platforms and ladders in the Auxiliary Building require painting. Grating in the Auxiliary Building has missing clips. Grating in the Diesel Generator Building has a loose clip. Structural steel in the Turbine Building has corrosion. These items have been corrected. Flashing on a roof hatch in the Auxiliary Building is cracked. This item will be monitored for future changes in aging effects.

No scope expansion was required. All items that remain classified as "Acceptable with Degradation" will be inspected again during the next inspection period. No cases of "Major degradation" were found.

Staff Evaluation

The staff finds the applicant response acceptable because the effects of aging are adequately managed in according with ACI 201.1R and ACI 349.3R.

Question No AMPA043 LRA Sec 43-B.2.1.32

Audit Question Clarify if WCGS have any concrete beams, columns, and structure components (e.g., floor barriers, stairs, sumps, etc.) that are not currently identified in the Structures Monitoring Program. The current program evaluation report for the Structures Monitoring Program is not clear on this account.

Final Response

The Structures Monitoring Program includes all concrete components in structures that are within the scope of license renewal and within the scope of the structures monitoring program.

Staff Evaluation

This question is for clarification purpose.

Question No AMPA044 LRA Sec 44-B.2.1.32
Audit Question Explain why the Structures Monitoring Program does not make reference to documents(s) or code(s) to be used as guidance for conducting a concrete condition survey and to evaluate the existing safety related concrete structures.

Final Response

The inspection methods, inspection frequency, and inspector qualifications are in accordance with WCGS procedures, which reference ACI 349.3R-96, ASCE 11-90, and ACI 201.1R-92.

LRA Appendix B Section B2.1.32, Program Description, will be amended to include the above statement.

Staff Evaluation

In the letter dated August 31, 2007, the applicant stated that LRA Appendix B Section B2.1.32, Program Description will be amended to include the following: ACI 349.3R-96, ACI 201.1R-92, and ASCE 11-90.

Question No AMPA045 LRA Sec 45-B.2.1.33
Audit Question Explain what is the baseline, the past, and the present survey reading (i.e, vertical movements) of the ultimate heat sink dam. Clarify what is the acceptance criteria and provide any operating experience related to this dam.

Final Response

The UHS dam is a normally submerged seismic Category I earthen structure whose side slopes and crest are protected with riprap. The crest of the dam was surveyed before being covered with riprap. The baseline survey of the settlement monuments was completed after construction and before filling of the cooling lake and the submergence of the UHS dam within the cooling lake. The settlement monuments are anchored within the dam embankment and project above the riprap.

Current dam elevations are determined by subtracting the as-built top of monument elevation and as-built top of dam elevation from the current monument elevation.

The UHS dam elevation is required to be at or above elevation 1070 MSL. The baseline elevation for the crest of the dam was 1070.30 MSL. The most recent elevation was found to be 1070.24. The top of dam elevation has always been acceptable.

Staff Evaluation

The staff finds that the response is acceptable because the applicant provided the information requested.

The variances between the new elevations and the adjusted previous years elevations revealed no abnormal changes, trends or unsafe movements of the dam structure (found: at elevation 1070.24 MSL vs required to be at or above elevation 1070 MSL)

Question No AMPA046 LRA Sec 46-B.2.1.33

Audit Question The ultimate heat sink is currently using ACI 201.1R as a guide for conducting concrete condition surveys. The LRA does not mention how the condition of existing concrete structures will be evaluated. Provide a description of these evaluations and its justifications.

Final Response

Question withdrawn by NRC.

Question No AMPA047 LRA Sec 47-B.2.1.33

Audit Question The Water Control Structures Program operating experience indicates

that the main dam, service and auxiliary spillways were repaired. Discuss when these repairs occurred and why the repairs were made

Final Response

The upstream main dam surface was repaired in 2001 near the water line with additional riprap due to the degradation and exposure of the sand and gravel riprap base at several locations. The 2004 surveillance report noted that riprap slope protection was in good condition and the repair work completed in 2001 has adequately corrected deficiencies noted in the 1999 inspection. The main dam is not in scope for license renewal as it is not relied upon to safely shut down the plant and is under the jurisdiction of the Kansas Department of Agriculture, Division of Water Resources.

The 1999 surveillance report discusses the condition of the service spillway. Some popouts and spalling have occurred and are being repaired as needed. The ogee crest was grouted prior to 1999 and some minor seepage is returning. Emerging trees have been removed along the spillway channel between 1994 and 1999. The 2004 report stated that previous patching and grouting was holding up well. However, in 2006, it was found that the previous repairs at joints in the floor of the service spillway chute have numerous shrinkage cracks. Some of the repairs have broken loose exposing the original concrete. A Work Order was generated to address this condition.

Some random cracking and spalling along the concrete auxiliary spillway have been noted several times. The cracks were evaluated in 1999 as not likely to indicate any serious deficiencies. The approach and discharge channels have had vegetation removed in the past and were reported clear of obstructions in the 2004 surveillance.

Staff Evaluation

The staff finds the response acceptable because the applicant provided the information requested. The staff finds that the corrective action program, which captures internal and

external plant operating experience issues, will ensure that operating experience is reviewed and incorporated in the future so that the effects of aging are adequately managed.

Question No AMPA048 LRA Sec 48-B.2.1.1

Audit Question In Section B2.1.1 (ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD), the LRA identifies six (6) exceptions to GALL AMP XI.M1. These exceptions include use of specific ASME Section XI code cases, use of risk informed ISI, and use of alternatives required by 10CFR50.55a.

The license renewal process has not included approval to use risk-informed ISI or approval to use specific ASME Section XI code cases.

Please clarify why these items are included in the LRA description of the program.

Final Response

The LRA will be amended to incorporate changes to Sections A1.1 and B2.1.1 to remove reference to ASME code cases, RI-ISI, or alternatives required by 10CFR50.55a. There will be one exception to NUREG 1801 as follows:

NUREG 1801 AMP XI.M1 specifies the use of ASME Section XI 2001 Edition with addenda 2002 and 2003. WCGS ASME Section XI ISI Program uses ASME Code 1998 Edition through the 2000 addenda for the third 10 year inspection interval. WCGS will use the ASME Code Edition consistent with the provisions of 10CFR50.55a during the period of extended operation.

(a) The above stated exception applies to NUREG 1801 Elements 1, 3, 4, 5, 6, and 7.

(b) The same exception statement applies to each of the NUREG 1801 Elements 1, 3, 4, 5, 6, and 7 as follows:

NUREG 1801 AMP XI.M1 specifies the use of ASME Section XI 2001 Edition with addenda 2002 and 2003. WCGS third interval ISI Program is using ASME Section XI 1998 Edition through 2000 addenda. Use of the 1998 Code through 2000 addenda is consistent with provisions in 10CFR50.55a to use the ASME Code in effect 12 months prior to the start of the inspection interval. WCGS will use the ASME Code Edition consistent with the provisions of 10CFR50.55a during the period of extended operation.

Staff Evaluation

The applicant's response states that the LRA will be revised to remove references to ASME code cases, RI-ISI, or alternatives required by 10 CFR 50.55a. The staff finds it acceptable to amend the LRA to remove references to ASME code cases, RI-ISI, or alternatives approved or required by 10 CFR 50.55a because these deviations from the requirements and specifications of ASME Code Section XI are approved per the provisions of 10 CFR 50.55a; they are not approved as part of the 10 CFR 54 license renewal process. Furthermore, WCGS is currently in its third inservice inspection (ISI) interval and deviations from the ASME Code Section XI requirements will expire before the beginning of the period of extended operation.

The staff finds the remaining exception to be acceptable because WCGS will use the ASME Code Section XI editions and addenda during the period of extended operation that have been approved pursuant to requirements of 10 CFR 50.55a and the approved code edition and addenda will provide requirements for inservice inspection during the period of extended operation that are comparable to those in the ASME Code Section XI edition and addenda that are currently referenced in the GALL Report.

The change(s) described above has (have) been incorporated in the LRA amendment, issued by the applicant's letter dated August 31, 2007.

Question No AMPA049 LRA Sec 49-B.2.1.1

Audit Question

LRA Table 3.1.1, item 3.1.1.16, states that, for Westinghouse Model 44 and 51 steam generators, if general and pitting corrosion of the shell is known to exist, additional inspection procedures are to be developed. LRA Section 3.1.2.2.2.4 states that "the steam generators at WCGS are

Model F, so the augmented inspection is not applicable." The GALL Report, Volume 2, Line IV.D1 12 states that "This issue is limited to Westinghouse Model 44 and 51 Steam Generators where a high stress region exists at the shell to transition cone weld." However, USAR Section 5.4.2.2 states that "the Model F steam generator is similar in configuration to the Model 51 steam generator in Westinghouse supplied plants." The operating experience described in the LRA does not include any discussion of WCGS steam generator inspection results.

(a) Provide additional information about the recent inspection results for the Model F steam generators. Address whether the inspection methods used would be able to detect general and pitting corrosion of the shell and whether any general or pitting corrosion of the shell has been found in the past.

(b) Discuss any operating experience regarding the high stress region at the shell to transition cone weld that is mentioned in the GALL Report, Volume 2, Line IV.D1 12.

[c] Discuss any industry operating experience found related to general or pitting corrosion of Westinghouse Model F steam generators

Final Response

The upper and lower steam generator shell to transition cone welds are part of the WCGS ISI program. The subject welds of one steam generator are 100% UT examined per examination category C-A, Item C1.10. There have been no rejectable indications identified in the UT inspections of the upper and lower steam generator shell to transition cone welds.

WCGS is not aware of any industry operating experience that has identified the presence of general or pitting corrosion of Westinghouse Model F steam generators.

Staff Evaluation

The applicant's response states that the upper and lower steam generator shell to transition cone welds are part of the WCGS ISI program. The staff finds the applicant's response acceptable because it provides the information requested. In addition, the information provided indicates that the applicant's operating experience with Westinghouse Model F steam generators is consistent with the experience observed for similar steam generators at other plants, and there are no aging effects unique to the applicant's equipment. This is supporting, background information that is not used explicitly in the WCGS LR SER.

Question No AMPA050 LRA Sec 50-B.2.1.1

Audit Question License renewal program evaluation report WCGS AMP B2.1.1 Rev. 1 describes the open items. However, the information seems to be incomplete.

(a) Please review the document and determine whether some of the text is missing, or clarify the intention of the item as written.
(b) The open item is numbered 1. Clarify if there are additional open items for this program.

Final Response

(a) For clarification, the item refers to the initial issue of the WCGS document that specifies the ISI classification bases for the third WCGS ISI interval. The document has not yet been issued.

(b) There is only one open item.

Staff Evaluation

The applicant's response provides clarification with regard to wording in the license renewal program evaluation report. The staff finds the applicant's response acceptable because it provides the information requested. The response provides appropriate clarification for the wording in the WCGS LR basis document and indicates that no information is missing from that document. This is supporting, background information that is not used explicitly in the WCGS LR SER.

Question No AMPA051 LRA Sec 51-B.2.1.3

Audit Question Since use of specific ASME Section XI code cases is approved under 10 CFR 50.55a, not as part of the 10 CFR 50.54, please clarify why discussions of specific code cases are included in the LRA.

Final Response

The LRA will be amended to incorporate changes to Section B2.1.3 to remove reference to ASME code cases. There will be two exceptions to NUREG 1801 as described below.

First NUREG 1801 exception:
NUREG 1801 AMP XI.M1 specifies the use of ASME Section XI 2001 Edition with addenda 2002 and 2003. WCGS ASME Section XI ISI Program uses ASME Code 1998 Edition through

the 2000 addenda for the third 10 year inspection interval. WCGS will use the ASME Code Edition consistent with the provisions of 10CFR50.55a during the period of extended operation.

(a) The above stated exception applies to NUREG 1801 Elements 1, 3, 4, 5, 6, and 7.

(b) The same exception statement applies to each of the NUREG 1801 Elements 1, 3, 4, 5, 6, and 7 as follows:

NUREG 1801 AMP XI.M1 specifies the use of ASME Section XI 2001 Edition with addenda 2002 and 2003. WCGS third interval ISI Program is using ASME Section XI 1998 Edition through 2000 addenda. Use of the 1998 Code through 2000 addenda is consistent with provisions in 10CFR50.55a to use the ASME Code in effect 12 months prior to the start of the inspection interval. WCGS will use the ASME Code Edition consistent with the provisions of 10CFR50.55a during the period of extended operation.

Second NUREG 1801 exception:
NUREG 1801, Section XI.M3 specifies the use of NRC Regulatory Guide 1.65, “Material and Inspections for Reactor Vessel Closure Studs” for reactor head closure studs and nuts. WCGS uses NRC Regulatory Guide 1.65 except (a) modified SA-540, Grade B-24 stud material is used, (b) stud bolting material was procured with a minimum yield strength of 130 ksi and a minimum tensile strength of 145 ksi, (c) volumetric inspection of removed studs is performed per the ASME Section XI Code.

(a) The above stated exception applies to NUREG 1801 Elements 1 and 7.

(b) The same exception statement applies to NUREG 1801 Elements 1 and 7 as follows:

NUREG 1801, Section XI.M3 specifies the use of NRC Regulatory Guide 1.65, “Material and Inspections for Reactor Vessel Closure Studs” for reactor head closure studs and nuts. WCGS is committed to Regulatory Guide 1.65 with three exceptions. These are discussed in USAR Appendix 3A as follows:

1. Modified SA-540, Grade B-24 stud material is used - The use of this material is within the limitations discussed in Regulatory Guide 1.85, Materials Code Case Acceptability

2.. Stud bolting material that does not exceed 170 ksi tensile strength is used - The closure stud bolting material is procured to a minimum yield strength of 130 ksi and a minimum tensile strength of 145 ksi. This strength level is compatible with the fracture toughness requirements of 10CFR50, Appendix G (paragraph I.C), although higher strength level bolting materials are permitted. Additional design considerations that permit visual and/or nondestructive inspection and prevent exposure to borated water also apply

3. Inservice Inspection of the reactor vessel closure studs is performed with the ASME Code 1998 Edition through the 2000 addenda for the third 10 year inspection interval. Volumetric inspection of removed studs is performed.

Staff Evaluation

The applicant's response states that the LRA will be amended. The staff finds it acceptable to amend the LRA to remove references to ASME code cases because these deviations from the requirements and specifications of ASME Code Section XI are approved per the provisions of 10 CFR 50.55a; they are not approved as part of the 10 CFR 54 license renewal process. Furthermore, WCGS is currently in its third inservice inspection (ISI) interval and approval to use code cases during the current ISI interval will expire before the beginning of the period of extended operation.

The staff finds the remaining exceptions to be acceptable on the following bases:

a) WCGS will use the ASME Code Section XI editions and addenda during the period of extended operation that have been approved pursuant to requirements of 10 CFR 50.55a and the approved code edition and addenda will provide requirements for inservice inspection during the period of extended operation that are comparable to those in the ASME Code Section XI edition and addenda that are currently referenced in the GALL Report.

b) The use of modified SA-540, Grade B-24 for reactor head closure studs is included in the WCGS CLB, and use of this material has been accepted by the NRC, as documented in RG 1.85.

c) The use of a material specification reactor head studs that did not include a limit on maximum tensile strength did not result in the actual maximum tensile strength of the reactor head studs exceeding the limit recommended in RG 1.65 (170 ksi). This was confirmed by staff review of certified material test reports for the WCGS reactor head studs, washers and nuts.

d) The 2002 addenda of ASME Code Section XI, which is referenced in the GALL Report, eliminated separate examination requirements for "in place" and "removed" studs. Therefore, the stud examination that WCGS performs is consistent with what is recommended in ASME Code Section XI edition and addenda that are referenced in the GALL Report.

The change(s) described above has (have) been incorporated in the LRA amendment, issued by the applicant's letter dated August 31, 2007.

Question No AMPA052 LRA Sec 52-B.2.1.3

Audit Question Provide additional information (e.g., results of testing on the actual WCGS stud and nut material) beyond the discussion provided in USAR Appendix 3A to substantiate that the maximum tensile strength of the reactor closure studs and nuts is less than 170 ksi.

Final Response

Copies of Certified Material Test Reports (CMTRs) are provided in the AMP Program Evaluation Report (PER) binder showing that the maximum tensile strength of the reactor closure studs and nuts is less than 170 ksi.

Staff Evaluation

The applicant provided certified material test reports for staff review. The staff finds the applicant's response to be acceptable because the requested documents were provided and staff review did not identify any discrepancies between the information provided in the certified material test reports and the summary information as provided in the LRA. Staff review of the certified material test reports confirmed that maximum tensile strength of reactor closure studs and nuts is less than 170 ksi.

Question No AMPA053 LRA Sec 53-B.2.1.21

Audit Question The GALL Report scope of the program description for AMP XI.M37 makes reference to "the licensee responses to Bulletin 88-09, as accepted by the staff in its closure letters on the Bulletin, and any amendments to the licensee responses as approved by the staff." A WCNOC response to NRC Bulletin 88-09 is provided in its letter WM 89-0015, dated January 18, 1989.

Clarify if the letter dated January 18, 1989 is the response as accepted by the staff and if there have been any subsequent amendments to this response. Provide a copy of the staff's acceptance of the letter dated January 18, 1989, and any amendment, if applicable.

Supplemental Request:
Provide documentation of NRC acceptance of WCNOC response to Bulletin 88-09.

The NRC has accepted an action item to determine if a generic response was issued.

Final Response

There is no documented staff response to Wolf Creek letter WM 89-0015 dated January 18, 1989. There have been no Wolf Creek submittals amending letter WM 89-0015 dated January 18, 1989.

Staff Evaluation

The applicant's response states that there has been no Wolf Creek submittals amending letter WM 89-0015, dated January 18, 1989. The staff finds the the applicant's response acceptable because it provides a complete answer to the staff's question and confirmed that the documentation reviewed by the staff as a basis for its AMP evaluation had not been amended by a subsequent communication from the applicant.

Question No AMPA054 LRA Sec 54-B.2.1.21

Audit Question The monitoring and trending of the Flux Thimble Tube Inspection Program license renewal program evaluation report states: "During each outage, all flux thimble tubes are inspected. If the predicted wear (as a measure of percent through wall) for a given flux thimble tube is projected to exceed the established acceptance criteria prior to the next outage, corrective actions are taken to reposition, cap or replace the tube." However, WCNOC

procedure RXE 03-006, “Incore Flux Thimble Wear Assessment,” step 6.2.5, appears to implement a conditional eddy current testing.

> Describe the inspections discussed in the license renewal program evaluation report. Clarify if this is an inspection using eddy current tests performed during the outage. Clarify the intention of step 6.2.5 in the procedure discussed above and whether this means that eddy current testing is conditional (i.e., based on predicted wear) rather than performed every outage.

Final Response

The Wolf Creek Flux Thimble Tube Inspection Program performs eddy current testing that is conditional (i.e., based on predicted wear). The Flux Thimble Tube Inspection Program calculates predicted wear and verifies that wear is acceptable for the next two subsequent refuel outages. The refueling at which eddy current testing will be required is determined and will be one refueling before the wear reaches 60% through wall for the thimble with the greatest projected wear. Wear Trending of thimble tubes is documented as well as projected wear (% through wall) at the next cycle. Any thimble with wear in an active location greater than 60% through wall or projected to be greater than 60% before the next outage should be repositioned. Any thimbles with greater than 80% through wall or projected to be greater than 80% before the next outage are capped or equivalent and considered for future replacement.

LRA sections B2.1.21 and A1.21 will be amended to state: “During each outage, flux thimble tube wear is evaluated and inspections performed based on evaluation results."

The changes described above have been incorporated in the LRA amendment, issued by the applicant’s letter dated August 31, 2007.

Staff Evaluation

The applicant provided clarifying information with regard to the Flux Thimble Tube Inspection Program and stated that a change will be made in the LRA's description of the program. The staff finds the applicant's response to be acceptable because it resolves an inconsistency between the description in the LRA and a requirement in the implementing procedure. The staff reviewed the applicant's response together with the more detailed evaluations of wear progression rates and eddy current inspection conservatism presented in WCAP-12866, which provides the technical basis for the applicant's flux thimble methodology. The staff noted that the applicant's conditional methodology for determining when to perform eddy current testing of the flux thimble tubes is based on plant-specific wear projections, which is consistent with the recommendations in GALL AMP XI.M37. Based on its review of the evaluations of wear progression rate data and eddy current inspection conservatism presented in WCAP-12866, the staff concludes that the applicant's methodology for determining when to perform eddy current examinations is adequate to ensure that no flux thimble tube is predicted to incur wear that exceeds the established acceptance criteria before the next inspection. Based on this conclusion, the staff determines that the applicant's conditional methodology for determining flux tube thimble examination frequency is consistent with the GALL Report's recommendations for the "monitoring and trending" program element and is acceptable.

Question No AMPA055 LRA Sec 55-B.2.1.21

Audit Question Provide the following documentation during the audit:

- examples of flux thimble wear trending data sheets (e.g., RXE 03-006, Attachment A)
- representative Flux Thimble Tube Program problem identification reports, work orders, etc, completed during previous refueling outages.

Supplemental Request:

Provide additional detail (narrative) concerning data collected during RF15.
Operating history summary.

Final Response A copy of RXE 03-006 including Attachment A (Wolf Creek Flux Thimble Wear Trending) that was completed during the October 2006 outage has been provided.

Staff Evaluation

The applicant provided a copy of the requested document for staff review. The staff finds the applicant's response acceptable because it provides the requested documents and the staff's review of the documents provided additional details of the flux thimble testing results during RF 15. The staff did not identify any omissions or inconsistencies is the documentation provided by the applicant.

Question No AMPA056 LRA Sec 56-B.2.1.5

Audit Question The PWSCC in nickel alloy penetration nozzles in the upper reactor vessel head currently is categorized as with low susceptibility. The revised NRC Order EA 03 009 requires that a bare metal visual examination meeting the requirements of IV.C.(5)(a) be performed every third refueling outage or every five years. In addition, it requires that a non visual NDE meeting the requirements of IV.C.(5)(b) be performed every four refueling outages or every seven years. The Nickel Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program operating experience provides a limited, somewhat indirect, discussion of the bare metal visual examination and no discussion of the non visual NDE.

Discuss the results of these examinations. If they have not been performed, discuss the current schedule for each of these examinations.

Final Response

A bare metal visual examination of the top of the Reactor Vessel Closure Head meeting the requirements of IV.C.(5)(a) was performed during RF15 (October 2006). No evidence of leakage was found.

With exception of Vessel Head Penetration nozzles 77 and 78, a non-visual NDE examination of the Nickel Alloy penetration nozzles of the Reactor Vessel Closure Head meeting the requirements of IV.C.(5)(b) was performed during RF15 (October 2006). No indication of cracking was identified during the examination. See the response to question AMP A057 (B2.1.5-2) for the NRC staff authorized relaxation of the requirement for NDE inspections of VHP nozzles 77 and 78.

Staff Evaluation

The applicant's response describes the results of both a bare metal visual examination and a non-visual NDE examination of the nickel-alloy penetration nozzles of the reactor vessel closure head. The staff reviewed the WCGS technical instructions used to perform the examinations and the results of the examinations. On the basis of its review, the staff determined that the methodology used is consistent with the requirements of Revised NRC Order EA 03-009, which is referenced in the GALL Report's description of the AMP. On the basis that the examination methodology is consistent with what is recommended in the GALL Report and that the results indicated no leakage from or cracking of the pentrations, the staff finds the applicant's response to be acceptable.

Question No AMPA057 LRA Sec 57-B.2.1.5

Audit Question WCNOC letter dated October 5, 2006, “Relaxation Request from the First Revised NRC Order EA 03 009 Regarding Requirements for Nondestructive Examination of Nozzles Below the J Groove,” requested a contingency relaxation of examination requirements for reactor pressure vessel penetration nozzles 74, 75, 76, 77, and 78.

Provide a discussion on the current status of this request and whether the contingency relaxation of examination requirements was needed. If relaxation of examination requirements was needed, discuss whether this relaxation is an exception to the recommendations in GALL AMP XI.M11A and justify the exception.

Final Response

During Refueling Outage 15, Wolf Creek performed a nonvisual NDE of Nozzles 74, 75, and 76 that met First Revised NRC Order EA-03-009. In NRC letter dated December 7, 2006, the NRC staff authorized relaxation of the requirement for NDE inspections of VHP nozzles 77 and 78 until inspection technology is developed to a state where the examination volume for the nozzles can be extended to be in full compliance with the order. The NRC staff safety evaluation found that Wolf Creek’s proposed alternate inspection for VHP nozzles 77 and 78 to perform an ultrasonic examination from 2 inches above the highest point of the root of the J groove weld to the maximum extent practical, but not less than 0.30 inches below the toe of J-groove weld on the downhill side provides reasonable assurance of the structural integrity of the VHP nozzles.

The relaxation of the requirement for NDE inspections of VHP nozzles 77 and 78 is not an exception because NUREG-1801 XI.M11A element 4 (Detection of Aging Effects) states in part: "Any deviations from implementing the appropriate required inspection methods of the Order, as amended, will be submitted for NRC review and approval in accordance with the Order, as amended." NRC letter dated December 7, 2006 authorized relaxation of the requirement for NDE inspections of VHP nozzles 77 and 78.

Reference:
1. NRC incoming letter 06-00684, dated 12/07/2006
2. WCNOC letter ET 06-0035, dated 10/05/2006

Staff Evaluation

The applicant's response provides additional discussion of operating experience and application of First Revised NRC Order EA-03-009 to the Nickel Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Head of PWRs Program. The staff finds the applicant's response to be acceptable because it provides the requested information and staff review of the information did not find any inconsistencies between the WCGS program and the requirements set forth in the First Revised NRC Order EA-03-009, which is referenced in the GALL Report's description of this program.

Question No AMPA058 LRA Sec 58-B.2.1.25

Audit Question The scope of GALL AMP XI.E2 includes electrical cables and connections (i.e., cable system) used in circuits with sensitive, high voltage, low level signals such as radiation monitoring and nuclear instrumentation that are subjected to aging management review. The scope of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental

Qualification Requirements Used in Instrumentation Circuits Program only includes the ex core neutron monitoring system. Explain why high radiation monitor cables and connections are not included in the scope of the program.

Final Response

The cables and connections associated with the in-scope High Range Area Radiation Monitors (GTRE59, GTRE60) are subject to 10 CFR 50.49 environmental requirements and therefore are not included in this aging management program. The EQ package for the High Range Area Radiation Monitors is EQWP J-361A. See Program Evaluation Report (PER) B2.1.25 Section 5.1.

Staff Evaluation

The staff finds the applicant response acceptable because high-range radiation monitors are subject to EQ requirements per 10 CFR 50.49. Cable systems associated with high-range radiation systems are not required an AMR and are not included in the scope of Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program.

Question No AMPA059 LRA Sec 59-B.2.1.25

Audit Question Identify any other sensitive, high voltage, low level signal circuits in addition to ex core neutron monitoring system at WCGS. Explain why these circuits are not within the scope of this program.

Final Response

The following is a list of the equipment which uses coax cables that could have sensitive, high voltage, low level signal circuits in addition to ex-ore neutron monitoring system at WCGS:

High Range Area Radiation Monitors
Containment Atmosphere Humidity Detectors
Unit Vent Radiation Monitors
Solid Radwaste System Radwaste Effluent Radiation Monitors
Post Accident Sample System Sampling Panels
Loose Parts Monitoring
Solid Radwaste Spent Resin Primary Storage Tank Inlet Element and Control Station
Balance of Plant Computer
Public Address System (Intercom)
Plant Security System Equipment.
Generator Hydrogen & Carbon Dioxide System
Miscellaneous Control Panels (Rad Cameras)
In-Core Neutron Monitoring System
Condensate Demineralizer System Acid Day Tank Level

The cables and connections associated with the in-scope High Range Area Radiation Monitors (GTRE59, GTRE60) are subject to 10 CFR 50.49 environmental requirements and therefore are not included the NUREG 1801 XI.E2 aging management program.

Containment Atmosphere Humidity Detectors, Unit Vent Radiation Monitors, Radwaste Effluent Radiation Monitors, Post Accident Sample System Sampling Panels, Loose Parts Monitoring, Solid Radwaste Spent Resin Primary Storage Tank Inlet Element and Control Station, Balance of Plant Computer, Public Address System (Intercom), Plant Security System Equipment, Generator Hydrogen & Carbon Dioxide System, Miscellaneous Control Panels (Rad Cameras), In-Core Neutron Monitoring System, and Condensate Demineralizer System Acid Day Tank Level provide no license renewal intended functions and do not meet any criterion found in 10CFR54.4(a)(1), 10CFR54.4(a)(2), or 10CFR54.4(a)(3)

Staff Evaluation

The staff finds the applicant response acceptable because these systems are not within the scope of license renewal and therefore not in-scope of GALL AMP XI.E2.

Question No AMPA060 LRA Sec 60-B.2.1.25

Audit Question GALL AMP XI.E2 states, in part, that in cases where a calibration or surveillance program does not include the cabling system in the testing circuit, the applicant will perform cable system testing. Clarify if ex core neutron monitoring system cables are disconnected during calibration surveillance. If they are, explain why testing of these cables are not proposed.

Final Response

The ex core neutron monitoring system cables are not disconnected during calibration surveillance.
Ref Procedures:

STS IC-431 "Channel Calibration NIS Source Range N-31"
STS IC-432 "Channel Calibration NIS Source Range N-32"
STS IC-440 "Channel Calibration NIS Intermediate Range and Power Range Detector High Voltage Plateaus"

Staff Evaluation

The staff finds the applicant's response acceptable because, in accordance with GALL XI.E2, testing of cable systems are not required if these cable systems are not disconnected during calibration surveillance.

Question No AMPA061 LRA Sec 61-B.2.1.26
Audit Question GALL AMP XI.E3 defines medium voltage as voltage from 2 kV to 35 kV. The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirement Program states that the in scope non EQ inaccessible medium voltage cables exposed to significant moisture simultaneously with significant voltage are 5 kV and 15 kV. Identify any inaccessible medium voltage cables that are from 2 kV to 35 kV. Explain why these cables are not subject to water tree aging effect and justify why they are not within the scope of the program.

Final Response

The only medium voltage cables that are from 2 kV to 35 kV at WCGS are 5 KV and 15 KV cables. The scope of this program includes all of the in-scope inaccessible medium voltage cables at the WCGS.

Staff Evaluation

The staff finds the applicant response acceptable because all inaccessible medium-voltage cables within the scope of GALL AMP XI.E2 at WCGS are 5 kV and 15 kV.

Question No AMPA063 LRA Sec 62-B.2.1.2
Audit Question Clarify when the EPRI 102134, Revision 6, was implemented.

Follow Up Question B.2.1.2-1: In response to the question on when EPRI 102134, Revision 6 was implemented, the response stated that EPRI 102134, Rev. 6 does not exist. However, EPRI 100824, Rev. 6 replaced EPRI 102134 and was implemented on 10/11/2005. The program description in the application, and in the ten-element evaluation, EPRI 102134, Rev. 6 is referenced. Please clarify this discrepancy. Furthermore, the Strategic Secondary Water Chemistry Plan – Rev 2 still addresses Rev. 5 of the EPRI guidelines, which we assume is EPRI 102134.

Followup question for AMPA063
The GALL AMP XI.M2 “scope of program” program element states that water chemistry control is performed in accordance with the guidelines in

(1) EPRI TR 105714, Revision 3, for primary water chemistry, (2) EPRI TR 102134, Revision 3, for secondary water chemistry, or (3) later revisions or updates of these reports as approved by the staff. The applicant's Water Chemistry Program description states that the program monitors and controls known detrimental contaminants like chlorides, fluorides, and dissolved oxygen, by following the guidelines provided in EPRI TR 105714, Revision 5, for primary water chemistry and EPRI TR 102134, Revision 6, for secondary water chemistry. The LRA claims consistency with the GALL Report.

Justify why the LRA does not take an exception when WCGS is not using the EPRI revisions recommended in the GALL Report. Provide a comparison of the GALL AMP referenced revisions to the LRA referenced revisions and explain why the use of a later version is acceptable by verifying that none of the controlled parameters are relaxed in the later version.

Final Response

Pressurized Water Reactor Secondary Water Chemistry Guidelines - Revision 6 (EPRI 1008224) was incorporated in Revision 11 to the Secondary Chemistry Control procedure (AP 02B-001) on 10/11/2005.

Response to Followup Question:
In the LRA and in the 10-element review, where "EPRI 102134, Rev. 6", is used or referenced, it is incorrect. The correct reference in the LRA and 10-element review should be "Revision 6 of the EPRI Pressurized Water Reactor Secondary Water Chemistry Guidelines" (1008224).

The Strategic Secondary Water Chemistry Plan, Rev. 2, was based on Rev 5 of the EPRI Secondary Water Chemistry Guidelines (102134). The Strategic Secondary Water Chemistry Plan, Rev. 3, was issued Mar. 13, 2007, and addresses Rev 6 of the EPRI Secondary Water Chemistry Guidelines (1008224). The LRA will be amended to reflect this information.

Response to Followup Question 2:
The GALL wording in the question was taken from NUREG-1801, Rev. 0. The GALL (NUREG-1801, Rev. 1) AMP XI.M2 "scope of program" program element states that "water chemistry control is in accordance with industry guidelines such as…EPRI TR-105714 for primary water chemistry in PWRs, and EPRI TR-102134 for secondary water chemistry in PWRs." No EPRI revisions are specified in the scope of program element, therefore, no exception was taken with respect to EPRI revisions. The WCGS Water Chemistry Program is currently based on the EPRI PWR Primary Water Chemistry Guidelines, Rev. 5 and EPRI PWR Secondary Water Chemistry Guidelines, Rev. 6, with one exception as discussed in LRA B2.1.2.

The following summarizes the key technical changes from Revision 5 to Revision 6 of the EPRI Secondary Water Chemistry Guidelines:

Guidance was added in Chapters 1, 5, and 6 to clearly indicate the elements of the Guidelines that are mandatory and "shall" requirements under NEI 03-08, and those that are recommendations. The only mandatory requirement is to have a Strategic Water Chemistry Plan. "Shall" requirements include the Action Level 1, 2, and 3 control parameters and

responses and the hold parameters in the control tables of Chapter 5 and 6, including both values and monitoring frequencies for these parameters, unless otherwise specifically indicated. The balance of the guidance elements provided in the Guidelines are recommendations. Chapter 2 was revised to reflect recent research regarding specific impurity effects on IGA/SCC, the effects of hydrazine on flow accelerated corrosion, and regarding the effects of amines on secondary side deposition processes.

The treatment of deposit control practices was significantly modified in Chapter 3 to reflect current practices and currently available methods. Chapter 3 also contains an expanded discussion on thermal performance issues, and new sections on the loss of hydrazine scenario and startup oxidant control.

The main discussion of integrated exposure was relocated from Appendix A to Chapters 4 and 7, and the discussion was revised to reflect its removal as a diagnostic parameter from Chapters 5 and 6. Chapter 4 was also revised to include a list of items that should be covered in strategic water chemistry plans.

Chapter 5 was revised to incorporate additional guidance regarding control of wet layup during short outages. The condition to which plants should go to as part of an Action Level 3 response was changed to "<5% power" from "hot or cold shutdown." The control tables for RSGs in Chapter 5 were thoroughly reviewed and edited. Some of the more significant changes to the tables were:

* Inclusion of Action Level 2 and 3 actions for loss of hydrazine.

* Addition of a requirement that plants reduce power to below 5% if sodium, chloride, or sulfate exceed 250 ppb, or if they exceed 50 ppb for more than 100 hours, while between 5% and 30% power.

* Reduction in the blowdown impurity level for sodium at the 30% hold from 20 to 10 ppb, and addition of an explicit recommendation that plants achieve sodium, chloride, and sulfate blowdown concentration below their respective Action Level 1 concentrations prior to exceeding 30% power.

* Additional guidance was added such that plants are no longer required to go to Action Level 3 as long as the impurity concentration remains below Action Level 2 values.

* Deletion of integrated exposure as a diagnostic parameter, and inclusion of lead and integrated corrosion product transport as diagnostic parameters.

* Addition of a footnote to allow reduced frequency for sampling for copper for plants that are copper free or have confirmed low levels of copper transport (<20 ppt).

Chapter 6 – changes to Chapter 6 are not included as this refers to OTSGs and is not applicable to WCGS.

Chapter 7 was revised to delete tables detailing sampling data requirements, to add more guidance regarding hideout returns, species to analyze in deposits, and integrated exposure evaluations, and to add a new section regarding effectiveness assessments. A discussion of

lead sampling and additional recommendations on corrosion product transport sampling was also added.

Staff Evaluation

The staff finds the applicant response acceptable because the GALL Report AMP in the program description states that later revisions of the EPRI documents are acceptable. Therefore, the staff finds that an exception to the GALL Report AMP is unnecessary. The staff reviewed the changes between the different revisions of the EPRI document, and finds the applicant's use of the later revisions acceptable because the parameters of operation in EPRI TR-105714 Revision 5 or EPRI TR-102134, Revision 6 to be generally the same as those of Revision 3 or more conservative. Later versions of these chemistry program guidelines are developed from collective operating experience using sound technical judgment, and are approved by the electric utility industry to improve water chemistry and thereby manage or mitigate aging effects.

Question No AMPA064 LRA Sec 63-B.2.1.2

Audit Question Explain the intent of the exception in the element of scope of the program. The exception states that WCGS is meeting the requirements for mixing the steam generator bulk solution. Clarify if this exception is related to the mixing or to the three samples per week. Clarify if this exception is also applicable to the parameters monitored or inspected program element. Clarify if this is an exception to GALL AMP XI.M2 element of scope of the program or if it is an exception to the EPRI 102314 guidelines.

Follow-up Question B2.1.2-2: What is the basis for this exception? Do you have an analysis that states that a 33-hour recirculation of stem generators followed by weekly sampling is better than or equivalent to obtaining three samples per week until values are stable when in cold shutdown conditions?

Final Response

The exception is to taking three samples per week. As explained in the evaluation, three samples per week are not necessary to demonstrate adequate mixing.

This exception has been taken against Element 1, Scope of Program, and not against Element 3, Parameters Monitored or Inspected, although technically, the requirement the exception is taken against is contained in the EPRI Secondary Water Chemistry Guidelines, and not NUREG-1801.

Follow up response:

Wolf Creek Generating Station has taken exception to the Guideline "The steam generator bulk solution should be mixed and sampled three times per week (after parameters are in the normal range) until the parameters are stable, then mixed and sampled weekly." This statement is found in Section 5.5.1.2 of Revision 6 of the Guidelines as well as in Table 5-1. This exception is documented in the Strategic Secondary Water Chemistry plan. The exception was initially taken for Revision 5 of the Guidelines.

This exception was taken based on operating experience/history. Prior to initial fill of the steam Generators (SG) during plant construction, calculations were performed to determine the required recirculation time to achieve mixing of the bulk solution. This calculation was based on the SG volume, flow-rate of the mix pumps, and recirculating three volumes of the bulk solution. The result was that a 33 hour recirculation time would thoroughly mix the bulk solution.

Staff Evaluation

The staff noted from the license renewal program evaluation report that the WCGS design incorporates pumps for recirculation of the steam generator fluid. On the basis that the applicant had performed calculations based on the steam generator volume, flow-rate of the mix pumps, and recirculation of three volumes of the bulk solution, and over twenty years of operating history, the staff finds the exception to be acceptable.

Question No AMPA065 LRA Sec 64-B.2.1.2

Audit Question The PIR operating experience report summary states that this PIR does not address any license renewal aging effect. Clarify this statement.

For example, PIR 20030900 addresses long standing anomalies regarding plant chemistry where increased levels of aggressive impurities such as chlorides and sulfates have been identified which could increase corrosion. Also, PIR 20021583 and PIR 20020270 address chemistry control issues of out of specified conditions that could impact corrosion.

Follow-up Question 2.1.2-3: Response indicates hat specific operating experience items were said to address a license renewal aging effect only when an explicit mention of the aging was made. None of these PIRs identified any actual aging.

Review of PIR 20021583, under problem description section d, there are words that state that chiller chemistry analysis indicate that excessive corrosion and possibly crud deposits may have occurred due to level of chloride detected and the amount of solids in the chemistry sample. It also states that chemistry problems may be broader than simple chemical contamination.

PIR 20020270 addresses higher pH. It also states that potential consequences are higher corrosion rate.

Other PIRs reviewed address similar chemistry issues. Yet, element 10 evaluation states that there have been no major chemical excursions during WCGS operating history. Please explain what "Major" means. Also, please justify in light of the PIRs identified above, why you believe there are no major chemistry excursions.

Final Response

Specific operating experience items were said to address a license renewal aging effect only when an explicit mention of the aging was made. None of these PIRs identified any actual aging. In cases like the ones noted, where there was direct discussion of programmatic

elements or the potential to affect aging, the operating experience item was linked to the AMP, designating it for further consideration during the AMP review.

Follow up Response:

Although the water chemistry program is intended to maintain water chemistry parameters within specifications, it is recognized that water chemistry parameters may occasionally exceed the limits specified in the plant procedures. As the amount of departure from specifications increases action levels increase. Prompt graduated corrective actions are specified at each action level to eliminate or mitigate degradation from the out of specification condition. A “major” chemical excursion as discussed in the license renewal application is an event where one or more chemical species exceeded an action level and the procedurally specified corrective actions were not complied with. None of the PIRs identified address events when the procedurally specified corrective actions were not complied with.

Staff Evaluation

The staff reviewed the corrective actions taken in the PIRs and determined that appropriate corrective actions as specified for each action level were taken and complied with. Based on this, the staff finds the applicant’s response acceptable.

Question No AMPA066 LRA Sec 65-B.2.1.2

Audit Question Water Chemistry Program operating experience describes that the program was developed using industry experience. However, it does not

address plant specific operating experience to confirm that the program, as implemented, will adequately manage aging effects. The 10 elements evaluation only addresses industry operating experience. Provide a summary of plant specific operating experience to provide reasonable assurance that aging effects will be adequately managed.

Follow-up Question 2.1.2-4: In response to the request to provide a summary of plant operating experience in element 10, you responded that plant operating experience is referenced in AMP element 10. There is no reference to plant experience in element 10, except for one statement that there have been no major chemical excursions during WCGS operating history. Please provide specific plant experience that was used to determine that the program will adequately manage the aging effects.

Final Response

Plant specific operating experience is referenced in AMP element 10. The evaluation provides a pointer to detailed discussions of numerous plant chemistry operating history issues and their resolution as described in station strategic plans. The discussion concludes by indicating that no major chemistry excursions have occurred during WCGS’ operating history.

Individual plant operating experience items were evaluated to determine relevance to actual aging effects/mechanisms and/or WCGS aging management programs. A particular operating experience item may have been linked to a specific AMP(s) and/or to one or more

material/environment/aging effect combinations based on the actual content of the item. Operating experience items were said to address a license renewal aging effect only when an explicit mention of the aging was made. Likewise, where there was direct discussion of programmatic elements or the potential conditions to affect aging that were within the control of the program, the operating experience item was linked to the AMP.

The operating experience items that were thusly linked to any material, environment, aging effect combinations, or to an AMP, were considered further during either the AMR phase, regarding which aging effects/mechanisms to assign, or during the AMP phase, as a potential input to Element 10.

A number of plant corrective action documents and work orders that were evaluated as relating to the chemistry program are included on the Plant Aging Management Document Retrieval and Research System and will be included in hardcopy form in the AMP binder provided during the AMP audit. These operating experience items involve the areas of system chemistry performance, chemistry related system operation, chemistry control technical details, equipment degradation, benchmarking, self assessments, and program enhancements. The operating experience does not include any examples of equipment degradation challenging an intended function that is related to deficiencies in the chemistry program. The evaluation of this operating experience contributed to the conclusion that there is a reasonable assurance that aging effects will be adequately managed.

Follow up response:

Out of specification values and unexplained adverse trends in water chemistry parameters are documented by a Condition Report. Two recent examples of this process include Condition Report 2006-001764 and Condition Report 2006-002233. The former example noted a large increase in turbine driven auxiliary feed water pump discharge conductivity, which was determined to be due to a leaking isolation valve from the emergency service water system (ESW). The corrective action included corrective maintenance to eliminate the in-leakage of ESW. The latter example documents the corrective actions taken in response to out of specification results for lithium concentration in the reactor coolant system. The action taken was to adjust the cation ion exchanger time in service.

Staff Evaluation

The staff finds the applicant's response acceptable because the applicant provided the appropriate plant operating experience. The staff noted that appropriate corrective actions were taken and that the program is effective in managing the aging effects.

Question No AMPA067 LRA Sec 66-B.2.1.10

Audit Question Low flow and stagnant areas of plant heating and central chilled water systems could show crud build up. Explain why a verification program such as a one time inspection is not used to confirm that significant degradation is not occurring. Furthermore, explain why this is not considered as an exception to the detection of aging effects program element.

Follow-up Question B2.1.10-1: The response does not address the

question. The GALL Report AMP XI.M21 in element 4, "detection of aging effects" states:

Control of water chemistry does not preclude corrosion or SCC at locations of stagnant flow conditions or crevices. Degradation of a component due to corrosion or SCC would result in degradation of system or component performance. The extent and schedule of inspections and testing should assure detection of corrosion or SCC before the loss of intended function of the component.

Therefore, please explain why this is not considered an exception if you are not performing any inspection for plant heating and central chilled water system.

Final Response

Preliminary Response

The plant heating and central chilled water systems are within the scope of license renewal per 10 CFR 54.4(a)(2) for spatial interaction concerns only. Therefore, the only component intended function applicable to these systems is (a)(2) pressure boundary. Crud buildup would not directly affect the intended function of these components. (Element 4)

NUREG-1801 does not suggest that an inspection is the only satisfactory option in this situation. Specifically, Element 4 states "The extent and schedule of inspections and testing should

assure detection of corrosion or SCC before the loss of the intended function of the component." This was interpreted to mean inspections and/or testing, as long as the loss of the intended function of the component was prevented. Periodic monitoring of the diagnostic chemistry parameters (testing) of copper and iron in the closed cooling water systems provides an indication of corrosion occurring on the system, and will assure detection of corrosion before the loss of the intended function of the component.

Follow-up Response

LRA B.2.1.10 will be amended to state the following exception to inspections and testing for systems in scope of license renewal due to 10CFR 54.4(a)(2) due to spatial interactions such as plant heating and central chilled water systems. LRA B.2.1.10 will be amended as follows to include this exception.

Exceptions to NUREG-1801
Parameters Monitored or Inspected - Element 3, Detection of Aging Effects - Element 4, Monitoring and Trending -Element 5, and Acceptance Criteria-Element 6

"WCGS will not perform inspection or testing of plant heating and central chilled water systems. Plant heating and central chilled water systems are in the scope of license renewal due to 10CFR 54.4(a)(2) due to spatial interactions only. Therefore the only intended function applicable to these systems is pressure boundary. Crud buildup would not directly affect the intended function of these components." The periodic sampling and maintenance of system

chemistry within specified limits is adequate to manage aging before the loss of intended function.

Staff Evaluation

The staff finds the applicant's response acceptable because plant heating and central chilled water systems are in the scope of license renewal due to 10 CFR 54.4(a)(2) for spatial interactions only. The only intended function applicable to these systems is pressure boundary, and periodic sampling and maintenance of system chemistry within specified limits is adequate to manage aging before the loss of intended function.

Question No AMPA068 LRA Sec 67-B.2.1.10

Audit Question For the exception on the parameters monitored or inspected, confirm if all component cooling water heat exchangers are periodically tested to measure heat transfer capability. Clarify if all heat exchangers are periodically NDE tested. If not, how are the heat exchangers selected for testing and inspection, and how are the results correlated to other component cooling water heat exchangers.

Final Response

It is not clear if this question is referring to the main CCW heat exchangers only, or all heat exchangers that credit this AMP, so the answer will address both.

The CCW heat exchangers are periodically tested to measure heat transfer capability. Flow and temperature measurements are used to calculate heat exchanger performance in terms of a fouling factor. Tube side (raw water) flow and differential pressure are also measured and used as an indicator of tube fouling. (Element 3)

Emergency Diesel Generator (EDG) performance testing monitors and trends various engine parameters to ensure target availability goals are met or exceeded. The monitored engine parameters include intercooler water pump pressure, jacket water pump pressure, intercooler temperatures, and jacket water temperatures. Trending of these parameters will detect component aging prior to a loss of intended function. (Element 3)

The CCW, EDG intercooler, and jacket water cooler heat exchangers (meaning all) are periodically NDE tested (ECT) to detect aging of the tube pressure boundary. (Element 4)

GALL AMP XI.M21 states, for the "parameters monitored or inspected" program element, that this program should monitor the effects of corrosion by surveillance testing and inspections in accordance with standards in EPRI TR-107396 to evaluate system and component performance. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure. Various CCW supplied heat exchangers, such as the letdown heat exchangers, residual heat removal heat exchangers, safety injection pump coolers, and the PASS sample coolers, are not periodically tested for flow, inlet and outlet temperatures, and differential pressure. The CCW heat exchangers are periodically tested to measure heat transfer capability. Shell-side (closed-cycle cooling water) flow and temperature measurements are used to calculate heat exchanger performance in terms of a fouling factor. Tube side (raw water) flow and differential pressure are also measured and used as an indicator of tube fouling. The CCW heat exchangers are periodically NDE tested (ECT) to detect aging of the tube

pressure boundary.

The performance monitoring and NDE of the CCW heat exchangers will provide a leading indicator that aging resulting in a loss of material and fouling of heat exchangers is effectively managed in the CCW system. An enhancement to the WCGS closed-cycle cooling water system program, identified in Element 5, to specify inspection of the internal surfaces of the CCW pump return line check valves during In-Service Testing activities will also provide additional indicators of the effective management of the effects of aging due to loss of material and fouling in the CCW system. A review of WCGS plant specific operating experience indicates there has been no evidence of significant fouling or loss of material observed in the closed cooling systems. In conclusion, the current heat exchanger performance monitoring, internal inspections activities (in conjunction with check valve IST), and CCW system operating experience will be proposed instead of performance testing of all CCW supplied heat exchangers to demonstrate that CCW chemistry program is effective in managing the aging effects in the CCW system. (Element 3)

Staff Evaluation

The staff finds the applicant's response acceptable because the performance monitoring of the heat exchangers, the NDE inspection of heat exchanger tubes, and the inspection of internal surfaces of check valves will provide assurance that loss of material and fouling of heat exchangers are adequately managed in the closed cooling water system. The staff also reviewed the operating experience and noted that there has been no evidence of significant fouling or loss of materials in the component cooling water system.

Question No AMPA069 LRA Sec 68-B.2.1.12

Audit Question LRA Section B2.1.12 states that “approximately 10 percent of each type of penetration seal (electrical and mechanical as practical) is visually inspected at least once every 18 months.” GALL AMP XI.M26 states that 10 percent of each types of penetration seal should be visually inspected to examine any degradation. Since 10 percent of each type (electrical and mechanical as practical) of penetration seal is not the same as 10 percent of each type of seal, please clarify if the 10 percent population of penetration seal includes all types of seals (e.g., cables trays, conduits, pipes, ducts, and seismic gaps.)

Final Response

FIRE BARRIER PENETRATION SEALS

The requirement for penetration seal inspection is contained in Section 6.3.11.8 of AP 10-100, Fire Protection Program, which states the following;

"STN FP-452, FIRE BARRIER PENETRATION SEALS INSPECTION, is performed at least once per 18 months to visually inspect approximately 10% of electrical and mechanical Penetration Seals. If Fire Protection determines that inspection results present an adverse trend, an additional population of the affected penetration sealing device type shall be inspected for acceptability. The number of penetration sealing devices inspected in this effort shall meet or exceed the total number of the affected type inspected in the original set. This process shall be

repeated until satisfactory results are obtained for the affected penetration sealing device type. Samples shall be selected such that each Penetration Seal will be inspected every 15 years."

An approximate 10% inspection arrangement for mechanical and electrical penetration seals allows flexibility in development and maintenance of the penetration seal inspection sets. Ten inspection sets have been developed by Fire Protection to ensure that all penetration seals separating safety-related fire areas or separating portions of redundant systems important to safe shutdown are inspected every 15 years. The inspection sets were developed based on previous penetration seal inspection dates with each set approaching an approximate 10% sample of electrical and mechanical penetration seals. As penetrations are added, revised, or deleted, throughout plant life, the total number of mechanical and electrical penetration seals change and resulting inspection set totals change. It is not prudent to shift penetrations from one selection set to another just to maintain a 10% overall selection set. Additionally, some seal types have been used on a limited basis, which would result in repeat inspections of seals within the 15 year time frame, if selection sets were solely based on seal type.

The AP 10-104 penetration seal surveillance requirements provide an acceptable methodology for implementation of the penetration seal inspection program, while ensuring that each penetration seal separating safety-related fire areas or separating portions of redundant systems important to safe shutdown be inspected every 15 years. Additionally, these seal surveillance requirements are consistent with NUREG-1552, where the NRC documented their assessment of fire barrier penetration seal programs in nuclear power plants. Specifically, relevant excerpts from Section 5.7 of NUREG-1552 state the following:

"....In general, the licensees inspect a portion of the total population of seals every refueling outage (about every 18 months). If penetration seals are found to be degraded or inoperable (e.g., breached, degraded, or improperly repaired), the licensees document the deficiencies and take the appropriate corrective actions....."

"The staff had previously addressed potential problems in IN 88-04, IN 88-56, and IN 94-28 (See Appendix A). On the basis of the assessment documented here, it is the staff's view that existing licensee and vendor seal installation programs are adequate to prevent potential penetration seal installation problems. In the event seals are improperly installed or breached, or become degraded, existing licensee surveillance, maintenance, and repair programs are adequate to reveal and correct potential problems."

FIRE BARRIERS

At least once per 18 months Wolf Creek performs a visual inspection of the exposed surface of each fire rated assembly (fire barriers separating redundant Post-Fire safe shutdowns systems) for the presence of breaches and gross deterioration. The 18 month fire rated assembly inspections include such items as seismic gap seals, cable tray fire stops, steel pipe caps, etc.

Staff Evaluation

The staff finds the applicant's response acceptable because the fire barrier inspection procedure performs a visual inspection of the exposed surface of each fire rated assembly (fire barriers separating redundant post-fire safe shutdowns systems) for the presence of breaches and gross deterioration. The fire rated assembly inspections include such items as seismic gap seals, cable tray fire stops, steel pipe caps, etc. The staff reviewed each of these procedures and

confirmed that inspections are performed on 10 percent of all fire barrier penetration seals and fire barriers at least once every 18 months.

Question No AMPA070 LRA Sec 69-B.2.1.12

Audit Question PIR 20012577 recommended removing penetration seals that are sealed with grout from the periodic 18 month penetration seal inspection. Confirm if this recommendation was implemented, and if so, clarify what is the inspection frequency for this type of penetration seals. If this frequency is different than the GALL Report recommended frequency, justify why this is not an exception.

Final Response

Grouted penetration seals are part of the Fire Barrier visual inspections that are performed at least once per 18 months to detect the presence of breaches and gross deterioration.

Staff Evaluation

The staff reviewed the procedure and finds the applicant's response acceptable because the grouted penetration seals are part of the fire barrier visual inspections that are performed at least once every 18 months to detect the presence of breaches and gross deterioration. Therefore, this is not considered an exception.

Question No AMPA071 LRA Sec 70-B.2.1.12

Audit Question The GALL Report states that no corrosion and mechanical damage of halon system is acceptable; no corrosion is acceptable in the fuel supply line; and no visual indications outside those allowed by approved penetration seal configurations for penetration seals. The Fire Protection Program License Renewal Evaluation Report states differently in the 10 program elements evaluation where the degradation is not acceptable if it prevents the system or penetration seal or fuel line from performing its intended function. Furthermore, the same document states for fuel supply line that leakage would indicate the potential of age related loss of material and would be observed and documented in the monthly operation of the diesel driven fire pump and corrective action would be initiated.

Explain why these are not exceptions to the acceptance criteria program element, and provide a basis for why these are acceptable. Clarify who determines how significant the corrosion or leakage is before the intended function is impaired.

Followup Questions:
The response to question B2.1.12-3 does not answer the question.

The GALL AMPXIM.26 element "detection of aging effects" recommends visual inspection of the halon system to detect any sign of degradation such as corrosion, mechanical damage, or damage to dampers. Also, element "Acceptance criteria" recommends any sign of corrosion and

mechanical damage is not acceptable.

The response stated that WCGS performs a functional deluge test to identify any mechanical damage. The halon system surveillance procedures STN FP-400A, 400B, 400C, etc. were reviewed. Neither of these procedures addresses visual inspection. Section 6.0, Acceptance Criteria, does not provide any criteria for corrosion or mechanical damage.

Please clarify how WCGS meets this GALL Report recommendation and if not, please justify why an exception to the GALL Report is not taken.

For diesel driven fire pump, the GALL Report element "acceptance criteria" recommends no corrosion is acceptable in the fuel oil supply line for the diesel driven fire pump.

The response stated that performance testing of the diesel-driven fire pump is used to detect degradation (corrosion) of the fuel supply lines. Please explain how the performance test will detect corrosion.

Final Response

Penetration Seals

NUREG-1801 XI.M26 element 6 (acceptance criteria) states: “Inspection results are acceptable if there are no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or puncture of seals.”

Acceptance criteria are defined in the WCGS procedures used to perform tests and inspections of the fire protection system. Fire barrier penetration seals inspection results are acceptable if there are no cracking, separation of seals from walls, separation of layers of materials, ruptures, or punctures of seals observed that might impact the seals fire protection functionality. Penetration seal inspection acceptance criteria is evaluated in M-663-00017A, Penetration Seal Typical Details.

Inspections are performed by Level II (minimum) QC personnel certified for the type of sealing device being inspected.

Diesel-driven fire pump fuel supply line:

NUREG-1801 XI.M26 element 6 (acceptance criteria) states: “No corrosion is acceptable in the fuel supply line for the diesel-driven fire pump.”
NUREG-1801 XI.M26 element 4 (detection of aging effects) states: “Periodic tests performed at least once every refueling outage, such as flow and discharge tests, sequential starting capability tests, and controller function tests performed on diesel-driven fire pump ensure fuel supply line performance. The performance tests detect degradation of the fuel supply lines before loss of the component intended function.”
Performance testing of the diesel-driven fire pump is used to detect degradation (corrosion) of the fuel supply lines. Satisfactory performance of the diesel driven fire pump means that no degradation (corrosion) was detected. A monthly operation and fuel level check is performed on

the diesel-driven fire pump and any leakage or any signs of corrosion that would prevent the system from performing its intended function are not acceptable. Leakage would indicate the potential of age related loss of material and would be observed and documented in the monthly operation of the diesel-driven fire pump and corrective action would be initiated. Diesel fire pump day tank level is checked once per shift in accordance with CKL ZL-009. This is also a data point for identifying system leakage.

Halon System:
NUREG-1801 XI.M26 element 6 (acceptance criteria) states: "Also, any signs of corrosion and mechanical damage of the halon/CO2 fire suppression system are not acceptable."
NUREG-1801 XI.M26 element 4 (detection of aging effects) states: "Visual inspections of the halon/CO2 fire suppression system detect any sign of added degradation such as corrosion, mechanical damage, or damage to dampers. The periodic function test and inspection performed at least once every six months detects degradation of the halon/CO2 fire suppression system before the loss of the component intended function."
Wolf Creek performs a functional deluge test of the halon fire suppression system to identify any mechanical damage of the halon fire suppression system that prevents the system from performing the intended functions.

Follow-up response:

The halon system has the internal environments of plant indoor air and dry gas. The following halon system materials have an internal environment of plant indoor air: galvanized carbon steel, and copper alloy. The following halon system materials have an internal environment of dry gas: bronze, carbon steel, galvanized carbon steel, cast iron, elastomer, copper alloy, and stainless steel. The material and environment combinations listed above do not require aging management per the AMR.

Carbon steel and cast iron materials in the halon system are exposed to an external environment of plant indoor air and will be visually inspected by the XI.M36 External Surfaces Monitoring Program.

The external surfaces of the diesel-driven fire pump fuel oil supply line will be visually inspected by the XI.M36 External Surfaces Monitoring Program.

The diesel-driven fire pump fuel oil supply line has an internal environment of fuel oil and is made of carbon steel. The NUREG-1801 row referenced for this components configuration is VII.G-21, which recommends the aging management programs of XI.M26, Fire Protection, and XI.M30, Fuel Oil Chemistry. XI.M30 Fuel Oil Chemistry utilizes the XI.M32 One-Time Inspection to verify the effectiveness of the Fuel Oil Chemistry Program using a representative sample of components in systems that contain fuel oil.

The first paragraph of LRA Section A1.12 will be amended to state the following:

"The Fire Protection program manages loss of material for fire rated doors, fire dampers, diesel-driven fire pump, and the halon fire suppression system, cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors, and hardness and shrinkage due to weathering of fire barrier penetration seals. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors are performed. The internal surface of the diesel-driven fire pump fuel oil

supply line is managed by the XI.M30 Fuel Oil Chemistry aging management program, which utilizes the XI.M32 One-Time Inspection to verify the effectiveness of the Fuel Oil Chemistry Program using a representative sample of components in systems that contain fuel oil, ensuring that there is no loss of function due to aging of diesel fuel oil supply line."

The first paragraph of LRA Section B2.1.12 will be amended to state the following:

'The Fire Protection program manages loss of material for fire rated doors, fire dampers, diesel-driven fire pump, and the halon fire suppression system, cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors, and hardness and shrinkage due to weathering of fire barrier penetration seals. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors are performed. The internal surface of the of the diesel-driven fire pump fuel oil supply line is managed by the XI.M30 Fuel Oil Chemistry aging management program, which utilizes the XI.M32 One-Time Inspection to verify the effectiveness of the Fuel Oil Chemistry Program using a representative sample of components in systems that contain fuel oil, ensuring that there is no loss of function due to aging of diesel fuel oil supply line."

The fifth paragraph of LRA Section B2.1.12 will be amended to state the following:

'The Fire Protection program performs a visual inspection, at least once per year, on fire rated doors to verify the integrity of door surfaces and for clearances to detect aging of the fire doors. The internal surface of the of the diesel-driven fire pump fuel oil supply line is managed by the

XI.M30 Fuel Oil Chemistry aging management program, which utilizes the XI.M32 One-Time Inspection to verify the effectiveness of the Fuel Oil Chemistry Program using a representative sample of components in systems that contain fuel oil, ensuring that there is no loss of function

due to aging of diesel fuel oil supply line. A visual inspection and function test of the halon fire suppression system is performed every 18 months."

Staff Evaluation

The staff finds the applicant's response acceptable because for halon system the materials and environment combinations provided in the response do not require aging management, which is consistent with the GALL Report recommendations. For the response on the diesel fire pump fuel oil supply line, the applicant will amend the application to clarify that a one-time inspection is used to verify the effectiveness of the Fuel Oil Chemistry Program, using a representative sample of components in systems that contain fuel oil. On this basis, the applicant response is acceptable.

The changes described above have been incorporated in the LRA amendment, issued by the applicant's letter dated August 31, 2007.

Question No AMPA072 LRA Sec 71-B.2.1.13
Audit Question The Fire Water Program license renewal program element report refers to Fire Protection Program in all elements. Clarify if the Fire Protection and

Fire Water System Programs are interchangeable. Clarify if this the same Fire Protection Program addressed in LRA Section B2.1.12.

Final Response

The Fire Water system is a subsystem of the Fire Protection system. The Fire Water AMP (XI.M27, LRA Section B2.1.13) addresses water-based fire protection components such as sprinklers, nozzles, hydrants, standpipes, hose stations and water storage tanks (buried fire water piping external surfaces are managed by the Buried Piping and Tanks Inspection program). The Fire Protection AMP (XI.M26, LRA Section B2.1.12) addresses fire rated doors, fire dampers, diesel-driven fire pump, fire barrier walls, ceilings and floors, barrier penetration seals and the halon fire suppression subsystem. Although both AMPs manage components in the WCGS Fire Protection system, they are not interchangeable because NUREG-1801 creates a separate division of responsibility for managing aging of the Fire Protection system components. Although NUREG-1801 creates this division, at WCGS there is no division between the two and all Fire Protection system components are governed by one program procedure (AP 10-100, Fire Protection Program). Thus, both the Fire Protection AMP XI.M26, and Fire Water AMP XI.M27 will refer to the "Fire Protection Program".

Staff Evaluation

The staff finds the applicant's response acceptable because although the GALL Report creates the division between the Fire Protection Program and the Fire Water System Program, at WCGS there is no division between the two and all Fire Protection system components are governed by one program procedure (AP 10-100, Fire Protection Program). Thus, both the Fire Protection AMP XI.M26, and Fire Water AMP XI.M27 refer to the "Fire Protection Program".

Question No AMPA073 LRA Sec 72-B.2.1.13

Audit Question Describe how the visual inspection performed under the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program referenced in the Fire Water System Program evaluates wall thickness.

Final Response

NUREG 1801, XI.M27, Fire Water System states that fire protection system piping is to be subjected to required flow testing in accordance with guidance in NFPA 25 to verify design pressure or evaluated for wall thickness, and that visual inspections can be used to satisfy this evaluation. Visual inspections performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program would detect wall thinning by identifying corrosion, surface or finish discontinuities, or a lack of symmetry of the component dimensions. If degradation is unacceptable, deficiencies would be resolved via WCNOCs corrective action program. The WCNOC corrective action program may then specify mechanical or NDE methods to be used in quantifying the degradation consistent with QCP 20-518, "Visual Examination of Heat Exchangers and Piping Components" or other approved station procedures. (WCGS-AMP-B2.1.22, Section 3.6, QCP 20-518).

Staff Evaluation

The staff reviewed selected instances documented by the applicant that identified issues with the Fire Water System Program and where the applicant had implemented corrective action. The staff noted that the applicant's corrective actions were timely and appropriate. On the basis that the visual inspections are performed, unacceptable degradation is identified in the corrective action program, and further action is taken to quantify the degradation by mechanical or NDE methods by appropriate station procedures, the staff finds the response acceptable.

Question No AMPA074 LRA Sec 73-B.2.1.13

Audit Question The Fire Water System Program description states that visual inspections of the fire protection system exposed to water, evaluating wall thickness to identify evidence of loss of material due to corrosion, is covered by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. However, the detection of aging effects program element in the GALL AMP states that these inspections must be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the design flow of the fire protection system.

Since the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program, discuss how this program will evaluate wall thickness and the inner diameter of the piping by only performing visual inspection.

Final Response

Visual inspections performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program would detect wall thinning by identifying corrosion, surface or

finish discontinuities, or a lack of symmetry of the component dimensions. If degradation is unacceptable, deficiencies would be resolved via WCNOCs corrective action program. The WCNOC corrective action program may then specify mechanical or NDE methods to be used in quantifying the degradation consistent with QCP 20-518, "Visual Examination of Heat Exchangers and Piping Components" or other approved station procedures. (WCGS-AMP-B2.1.22, Section 3.6, QCP 20-518).

Staff Evaluation

The staff reviewed selected instances documented by the applicant that identified issues with the Fire Water System Program and where the applicant had implemented corrective action. The staff noted that the applicant's corrective actions were timely and appropriate. On the basis that the visual inspections are performed, unacceptable degradation is identified in the corrective action program, and further action is taken to quantify the degradation by mechanical or NDE methods by appropriate station procedures, the staff finds the response acceptable.

Question No AMPA075 LRA Sec 74-B.2.1.13

Audit Question The GALL AMP recommends annual fire hydrant hose hydrostatic tests. The Fire Water Program states that hydrostatic test of hoses occurs once

every 3 years. Justify and provide a basis for this 3 year frequency. Clarify if hydrostatic test frequency of hoses once every 3 years is documented in the WCGS Fire Protection Program and in commitments to 10 CFR 50.48 using the Branch Technical Position (BTP) Auxiliary and Power Conversion Systems Branch (APCSB) 9.5 1, "Guidelines for Fire Protection for Nuclear Power Plants," dated May 1, 1976, and BTP APCSB 9.5 1, Appendix A, dated August 23, 1976.

WCGS also states that it may replace an existing fire hose with a new fire hose every five years in lieu of performing a hydrostatic test. This implies that the fire hydrant hose will not be tested in five years. Justify how WCGS ensures that the hose has not degraded within these five years and will perform its intended function if no testing has been performed.

Final Response

WCGS USAR Table 9.5E-1, Section III.E, "WCGS Fire Protection Comparison to 10CFR50 Appendix R', states that interior standpipe hose is tested every three years or the fire hose is replaced every five years. This is part of the WCGS current licensing basis. Since this is part of the approved licensing basis, clarification as to previous branch technical positions and commitments would not be applicable. However, for information purposes, hydrostatic testing of fire hoses is not discussed in the Branch Technical Position (APCSB) 9.5-1 (May 1976) or 9.5-1 Appendix A (August 1976). The basis for testing/replacement of interior fire hose is from NFPA 1962, Inspection, Care, and Use of Fire Hose Couplings and Testing of Fire Hose. Specifically, Section 4.3.2 requires hydro-testing not to exceed 5 years from manufacture date and every 3 years thereafter. WCGS addresses this requirement by replacing the hose every 5 years. It is more economical than the manpower cost associated with performing hydro-testing.

Staff Evaluation

In its response the applicant stated that WCGS USAR Table 9.5E-1, Section III.E, "WCGS Fire Protection Comparison to 10CFR50 Appendix R', states that interior standpipe hose is tested every three years or the fire hose is replaced every five years. This is part of the WCGS current licensing basis. The staff reviewed the USAR information and found that it established the current licensing basis. On the basis of this review, the staff finds the exception to hydrotest the fire hydrant hose every three years or replace them every five years to be acceptable.

Question No AMPA076 LRA Sec 75-B.2.1.16

Audit Question The LRA states that the One Time Inspection Program is a new AMP. However, in the 21 years of plant operation, WCGS must have collected information on the aging of systems and components in primary water, secondary water, lube oil and fuel oil environments as part of system surveillance tests or the maintenance program. Furthermore, as part of evaluating industry experience, WCGS may have also evaluated these systems. Provide industry and plant operating experience that could be relied on to verify the effectiveness of the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis Programs.

Final Response

As stated in the Program Evaluation Report (PER) B2.1.16, One Time Inspection, Section 3.10, there is no operating experience that indicates that the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Programs will not be effective in preventing aging effects during the period of extended operation. In accordance with NUREG-1801 XI.M32, element 4, one time inspections will be implemented and completed no earlier than 10 years prior to the period of extended operation.

Staff Evaluation

The staff interviewed the applicant's technical personnel to confirm that plant-specific operating experience indicated all degradation are bounded by industry experience. The staff recognized that the applicant's corrective action program, which records internal and external plant operating experience, ensures continued review of operating experience with incorporation of appropriate changes to plant program. On this basis, the staff finds the applicant response acceptable.

Question No AMPA077 LRA Sec 76-B.2.1.23
Audit Question The Lubricating Oil Analysis License Renewal Program Evaluation Report states that the plant's Predictive Maintenance Group reviews lubricating oil analysis results and determines the acceptability for continued service using engineering judgment. Provide documentation that shows the analyses trending performed by the Predictive Maintenance Group.

Final Response

Examples of lube oil analysis results documents have been provided in the hardcopy AMP binder available at the site during the audit for the Turbine Driven Auxiliary Feedwater Pump and Safety Injection Pumps. Oil analysis results are reviewed by the predictive maintenance group to determine if alert levels have been reached or exceeded. This review checks for unusual trends.

Staff Evaluation

The staff finds the applicant response acceptable because the examples of lubricating oil analysis, that are reviewed by the Predictive Maintenance Group, indicate that alert levels are not reached or exceeded.

Question No AMPA078 LRA Sec 77-B.2.1.23
Audit Question Provide the basis and associated documentation for the oil sampling frequencies

Final Response

Lube oil sampling frequencies were initially established using a combination of EPRI guidance, equipment vendor recommendations, and the oil supplier's assessment based on equipment usage patterns. These sampling frequencies are evaluated on an ongoing basis based on plant operating experience. In most cases, these original frequencies have proven to be adequate and have not been changed. However, frequencies may be adjusted towards more frequent sampling if sample results (for example, an unexpected increase in wear particle concentration) or operating history (oil-related equipment failure) warrant. Industry benchmarking and self

assessments have also been performed to evaluate the sample frequencies within the total context of all the preventive and predictive activities for the components.

There is no formal document reflecting a basis for the sampling frequencies. Individual sampling frequencies are identified in the preventive maintenance requirements for each component.

Staff Evaluation

The staff finds the applicant response acceptable because lubricating oil sampling frequencies are based EPRI guidance, equipment vendor recommendations, and operating history as recommended by GALL AMP XI.M39.

Question No AMPA079 LRA Sec 78-B.2.1.9
Audit Question A review of QCP 20 518, "Visual Examination of Heat Exchangers and Piping Components," indicates that visual inspection can detect wall thinning. Explain and provide supporting documentation that show how visual inspection will be able to detect wall thinning.

Final Response

QCP 20-0518 states that "Where practical, component wall thinning shall be quantified to determine the extent of condition. Depth of thinning may be determined by mechanical means or other suitable NDE methods." (Step 6.5) Visual inspection would detect wall thinning by identifying corrosion, surface or finish discontinuities, or a lack of symmetry of the component dimensions. Mechanical means or NDE methods could then be used to further quantify the degradation.

Staff Evaluation

The staff finds the applicant's response acceptable because visual inspection provides an indication of wall thinning by the identification of degradation such as corrosion and erosion. Areas where degradation is identified are subject to NDE examination.

Question No AMPA080 LRA Sec 79-B.2.1.9
Audit Question The Open Cycle Cooling Program description states that NDE examinations are not performed in containment coolers. Performance testing can indicate if a leak is present; however, it cannot detect an eminent leak due to wall thinning. Explain how wall thinning is detected and trended for this component.

Final Response

The relevant text from NUREG-1801 XI.M20 element 4 states: Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, eddy current testing, and heat transfer capability testing, are effective methods to measure surface condition and the extent of wall thinning associated with the service water system piping and components, when determined necessary.

The introduction to NUREG-1801 element 5 states: Inspection scope, method (e.g., visual or

nondestructive examination [NDE]), and testing frequencies are in accordance with the utility commitments under NRC GL 89-13.

Performance of the containment coolers is monitored utilizing hydraulic and thermal testing methodologies. The containment coolers are tested for hydraulic performance using the pressure drop method. The containment coolers are tested for thermal performance using the heat transfer method. Visual inspection, periodic cleaning, and NDE (ECT) are not performed on the containment coolers. ECT is not viable for the Containment Coolers due to accessibility constraints, therefore wall thinning cannot be directly measured.

Inspection scope, method, and testing frequency are consistent with the Wolf Creek commitments identified in Wolf Creek letter ET 99-0042, Updated Response to Generic Letter 89-13 dated November 17, 1999.

Staff Evaluation

The staff finds the applicant response acceptable because visual inspection and performance testing frequencies are in accordance with WCGS commitments to Generic Letter 88-13 as recommended by GALL AMP XI.M20.

Question No AMPA081 LRA Sec 80-B.2.1.9

Audit Question Procedure AP 23L-001, Revision 2, Section 2.0, “Lake Water Systems Corrosion and Fouling Mitigation Program" and the Open Cycle Cooling License Renewal Evaluation Report indicate a difference in the components and systems that are subject to the scope of this program.

Clarify the discrepancy and clearly identify which components and systems are managed under this program.

Final Response

Procedure, AP 23L-001, “Lake Water Systems Corrosion and Fouling Mitigation Program”, establishes the general requirements for implementation of and maintenance of programs which monitor the performance and structural integrity of lake water systems which provide cooling for plant components. Procedure AP 23L-001, Revision 2, Section 2.0, identifies that the procedure applies to the following systems:

- Service Water (WS & ES)
- Essential Service Water (EF)
- Circulating Water (CW & DA)
- Fire Protection (EP & KC)

AMP B2.1.9 Open-Cycle Cooling Water AMP section 3.1 identifies the plant systems that receive cooling water (raw water environment) from the Essential Service Water System and Service Water Systems. AMP B2.1.9 is credited with managing the aging of components and heat exchangers that are exposed to a raw water environment in those systems. Element 1 identifies that the AMP manages aging in the following systems:

- Essential Service Water
- Chemical and Volume Control (CVCS chiller supply and Return Piping)

- Service Water
- Essential Service Water Chemical Addition
- Component Cooling Water (Component Cooling Water Heat Exchangers)
- Spent Fuel Pool Cooling and Cleanup (Spent Fuel Pool Make-Up Piping)
- Stand-by Diesel Engine (DG Intercoolers, DG Lube Oil Coolers, and DG Jacket Water Heat Exchangers)
- Auxiliary Building HVAC (CCW Pump Room Coolers, Centrifugal Charging Pump Room Coolers, Containment Spray Pump Room Coolers, Electrical Penetration Room Coolers, RHR Pump Room Coolers, and Safety Injection Pump Room Coolers)
- Containment Cooling (Containment Coolers)
- Control Building HVAC (Control Room A/C Unit Condensers and Class 1E Switchgear A/C Unit Condensers)
- Fuel Building HVAC (Spent Fuel Pool Pump Room Cooler)
- Miscellaneous Buildings HVAC (AFW Pump Room Cooler)

Based on comparison of the list given in the Procedure to the list given in the AMP there appears to be a discrepancy. However, while the procedure describes the scope at the system level, the AMP lists the components that the systems serve. At Wolf Creek, the components and heat exchangers are assigned to the functional system, not the cooling system (i.e., ESW and SW).

AMP B2.1.12, Fire Water System Program provides aging management of fire protection components exposed to a raw water environment (lake water). The Circulating Water System is not within the scope of License Renewal.

Staff Evaluation

The staff finds the applicant response acceptable because there is no discrepancy between the components and systems within the scope the Open Cycle Cooling License Renewal Evaluation Report and procedure AP 23L-001. The scope of AP23L-001 is defined on the system level, whereas the scope the Open Cycle Cooling License Renewal Evaluation Report is defined on the component level. All OCCW components, that are subjected to AMR, are in the systems cited in AP23L-001.

Question No AMPA082 LRA Sec 81-B.2.1.9

Audit Question The Open Cycle Cooling Program PIR No. 2002-0407 describes operating experience with de-alloying of heat exchanger tubing. The applicant credits a one time inspection in the Selective Leaching of Materials Program and committed to expand the inspection scope and to develop an inspection schedule if de-alloying is found. As a result of this operating experience described in PIR No. 2002-0407, provide the plan and schedule for these additional inspections.

Final Response

The indications described in PIR 2002-0407 in the copper-nickel tubes were suspected to be the result of dealloying but that assumption was never verified.

It was concluded that the degradation had not caused significant deterioration of the tube walls. The corroded areas were not significant enough to determine wall loss or tube wall thinning or if

significant deterioration had taken place. The suspected dealloying shows up as a bright area on the inside of the tube walls, therefore it is easily observed. The normal oxidized coating isn't present. For these heat exchangers the identified corrosion appeared to be in the early stages (occurring within the last few years). WCGS continues to monitor the condition, and compares new test data with past data in order to help determine if dealloy conditions are causing further degradation of heat exchanger tubes.

As a result, the Selective Leaching of Materials Program was not credited for any of the heat exchangers identified in the PIR. If it is eventually verified that dealloying is in fact occurring, and that the projected degradation could affect these components intended functions, the Selective Leaching of Materials Program may be credited at that time.

Staff Evaluation

The staff finds that applicant response acceptable because followup investigations, including metallography, found no dealloying.

Question No AMPA083 LRA Sec 82-B.2.1.17
Audit Question Provide additional information that demonstrates that alternative mechanical methods to hardness testing are reliable for detecting selective leaching.
Final Response

When selective leaching occurs in gray cast iron components, the iron is dissolved leaving

behind a porous mass, consisting of graphite, voids and rust. This is known as graphitization. Additionally, selective leaching in copper alloys occurs when zinc is dissolved in the liquid solution that comes in contact with the copper alloy component. When the zinc is removed a weakened and corroded structure is left behind. This is known as dezincification. The combination of visual inspections in conjunction with mechanical methods will result in selective leaching being detected. The visual inspection will detect visible corrosion while the chipping and scraping of the mechanical methods will detect a corroded component structure. If these methods detect dezincification or graphitization then a follow up examination/evaluation will be performed. The examination/evaluation may require confirmation of selective leaching with a metallurgical evaluation (which may include a microstructure examination.)

There are no aluminum-bronze (greater than 8% aluminum) components in the scope of license renewal at WCGS.

Staff Evaluation

The staff finds the applicant response acceptable because scraping and chipping of components that are subject to selective leaching will detect a weakened structure of the material.

Question No AMPA084 LRA Sec 83-B.2.1.17
Audit Question LRA Section A.1.17 and the Selective Leaching Program License Renewal Evaluation Report, WCGS AMP B2.1.17 Rev 1, address "visual, mechanical methods." Clarify the meaning of this term (i.e., "visual and mechanical methods" or "visual or mechanical methods.")

Final Response

The term (visual, mechanical methods) as seen in LRA Section A.1.17 means "visual and mechanical methods". Please see the response to question 83 for clarification of the visual and mechanical inspection.

LRA section A.1.17 will be amended to change "visual, mechanical methods" to "visual and mechanical methods"

Staff Evaluation

The staff finds the applicant response acceptable because the applicant committed to revise LRA Section A1.17 to provide clarification as to which methods will be used to detect selective leaching.

The change described above has been incorporated in the LRA amendment, issued by the applicant's letter dated August 31, 2007.

Question No AMPA085 LRA Sec 84-B.2.1.14

Audit Question The applicant stated that no preventive action is taken for the diesel fire pump fuel tank because the internals are inaccessible. The applicant also stated that biocides and/or corrosion inhibitors have not been used to mitigate corrosion. The staff noted that since water and particulate contamination and corrosion has been detected in other WCGS fuel oil tanks, it is possible that MIC, pitting and general corrosion might be present in the diesel fire pump fuel tank as well. Undetected degradation could be progressing through the tank wall since cleaning and visual inspection has not been performed in the diesel fire pump fuel tank. The applicant indicated that operating experience for the other fuel oil tanks justifies not having to implement preventive actions. Provide additional information that justify not having to implement preventive actions such as cleaning and visual inspections on a periodic basis if alternate inspection methods such as UT are not employed.

Final Response

The diesel fire pump fuel oil tanks have similar internal material of construction and environment as the emergency fuel oil day tanks. Periodic sampling and testing for water and sediment has demonstrated that neither the fuel oil day tanks nor the diesel fire pump fuel tanks have any history, within the last ten years, of water and sediment levels exceeding the normal chemistry level of 0.05%. This demonstrates that both tanks have the same material and internal environment.

The periodic sampling, cleaning, and visual inspection of the emergency fuel oil day tanks will act as a representative sample and ensure that significant aging is not occurring in other fuel oil day tanks. The emergency fuel oil tanks inspection results will be of value in assessing the condition of the diesel fire pump fuel oil tanks since these tanks have similar internal materials and environments.

Any adverse condition found in the inspected emergency fuel oil day tanks will be assumed to be occurring in the emergency fuel oil day tanks and preventive actions will be taken in accordance with the WCGS corrective action program.

One-time inspection of the bottom of the diesel driven fire pump fuel oil tank will confirm the effectiveness of this approach. LRA Sections A1.14 and B2.1.14 and LRA commitment number 6 for Fuel Oil Chemistry (RCMS 2006-203) will be amended to include a one time ultrasonic (UT) or pulsed eddy current (PEC) thickness examination on the external surface of engine driven fire pump fuel oil tank (1DO002T) to detect corrosion related wall thinning. If UT is used, the examination will be on a 4 inch grid. The examination will be performed once during the 8 years between 10 years prior to the period of extended operation and 2 years prior to the period of extended operation.

Staff Evaluation

The staff found the applicant response acceptable because the applicant committed to perform a one-time NDE inspection of the bottom of the diesel fire pump fuel tank two years prior to entering the period of extended operation. NDE inspection will determine if wall thinning is occurring in this fuel tank.

The changes described above have been incorporated in the LRA amendment, issued by the applicant's letter dated August 31, 2007.

Question No AMPA086 LRA Sec 85-B.2.1.14
Audit Question Provide the acceptance criteria and the basis for minimum wall thickness.

Final Response

The acceptance criteria and the basis for minimum wall thickness have not yet been determined. STN MT-002 inspection procedure provides for supplemental ultrasonic thickness measurements if there are indications of reduced cross sectional thickness found during the visual inspection and requires that Engineering evaluate all indication and specify required repair.

Staff Evaluation

Although an acceptance criteria based on minimum wall thickness has not been established, the staff finds the applicant response acceptable because there are no incidence of wall thinning detected by UT examination. If wall thinning is discovered in the future, the staff noted that the applicant will perform an engineering evaluation to the justification for the acceptance of wall thinning and/or tank repair.

Question No AMPA087 LRA Sec 86-B.2.1.14
Audit Question Clarify if microbiological activity will be monitored and biocide and corrosion inhibitors be added if reduction of thickness is discovered during UT. If not, please provide a justification.

Final Response

When fuel oil particulate levels equal or exceed 6 mg/L and have been verified by a second particulate analysis, the Procedure, AP 02-003, “Chemistry Specification Manual”, requires a system engineer be contacted for possible corrective actions, including biological testing of fuel. Corrective actions are taken to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance. Additionally, when the presence of biological activity is confirmed, a biocide is added to fuel oil.

When reduction of thickness is discovered during UT, an engineering evaluation of all indications is required. Specific corrective actions are implemented in accordance with the plant quality assurance (QA) program.

Staff Evaluation

The staff finds the applicant response acceptable because additions of biocides and/or corrosion inhibitors to fuel oil will be considered as a part of engineering evaluation if degradation is discovered in fuel oil tanks. The staff noted that biocides were added to an emergency diesel fuel tank after minor corrosion was discovered.

Question No AMPA088 LRA Sec 87-B.2.1.14

Audit Question USAR, Section 9.5.4.1.2 indicates that biocides are used to mitigate corrosion. However, the exception to the GALL Report described in preventive action program element of the Fuel Oil Chemistry Program indicates that biocides are not added on a routine basis. Provide additional information and supporting documentation related to biocide additions to diesel fuel.

Final Response

Biocides are not added on a routine basis. Biocides are only added when testing indicates biological activity. Per the chemistry requirements when operations removes water from the diesel storage tank during performance of either STS JE-004A or STS JE-004B, the water removed shall be tested for biological activity. Test results at 103 or greater CFU/ml, for a treated tank, or 105 or greater CFU/ml, for an untreated tank, shall be cause to have operations treat the affected tank with Kathon FP 1.5. The recommended dosing level is one gallon of Kathon FP 1.5 per 10,000 gallons of fuel in the tank.

The Emergency Diesel Generator Fuel is analyzed for particulate when received and is also tested monthly. Procedure AP 02-003, section 6.43.1 states.

Note 1: If the value is 6 mg/L or greater, resample and verify TSS results.

Note 2: Pull an extra liter from the bottom of the tank for possible biological testing.

Note 3: If 6 mg/L or greater particulate is verified by a second analysis, contact System Engineering for possible corrective actions, including biological testing of fuel.

Procedures, STS JE-004A/B, “Emergency Fuel Oil Storage Tank Water Check/Removal”’ directs for Operations personnel to contact Chemistry if water is detected during the monthly surveillance.

The Diesel Fire Pump Fuel is analyzed for acceptance prior to the new fuel being offloaded into the day tank. This activity is controlled by Procedure, SYS DO-110, “Diesel Fire Pump Day Tank”. Additionally, the day tank fuel is sampled every 92 days per Procedure ,STN FP-600, “Fire Pump Diesel Fuel Storage Tank”.

Staff Evaluation

The staff found the applicant response acceptable because applicant provided details on the criteria for biocide additions to fuel oil. Use of biocides are considered only when testing indicates biological activity. The primary method to limit biological activity is to maintain an environment that is not conducive microbes.

Question No AMPA089 LRA Sec 88-B.2.1.14
Audit Question The Fuel Oil Chemistry Program operating experience shows that corrosion has been discovered in the emergency fuel oil storage tank. Provide the frequency at which UT is performed when degradation is discovered in diesel fuel tanks.

Final Response

Emergency Fuel Oil Tanks

UT inspections are only required if indications of reduced cross sectional thickness is found. The frequency at which UT is performed on the Emergency Fuel Oil Tanks has not been determined because degradation, which requires a UT, has not been found.

A visual inspection in 2002 revealed that the interior coating of one of the emergency fuel oil storage tanks was deteriorated and some rust had developed in the interior walls of the tank. An engineering evaluation determined that the failure of the interior coating of the emergency fuel oil storage tank should not result in degradation or failure of the diesel system to perform its intended functions. It was also determined that the rust identified during this inspection was an acceptable condition because it is not at a stage that could result in the component failures to perform its intended function and any degraded conditions in future inspections will be documented in a non-conformance work order. Upon the discovery of the condition of the emergency fuel oil storage tank interior coating, a biocide was added to that tank and all of the diesel fuel in the emergency fuel oil storage tanks was subsequently replaced with new fuel. Since the discovery of the condition of the emergency fuel oil storage tank interior coating, one of the emergency fuel oil day tanks has been visually inspected, and no coating degradation was found. In 2006 both day tanks were inspected and no debris was found and no degradation of the coatings was found.

Staff Evaluation

The staff found the applicant response acceptable because it was determined that corrosion was minor and that further corrosion has not been observed.

Question No AMPA090 LRA Sec 89-B.2.1.14
Audit Question Provide the acceptance criteria and the basis for all fuel quality parameters such as flash point, sulfur content, total particulate, water and sediment content, etc.

Final Response

The acceptance criteria for the Emergency Diesel Generator Fuel and the Diesel Fire Pump Fuel are as follows. Reference Procedure, AP 02-003, "Chemistry Specification Manual"' page 51 and 63.

Emergency Diesel Generator Fuel

Parameter	Limit
API gravity	27º - 39º API
Kinematic visc.	1.9 <= x <= 4.1 Cst @ 40ºC
Water & Sediment	<= 0.05%
Flash Point	>= 51.7ºC
Particulates	<= 10 mg/l (Normal Value <5 mg/l, Supv Value <6 5 mg/l
Cloud Point	<= -9ºC (Supv Value -13ºC
Carbon Residue	< = 0.35%
Ash	<= 0.01%
Dist.Temp.@ 90% Point	282.2ºC <= x <= 338ºC
Sulfur	<= 0.5%
Copper Corrosion	Max. No. 3
Cetane Number	Min. 40 (Supv Value >= 45

Diesel Fire Pump Fuel

Parameter	Limit
Kinematic visc.	1.3 <= x <= 4.1 Cst @ 40ºC
Water & Sediment	<= 0.05%
Particulates	<=10 mg/liter (supv limit <=6 mg/liter)

WCGS uses the recommendations and methodology of D1796-83 to determine the amount of contamination due to water and sediment in diesel fuel. The testing conducted using ASTM D1796 gives quantitative results, whereas D2709 testing gives only pass-fail results; therefore, the D1796 method gives more descriptive information about the fuel oil condition than the D2709 method. WCGS uses the recommendations and methodology of the modified D2276-78 Method A for determination of particulates in diesel fuel.

Staff Evaluation

The staff found the applicant response acceptable because the acceptance criteria and the basis for fuel quality parameters are in accordance with Technical Specifications as recommended by the GALL Report.

Question No AMPA091 LRA Sec 90-N/A

Audit Question Several of the License Renewal Program Evaluation Reports identify "Open Items" in section 5.2 of the report. The open items typically identify need (or potential need) to revise specified plant procedures or similar documents.

Explain which processes are used to ensure that these open items are tracked and closed. Clarify if the License Renewal Program Evaluation Reports will be updated to reflect closure of these open items.

Final Response

The purpose of the AMP open items was to track progress of an item as information became available. AMP open items were used to identify items that might change shortly before or shortly after issue of the LRA. Significant open items were entered in one of the following Wolf Creek processes for tracking:

- Corrective Action process as a Performance Improvement Request (PIR) or Condition Report
- Regulatory Commitment Management System (RCMS number assigned)

The License Renewal Program Evaluation Reports would be updated if the open item is completed prior to issue of the LRA annual update and the update changes the content of the WCGS evaluations for one of the AMP 10 elements.

The following is a listing and/or status of AMP open items:

B.2.1.1 - XI.M1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
Supporting information for 3rd Interval ISI – non-significant AMP impact.

B.2.1.3 - XI.M3 Reactor Head Closure Studs
Revisions issued – no AMP impact

B.2.1.5 - XI.M11 Nickel-Alloy Penetration Nozzles Welded To The Upper Reactor Vessel Closure Heads Of Pressurized Water Reactors
Editorial change for consistency - non-significant AMP impact.

B.2.1.8 - XI.M19 Steam Generator Tube Integrity
Coordination with AMP XI.M2 Water Chemistry AMP – Water Chemistry AMP submitted with exception – no AMP impact.

B.2.1.9 - XI.M20 Open-Cycle Cooling Water System
Condition Report 2006-000489

B.2.1.10 -XI.M21 Closed-Cycle Cooling Water System
RCMS 2006-200

B.2.1.11 - XI.M23 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
PIR 05-3094

B.2.1.22 - XI.M38 Inspection Of Internal Surfaces In Miscellaneous Piping And Ducting Components
RCMS 2006-208

B.2.1.25 - XI.E2 Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits

RCMS 2006-210

B.2.1.27 - XI.S1 ASME Section XI, Subsection IWE
One procedure changed no AMP impact – one procedure in revision

B.2.1.32 - XI.S6 Structures Monitoring Program
RCMS 2006-214
PIR 20052848

Plant Specific - PSNI Nickel Alloy Aging Management
Editorial change for consistency between procedures

Staff Evaluation

The applicant's response provides clarification of the "open items" identified in several of the WCGS license renewal program evaluation documents. Staff noted that they are generally editorial or administrative in nature and do not affect the information submitted by the applicant in the LRA. On this basis, the staff finds the applicant's response to be acceptable.

Question No AMPA092 LRA Sec 91-N/A
Audit Question The PIR operating experience reports for several AMPs include PIRs up to 2004 only. Please provide additional PIRs issued during 2005 and 2006 pertinent to the respective AMPs.

Final Response

PIRs through PIR 20051006 dated April 12, 2005 (in AMP B.2.1.32 Structures Monitoring) were reviewed for AMP 10 element evaluations. PIRs for the remainder of 2005 and all of 2006 were reviewed to identify PIRs that explicitly identify an aging effect or identify an AMP issue that can be attributed to managing an aging effect. Results of the review were made available during the AMP audit.

Staff Evaluation

The applicant provided the requested information during the second on-site audit.

Question No AMPA111 LRA Sec 92-B.2.1.21
Audit Question Please provide additional details to supplement the Operating Experience in the LRA for WCGS AMP B2.1.21, Flux Thimble Tube Inspections:

A) When was inspection in accordance with NRC IE Bulletin 88-09 first performed at WCGS?

B) Has inspection using eddy current testing been performed on every flux thimble at every outage since such testing was first begun?

C) The Operating Experience in the LRA states that eleven flux thimble tubes have been replaced and that ten were replaces with chrome plated tubes in identified wear areas which are more wear resistant. Why was

the eleventh flux thimble tube not replaced with more wear resistant material in wear areas? What was the material of construction for the eleventh flux thimble tube replacement?

D) Please provide a summary of additional operating experience from the Fall 2006 refueling outage.

Final Response

A) The first thimble tube inspection using eddy current testing (ECT) with recorded wear results was performed during Refuel 4, Spring 1990.

B) Eddy current testing has been performed on every flux thimble at every outage since such testing was first begun.

C) The ten thimbles replaced due to thimble wall thinning were ordered with the chrome plating and available for replacement during RF12. However, during cycle 12, after the new chrome plated thimbles had been ordered, thimble J08 developed an obstruction which would not allow the incore detector to traverse the thimble. The eleventh thimble, J08, was replaced due to the obstruction, and not due to through wall wear. Since a chrome plated thimble was not available and thimble wear was not a concern for this thimble, an available thimble of original design and manufacturing was used to replace the obstructed thimble.

D) All 58 thimbles were ECT inspected during Refuel 15, Fall 2006. All thimbles met acceptance criteria for an additional cycle of operation. No thimble tubes were repositioned or replaced.

Staff Evaluation

The applicant provided additional details with regard to operating experience with the Flux Thimble Tube Inspection Program. The staff finds the applicant's response acceptable for the following reasons:

a) Eddy current testing, which is recommended in the GALL Report, has been performed on

b) Testing has been able to identify degraded conditions in sufficient time for corrective actions to be taken before failure of the flux thimbles occurs. On this basis, the operating experience supports a conclusion that the acceptance criteria are sufficiently conservative.

c) The applicant's test results are consistent with results from similar testing at other plants. There have been no aging or rate-of-aging effects identified that are unique to WCGS.

Question No AMPA112 LRA Sec 93-B.2.1.10

Audit Question B.2.1.10-3: The 'monitoring and trending" element enhancement states that new periodic preventive maintenance activities will be developed to specify performing inspections of the internal surfaces when valves are disassembled for operational readiness inspections. However, the "acceptance criteria" element is not enhanced to indicate that new acceptance criteria will be developed for these new inspections. Please

explain where the acceptance criteria for these new inspections will be provided.

Final Response

As stated in Sections A1.10 and B2.1.10 of the LRA, a new periodic Preventive Maintenance activity will be developed to specify performing inspections of the internal surfaces of valve bodies and accessible piping while the valves are disassembled for operational readiness inspections. The acceptance criteria will be specified in this Preventive Maintenance activity.

Section A1.10 of the LRA and LRA commitment number 3 for the Closed-Cycle Cooling Water System (RCMS 2006-200) will be amended to include the following statement: “The acceptance criteria will be specified in this Preventive Maintenance activity.”

Section B2.1.10 of the LRA in the Enhancement for Monitoring and Trending - Element 5, the paragraph will be amended as follows:
"A new periodic preventive maintenance activity will be developed to specify performing inspections of the internal surfaces of the valve bodies and accessible piping while the valves are disassembled for operational readiness inspections to detect loss of material and fouling. The acceptance criteria will be specified in this Preventive Maintenance activity."

Staff Evaluation

The staff finds the applicant's response acceptable because the acceptance criteria is specified in the enhanced preventive maintenance activity, as documented in the Commitment No. 3 of the LRA Amendment 4, dated October 11,2007.

Question No AMPA114 LRA Sec 95-B.2.1.26

Audit Question In WCGS-AMP-B.1.2.26, Revision 1, Section 3.10 under Operating Experience, you have stated that a review of plant operating experience history determined that water has accumulated in cable manholes. In 2004, the cable manholes for the in-scope medium voltage cables exposed to significant moisture simultaneously with significant voltage were inspected for degradation of the cable support member to water.

However, in PIR No. 19981790, you have stated that you identified a substantial amount of water in Man-Hole 119. This manholes contain 13.8 kV cable that go to the circulation water. This manhole also does contain other in-scope of medium-voltage cables. It appears that no corrective action was taken and an evaluation was performed and concluded that cable was o.k. to be submerged. If these cables are allowed to be wet for a period of time, there is a possibility of cable degradation that can effect their safety-functions during the current and period of extended operation. Describe corrective actions taken to address water problem in manholes. Will Procedure MPE CI-004 be implement during the current and during period of extended operation?

Final Response

The evaluation of PIR 1998-1790 was based on the criteria available at that time. Since 1998 additional guidance and information has become available. Based on this information, Wolf Creek initiated a preventive maintenance (PM) program to inspect applicable manholes containing medium-voltage cables. This PM program was revised to include information from draft procedure MPE CI-004. This inspection includes removal of water, if required, visual inspection for corrosion and degradation of cable tray supports and visual inspection for cable jacket degradation. Procedure MPE CI-004 will be implemented before the period of extended operation.

Staff Evaluation

The project team initially accepted the applicant response, based on applicant's corrective action program that has initiated a preventive maintenance (PM) program to inspect applicable manholes containing medium-voltage cables. However, during a regional inspection in September 2007, water was found in the emergency service water (ESW) cable manholes. These cables are within the scope of license renewal. In light of this operating experience, the project team is concerned that cables that were submerged for a period of time may not perform their intended functions during the period of extended operation. The inspection and water removal frequency of at least once every two years as proposed in the applicant's Inaccessible Medium-Voltage Not Subject to 10 CFR 50.49 Environment Qualification Program may not be adequate to detect water accumulation in the manholes. The project team will continue to resolve this issue with the specialists in the appropriate NRC groups. (OI-3.0.3.1.10-2)

Question No AMPA115 LRA Sec 96-B.2.1.26
Audit Question Describe a program used to capture internal and external plant operating experience issues.

Final Response

Wolf Creek's existing corrective action program captures internal and external plant operating experience issues.

Staff Evaluation

The staff finds that applicant response acceptable because corrective action program will ensure that operating experience is reviewed and incorporated in the future so that the effects of aging are adequately managed.

Question No AMPA118 LRA Sec 97-B.2.1.36
Audit Question GALL XI.E6 states that the specific type test is to be a proven test such as thermography, contact resistance testing, or other appropriate testing justify in the application. In addition, EPRI TR-104231, "Bolted Joint Maintenace & Application Guide," recommend measure contact resistance using low ohm meter to detect loose connections. In B2.1.36, you states that infrared thermography testing is used to identify loose connection. Explain how thermography is an effective method for detecting loose connections or high resistance for cable connections in low current or low load circuit where temperature rise may not be detectable.

Final Response

LRA sections B2.1.36 and A1.36 will be amended to include contact resistance testing, or other appropriate testing methods for low voltage low current or low load circuit.

Staff Evaluation

The staff finds the applicant response acceptable because contact resistance testing is effective for low voltage, low current, or low load circuit. Thermography may not be effective to detect high resistance for cable connections in low voltage, low load, and low current circuits.

Question No AMPA119 LRA Sec 98-B.2.1.36

Audit Question GALL XI.E6 states that the location (high temperature, high humidity) be considered for cable connection sampling. In AMP B2.1.36, you have stated that the selected sample include plant indoor air environment. Explain how aging effect of loose connections and/or high resistance due to corrosion are not a potential aging require management for electrical cable connections in outdoor environment.

Final Response

LRA section B2.1.36 will be amended to include electrical cable connections in outdoor air.

Staff Evaluation

The staff finds the applicant response acceptable because the cable connections in outdoor environment are now included within the scope of this program and will be inspected. This environment is consistent with GALL Report.

Question No AMPA120 LRA Sec 99-B.2.1.26

Audit Question ISG-2 states, in part, that restoration of offsite power paths be included in the scope of license renewal. These paths typically consist of the first breaker in the switchyard to the start up transformers to the safety-related 4.16 kV buses. The scope of your Inaccessible Medium Voltage Cables not Subject to 10 CFR 50.49 EQ requirements only include underground cables from disconnection switch 13-23 to ESF transformer to 4.16 kV safety buses. It does not include underground cables from secondary side of transformer No. 7 to disconnection switch 13-23 which provide the remaining part for SBO restoration. When underground cables are subject to water tree, no matter how many redundancy path it have, common mode failures may occur to all underground cables. If the underground cables connecting disconnect switch 13.23 are not managed/tested, provide your technical justification how you satisfy with ISG-2 to ensure that SBO restoration paths are maintained during the extended period of operation.

Final Response

The WCGS per ISG-2 includes in the scope of License Renewal two paths of SBO restoration power. The WCGS connections to the switchyard are through disconnects not circuit breakers. One path is from disconnect 345-163 via overhead lines to the station start-up transformer. The other path is from disconnects 13-21 or 13-23 via underground cable to the station ESF transformer. This configuration conforms to the requirement of Criterion 17 that states, “the onsite electrical distribution system shall be supplied by two physically independent circuits designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions.”

The entire WCGS plant system portion of the SBO restoration power system is within the scope of license renewal. This is consistent with ISG-2 Staff Position which states “Consistent with the requirements specified in 10 CFR 54.4(a)(3) and 10 CFR 50.63(a)(1), the plant system portion of the offsite power system should be included within the scope of license renewal”. The 345KV switchyard system equipment beyond disconnect 345-163 and the 13.8KV switchyard system equipment beyond disconnects 13-21 and 13-23 including the 13.8KV switchgear, circuit breaker 13-48, transformers No4/No 5/No. 7 and the underground cables are part of the offsite transmission system (grid) and are not part of the plant system portion of offsite power and therefore not within the scope of License Renewal. Westar Energy is the owner of the Wolf Creek switchyard and is responsible for switchyard equipment design, operations and maintenance.

Staff Evaluation

The staff found the applicant response unacceptable. Appendix A of 10 CFR 50, GDC-17 requires that the onsite electrical distribution system shall be supplied by two physically independent circuits designed and located so as to minimize the extend practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. The staff's position in ISG-2 is that physically independent power paths are maintained for SBO restoration for offsite power during extended period of operation. The staff clearly defined the plant's system boundary of the offsite power system. The offsite power systems consist of a transmission system (grid) component that provides a source of power and a plant system component that connects that power source to a plant's onsite electrical distribution system which powers safety equipment. The staff has historically relied upon the well-distributed system which powers safety equipment of the grid to provide necessary level of reliability to support nuclear power plant operations. For the purposes of the license renewal rule, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of license renewal. This path includes the switchyard circuit breakers that connect the offsite system power transformers (startup transformers), the transformer themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical distribution system, and the associated control circuits and structures. Ensuring that the appropriate offsite power system long-lived passive structures and components that are part of this circuit path are subjected to an aging management will assure that the bases underlying the SBO requirements are maintained over the period of the extended license. This is consistent with the Commission's expectations in including the SBO regulated event under 10 CAR 54.4(a)(3) of the license renewal rule. Managing only a portion of independent power path (the equipment beyond disconnect switches 13-21 and 13-23) does not satisfy the staff's position in IS-2. The fact that Wester Energy is the owner of the Wolf Creek switchyard does not preclude the applicant from managing the complete circuit paths as defined in ISG-2. (OI-3.0.3.1.10-1)

Question No AMPA121 LRA Sec 100-B.2.1.9

Audit Question During review of operating experience, it was noted that in PIR 20020407 there was degradation discovered during visual examination that appeared to be resulting from de-alloying in the Emergency Diesel Generator Heat Exchanger train "A" tubing (copper alloy C44300). Subsequent eddy current testing revealed multiple degradation indications. Metallurgical evaluation of the tubing showed no de-alloying. Most indications were identified as erosion-corrosion. One indication was a stress corrosion crack. SCC of copper alloys is usually associated with ammonia or polluted waters. Please provide the details of augmented inspection, trending, mitigation etc. resulting from this degradation incident.

Final Response

There was one indication in the Emergency Diesel Generator Intercooler Heat Exchanger that was called a stress corrosion crack. It was an axial crack. The exact initiation mechanism could not be conclusively established since the original ID surface was lost due to flow-assisted corrosion.

On-going corrective actions include preventive maintenance to eddy current test, analyze the data, and take corrective actions for any tubes that do not meet acceptance criteria.

Also, the Emergency Diesel Generator Heat Exchangers are being replaced with AL6X tubing material. The Intercooler Heat Exchangers were replaced during RF15, in 2006. The Lube Oil Coolers are targeted for replacement in RF16, in 2008 or during a planned maintenance outage at power. The Jacket Water Coolers are targeted for replacement in RF18, in 2011 or during a planned maintenance outage at power.

Staff Evaluation

The staff found the applicant response acceptable because on-going eddy current examinations and preventive maintenance will identify any new degradation and heat exchangers with copper alloy tubing have been or are scheduled to be replaced with heat exchanger AL6X stainless steel tubing. AL6X stainless steel is highly resistant to pitting and crevice corrosion and SCC in raw water including water contaminated with ammonia.

Question No AMPA122 LRA Sec B.2.1.9

Audit Question During review of operating experience, it was noted that in PIR 20040688 that there was an increase in leakage trend in the Electrical Pen Room cooler, the RHR Pump "A" cooler, the CCP "A" Room cooler and the Containment Air "D" Cooler. What was the cause of the leaks? What actions are being taken to address the increased leak trend?

Final Response

About half of the room cooler leaks are the result of an isolated pit going through wall in the tubing. In the remaining half of the leaks, we encountered through wall pitting combined with some flow erosion in the H-bend areas. Tubes with deep through wall pitting were allowed to

remain in service because past Eddy Current acceptance criteria allowed it. The Eddy Current acceptance criteria was changed and past ECT data was reviewed to select room coolers for replacement. The RHR pump "A" cooler leak caused a lot of unavailability time and Room Coolers were declared a Maintenance Rule (a)(1) issue. Corrective action consists of changing out degraded coolers. Out of sixteen total room coolers, eleven have been replaced, three are scheduled to be replaced by RF16 (2008) and the remaining two are being targeted for replacement by the end of 2008. New cooler bundles are procured with AL6XN tube materials.

On-going actions include preventive maintenance to eddy current test, analyze the data, and take corrective actions for any tubes that do not meet acceptance criteria.

Containment Air "D" Cooler
The failure mechanism of pitting and erosion for the tubes and U-bends is assumed to be consistent with other copper nickel tube bundles in the room coolers. This assumption is based on same materials and same water source being used in the containment coolers and the room coolers. Apparent cause is planned for the tube bundles being replaced in RF16 (2008). Future corrective actions will be based on the apparent cause.

Due to the configuration of these coolers, eddy current testing is not possible. Flow and dP and heat transfer capability are periodically verified per Wolf Creek's commitment to Generic Letter 89-13. Any leakage is detected early by continuous monitoring leak detection systems.

Staff Evaluation

The staff found the applicant response acceptable because degraded room cooler tube bundles will be replaced with AL6X stainless steel. AL6X stainless steel is highly resistant to pitting and crevice corrosion and SCC in raw water including water contaminated with ammonia.

Question No AMPA123 LRA Sec

Audit Question There is no aging management program to manage the aging of coatings. Please justify not having an aging management program for coatings. The failure of coatings could result in aging effects for the steel shell in containment. The failure of coatings could also result in the failure of safety systems to perform their intended functions (for instance, safety injection).

Final Response

Coatings of the Wolf Creek Reactor Building steel liner are not within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3). Coatings of the Wolf Creek Reactor Building steel liner do not have an intended function.

LRA Table 3.5.2-1 notes that consistent with GALL line item II.A1-11, loss of material due to general, pitting, and crevice corrosion of the Wolf Creek Reactor Building steel liner is managed by AMP B2.1.27, ASME Section XI Subsection IWE. The coated surfaces of the Wolf Creek Reactor Building liner are visually examined by AMP B2.1.27, ASME Section XI Subsection IWE as an indication of the condition of the steel surfaces underneath the coating. Reactor Building ASME Code Section XI, IWE 3510.2, "Visual Examination of Coated and Non-coated areas," states that "The condition of the inspected area is acceptable if there is no evidence of damage

or degradation which exceeds the visual acceptance criteria specified by the Owner." Detailed visual examination acceptance criteria at Wolf Creek identifies the following conditions as rejectable for coated surfaces:

- Cracking
- Flaking
- Blistering
- Peeling
- Discoloration
- Deformation
- Other signs of distress

All rejectable indications require initiation of a Non-Conformance Report (NCR) and evaluation in accordance with the WCGS corrective action process.

The effects of containment debris on the intended function of the RHR & Containment Spray sump screens is being addressed by industry efforts to resolve GSI-191. The contribution of coatings to the containment debris is event driven and is not related to aging.

Staff Evaluation

The staff agreed that since there are no GALL line items that specify the use of the coatings aging management program, there is no need to have a coatings aging management program. Rather, the aging of coatings in containment will be managed using the AMP B2.1.27, ASME Section XI, Subsection IWE aging management program. The staff's position on this issue concerning the requirement for an aging management program for coatings was discussed with the NEI and nuclear industry, during the meeting held on July 25, 2007.

Question No AMPA124 LRA Sec B.3.1

Audit Question In elements "Detection of aging effects" and "corrective action program", the application states that action levels of the Fatigue Management Program will be enhanced to ensure that… Please explain what you mean by action levels.

Final Response

The WCGS Fatigue Management Program provides for periodic evaluation (once per operating cycle) of fatigue usage and cycle count tracking of critical thermal and pressure transients to verify that design limits on fatigue usage will not be exceeded. The program will be enhanced to include action limits (values for accrued transient cycles and calculated cumulative fatigue usage (CUF) that require initiation of corrective actions) and definition of acceptable corrective actions that may be implemented to assure that ASME Code limits on CUF are not exceeded. For locations identified in NUREG/CR-6260, action limits will be based on fatigue usage calculated including the environmental effects of the reactor coolant.

1. Cycle Count Action Limits:

A limit will be established that requires corrective action when the cycle count for any of the critical thermal and pressure transients is projected to reach a high percentage (e.g., 90%) of the

design specified number of cycles before the end of the next operating cycle. Appropriated corrective actions if this limit is reached include:

a. Review of fatigue usage calculations to determine whether the transient in question contributes significantly to CUF or to identify the components and analyses (e.g., HELB screening calculations and LBB crack propagation) that are affected by the transient in question.
b. Evaluation of remaining margins on CUF based on cycle based or stress based CUF calculations using the fatigue monitoring program software.
c. Redefinition of the specified number of cycles (e.g., by reducing specified numbers of cycles for other transients and using the margin to increase the allowed number of cycles

for the transient that is approaching its specified number of cycles).

2. Cumulative Fatigue Usage Action Limits:

A limit will be established that requires corrective action when calculated CUF (from cycle based or stress based monitoring) for any monitored location is projected to reach 1.0 within the next 2 or 3 operating cycles. Appropriate corrective actions if this limit is reached include those listed below. These corrective actions are equally applicable to WCGS NUREG/CR-6260 locations with consideration of the environmental effects of reactor coolant.

a. Determine whether the scope of the monitoring program must be enlarged to include additional affected reactor coolant pressure boundary locations, to ensure that other locations do not approach design limits without an appropriate action.
b. Enhance fatigue monitoring to confirm continued conformance to the code limit.
c. Repair the component.
d. Replace the component.
e. Perform a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded.
f. Alter plant operation to reduce the rate of fatigue usage accumulation rate.
g. Perform a flaw tolerance evaluation and impose component-specific inspections.

LRA Chapter 4.3.1, Appendix A.2.1, and Appendix B.3.1 will be amended to conform to this response.

Staff Evaluation

In its response the applicant provided details on action levels and corrective actions. On the basis that appropriate action limits and associated corrective actions have been defined, the staff finds the enhancement acceptable. The applicant has amended LRA Section 4.3.1, Appendix A.2.1, and Appendix B.3.1 as stated above through LRA Amendment 1, dated June 1, 2007.

Question No AMPA125 LRA Sec B.3.1

Audit Question In elements "detection of aging effects" and "corrective action program", the application states that corrective actions of the Fatigue Management program will be enhanced to ensure that… Please clarify where these corrective actions are identified?

Final Response

The response to AMPA124 describes action limits that will be incorporated into the fatigue monitoring aging management program and specifies the corrective actions that are appropriate in response to each action limit.

Staff Evaluation

In its response the applicant provided details on action levels and corrective actions. On the basis that appropriate action limits and associated corrective actions have been defined, the staff finds the enhancement acceptable.

Question No AMPA126 LRA Sec B.2.1.22

Audit Question Please explain why the pertinent operating experience related to internal surface inspections of piping and ducting components that may have been performed during the plant maintenance and surveillance activities is not included in the operating experience section of the LRA? Currently, no operating experience has been included.

Final Response

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program. Therefore no programmatic operating experience has been gained.

The Inspection of Internal Surfaces Program will be implemented via existing predictive maintenance, preventive maintenance, surveillance testing and periodic testing work order tasks. Such tasks have been in place at Wolf Creek since the plant began operation. These activities have proven effective at maintaining the material condition of systems, structures, and components and detecting unsatisfactory conditions. A review of PIRs from 1995 to 2006 for HVAC components in the scope of license renewal and within the scope of this AMP did not identify any loss of intended functions due to loss of material in HVAC ducting, nor hardening and loss of strength associated with elastomers used in HVAC flexible connections. Operating experience from mechanical components in other mechanical systems (non-HVAC) within the scope of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting components AMP will be reviewed during implementation of the AMP prior to the period of extended operation.

System Engineers review operating experience for possible impact to the equipment in their systems. The basis for parameters monitored and inspection intervals is based on vendor recommendations, historical performance, and industry wide operating experience. The new program will be reviewed to account for industry and station operating experience.

Staff Evaluation

The staff finds the applicant's response acceptable because the response includes adequate explanation that applicant's new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will be reviewed by the applicant to account for the industry and the plant experience.

Question No AMPA127 LRA Sec B.2.1.22

Audit Question NUREG-1801, element 6 recommends that indications of various corrosion mechanisms or fouling that would impact component intended function are reported and will require further evaluation. Does the WCGS aging management program include monitoring of fouling? If not, please justify why this is not an exception to element 6 of NUREG-1801?

Final Response

Monitoring for fouling was not included because it was not identified as an aging effect for any component currently in scope for this AMP. The LRA will be amended to reflect this fact and to eliminate any concern that this might be an exception.

The first sentence of LRA Section A1.22 will be amended to state: "The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages cracking, fouling, loss of material and hardening - loss of strength."

LRA Section B2.1.22 will be amended as follows:
The first sentence changed and a second sentence added to state: "The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages cracking, fouling, loss of material and hardening - loss of strength. Fouling has not been identified as an aging effect in any component currently in scope for this AMP."

The Wolf Creek comparison to NUREG-1801 under section 2.1 of WCGS-AMP-B2.1.22 is amended as follows:
The first sentence changed and a second sentence added to state, "The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages cracking, fouling, loss of material and hardening - loss of strength. Fouling has not been identified as an aging effect in any component currently in scope for this AMP."

Staff Evaluation

The staff finds the applicant's response acceptable because the applicant amend the applicable sections of the LRA and applicant's document number WCGS -AMP-B2.1.22 to address monitoring of fouling as recommended by NUREG-1801 in LRA Amendment 3, dated June 1, 2007.

Question No AMPA128 LRA Sec B.3.2

Audit Question Provide examples of operating experiences showing that the Environmental Qualification (EQ) of Electrical Components Program has succeeded in managing aging degradation in a timely manner. Also, describe any corrective action or program enhancement as a result of these operating experiences.

Final Response

The WCNOC Preventative Maintenance (PM) program manages age related replacement / refurbishment of equipment and surveillance activities based on a schedule dictated by the

WCNOC EQSD-III document. Any unexpected adverse conditions that are identified during operational and maintenance activities in regards to aging degradation issues would be managed through the plant's corrective action program or via work orders generated and assigned to the EQ Program Engineer. The EQ Program Engineer also reviews and evaluates industry operating experience and other sources of information (such as Scientec's monthly newsletter) for applicability to WCNOC, and where necessary implements the necessary corrective actions.

No examples of age related failures of EQ equipment could be identified for the life of the plant. There are several examples of industry operating experience that were reviewed that required

no action due to already sufficient requirements, such as identified in PIR 2002-2756 ("Normally Energized ASCO Solenoid Valves (SOV) That Are in Service Beyond Their Qualified Life") and ITIP 5025 (generated for NRC Regulatory Issue Summary 2003-09 "Environmental Qualification of Low-Voltage Instrumentation and Control Cables"). There is reasonable assurance that the existing WCNOC EQ Program is sufficient, and able to manage age related issues prior to actual equipment failures.

Staff Evaluation

The staff finds the applicant response acceptable because the existing EQ program is sufficient and is adequate in managing aging degradation in a timely manner.

Question No AMPA129 LRA Sec B.3.2

Audit Question Provide a sample of electrical components in EQ master list including EQWP J-361A for high-range radiation monitor cables. These cable were excluded from the scope of AMP B2.1.25. Also, provide a sample of maintenance performed on some EQ electrical components to maintain their qualified life.

Final Response

Provided hard copy of pages 65 and 66 of the EQ master document EQSD-II (Revision 25). This document identifies how Wolf Creek classifies the components in regards to the accident conditions along with room locations and environments. These two pages include the high radiation monitor components (J-361A) along with some other components.

Provided the first five pages of EQSD-III (Revision 8) that shows the replacement/refurbishment schedule for the age restricted parts of valve ABHV0011. In addition to these sheets four pages from a sample Work Order (WO 98-128835-001) are provided. This WO performed the EQ maintenance activity for valve ABHV0011. These pages identify the WO number and the scope of the work.

Staff Evaluation

The staff finds the applicant response acceptable because the sample of EQ components showed how the applicant maintained a list of electrical components in the EQ master list. The

sample also showed that maintenance is performed on EQ electrical components to maintain the qualified life.

Question No AMPA130 LRA Sec B.3.2

Audit Question Under "acceptance criteria" element, you have stated that an enhancement will be made to be consistent with GALL's acceptance criteria element. Specially, the enhancement states that the program documents will be enhanced to describe methods that may be used for qualified life evaluation for the period of extended operation. Describe methods that may be used for qualified life evaluation for the period of extended operation. How these methods are consistent with GALL's AMP X.E1 under the "acceptance criteria" element.

Final Response

LRA sections A2.3 and B3.2 and LRA commitment number 22 for Environmental Qualification of Electrical Components (RCMS 2006-219) will be amended to remove the stated enhancement. The current WCGS EQ program methods will be used for qualified life evaluation in the period of extended operation.

Staff Evaluation

The staff found the applicant response acceptable because current Environment Qualification of Electrical Component Program per 10 CFR 50.49 requirement already includes methods for extending the qualified life of EQ electrical components. If the qualification life cannot be extended, the EQ electrical component will be replaced or refurbished.

Question No AMPA131 LRA Sec B.3.1

Audit Question In LRA Section B3.1, the applicant credited an enhancement “confirmation process” program element stating that “The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to invoke Appendix B procedural and record requirements.” However, the enhancement description provided in Commitment No. 21, item 4, is different. Clarify this discrepancy and justify the differences between the enhancement description in the LRA and the one in the commitment list.

Final Response

WCGS will supplement LRA Appendix A2.1 and Appendix B3.1 as described in the response to AMPA124.

Commitment No. 21, Item 1 corresponds to the first bullet of LRA Appendix A2.1 and to the first paragraph of LRA Appendix B3.1 under "Enhancements," "Detection of Aging Effects, Element 4, and Corrective Actions - Element 7."

Commitment No. 21, Item 2 corresponds to the second bullet of LRA Appendix A2.1 and to the second and third paragraphs of LRA Appendix B3.1 under "Enhancements," "Detection of Aging Effects, Element 4, and Corrective Actions - Element 7."

Commitment No. 21, Item 3 corresponds to the third bullet of LRA Appendix A2.1 and to the fourth paragraph of LRA Appendix B3.1 under "Enhancements," "Detection of Aging Effects, Element 4, and Corrective Actions - Element 7."

Commitment No. 21, Item 4, "10 CFR 50 Appendix B procedural and record requirements," corresponds to the fourth bullet of LRA Appendix A2.1 and to LRA Appendix B3.1, "Enhancements," "Confirmation Process - Element 8."

These are consistent.

The sentence following Commitment No. 21, Item 4 should be a separate paragraph:

"Prior to the period of extended operation, changes in available monitoring technology or in the analyses themselves may permit different action limits and action statements, or may re-define the program features and actions required to address the fatigue time-limited aging analyses (TLAAs)"

This sentence anticipates future events that may require adjustments to the program. It applies to the first three of these items, not to Item 4. WCGS does not anticipate any future events that would affect the commitment to 10 CFR 50 Appendix B procedural and record requirements.

Staff Evaluation

In its response the applicant stated that the sentence following Commitment No. 21, Item 4 should be a separate paragraph:

This sentence anticipates future events that may require adjustments to the program. It applies to the first three of these items, not to Item 4. WCGS does not anticipate any future events that would affect the commitment to 10 CFR 50 Appendix B procedural and record requirements.

The staff finds the applicant response acceptable because the commitment to the 10 CFR 50 Appendix B procedural and record requirements is still valid for future events.

Question No AMPA132 LRA Sec B.2.1.21

Audit Question WCGS' letter WM 89-0015, "Response to NRC Bulletin 88-09," dated January 18, 1989, states, in part, "The thimble tube inspection program requires that of [sic] any tubes with wall loss of 60 percent or more be removed from service."

The Flux Thimble Tube Inspection Program implementing procedure RXE 03-006 states "Any thimbles with wear in an active location greater than 60 percent through wall or projected to be greater than 60 percent before next outage should be repositioned.." It also states, "Any thimbles with wear greater than 80 percent through wall or projected to be greater than 80 percent before next outage shall be capped, or equivalent, and considered for future replacement."

GALL AMP XI.M37, under "acceptance criteria" program element, states "Acceptance criteria different from those previously documented in NRC acceptance letters for the applicant's response to Bulletin 88-09 and

amendments thereto should be justified."

a. Provide a technical justification for the change from 60 percent to 80 percent through wall wear criteria for removing a flux thimble tube from service.

b. Address whether the 80 percent acceptance criteria includes the allowances for uncertainties that are recommended in the GALL Report and whether the methodology for projecting wear for the following operating cycles is conservative.

Final Response

a. WCAP-12866, Bottom Mounted Instrumentation Flux Thimble Wear, was used to justify the change from 60% to 80% through wall wear criteria at Wolf Creek for removing flux thimble tubes from service. Appendix A of WCAP-12866 provides the results of pressure testing and a finite element analysis and determined the maximum allowable wall loss. Based on the Westinghouse tests results, it was conservatively determined that a flux thimble can remain in service with up to 80% wall loss. The 80% wall loss acceptance criteria will maintain the structural and functional integrity of the flux thimble tubes and the flux thimble tubes can remain in service up to 80% wall loss.

It is noted that Wolf Creek procedures address corrective actions at 60% indicated wall loss to prevent further through wall loss by wear.

b. Based on the Westinghouse tests, eddy current data over estimates the depth of actual wear scars. Using eddy current thimble wear data to predict wear will result in very conservative predictions of wall loss. Although the WCAP states, " it is not necessary to add additional uncertainty margin to the eddy current wall loss indications...," Wolf Creek uses an uncertainty margin of 5% for conservatism.

Conservatism of the methodology for projecting wear for the following operating cycles is confirmed by WCAP test data that exhibits an exponentially decreasing curve of flux thimble wall loss versus operating time.

Staff Evaluation

The applicant provided additional discussion of the technical basis for the acceptance criteria in the Flux Thimble Tube Inspection program. The staff reviewed the detailed test data and evaluations provided in WCAP-12866. The staff noted that the test results provided in WCAP-12866 are applicable for the applicant's flux thimble tube designs and operating environment, and that based on the test results the 80 percent through-wall loss acceptance criterion is adequate because it includes appropriate conservatism to ensure that structural and functional integrity of the flux thimble tubes will be maintained. On this basis, the staff finds that the applicant has adequate technical justification for the change in the acceptance criterion from what was previously documented in the applicant's response to Bulletin 88-09 and that the applicant's use of an 80 percent through-wall loss criterion for removing a thimble tube from service by capping or equivalent is acceptable. The staff notes that the applicant's original response to Bulletin 88-09 did not provide any specific criteria for repositioning the flux thimble tubes to prevent further through-wall wear in an already worn location; therefore, the addition of such a criteria is an added corrective action relative to what was described in the applicant's

original response. On this basis the staff finds that the applicant's acceptance criteria has an adequate technical basis and is consistent with the recommendations of the GALL Report.

Question No AMPA133 LRA Sec B.2.1.21
Audit Question Provide the limit on maximum number of flux thimble tubes that can be removed from service. Explain what is the basis for that limit.

Final Response

The maximum number of thimbles that can be removed from service can be as high as 14 as specified in the basis for Technical Requirement (TR) 3.3.10 Movable Incore Detectors:

"TR 3.3.10 specifies that the Movable Incore Detection System shall be OPERABLE. OPERABILITY with greater than or equal to 75% of the detector thimbles, a minimum of two detector thimbles per core quadrant, and sufficient movable detectors, drive, and readout equipment to map these thimbles ensures that measurements obtained from use of this system accurately represent the spatial neutron flux distribution of the core when the system is used for the specified activities"

Although TR 3.3.10 permits as many as 14 (25%) of the 58 thimbles to be out of service, Wolf Creek strives to maintain all thimbles operable and takes timely corrective actions to return inoperable thimbles to service as soon as practical. In Refuel 11 Wolf Creek had to cap two thimbles. Those two thimbles and nine additional thimbles were replaced in the next refueling outage (Refuel 12) per WO 00-221918-000. That was the only time to date that thimbles were removed from service (capped) due to fretting wear.

Staff Evaluation

The applicant provided additional information with regard to operability requirements for flux thimble tubes. The staff finds the applicant's response acceptable because it provides a detailed answer to the question asked. The maximum number of flux thimbles that can be removed from service is specified in the Technical Requirements Manual and is part of the CLB; this limitation will not be changed during the period of extended operation.

Question No AMPA134 LRA Sec B.2.1.4
Audit Question Within the Boric Acid Corrosion Monitoring Program, WCGS is treating fasteners too difficult to remove for engaged thread inspection as "seized" in the context of being interference fit or staked to prevent backing out. This practice is based on an interpretation of a footnote on page 4 of NRC inspected in place." As a result, the engaged threads of certain stuck fasteners designed to be removable, but are difficult to remove, are not being inspected as required by ASME Section XI.

Are these fasteners being inspected in place? If not, has WCGS requested relief from the Section XI requirement?

Final Response

This question originated from a review of WCGS OE. PIR 1997-3658 problem initiation stated that within the Boric Acid Corrosion (BAC) Monitoring Program, WCNOC is treating fasteners too

difficult to remove for engaged thread inspection as "seized" in the context of being interference fit or staked to prevent backing out. This practice is based on an interpretation of a footnote on page 4 of NRC IE Bulletin 82-02, which states "fasteners seized or designated with interference fit may be inspected in place." As a result, the engaged threads of certain stuck fasteners designed to be removable, but are too difficult to remove, are not being inspected as required by ASME Section XI.

The PIR resolution is as follows:

"The statement within this PIR which implies that this is an ASME Section XI inspection is incorrect. The inspection was required by NRC Bulletin 82-02 which stated that Section XI acceptance criteria was to be utilized. The Bulletin also stated that fasteners which were seized or interference fit could be inspected in place. This indicates that either excessive force would be required to remove the fastener (seized) or the fastener was designed to be difficult to remove or back out (interference fit). In either case this allowance is technically justified when considering that a borated water path into the fastener threads would have to begin at an exposed surface. Also, boric acid corrosion needs oxygen which also is not present in sufficient quantities internal to a seized fastener. Both the borated water path and oxygen supply would be present at the exposed surface of the fastener thus the Bulletin was correct in allowing such fasteners to be inspected in place."

Based on the above, seized or interference fit fasteners are inspected in place, and no ASME relief is required since the BAC AMP inspection is not a code requirement.

Staff Evaluation

The staff finds that the applicant's response is acceptable because the seized or interference fit fasteners are inspected in place, and the inspections are not required by the ASME Code. Therefore, relief from the code requirements is not required.

Question No AMPA135 LRA Sec B.2.1.8

Audit Question The Steam Generator Tube Integrity Program does not indicate that the steam generator feedwater ring is within the scope of the AMP. In LRA Section 3.1.2.2.14 the applicant states that the issue discussed in SRP LR Section 3.1.2.2.14 is not applicable to WCGS; however, the applicant credits the Water Chemistry and Steam Generator Tube Integrity Programs to manage loss of material due to flow accelerated corrosion in the steam generator feedwater inlet rings and supports. Please clarify how the scope of this AMP appropriately provides for inspections of this component and how the inspection method, sample size, and frequency performed will be capable of managing loss of material (wall thinning) due to flow accelerated corrosion in the steam generator feedwater inlet ring.

Final Response

The scope of the Wolf Creek Generating Station (WCGS) Steam Generator Tube Integrity Program is consistent with NEI 97-06, Steam Generator Program Guidelines. NEI 97-06 recommends that secondary side components that are susceptible to degradation be monitored if their failure could affect the intended function of the steam generator. The WCGS Steam

Generator Tube Integrity Program includes the feedwater ring and J tubes as part of the secondary side inspections.

The WCGS Steam Generator Tube Integrity Program provides instructions for visual inspections of the upper steam drum, including the feedwater ring and the J tubes, on at least one steam generator each outage.

Staff Evaluation

The applicant's Steam Generator Tube Integrity Program is consistent with NEI 97-06 as recommended in GALL AMP XI.M18, "Steam Generator Tube Integrity." Therefore, this response is acceptable to the staff.

Question No AMPA136 LRA Sec B.2.1.8

Audit Question Clarify if the Steam Generator Tube Integrity Program has been augmented or enhanced to include inspections of the following commodity groups:

·steam generator feedring and feedring J-tubes
·steam generator flow distribution baffle

·steam generator internal structures - non pressure boundary miscellaneous parts
·steam generator secondary blowdown apparatus

If so, justify why the augmented or enhanced inspections bases for these commodity groups are considered to be capable of managing the applicable aging effect in the applicable AMR items (i.e., cracking, wall thinning, or loss of material).

If the Steam Generator Tube Integrity Program has not been enhanced or augmented to cover these commodity groups, clarify which program will be used to inspect for the applicable aging effects in these commodity groups, and justify why the inspection methods are considered to be capable of managing the applicable effects of concern.

Final Response

The WCGS Steam Generator Tube Integrity Program includes a Secondary Side Condition Monitoring and Operational Assessment that are used to document the secondary side integrity plan. Elements of this integrity plan include secondary side cleanings and secondary side visual inspections. Eddy current analysis is performed to determine sludge and scale build-up. The Eddy current analysis supplements visual inspections to determine the overall condition of the steam generator. Wolf Creek has performed a thorough baseline visual inspection of the secondary side of the steam generators. Wolf Creek operating experience has not identified any aging related failures that resulted in a loss of intended functions for steam generator secondary side components.

Aging management activities for the following commodity groups are included in the secondary side integrity plan:

(1) steam generator feedring and feedring J-tubes

The WCGS Steam Generator Tube Integrity Program manages the aging of the feedring and the feedring J-tubes. See response to AMPA135. The justification for managing the aging effect of wall thinning of the feedring is provided in the response to the Audit Question AMRA015. The management of the aging effects of cracking and loss of material for the J-tubes is consistent with the steam generator anti-vibration bars evaluated by GALL lines IV.D1-14 and IV.D1-15.

(2) steam generator flow distribution baffle

According to Updated Safety Analysis Report (USAR) 5.4.2.2, the flow distribution baffle serves to minimize the sludge deposit by directing flow to the center of the tube bundle. Eddy current analysis is performed to determine sludge and scale build-up. Sludge accumulation is monitored for areas of concern, including tube support plates and the quatrefoils of the support plates.

(3) steam generator internal structures - non pressure boundary miscellaneous parts

Overall condition of the internal structures is monitored by visual inspection of the secondary side. This includes areas of tube support plates and upper steam drum. The management of the aging effect of loss of material is consistent with the steam generator tube wrapper evaluated by GALL line IV.D1-9.

(4) steam generator secondary blowdown apparatus

Foreign object search and visual inspection are performed for the tubesheet annulus and the blowdown lane. This is performed following sludge lancing or as eddy current inspection data indicates. The management of the aging effects of cracking and loss of material is consistent with the steam generator anti-vibration bars evaluated by GALL lines IV.D1-14 and IV.D1-15.

Staff Evaluation

In the response to this question, the applicant stated that the management of aging for steam generator feedring and feedring J-tubes is consistent with GALL AMP XI.M18, “Steam Generator Tube Integrity.” The management of aging effects of cracking and loss of material for the J-tubes is consistent with GALL lines IV.D1-14 and IV.D1-15 and therefore, are acceptable to the staff.

For the steam generator flow distribution baffle, they minimize the sludge deposit by directing the flow to the center of the tube bundle. Sludge and scale buildup are monitored using eddy current analysis and cleaned up by sludge lancing as necessary. The staff finds this to be normal practice and it is acceptable.

For steam generator internal structures, non pressure boundary, the aging effect of loss of material is managed consistent with GALL line IV.D1-9 and is therefore, acceptable to the staff. The management of aging effects of cracking and loss of material for the J-tubes is consistent with GALL lines IV.D1-14 and IV.D1-15 and therefore, are acceptable to the staff.

Question No AMPA137 LRA Sec B.2.1.6

Audit Question In its response to audit question AMPA008, the applicant provided details of the actions taken to address the erroneous wear rate predictions by the CHECWORKS model as reported in PIR 20002032. The response states that the possible cause of the erroneous predictions could be the backing rings installed during construction.

a) Explain if the EPRI specialist who reviewed the CHECWORKS model agreed with the WCGS position that the erroneous predictions were caused by the backing rings. Provide supporting information.

b) Describe if similar erroneous predictions have been experienced after the modifications to the CHECWORKS model were performed. Explain the specific actions taken by WCGS to assure that the wear rate predictions at other locations with backing rings will be correctly interpreted.

Final Response

a) The Electric Power Research Institute (EPRI) specialist brought on site in August-September of 1999 agreed that the backing rings that were installed at these locations could be the causes for wear in this line and for the erroneous wear rate predictions in the CHECWORKS model.

EPRI was requested to provide technical assistance to flow-accelerated corrosion (FAC) engineering in the evaluation of the WCGS inspection results, at the location equivalent to Callaway's rupture location, and potential applicability to other locations at WCGS. The key objective of the EPRI/WCNOC joint effort evaluation was to identify piping locations for emergent, on-line inspections, in order to detect unexpected pipe wall thinning due to conditions similar to the Callaway failure. Secondary objectives were to look for improvements to the CHECWORKS FAC model and identify additional locations for inspection in future outages.

b) Recent inspections (RF13, 14 & 15) have not identified other locations with high wear.

In August of 1999, the Callaway station had a rupture of a 6-inch drain line from the moisture separator reheater drain tank. Since Wolf Creek is similar to Callaway in design, Wolf Creek performed inspection of the equivalent location of the Callaway failure. In order to determine locations for future inspections, a review of the FAC model in CHECWORKS was performed by EPRI. EPRI completed this review and found no major problem with the Wolf Creek model in the CHECWORKS program. EPRI also provided a list of additional inspection locations. From the inspection performed of the piping in the equivalent location to Callaway's failure, Wolf Creek replaced these components immediately with like-for-like components (Aug. of 1999). In Refueling Outage 12 (RF12, 2002), Wolf Creek replaced the complete line from the control valve to the inlet nozzle of the high-pressure heater; this is approximately one hundred and fifteen feet of pipe, with FAC resistant chrome-moly pipe and without backing rings. Therefore, this portion of piping is no longer considered to be susceptible to FAC.

The CHECWORKS program is an EPRI developed computer program that is used by the

nuclear industry for the prediction of wear in susceptible piping. This program is continually being evaluated and updated by EPRI. EPRI uses input from plants from all over the United States for updates to the program. Wolf Creek upgraded the CHECWORKS program in March 2006, to use the latest version of CHECWORKS (SFA version 2.1) from version 1.0G. The model was verified/updated again at that upgrade.

Adjustments to the CHECWORKS model based on inspection data can be used to assure that the wear rate predictions at other locations with backing rings will be correctly interpreted. The EPRI CHECWORKS software program uses an empirical model to predict FAC wear rates on a component-by-component basis. Once inspection data becomes available the empirical model (CHECWORKS) adjusts its predictions to calibrate the predictions to the field data and determine absolute wear rates. This adjustment method is known as applying the line correction factor (LCF). Therefore, as a good correlation (low LCF) is established, it can serve as the basis for determining the wear status of those components that have not been inspected and indicate that the actual versus predict wear correlate. After each outage the inspection data is incorporated into CHECWORKS program and new wear rate predictions are determined. In Refueling Outages 13, 14 and 15, Wolf Creek inspected on average about 40 to 50 locations each outage that were incorporated into the CHECWORKS model. In general, Wolf Creek has LCF values that indicate a good correlation between the actual and predicted wear. A good correlation is typically indicated by the LCF being within the range of 0.5 to 2.5.

Staff Evaluation

This question was a follow up question on applicant's response to the staff's previous question AMPA008. The staff finds the applicant's response acceptable because the applicant provided details on the subsequent inspections and clarified that no further erroneous predictions were experienced after adjustments based on the collected inspection data were made to the CHECWORKS model.

Question No AMRA001 LRA Sec 3.1

Audit Question LRA Table 3.1.1, item 3.1.1.63, states that this line is consistent with the GALL Report with AMP exceptions.

This line corresponds to GALL Report, Volume 1, Table 1, item 63, which identifies the Inservice Inspection (IWB, IWC, and IWD) as the AMP. This line includes GALL Report Volume 2, item IV.B2-26, lower internal assembly, radial keys and clevis inserts made of stainless steel.

LRA Table 3.1.2-1 does not appear to include any lower internals assembly components that references to LRA Table 3.1.1, item 3.1.1.63; and it does not include any line corresponding to GALL Report, Volume 2, item IV.B2-26. However, It does include a line (page 3.1-62) for "lower internals assembly (clevis insert bolts, radial keys, clevis inserts)" made of nickel alloys, where the aging effect is identified as "loss of material" and the AMP is identified as the Water Chemistry Program.

For the components "lower internals assembly (clevis insert bolts, radial keys, clevis inserts):

a. Explain whether the components are subject to aging effect of loss of material due to wear? Provide a justification for your conclusion.

b. Justify why the Water Chemistry Program by itself would provide adequate aging management for those components.

c. Explain if the components are included within the scope of the ISI Program. If so, clarify under what examination category are they included?

d. Describe any site-specific or industry operating experience with regard to failure of these components that has been identified by WCGS.

Final Response

(a) The clevis insert bolts, radial keys and the clevis inserts are subject to aging effect of loss of material due to wear. LRA Table 3.1.2-1 will be amended to include a new line for clevis insert bolts, radial keys, clevis inserts made of nickel alloy in a reactor coolant environment with an aging effect of loss of material that is managed by the ASME Section XI ISI AMP. The new line will reference GALL Report, Volume 2, item IV.B2-34.

(b) The line in LRA page 3.1-62 for "lower internals assembly (clevis insert bolts, radial keys, clevis inserts)" of nickel alloys with the aging effect of "loss of material" is due to the aging mechanism of pitting and crevice corrosion. Based on GALL Report, Volume 2, item IV.B2-32, the Water Chemistry Program would provide adequate aging management for pitting and crevice corrosion. The new line to be added for item (a) above will rely on the ASME Section XI ISI AMP to manage the aging effect due to wear.

[c] The components are included within the scope of the ISI Program under examination Category of B-N-2 and B-N-3. The clevis, clevis insert, and clevis insert bolts are inspected every 10 years under Category of B-N-2 and the radial keys attached to the core barrel are inspected under Category of B-N-3 with same interval.

(d) There is no operating experience with regard to failure of these components that has been identified by WCGS. They have been inspected three times, once at initial installation, and twice since then. No wear has been detected.

Staff Evaluation

The applicant's response states that the clevis insert bolts, radial keys and clevis inserts in an environment of reactor coolant are subject to the aging effect of loss of material due to wear. By letter dated August 31, 2007, the applicant amended LRA Table 3.1.2-1 to include a new line item as stated in the response. The staff finds this response and the LRA amendment to be acceptable on the basis that the ISI program provides adequate aging management for these components with this aging effect, and the MEAP combination added into the LRA is consistent with the GALL report.

The applicant's response also provided the additional details related to operating experience as requested by the staff, and the staff finds this additional information acceptable.

Question No AMRA002 LRA Sec 3.1
Audit Question GALL Report, Volume 2, Item IV.A2-5, lists a vessel flange leak detection line and recommends a plant-specific AMP be evaluated. This line references to GALL, Volume 1, Table 1, Line 23. LRA Table 3.1.1, item 3.1.1.23, identifies the ASME Section XI ISI, Subsections IWB, IWC and IWD, and Water Chemistry as the plant-specific AMPs. However, item 3.1.1.23 only identifies the following components: "RV penetrations (instrument tubes (top head), high pressure conduits)"

a. Explain why the LRA does not include a vessel flange leak detection line in this item

b. Explain the function and configuration of the components identified as "high pressure conduits"

Final Response

(a) The vessel flange leak detection line is addressed by the RV Closure Head (O-Ring Leak Monitoring Tubes) in LRA Table 2.3.1-1. It is made of nickel alloy, thus is not associated with GALL Report, Volume 2, Item IV.A2-5, which is based on the material of stainless steel. The RV Closure Head (O-Ring Leak Monitoring Tubes) is evaluated with GALL Report, Volume 2, Items IV.A2-14 and IV.A2-18 (see LRA Table 3.1.2-1, page 3.1-43), and is referenced to LRA Table 3.1.1, items 3.1.1.83 and items 3.1.1.65, respectively.

(b) High Pressure Conduits are the guide tubes that enclose the flux thimble tubes from the bottom of the vessel and provide a pressure boundary function for the reactor coolant system.

Staff Evaluation

The applicant clarified that the "high pressure conduits" are the same components that are called "bottom mounted guide tubes" in the GALL Report and that the WCGS O-Ring leak monitoring tubes are made of nickel alloy, not stainless steel as in GALL Report Item IV.A2-5. This clarification is sufficient for the staff to establish that the use of the ISI program and Water Chemistry program to manage the aging effect of cracking due to SSC for the stainless steel bottom mounted guide tubes is acceptable and is consistent with the GALL Report. There also is sufficient information for the staff to determine that the AMR results for the WCGS O-Ring leak monitoring tubes is consistent with the GALL Report. On the basis that the applicable AMR results in the LRA are consistent with the GALL Report, the staff finds the applicant's response to be acceptable.

Question No AMRA003 LRA Sec 3.1
Audit Question GALL Report, Volume 2, items IV.A2-6, IV.A2-7 and IV.A2-8, lists three aging effects for the "control rod drive head penetration - flange bolting" and identifies the AMP as XI.M18, "Bolting Integrity." However, comparable line items have not been found in LRA Table 3.1.2-1:

a. Explain why comparable line items for control rod drive head penetration -

flange bolting is not included in LRA Table 3.1.2-1.

b. If there are comparable line items for control rod drive head penetration -

flange bolting, please identify the material, environment, aging effect(s) and AMP for these components at WCGS.

Final Response

Based on the description of the reactor vessel closure head in USAR 5.3.3.1 and CRDM housing in USAR 3.9(N).4.1, the lower portion of latch housings are seal-welded to the vessel closure head adapters. GALL Report, Volume 2, items IV.A2-6, IV.A2-7 and IV.A2-8, for the "control rod drive head penetration - flange bolting" are not applicable to WCGS.
Staff Evaluation

The applicant's response provides sufficient information to explain why lines comparable to GALL Report lines IV.A2-6, IV.A2-7 and IV.A2-8 are not applicable for WCGS. On the basis that a sufficient explanation has been provided, the staff finds the applicant's response acceptable.

Question No AMRA004 LRA Sec 3.1
Audit Question GALL Report, Volume 2, item IV.A2-10, provides the MEAP combination for component "control rod drive head penetration - pressure housing." However, the LRA does not contain a comparable line.

a. Explain why WCGS does not have a line comparable to the one in the GALL Report.

Final Response

GALL Report, Volume 2, item IV.A2-10, is a line for material of CASS with aging effect of cracking. The following components of the "control rod drive head penetration - pressure housing" are not CASS and IV.A2-10 is not applicable for "control rod drive head penetration - pressure housing" of WCGS:

(1) Latch Housing, Travel Housing, CRDM Cap and CRDM Flange are made of SA-182, F304 stainless steel. The corresponding GALL lines for the applicable aging effects are IV.A2-11 and IV.A2-14.

(2) CRDM Tubes are made of nickel alloy and the corresponding GALL lines for the applicable aging effects are IV.A2-9 and IV.A2-14.

Staff Evaluation

The applicant's response provides sufficient information to explain why a line comparable to GALL Report line IV.A2-10 is not applicable for WCGS. On the basis that a sufficient explanation has been provided, the staff finds the applicant's response acceptable.

Question No AMRA005 LRA Sec 3.1

Audit Question GALL Section XI.M12, "Thermal Aging Embrittlement of CASS," states that for low molybdenum content (0.5 wt percent max.) steels, only static-cast steels with more than 20 percent ferrite are potentially susceptible to

thermal embrittlement. The discussion in LRA Table 3.1.1, line 3.1.1.57, states that this aging effect is not applicable at WCGS because the molybdenum and ferrite values are below the threshold for thermal aging embrittlement.

The LRA states (Note 2, page 3.1-94) that WCGS Certified Material Test Reports support the limiting values of molybdenum and ferrite content of CASS Class 1 piping at WCGS.

What are the actual maximum reported molybdenum and ferrite values for static cast CASS Class 1 piping at WCGS? Provide a copy of the supporting documentation for review during the site visit.

Final Response

The WCGS reactor coolant loop pipe fittings are static castings. The WCGS reactor coolant loop straight piping sections are centrifugal castings.

The actual maximum reported molybdenum and ferrite values for static cast CASS Class 1 piping at WCGS are 0.35% molybdenum and 19.5% ferrite. WCGS Certified Material Test Reports supporting the limiting values of molybdenum and ferrite content of CASS Class 1 piping at WCGS were made available for NRC review during the site visit.

Staff Evaluation

The applicant's response provides specific values for molybdenum and ferrite content for WCGS piping. The maximum molybdenum and ferrite values stated by the applicant in its response are below the threshold for susceptibility to thermal embrittlement, and the stated values were confirmed by the staff's review of applicable certified material test reports. On this basis, the staff finds the applicant's response acceptable.

Question No AMRA006 LRA Sec 3.1

Audit Question Lines in LRA Table 3.1.2-2 for piping and valves made of stainless steel in a demineralized water (treated water) environment have an aging effect of "loss of material due to pitting and crevice corrosion" and the effect is managed by the Water Chemistry and One-Time Inspection Programs. These lines appear to have the same component and MEAP combinations as GALL Report, line V.C-4. However, LRA Table 3.1.2-2 refers to Note G indicating that the environment is not in the GALL Report for this component and material.

Explain why Note G was used for these lines in the LRA.

Final Response

The Lines in LRA Table 3.1.2-2 for piping and valves made of stainless steel in a demineralized water in LRA Table 3.1.2-2 (the last line in page 3.1-76 and the last line in page 3.1-91) will be amended with the new lines using GALL Report, line V.C-4 and the Note changed to D.

Staff Evaluation

As stated in the applicant's response, by letter dated August 31, 2007, the LRA was amended to reference the MEAP combinations to a similar line in LRA Table 3.1.2-2 and changing the reference from Note G to Note D. These changes result in AMR result lines in the LRA that are consistent with the GALL Report. On the basis that the amended lines are consistent with the GALL Report, the staff finds the applicant's response acceptable.

Question No AMRA007 LRA Sec 3.1

Audit Question LRA Table 3.1.2-2 does not appear to include a line that is comparable to GALL Report, Volume 2, item IV.C2-21, which includes pressurizer instrumentation penetrations, heater sheaths and sleeves, etc.

a. Explain why WCGS does not have a line comparable to the one in the GALL Report.

b. If the components listed in GALL Report, Volume 2, item IV.C2-21, are within the scope of license renewal at WCGS, please provide the AMR results.

Final Response

(a) The material of the subject components are not nickel alloy or nickel alloy cladding. Thus GALL Report, Volume 2, item IV.C2-21 is not applicable to these components of WCGS.

(b) The subject components of WCGS are within the scope of license renewal and are evaluated in LRA Table 3.1.2-2 from page 3.1-81(the last line) to page 3.1-85 (the first line).

Staff Evaluation

The response provided by the applicant is sufficient to explain as to why a line comparable to GALL Report line IV.C2-21 is not applicable for WCGS and also to identify where the applicable AMR results for similar WCGS components are presented in the LRA. On the basis that an adequate explanation has been provided, the staff finds the applicant's response acceptable.

Question No AMRA008 LRA Sec 3.1

Audit Question Provide a technical or CLB reference to support the following statement from LRA Table 3.1.1, item 3.1.1.80: "WCGS reactor vessel internals are forged stainless steel not cast austenitic stainless steel."

Final Response

LRA Table 3.1.1, item 3.1.1.80 is a roll-up summary for the applicable GALL lines IV.B2-21 and IV.B2-37.

GALL lines IV.B2-21 is for aging evaluation of (1) Lower Support Casting and (2) Lower Support

Plate Columns. The lower support assembly of WCGS is equipped with Lower Support Forging instead of Lower Support Casting. Based on Design Specification for Nuclear Reactor Internals,

M-703-00207, the Lower Support Forging and the Lower Support Plate Columns are designed with 300 series stainless steel. Thus the GALL line IV.B2-21 is not applicable to WCGS.

GALL lines IV.B2-37 is for aging evaluation of Upper Support Columns. Based on Design Specification for Nuclear Reactor Internals, M-703-00207, the Upper Support Plate Columns are designed with 300 series stainless steel. Thus the GALL line IV.B2-37 is not applicable to WCGS.

In summary, CASS is not applicable to the subject components and the GALL lines IV.B2-21 and IV.B2-37 are not applicable to WCGS. Thus, LRA Table 3.1.1, item 3.1.1.80 is also not applicable to WCGS.

Staff Evaluation

The applicant's response provides sufficient documentation to support the LRA statement that WCGS reactor vessel internals are forged stainless steel, not cast austenitic steel. On the basis that sufficient supporting documentation has been provided, the staff finds the applicant's response to be acceptable.

Question No AMRA009 LRA Sec 3.1

Audit Question

LRA Table 3.1.2-2 has several components (corresponding to GALL Report, Volume 2, item IV.C2-22) associated with the pressurizer relief tank which references LRA Table 3.1.1, item 3.1.1-68. These components can be divided into two categories with respect to AMPs identified in the LRA. One category is those that are managed by the ASME Section XI ISI, Subsections IWB, IWC and IWD and the Water Chemistry Programs. These components reference Note D, and the AMPs (with exceptions) are consistent with the GALL Report recommendations. The other category of components are those that are managed by the Water Chemistry Program only. These components reference Notes E and 1. Note 1 explains that these are not ASME Section XI components; therefore, the ASME Section XI ISI AMP will not be used.

a. For the components managed only by the Water Chemistry Program, provide a technical justification to support that the Water Chemistry Program by itself provides adequate aging management during the period of extended operation.

b. Provide a justification for not performing an inspection to confirm the effectiveness of the Water Chemistry Program to manage the aging effect of cracking.

Final Response

The affected items of LRA Table 3.1.2-2 regarding non-ASME components of Stainless Steel in the environment of Treated Borated Water for aging effect of Cracking are:

(1) Component Type of Flow Element with Intended Function of LBS in page 3.1-73.
(2) Component Type of Piping with Intended Function of SIA and LBS in page 3.1-78.
(3) Component Type of Pressurizer Relief Tank with Intended Function of SIA in page 3.1-79.
(4) Component Type of Rupture Disc with Intended Function of LBS in page 3.1-88.
(5) Component Type of Thermowell with Intended Function of LBS in page 3.1-90.
(6) Component Type of Valve with Intended Function of LBS and SIA in page 3.1-93.

For these components, the aging evaluation for the aging effect of Cracking due to SCC will use GALL line V.D1-31 which relies on Water Chemistry for managing the aging effect of Cracking.

LRA Table 3.1.2-2 will be amended to use GALL line V.D1-31 for the above listed lines. The Standard Note will be "B" instead of "E" and Plant Specific Note #1 following Table 3.1.2-2 will be changed to indicate #1 is not used, without renumbering other Specific Notes.

Staff Evaluation

The applicant's response results in an LRA amendment to reference the lines where Water Chemistry (only) is identified as GALL Report item V.D1-31, which has similar component, material, and environment and the aging effect of cracking is managed by Water Chemistry (only). The applicant's response also states that the affected components are non-ASME class pressure boundary components and that, therefore, they are not included in the ISI program. On the basis that the LRA amendment submitted by the applicant's letter dated August 31, 2007 provides AMR results that are consistent with the GALL Report's AMR results for similar components, the staff finds the applicant's response to be acceptable.

Question No AMRA010 LRA Sec 3.1

Audit Question GALL Report, item IV.C2-11, is described as "piping, piping components, and piping elements." The comparable line item in LRA Table 3.1.2-2 (page 3.1-74) is "heat exchanger tube side (HX # 3, 4, 6, 7, 8)" for the reactor coolant pump bearing heat exchangers.

a. Justify the reference to Note D for this line item.

Final Response

(a) As defined at the end of LRA Table 3.1.2-2, Note D is used for the cases where the subject components are different from the subject GALL item, but consistent with the GALL item for material, environment, and aging effect. AMP takes some exceptions to GALL AMP. Copper-Nickel is a type of copper alloy, thus the material, environment and aging effect are consistent with GALL IV.C2-11. The AMP of Closed-Cycle Cooling Water System is credited for aging management. According to LRA Section B2.1.10, WCGS AMP of Closed-Cycle Cooling Water System is consistent with exception to GALL, Section XI.M21, "Closed-Cycle Cooling Water." Since heat exchanger tube is not included in the definition of "piping, piping components, and piping elements" in GALL Table IX.B, Standard Note D is selected.

Staff Evaluation

The applicant's response provides a sufficient explanation of why Note D is used for this AMR result line. On the basis that a sufficient explanation for using Note D has been provided, the staff finds the applicant's response to be acceptable.

Question No AMRA011 LRA Sec 3.1

Audit Question In the LRA tables 3.1.2-X, there is no component line item similar to GALL Report, item IV.C2-12. The discussion in LRA Table 3.1.1.56 states that WCGS does not have copper alloy components (more than 15 percent Zn) exposed to closed cycle cooling water within the scope of license renewal.

a. Confirm that the components that references to LRA, item 3.1.1.54, are the only in-scope copper alloy components exposed to closed cycle cooling water at WCGS.

b. Explain, what documentation supports a determination that the copper alloy in these components contains less than 15 percent Zn.

Final Response

(a) LRA Table 3.1.1 items 54 and 56 are the summary of aging evaluation regarding GALL items IV.C2-11and IV.C2-12 for copper alloy components in Reactor Coolant system. It does not include all in-scope copper alloy components exposed to closed cycle cooling water at WCGS. There are copper alloy components of Auxiliary System addressed in LRA Section 3.3 that are exposed to closed cycle cooling water. They are summarized in LRA Table 3.3.1, items 51and 84.

(b) The subject copper alloy components in Reactor Coolant system are cooling tubes for RCP pump motor air cooling and bearing oil cooling. The material is copper-nickel of ASME Spec SB-111-706 and SB-171-706. The reference of the material is QR-54586 (Quality Release/Certification of Compliance).

Staff Evaluation

The applicant's response provides a sufficient explanation, based on system design, as to why there are no components similar to GALL Report item IV.C2-12. The response also identifies adequate documentation supporting the composition of the copper alloy. On the basis that a sufficient explanation has been provided and supporting documentation is adequately identified, the staff finds the applicant's response to be acceptable.

Question No AMRA012 LRA Sec 3.1

Audit Question GALL Report, item IV.C2-18, identifies the ASME Section XI ISI, Subsections IWB, IWC and IWD and Water Chemistry Programs as the applicable AMPs for pressurizer components. The LRA is consistent with the GALL Report in that it identifies the same AMPs. However, the GALL Report includes a further discussion stating that the area of the weld metal between the surge nozzle and the lower vessel head is periodically inspected as part of the ISI program.

a. Confirm if WCGS performs periodic inspection in the area of the weld metal between the surge nozzle and the lower vessel head as part of the ISI program.

b. Clarify, what is the periodicity of the inspection.

c. Clarify what is the ASME Section XI examination category for this component.

d. Discuss any adverse indications found in the area of the described weld and any repairs made or flaw indications found and evaluated as acceptable.

Final Response

(a) (b) As described in WCGS USAR, Section 5.4.10.4, the weld between the surge nozzle to the pressurizer lower head is designed and constructed to present a smooth transition surface for ultrasonic inspection to implement the requirements of the ISI program. As demonstrated by the third interval ISI program plan, WCRE-16, Table 1 of BB system, the UT inspection for the subject weld is scheduled for once for every ISI plan interval, i.e., once every 10 years.

[c] The ISI category for the inspection of the weld between the surge nozzle to the pressurizer lower head is B-D, Code Item number of B3.110.

(d) No indications were found in the inspection of Refueling Outage 13 (the second ISI interval). The inspection results were available during the site audit.

Staff Evaluation

The applicant's response provides additional discussion of inspections performed on the pressurizer components and also includes the requested details related to inspection areas, the inspection frequency and the inspection results as requested by the staff. On the basis that the requested information was provided and the staff review did not identify any discrepancies in the additional information, the staff finds the applicant's response to be acceptable.

Question No AMRA013 LRA Sec 3.1

Audit Question LRA Table 3.1.2-3 (page 3.1-101), contains two lines corresponding to GALL Report, item IV.D1-6. The component descriptions and MEAP combinations for both lines are identical and are consistent with the GALL Report. The only differences between the lines are the intended functions and the Notes. Explain why Note B is used for one of these lines and Note D is used with the second of these two lines.

Final Response

The subject items in LRA Table 3.1.2-3 (page 3.1-101) will be amended to clarify that (1) the item with a function of DF is the Primary Channel Divider Plate. It matches the component description of GALL Report, item IV.D1-6. With the exception of the "Water Chemistry" AMP, a Standard Note of "B" is used. (2) the item with a function of NSRS is the SG Primary Nozzle

Closure Ring. It does not match the component description of GALL Report, item IV.D1-6. With the exception of the "Water Chemistry" AMP, a Standard Note of "D" is used.

The last item in page 3.1-100 with a function of PB also needs to be amended to clarify that component is the Tubesheet - Primary Face.
Staff Evaluation

The applicant's response provides an adequate explanation of the difference in the two AMR result lines and why Note B is used with one line item but Note D with the other. The applicant also amended the LRA to include additional clarifying details in Table 3.1.2-3. On the basis that the applicant's response provided an explanation for the use of the two different notes and the LRA amendment provided an appropriate clarification, the staff finds the applicant's response acceptable.

Question No AMRA014 LRA Sec 3.1

Audit Question

The LRA does not include a comparable line to GALL Report, item IV.D1-16, “steam generator structure - tube support lattice bars.” This is discussed in LRA Table 3.1.1, item 3.1.1.78, which states that “WCGS steam generator does not contain lattice bars, so the applicable NUREG-1801 line was not used.”

In addition, the LRA does not include a component similar to that in GALL Report, item IV.D1-17, “steam generator structure - tube support plate.”

a. Clarify if the WCGS steam generators include the lattice support bars identified in the GALL Report. If so, what are those components, and where are the AMR results discussed in the LRA.

b. Clarify if the WCGS steam generators include a component comparable to GALL Report, item IV.D1-17, “steam generator structure - tube support plate,” that might be subject to the aging effect of ligament cracking due to corrosion.

Final Response

(a) The steam generator of WCGS is a Westinghouse Model F design. There are no lattice support bars identified in WCGS USAR, the design specification, M-711-0011, or the stress analysis, M-711-0008.

(b) WCGS steam generators include a component comparable to GALL Report, item IV.D1-17, “steam generator structure - tube support plate” and is addressed in LRA Table 3.1.2-3, page 3.1-108. The material is stainless steel instead of carbon steel used in GALL Report, item IV.D1-17. This issue of ligament cracking was identified in Supplement 1 to NRC IN 96-09 and applicable to the plants with carbon steel support plates. WCGS steam generator tube support plate is made of stainless steel, thus ligament cracking is not an applicable aging effect.

Staff Evaluation

The applicant's response provides an explanation, based on design features of the steam generators, as to why the LRA does not include an AMR results line comparable to GALL Report items IV.D1-16 and IV.D1-17. On the basis that the applicant's response provides an adequate explanation and includes supporting design documentation to explain why the GALL AMR results are not applicable at WCGS, the staff finds the applicant's response to be acceptable.

Question No AMRA015 LRA Sec 3.1

Audit Question

In the LRA Table 3.1.2-3, page 3.1-97, there are two line items corresponding to GALL Report, item IV.D1-26, "steam generator feed ring made of carbon steel," with internal and external environments of "secondary water" for which the aging effect is wall thinning. The GALL Report recommends a plant-specific AMP be evaluated for this component, material, environment and aging effect combination. The AMPs listed in the LRA for these lines are the Steam Generator Tube Integrity and Water Chemistry Programs. The Notes associated with these lines are E and 1. Note 1 states, "Feedring wall thinning was described in NRC IN 91-19. This aging has been detected only in certain CE System 80 Steam Generators. The WCGS steam generators are Westinghouse Model F. No plant specific experience at WCGS or other units with Model F steam generators suggests wall thinning of the Model F is occurring. Therefore WCGS has determined this condition is not applicable and no further action is needed."

It is not clear whether WCGS is crediting the listed AMPs for managing the aging effect of wall thinning in the components during the period of extended operation. If the AMPs are being credited, then Note A would seem appropriate rather than Note 1. If the AMPs are not being credited, then it is not clear why they are listed on the applicable lines in LRA Table 3.1.2-3.

Explain why the Steam Generator Tube Integrity and Water Chemistry Programs are sufficient to manage the aging effect of wall thinning in the steam generator feed ring during the period of extended operation. Please justify your response.

Final Response

The AMPs of "Steam Generator Tube Integrity and Water Chemistry Programs" are credited for managing the aging effect of wall thinning of the feedrings. As indicated in LRA Section 3.1.2.2.14, the AMPs are conservatively credited to manage wall thinning of feedrings although wall thinning is not applicable to Model F steam generators.

To clarify, the Plant Specific Note 1 for LRA Table 3.1.2-3 will be amended to indicate "no further evaluation is recommended" instead of "no further action is required" at the end of the statements.

The Steam Generator Tube Integrity and Water Chemistry Programs are sufficient to manage the aging effect of wall thinning in the steam generator feed ring during the period of extended operation based on GALL item IV.D1-16, which credits the AMPs of the Steam Generator Tube

Integrity and Water Chemistry Programs to manage the aging effect of wall thinning for the same material and environment,

Staff Evaluation

The applicant's response provided an adequate explanation of why the Steam Generator Tube

Integrity and Water Chemistry Programs are sufficient to manage the aging effects of wall thinning in the steam generator head ring. The follow up LRA amendment also included an additional clarification via the plant-specific note 1 in Table 3.1.2-3. On the basis that an adequate explanation has been provided, the staff finds the applicant's response acceptable.

Question No AMRA016 LRA Sec 3.1

Audit Question LRA Section 3.1.2.2.16.1 states that control rod drive mechanism and pressurizer components are stainless steel [not nickel alloy] for WCGS and; therefore, no additional commitments or further evaluation are required.

a. LRA Section 3.1.2.2.16.1 is titled "steam generator heads, tube sheets, and welds made or clad with stainless steel." Explain why control rod drive mechanisms and pressurizer components are discussed in this subsection.

b. Provide technical or CLB documentation that supports the LRA statement that the control rod drive mechanism and pressurizer components are stainless steel. Please have a copy or summary of that documentation for review at the site.

Final Response

(a) Based on items #34 and #35 of NUREG-1800, Table 3.1-1, Further Evaluation recommended in NUREG-1800, subsection 3.1.2.2.16.1 is addressed in items #34 and #35 of LRA Table 3.1.1. The details are provided in LRA Section 3.1.2.2.16.1. Item #35 is applicable to once-through steam generator only. Pressurizer components are not involved in either item #34 or #35 of LRA Table 3.1.1. To clarify, LRA Section 3.1.2.2.16.1 will be amended:

(1) The title of LRA Section 3.1.2.2.16.1 will read "Cracking on steam generator heads, tube sheets, control rod drive head penetration pressure housings and welds."

(2) The statement will read "These control rod drive mechanism housings are stainless steel for WCGS, therefore no additional commitments or further evaluation is required."

(3) Add the statement of "WCGS has a recirculating steam generator, not a once-through steam generator, so the further evaluation for steam generator components is not applicable to WCGS."

(b) A copy of CLB document regarding CRDM housing was available during site audit.

Staff Evaluation

As stated in the applicant's response, the LRA was amended to eliminate the inconsistency between the title of LRA Section 3.1.2.2.16.1 and the discussion in that subsection. The response also provided adequate CLB documentation to support the statement that the components are made of stainless steel. On the basis that the LRA has been amended to eliminate the inconsistency and the adequate supporting documentation has been provided, the staff finds the applicant's response to be acceptable.

Question No AMRA017 LRA Sec 3.2

Audit Question LRA Table 3.2.2-2 designates Note G for stainless steel piping, valves, and tanks in the containment spray system because the environment is not in the GALL Report for this component and material.

a. Provide the temperature range of operation for these components.

b. Provide references that indicate industry applications where there are no considerations for aging

FollowupQuestion:
Provide source documents to substantiate max temp stainless steel in EN system is 125F for components.
a. Exposed to sodium hydroxide

b. Internet search or Hendrix Ground corrosion & Materials lists stainless steel as a common material for use up to 200F and 50% W NaOH.

c. Evaluation of WCGS stainless steel components in EN system exposed to sodium hydroxide is consistant with VC summer LRA, Table 3.2-2, item 5.

Final Response

a.) According to WCGS system flow drawings, the maximum temperature that the stainless steel containment spray system components exposed to a sodium hydroxide environment would experience is 125 F.

b.) An internet search of the Hendrix Group Corrosion and Materials Technology Site lists stainless steel as a common material for use up to 200F and 50%w NaOH. The aging effect and AMP were conservatively assigned. The WCGS stainless steel containment spray components exposed to a sodium hydroxide environment were evaluated consistent with the Virgil C. Summer license renewal application Table 3.2-2, AMR Item 5 and associated SER (NUREG-1787).

Follow up response:

a) Piping Class Summary sheets for system EN (HPCI) show that the piping design temperature is 125 F. Piping normal operating temperature is listed as 100 F. The Tank Data Sheet for the Containment Spray Additive Tank (plant tag TEN01), indicates that the normal tank operating temperature is 120° F.

b) Hendrix corrosion and material data was provided at the site audit. Internet links to the pertinent data are:
http://www.hghouston.com/naoh_tbl.html
http://www.hghouston.com/naoh.html

c) VC Summer LRA Table 3.2-2 was provided at the site audit.

Staff Evaluation

The staff finds the applicant's response acceptable on the basis that the applicant adequately demonstrated that the maximum temperature to which the in-scope components in containment spray system are exposed is below 125 degrees F and that stainless steel in the 50%w sodium hydroxide solution environment can be used up to 200 degrees F. OTI, as proposed by the applicant, will detect any slowly progressing LOM.

Question No AMRA018 LRA Sec 3.2

Audit Question The GALL Report, Section V.D1, does not include any nickel alloy components. The applicant credits the Water Chemistry Program for managing loss of material caused by pitting and crevice corrosion. The Water Chemistry Program effectively manages aging effect of loss of material of nickel alloys in treated borated water only when there is not any stagnant flow. Accumulators typically have low flow; therefore, additional action may be necessary to verify that long term corrosion is not occurring. Explain what additional provisions WCGS will be taken to ensure that corrosion is not slowly progressing.

Followup Question:
The water chemistry AMP provides verification of the lack of LOM through the OTI program. However, the OTI AMP applicability does not provide for inspection of nickel-based alloys in treated borated water in the high pressure injection system. What actions are taken to verify that LOM is not occurring on the inside of nickel-based alloy components?

Final Response

Accumulator tank nickel alloy components in a treated borated water environment, require aging management of cracking and loss of material. The loss of material aging effect will be managed by the Water Chemistry AMP. The cracking aging effect will be managed by the Water Chemistry AMP augmented by the plant specific Nickel Alloys AMP. The plant specific nickel alloy AMP periodically inspects the accumulator tank nickel alloy components.

Follow up response:

The Water Chemistry AMP will be augmented by the One-Time Inspection AMP for verification that loss of material is not occurring in accumulator tank nickel-alloy components. LRA Table 3.2.2-10 will be amended to include the One-Time Inspection AMP in addition to the Water Chemistry AMP for managing the aging effect of loss of material. As a result, the One-Time Inspection program will include a one-time inspection of selected accumulator tank nickel-alloy components at susceptible locations.

Staff Evaluation

The staff finds the applicant response acceptable because the addition of one-time inspection to water chemistry management is an acceptable method to determine whether or not loss of material is occurring slowly such that the intended function of the HPCI accumulators will be maintained during the period of extended operation.

Question No AMRA019 LRA Sec 3.3

Audit Question LRA Table 3.3.1, item 3.3.1.07, lists stainless steel non regenerative heat exchanger components exposed to treated borated water greater than 60C (greater than 140F). In the discussion column, the LRA states that "this line item is not applicable. Other available applicable NUREG 1801 lines were used." Clarify if this means that WCGS does not have any non regenerative heat exchangers exposed to treated borated water greater than 60C (greater than 140F).

Final Response

The Letdown, Excess Letdown and Seal Water heat exchangers are exposed to treated borated water greater than 1400 F (tube-side) and Component Cooling Water (shell-side). The shell-side is managed by the Closed-Cycle Cooling Water Program using item number 3.3.1.46. The tube-side is managed by Water Chemistry and One-Time inspection Programs using item number 3.3.1.08. The Closed-Cycle Cooling Water Program (B2.1.10) includes eddy current testing for heat exchanger shell-side components exposed to Component Cooling Water. Radiation monitors are installed in each train of the Component Cooling Water System and alarm when abnormal radioactivity levels are detected. Heat exchanger outlet temperature of the heat exchangers are not typically monitored, this was noted as a program exception to the Closed-Cycle Cooling Water Program.

The LRA item number 3.3.1.07 discussion column will be amended to read the following:

"Not applicable. The Letdown, Excess Letdown and Seal Water heat exchangers are exposed to treated borated water greater than 140 F (tube-side) and Component Cooling Water (shell-side). The shell-side is managed by the Closed-Cycle Cooling Water Program using item number 3.3.1.46. The tube-side is managed by Water Chemistry and One-Time inspection Programs using item number 3.3.1.08. The Closed-Cycle Cooling Water Program (B2.1.10) includes eddy current testing for heat exchanger shell-side components exposed to Component Cooling Water. Radiation monitors are installed in each train of the Component Cooling Water System and alarm when abnormal radioactivity levels are detected. Heat exchanger outlet temperature of the heat exchangers are not typically monitored, this was noted as a program exception to the Closed-Cycle Cooling Water Program."

Staff Evaluation

On the basis that the applicant is verifying the effectiveness of water chemistry by means of eddy current testing and monitoring of radioactivity under a separate Table 3.3.1 line item, the staff finds the response acceptable and confirms that this line item is not applicable to WCGS.

Question No AMRA020 LRA Sec 3.3

Audit Question LRA Table 3.3.1, item 3.3.1.10, lists high strength steel closure bolting exposed to air with steam or water leakage. Clarify what is the material of the closure bolting used in high pressure pumps in the chemical and volume control system.

Final Response

The high pressure pumps associated with the Chemical and Volume Control System are the Boric Acid Transfer Pumps, Normal Charging Pump, Centrifugal Charging Pumps, and Boron Injection Makeup Pump. Bolting for these pumps is stainless steel grades ASTM A564 Gr. 630 and ASTM A194, Gr. 6.

Staff Evaluation

This was an information only question. Bolting material was provided and the applicant's response is acceptable.

Question No AMRA021 LRA Sec 3.3

Audit Question LRA Table 3.3.1, item 3.3.1 46, lists stainless steel and stainless clad steel piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water greater than 60C (greater than 140F). The Closed Cycle Cooling Water System Program is credited for managing the aging effect of cracking due to SCC. One of the implementing procedures referenced in this program is QCP-20-518, "Visual Examination of Heat Exchangers and Piping Components." However, it is not clear how the use of this procedure will manage cracking as in the definition section of this document, cracking is included under general corrosion. Please clarify.

Final Response

The Closed Cycle Cooling Water System Program is credited for managing the aging effect of cracking due to SCC. QCP-20-518 is a visual inspection procedure and prescribes visual examination requirements for the detection of cracking (and other indications). The procedure documents "as-found" conditions, provides trend data to engineering, and where practical, creates video or photographic records of the examination. Unacceptable conditions such as cracks are documented through the corrective action program. The corrective action program would assess the components condition and any aging effects would be evaluated.

QCP-20-518 will be revised to define cracking, provide additional guidance for detection of cracking and specific acceptance criteria relating to "as-found" cracking. A new commitment for this procedure revision was added to the License Renewal Application list of regulatory commitments.

Staff Evaluation

The applicant amended the LRA to include Commitment No. 32 to revise the procedure QCP-20-518 to define cracking, and provide additional guidance for detection of cracking. The applicant also amended the LRA AMP B2.1.10, Closed-Cycle Cooling Water System Program to add an enhancement to revise the procedure. On this basis, the staff finds the response acceptable.

Question No AMRA022 LRA Sec 3.3
Audit Question LRA Table 3.3.1, item 3.3.1.53, lists steel compressed air system piping,

piping components, and piping elements exposed to condensation (internal). The LRA states that the 10 CFR 50 Appendix J Program is credited in lieu of the Compressed Air Monitoring Program recommended in the GALL Report to manage the aging effect of loss of material due to general corrosion for containment isolation piping and valves. The 10 CFR 50 Appendix J Program only ensures that the containment isolation valve does not leak through the seat and performs the containment isolation function. The visual inspection performed in this AMP only detects aging in the external surface, not in the internal surface, of piping and valves. Please explain how loss of material on the inside surface of piping and valves will be detected. (This item applies to LRA Table 3.3.2.6, compressed air system, for containment isolation piping and valves).

Final Response

The piping in question is service air containment penetration piping and components on License Renewal Boundary Drawing LR-WCGS-KA-M-12KA02 (D-6). The containment isolation piping is safety-related but is attached to non-safety related structural integrity attached (SIA) piping.

WCGS containment isolation valve testing test procedures pressurize the entire safety-related containment isolation piping section. Not only is isolation valve seat leakage tested but the entire pressure boundary is tested. The safety-related piping and valves are in-scope for pressure boundary. 10 CFR 50 Appendix J Program testing of containment isolation piping and valves provides a positive means for detection of loss of pressure boundary integrity intended function.

The LRA will be amended to add AMP XI.M38 (Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components) for loss of material inspection of the service air containment penetration piping internal surfaces. Credit will be taken for both the 10 CFR 50 Appendix J Program testing and AMP XI.M38 internal inspection.

Staff Evaluation

The applicant amended the LRA to add the Inspection of Internal Surfaces In Miscellaneous Piping and Ducting Components Program to manage loss of material of the service air containment penetration piping internal surfaces. On the basis that periodic visual inspections are performed, the staff finds the applicant's response acceptable.

Question No AMRA023 LRA Sec 3.3
Audit Question LRA Table 3.3.1, item 3.3.1.68, states that this line is consistent with the GALL Report except that a different AMP is credited to manage steel piping, piping components, and piping elements with internal surfaces exposed to raw water. The LRA states that the Fire Water System

Program will be credited in conjunction with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effects. This corresponds to several line items in LRA Table 3.3.2-14 for the fire protection system for which Note E is referenced.

Explain how these two programs are used in conjunction to manage these aging effects.

Final Response

The Fire Water System program manages loss of material for water-based fire protection systems. Periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests considering National Fire Protection Association (NFPA) codes and standards ensure that the water-based fire protection systems are capable of performing their intended functions. The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler nozzle to verify that each open head spray/sprinkler nozzle is unobstructed. The Fire Water System program tests a representative sample of fire protection sprinkler heads or replaces those that have been in service for 50 years, using the guidance of NFPA 25 2002 Edition, and tests at 10 year intervals thereafter during the period of extended operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

Visual inspections evaluating wall thickness to identify evidence of loss of material due to corrosion, ensuring against catastrophic failure, are covered by the aging management program XI.M38 "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components". The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP manages cracking, loss of material and hardening - loss of strength for components whose internal inspections are not covered by other aging management programs. Thus, the Fire Water System program internal visual inspections are covered by the Internal Inspection program. Other inspections such as, fire detection and suppression testing and maintenance, yard fire hydrant inspections and flushing, powerblock fire hose testing, hose station gasket inspections and sprinkler/spray nozzle inspections are covered by the Fire Protection program.

Internal visual inspections will be conducted during periodic maintenance, surveillance testing and corrective maintenance to the fire protection system components in the program.

Staff Evaluation

The applicant provided information about how the Fire Water system program was used in conjunction with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage the aging effects. On the basis that periodic visual inspections are performed to evaluate wall thickness as recommended by GALL AMP XI.M27, the staff finds the applicant's response acceptable.

Question No AMRA024 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-1, fuel storage and handling system, the applicant credited the Structures Monitoring Program to manage the aging effect of loss of material for carbon steel new fuel racks in a plant indoor air - external environment. This AMP references implementing procedure AI

23M-007; however, the procedure does not specifically identify new fuel racks in the component or structure list. Identify where are the new fuel racks listed as within the scope of the Structures Monitoring Program.

Final Response

WCGS carbon steel fuel racks are evaluated as structural steel, consistent with NUREG-1801 line VII.A1-1. The scope of AI 23M-007 applies to structures, passive components and civil engineering features in-scope for the Maintenance Rule and additional structures and components in-scope for License Renewal. Although the new fuel racks are not specifically listed in the procedure, the carbon steel new fuel racks are included with procedure AI 23M-007 Attachment C, Fuel Building structural steel components.

Staff Evaluation

The staff finds the applicant response acceptable because the response identified where the new fuel racks were located in the Structures Monitoring program.

Question No AMRA025 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-2, fuel pool cooling and cleanup system, the applicant credited the Closed Cycle Cooling Water System Program to manage the aging effects of loss of material and reduction of heat transfer for piping, thermowell, valves, and heat exchanger components in a closed cycle cooling water internal and external environment. However, the fuel pool cooling and cleanup system is not included within the scope of the Closed Cycle Cooling Water System Program. Please clarify.

Final Response

The component cooling water system provides closed cycle cooling water to the fuel pool cooling and cleanup system. According to the WCGS Strategic Closed Cooling Water Chemistry Plan, “The component cooling water systems (CCWs), A and B systems, are closed loop systems designed to remove heat from various plant components during plant operation, plant cool-down and during post accident conditions.” The component cooling water system in the scope of the Closed Cycle Cooling Water System AMP and the associated WCGS Strategic Closed Cycle Cooling Water Chemistry Plan refer to all components that receive component cooling water.

The Closed Cycle Cooling Water System AMP will be used to manage fuel pool cooling and cleanup system components within the scope of license renewal that receive closed cycle cooling water from the component cooling water system.

A STARS License Renewal Project Change Tracking Form (PCTF-0179) was created to revise the 10 element review for AMP B2.1.10 as follows:
The program is credited with managing the aging of components that are exposed to closed cycle cooling water. (Reference: Strategic Closed Cycle Cooling Water Chemistry Plan, Sections 2.0, 7.0, 8.0, 9.0, and 12.0):

- Component Cooling Water (CCW)

- Emergency Diesel Engine (EDE) Cooling Water System
- Plant Heating *
- Central Chilled Water System *
- Miscellaneous Buildings HVAC *, **
- Fuel Building HVAC *, **
- Control Building HVAC *, **
- Auxiliary Building HVAC *, **
- Containment Purge HVAC *, **
- Reactor Coolant System
- Chemical & Volume Control System
- Fuel Pool Cooling and Cleanup System
- Residual Heat Removal System
- High Pressure Coolant Injection System
- Central Chilled Water System*
- Liquid Radwaste System
- Nuclear Sampling System

Staff Evaluation

The staff finds the applicant response acceptable because the applicant revised the Closed-Cycle Cooling Water System Program basis document to include the fuel pool cooling and cleanup system.

Question No AMRA026 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-7, chemical and volume control system, the applicant credited the Closed Cycle Cooling Water System Program to manage the aging effects of loss of material, reduction of heat transfer and cracking for several stainless steel components in a closed cycle cooling water internal and external environment. However, the chemical and volume control system is not included within the scope of the Closed Cycle Cooling Water System Program. Please clarify.

Final Response

The component cooling water system provides closed cycle cooling water to the chemical and volume control system. According to the WCGS Strategic Closed Cooling Water Chemistry Plan, “The component cooling water systems (CCWs), A and B systems, are closed loop systems designed to remove heat from various plant components during plant operation, plant cool-down and during post accident conditions.” The component cooling water system in the scope of the Closed Cycle Cooling Water System AMP and the associated WCGS Strategic Closed Cycle Cooling Water Chemistry Plan refer to all components that receive component cooling water.

The Closed Cycle Cooling Water System AMP will be used to manage chemical and volume control system components within the scope of license renewal that receive closed cycle cooling water from the component cooling water system.

A STARS License Renewal Project Change Tracking Form (PCTF-0179) was created to revise the 10 element review for AMP B2.1.10 as follows:
The program is credited with managing the aging of components that are exposed to closed

cycle cooling water. (Reference: Strategic Closed Cycle Cooling Water Chemistry Plan, Sections 2.0, 7.0, 8.0, 9.0, and 12.0):

- Component Cooling Water (CCW)
- Emergency Diesel Engine (EDE) Cooling Water System
- Plant Heating *
- Central Chilled Water System *
- Miscellaneous Buildings HVAC *, **
- Fuel Building HVAC *, **
- Control Building HVAC *, **
- Auxiliary Building HVAC *, **
- Containment Purge HVAC *, **
- Reactor Coolant System
- Chemical & Volume Control System
- Fuel Pool Cooling and Cleanup System
- Residual Heat Removal System
- High Pressure Coolant Injection System
- Central Chilled Water System*
- Liquid Radwaste System
- Nuclear Sampling System

Staff Evaluation

The staff finds the applicant response acceptable because the applicant revised the Closed-Cycle Cooling Water System Program basis document to include the chemical and volume control system.

Question No AMRA027 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-7, chemical and volume control system, the applicant referenced Note I for stainless steel heat exchanger components in an internal environment of treated borated water and has also referenced a GALL Report, Volume 2 item, and a Table 1 item. However, Note I is not defined at the legend of Table 3.3.2.7. Since Note I implies that this line item is not consistent with the GALL Report, please clarify why a GALL Report, Volume 2 item, and a Table 1 item is referenced for these Notes.

Final Response

Note I: Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.

No vessel, tank, pump, or heat exchanger designs at WCGS are supported by TLAAs as defined in 10 CFR 54.3 except ASME Class 1 components and the Class 2 portions of the steam generators. The design of this WCGS component is therefore not supported by TLAAs.

The LRA Table 3.3.2-7 will be amended as follows:

Delete TLAA Line with component type of Heat Exchanger (HX # 45, 46, 47, 49, 51, 52, 53, 54, 55, 6, 57, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 68) and Notes I and 7.

Staff Evaluation

The staff finds the applicant's response acceptable because no vessel, tank, pump, or heat exchanger designs at WCGS are supported by TLAAs as defined in 10 CFR 54.3, except ASME Class 1 components and the Class 2 portions of the steam generators, and the design of this WCGS component is therefore not supported by TLAAs.

Question No AMRA028 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-7, chemical and volume control system, the applicant referenced Notes G and 1, which implies that these items are not consistent with the GALL Report, for an MEAP combination of copper alloy (brass copper less than 85 percent) in an external environment of plant indoor air with no aging effects and no AMP credited. However, in other tables the applicant references Note A for the same MEAP combination.

For example:
a. In LRA Table 3.3.2-14, this combination references Note A and GALL Report, item VIII.I 2
b. In LRA Table 3.3.2-7, this combination references Note 1 stating that "This non NUREG-1801 line was used to account for copper alloy in plant indoor air (external) in the chemical and volume control system. See precedent of NUREG 1801, line VIII.I 2."
c. In LRA Table 3.3.2-16, this combination references Notes G and 3. Although it is the same combination, the staff notes that the definition of Note 3 in LRA Table 3.3.2-16 is different than the definition of Note 1 in LRA Table 3.3.2-7. Also, the staff notes that the applicant uses different notes (A or G) for the same combination. If the same MEAP combination is applicable, explain why Note A is not used consistently. Clarify this discrepancy and justify your response.

Final Response

LRA Table 3.3.2-7 will be amended to reference Note A and GALL Report Item VIII.I-2.
LRA Table 3.3.2-16 will be amended to reference Note A and GALL Report Item VIII.I-2.
LRA Table 3.3.2-14 remains unchanged and currently references Note A and GALL Report Item VIII.I-2. The existing note definitions will be amended to update and make consistent.

Staff Evaluation

The staff finds the applicant response acceptable because the applicant amended the application to revise the footnote to "A" and referenced GALL Volume 2 item, which makes the LRA line item consistent with the GALL Report.

Question No AMRA029 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-9, control building HVAC system, the applicant referenced Note I for elastomer flex connectors in an environment of plant indoor air and ventilation atmosphere and referenced a GALL Report item and a Table 1 item. Since Note I implies that this line item is not

consistent with the GALL report, clarify why a GALL Report item and a Table 1 item is referenced.

Final Response

Flexible connectors for the Control Building HVAC system are synthetic elastomers (neoprene) in an environment of air-indoor-uncontrolled. The general thermal environment in the Control Building is maintained less than 95 F.

The aging effect listed for GALL line VII.F1-7 is hardening and loss of strength / elastomer degradation. NUREG-1801 Chapter IX.C, defines Elastomers as "materials rubber, EPT, EPDM, PTFE, ETFE, viton, vitril, neoprene, and silicone elastomer. Hardening and loss of strength of elastomers can be induced by elevated temperature (over about 95°F (35°C), and additional aging factors such as exposure to ozone, oxidation, and radiation." NUREG-1801, Chapter IX.D, has a definition for Air-indoor-uncontrolled (>95 F). This definition discusses the temperature threshold for elastomer thermal aging, "If ambient is <95°F, then any resultant thermal aging of organic materials can be considered to be insignificant, over the 60-yr period of interest." The EPRI guideline, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Appendix D Section 2.1.8 states in part that, "synthetic rubbers are not affected by ozone and are typically much more resistant to sunlight (or other forms of ultraviolet radiation)."

NUREG-1801 GALL line VII.F1-7 specifies hardening and loss of strength as the aging mechanism. However the GALL also states that if the temperature threshold is not exceeded, that elastomer thermal aging is insignificant. The EPRI guide states that synthetic rubbers such as neoprene are not affected by ozone, sunlight or other forms of ultraviolet radiation. Thus, hardening and loss of strength of the Control Building HVAC flexible connectors is not expected.

The LRA will be amended as follows:

- LRA Table 3.3.2-9, Control Building HVAC System, Component Type "Flexible Connectors" will be amended to eliminate reference to GALL line VII.F1-7. A Non-GALL row will be created. The Non-GALL row will have the identical material, environment, aging effect and AMP as currently listed for the flexible connectors. Notation will also be included describing why these elastomers are not subject to hardening (similar to discussion above).
- LRA Table 3.3.1 item 3.3.1.11 will be amended to remove discussion of the exception to NUREG-1801 for Control Building Flexible Connectors.

Staff Evaluation

The applicant amended the application to add a non-GALL item with footnote "I" and removed the exception from the discussion column of Table 3.3-1, item 3.3.1.11. Since the temperature of the environment is less than 95 degrees F, there are no aging effects that require aging management. On this basis, the staff finds the applicant response acceptable.

Question No AMRA030 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-10, fuel building HVAC system, the applicant referenced Note A for carbon steel adsorber in an internal environment of ventilation atmosphere; however, a GALL Report item and a Table 1 item

were not referenced. Note A implies that this line is consistent with the GALL Report. Therefore, if the line is consistent with the GALL Report, identify the GALL Report and the Table 1 items. If the line is not consistent, clarify the discrepancy.

Final Response

Note A was inadvertently used. Unlike other carbon steel ventilation components, it is unlikely that an adsorber would have condensation as an internal environment. The adsorbers 1st stage contain moisture separators to ensure moisture does not impregnate the charcoal filters. Therefore, a separate plant specific aging evaluation was created.

The LRA will be amended as follows:
LRA Table 3.3.2-10, Fuel Building HVAC System, Component Type "Adsorber" will be amended to use note "G" in lieu of note "A". A plant specific note will be added that states, "GALL row VII.F2-3 has an internal environment of condensation. Unlike other carbon steel ventilation components, it is unlikely that an adsorber would have condensation as an internal environment. The adsorbers 1st stage contain moisture separators to ensure moisture does not impregnate the charcoal filters. Therefore, a separate (non condensation) row needed to be created since the ventilation atmosphere is dry and no aging effects are expected."

Staff Evaluation

The staff finds the applicant response acceptable because the applicant stated that note "A" was inadvertently used and that the correct note reference should be "G". With this change, there is no discrepancy. On this basis, the staff finds the applicant response acceptable.

Question No AMRA031 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-16, emergency diesel engine system, the applicant referenced Note D for copper alloy heat exchanger component in an external environment of lube oil; however, a GALL Report item and a Table 1 item were not referenced. Note D implies that this line is consistent with the GALL Report. Therefore, if the line is consistent with the GALL Report, identify the GALL Report and the Table 1 items. If the line is not consistent, clarify the discrepancy.

Final Response

Note D was incorrectly used. GALL does not consider reduction of heat transfer/fouling for copper alloy heat exchanger tubes in lubricating oil. Therefore, a separate plant specific aging evaluation was created.

The LRA will be amended as follows:
LRA Table 3.3.2-16, Emergency Diesel Engine System, Component Type "Heat Exchanger Tube Side HX#150) will be amended to use note "H,4" in lieu of note "D,4". Plant specific note #4 already exists for this row. No changes to the existing plant specific note are required.

Staff Evaluation

The staff finds the applicant response acceptable because the applicant stated that note "D,4" was inadvertently used and that the correct note reference should be "H,4". With this change, there is no discrepancy. On this basis, the staff finds the applicant response acceptable.

Question No AMRA032 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-16, emergency diesel engine system, the applicant referenced Note A for stainless steel valve in an internal environment of wetted gas; however, a GALL Report item and a Table 1 item were not referenced. Note A implies that this line is consistent with the GALL Report. Therefore, if the line is consistent with the GALL Report, identify the GALL Report and the Table 1 items. If the line is not consistent, clarify the discrepancy.

Final Response

Note A was incorrectly assigned to this non-GALL aging evaluation line.

The LRA will be amended as follows:
LRA Table 3.3.2-16, Emergency Diesel Engine System, Component Type "Valve", environment "wetted gas" will be amended to use note "G,1" in lieu of note "A,1". Plant specific note #1 already exists for this row. No changes to the existing plant specific note are required.

Staff Evaluation

The staff finds the applicant response acceptable because the applicant stated that note “A,1” was inadvertently used and that the correct note reference should be “G,1”. With this change, there is no discrepancy. On this basis, the staff finds the applicant response acceptable.

Question No AMRA033 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-16, emergency diesel engine system, the applicant credited the Open Cycle Cooling Water System Program to manage the aging effect of loss of material for carbon steel piping and valves in an environment of raw water. However, the Open Cycle Cooling Water System Program includes standby diesel engine within the scope of the program, but not the emergency diesel engine system. Clarify if the standby diesel engine is considered as part of the emergency diesel engine system. Explain why the emergency diesel engine system is not included within the scope of this program.

Final Response

The Emergency Diesel Engine System is also known as the Standby Diesel Engine System. LRA Section 2.3.3.16 states this fact in the first sentence of the system description.

Staff Evaluation

This question was for information only. Since the emergency diesel engine system is also known as the standby diesel engine system, the staff finds the applicant response acceptable.

Question No AMRA034 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-17, floor and equipment drains system, the applicant credited the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program in lieu of the Lubricating Oil Analysis and One Time Inspection Programs to manage loss of material in stainless steel tanks. The bottom of the tanks are very susceptible to this aging effect. Clarify if the credited program will include wall thickness measurement of the bottom of the tanks.

Final Response

The stainless steel reactor coolant pump drain tank receives lubricating oil leakage from the reactor coolant pump motors. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will manage the loss of material due to pitting and crevice corrosion for stainless steel components in a lubricating oil environment by visual inspections for loss of material. If internal inspections detect loss of material, the aging would be resolved via the WCGS corrective action program.

See also AMRA038.

Staff Evaluation

The applicant responded that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will manage the loss of material due to pitting and crevice corrosion for stainless steel components in a lubricating oil environment by visual inspections for loss of material. If internal inspections detect loss of material, the aging will be resolved via the WCGS corrective action program. On the basis that periodic visual inspections will be performed and any discrepancy will be evaluated for further corrective actions, including UT measurement for wall thickness, the staff finds the response acceptable.

Question No AMRA035 LRA Sec 3.3

Audit Question In LRA Tables 3.3.2-8, 3.3.2-9, 3.3.2-10, and 3.3.2-12 reference Note E and GALL Report item VII.F2-14 for copper and copper nickel heat exchanger tube side component. These tables also credit the External Surfaces Monitoring Program to manage loss of material in an external environment of plant indoor air. The GALL Report recommends a plant specific AMP for item VII.F2 14. The External Surfaces Monitoring Program description states that visual inspections conducted during system engineer walkdowns are used to identify aging effects. The external surface of heat exchanger tubes would normally be inside the heat exchanger shell and would not be visible during a typical system engineer walkdown. Clarify how a visual inspection during a system walkdown would identify this aging effect. (Please note that LRA Table 3.3.2 5 for the same component and material in a similar external environment, credits the Inspection of Internal surfaces in Miscellaneous Piping and Ducting Components Program, which includes visual inspection when component is disassembled as part of the surveillance procedure.)

Final Response

The heat exchanger tube side components assigned to the External Surfaces Monitoring Program are not heat exchanger tubes, but the heat exchanger header assembly. This assembly protrudes through the ductwork and connects to the cooling water supply. Drawings M618-0001 and M618-0002 show typical details of the coil and header assembly. Review of the drawings show that the header assembly only protrudes approximately 3" outside of the ducting. This is the location of the flanged header and where it is connected to plant cooling water piping. Thus, the majority of the header assembly is located inside the ducting. LRA Tables 3.3.2-8, 3.3.2-9, 3.3.2-10 and 3.3.2-12 will be amended to place these components in an environment of Ventilation Atmosphere (external) and assign the Inspection of Internal surfaces in Miscellaneous Piping and Ducting Components Program as the aging management program. The following components are affected:

Auxiliary Building HVAC System (GL) - LRA Table 3.3.2-8
GALL VII.F2-14 - Heat Exchanger Tube Side (HX# 93,95,97,99,101,103)

Component No.	Component Name
SGL09A-02	SAFETY INJECTION PUMP ROOM COOLER HEAD
SGL09B-02	SAFETY INJECTION PUMP ROOM COOLER HEAD
SGL10A-02	RHR PUMP ROOM COOLER HEAD
SGL10B-02	RHR PUMP ROOM COOLER HEAD
SGL11A-02	COMPONENT COOL. WATER PUMP ROOM COOLER HEAD
SGL11B-02	COMPONENT COOL. WATER PUMP ROOM COOLER HEAD
SGL12A-02	CHARGING PUMP ROOM COOLER HEAD
SGL12B-02	CHARGING PUMP ROOM COOLER HEAD
SGL13A-02	CONTAINMENT SPRAY PUMP ROOM COOLER HEAD
SGL13B-02	CONTAINMENT SPRAY PUMP ROOM COOLER HEAD
SGL15A-02	PENETRATION ROOM COOLER HEAD
SGL15B-02	PENETRATION ROOM COOLER HEAD

Control Building HVAC System (GK) - LRA Table 3.3.2-9
GALL VII.F1-16 - Heat Exchanger Tube Side (HX# 117,122,123)

Component No.	Component Name
SGK04A-06	CONTROL ROOM A/C UNIT CONDENSER CHANNEL HEAD
SGK04B-06	CONTROL ROOM A/C UNIT CONDENSER CHANNEL HEAD
SGK05A-06	CLASS IE ELEC. EQUIP. A/C UNIT CONDENSER CHANNEL HEAD
SGK05B-06	CLASS IE ELEC. EQUIP. A/C UNIT CONDENSER CHANNEL HEAD
SGK05A-02	CLASS IE ELEC. EQUIP. A/C UNIT COOLING COIL HEADER
SGK05B-02	CLASS IE ELEC. EQUIP. A/C UNIT COOLING COIL HEADER

Fuel Building HVAC System (GG) - LRA Table 3.3.2.10
GALL VII.F2-14 - Heat Exchanger Tube Side (HX# 131)

Component No.	Component Name
SGG04A-02	FUEL POOL COOLING PUMP RM COOLER HEAD
SGG04B-02	FUEL POOL COOLING PUMP RM COOLER HEAD

Miscellaneous Buildings HVAC System (GF) - LRA Table 3.3.2-12
GALL VII.F2-14 - Heat Exchanger Tube Side (HX# 137)

Component No.	Component Name

SGF02A-02	AUX FW PUMP ROOM COOLER HEAD
SGF02B-02	AUX FW PUMP ROOM COOLER HEAD

Staff Evaluation

The applicant amended the application to assign the Inspection of Internal surfaces in Miscellaneous Piping and Ducting Components Program as the aging management program, in lieu of the External Surfaces Monitoring Program. With this change, the inspections will be performed during a surveillance test or during preventive maintenance, rather than during a system walkdown. On the basis that periodic inspections will be performed by visually looking inside the component, the staff finds the applicant response acceptable.

Question No AMRA036 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-6, compressed air system, the LRA references Note E and GALL Report item VII.D-2 for carbon steel piping, orifice and valve components. It also credits the Inspection of Internal surfaces in Miscellaneous Piping and Ducting Components Program to manage loss of materials in an internal environment of wetted gas in lieu of the Compressed Air Monitoring Program as recommended by the GALL Report. The AMP recommended by the GALL Report states that checks of air quality is performed as part of preventive actions to ensure that oil, water, rust, dirt, and other contaminants are kept within the specified limits. Since the LRA credits a different AMP, clarify if the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will perform air quality checks as recommended by the GALL Report.

Final Response

Air quality checks are not part of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP (XI.M38). The AMP conducts internal visual inspections of compressed air system piping and components to manage cracking, loss of material, and loss of strength. The AMP inspections are not one-time inspections but are periodic inspections.

The wetted gas environment listed in LRA Table 3.3.2-6 for the compressed air system applies to two sections of piping and components as discussed below:

1.) Dry nitrogen vent piping off the safety-related auxiliary feedwater and main steam atmospheric relief valve accumulators that discharge to atmosphere.

    See License Renewal Boundary Drawing LR-WCGS-KA-M-12KA05 (B-7, H-7, H-8, D-7, D-8, F-6, F-7, A-4, B-4, and C-4). The internal environment is dry nitrogen that discharges to atmosphere. A wetted gas environment was conservatively chosen since there could be moisture introduced from the outside atmosphere that mixes with the dry nitrogen. Air quality checks based on compressed air from instrument air compressors do not apply. Periodic internal visual inspection of the piping and components provides a positive means for detection of aging effects that could lead to loss of system intended function.

2.) Service air containment penetration piping and components on License Renewal Boundary Drawing LR-WCGS-KA-M-12KA02 (D-6).
A portion of the piping is safety-related for containment isolation and the attached piping

is non-safety related structural integrity attached (SIA). The SIA piping sections are relatively short sections that are easily accessible for periodic internal visual inspection. Periodic internal visual inspection of the piping and components provides a positive means for detection of aging effects that could lead to loss of the SIA intended function. Performance of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP (XI.M38) periodic internal inspections will provide reasonable assurance that compressed air system intended functions are maintained.

Staff Evaluation

The applicant response is acceptable because the periodic internal visual inspection of the piping and components provides a positive means for detection of aging effects that could lead to loss of the structural integrity intended function.

Question No AMRA037 LRA Sec 3.3

Audit Question In LRA Table 3.3.1, items 3.3.1-8 and 3.3.1-9, the AMP column did not reflect what is recommended in the GALL Report for the same items. The GALL Report, Volume 1, Table 3, for these lines recommends the Water Chemistry Program and a plant specific verification program. LRA Table 3.3.1, only credits a plant specific program. The GALL Report also states that this line item applies to the GALL Report, Volume 2, items VII.E1-5 and VII.E1-7. Clarify this discrepancy and confirm if the information provided in the LRA Table 3.3.1 AMP column is incorrect.

Final Response

LRA Table 3.3-1, items 3.3.1.08 and 3.3.1.09 AMP columns are incorrect and should reference the Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16) programs. The discussion column of LRA Table 3.3-1, items 3.3.1.08 and 3.3.1.09, specify that the aging management program(s) used to manage aging include the Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16) programs. These programs are also identified for the Chemical and Volume Control System in LRA Section 3.3.2.1.7.

Chemical and Volume Control system stainless steel high pressure pumps (meeting the conditions of 3.3.1.09) were assigned GALL line VII.E1-7 and identified both the XI.M2, Water Chemistry and XI.M32, One-Time Inspection aging management programs.
Chemical and Volume Control system regenerative heat exchangers (meeting the conditions of 3.3.1.08) were assigned GALL line VII.E1-5 and identified both the XI.M2, Water Chemistry and XI.M32, One-Time Inspection aging management programs.

The LRA will be amended as follows:
- LRA Table 3.3.1, item 3.3.1.08 aging management column to state, "Water Chemistry (B2.1.2) and a plant specific verification program. The AMP is to be augmented by verifying the absence of cracking due to stress corrosion cracking and cyclic loading. A plant specific aging management program is to be evaluated."

- LRA Table 3.3.1, item 3.3.1.09 aging management column to state, "Water Chemistry (B2.1.2) and a plant specific verification program. The AMP is to be augmented by verifying the absence of cracking due to stress corrosion cracking and cyclic loading. A plant specific aging management program is to be evaluated."

Staff Evaluation

The applicant response is acceptable because the applicant stated that the LRA Table 3.3-1, items 3.3.1.08 and 3.3.1.09 AMP columns are incorrect and should reference the Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16) programs. By letter dated August 31, 2007, the applicant amended the application to correct this discrepancy.

Question No AMRA038 LRA Sec 3.3

Audit Question In LRA Table 3.3.2-17, floor and equipment drains system, the LRA references Note E and GALL Report, item VII.G-18, for stainless steel tank. The table also credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage loss of materials in an environment of contaminated lubricating oil. The GALL Report item VII.G-18 is for component type piping, piping components, and piping elements. The GALL Report, Chapter IX, Section IX.B, provides definitions of structures and components, the term piping, piping components, and piping elements; but it does not include tanks. GALL Report, Section IX.B, defines tanks separately from piping and piping components due to the potential need for a different AMP. The bottom of the stainless steel tank, where contaminated lubricating oil and sediment would collect, is more susceptible to loss of material due to pitting and crevice corrosion than piping components. Confirm if wall thickness of the bottom of the tank is measured as part of the proposed AMP.

Final Response

The stainless steel reactor coolant pump drain tank receives lubricating oil leakage from the reactor coolant pump motors. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will manage the loss of material due to pitting and crevice corrosion for stainless steel components in a lubricating oil environment by visual inspections for loss of material. If internal inspections detect loss of material, the aging will be resolved via the WCGS corrective action program.

See also AMRA034.

Staff Evaluation

The applicant responded that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will manage the loss of material due to pitting and crevice corrosion for stainless steel components in a lubricating oil environment by visual inspections for loss of material. If internal inspections detect loss of material, the aging will be resolved via the WCGS corrective action program. On the basis that periodic visual inspections will be performed

and any discrepancy will be evaluated for further corrective actions, including UT measurement for wall thickness, the staff finds the response acceptable.

Question No AMRA039 LRA Sec 3.3
Audit Question In LRA Table 3.3.2-14, fire protection system, the LRA references Note J and 1 for elastomer flex hoses in an external environment of plant indoor air. The table also states that there are no aging effects and no AMP required. Note 1 indicates that these components are in an environment of less than 95oF. The normal plant indoor air environment could see high humidity and higher temperatures. In LRA Table 3.3.2 8, for elastomer material in plant indoor air environment, the applicant identified an aging effect of hardening and loss of strength and credited an AMP.

Identify where the flex hoses are located in LRA Table 3.3.2 14 and justify why an aging effect is not considered.

Final Response

The flex hoses are associated with the Halon cylinder banks. Halon cylinder banks are located in the Auxiliary Building, Communications Corridor and Control Building. The general thermal environment in the Control Building is maintained less than 95 degrees F. The general thermal environment in the Auxiliary Building is less than 104 degrees F.

Elastomer degradation - hardening and loss of strength. NUREG-1801 Chapter IX.C, defines Elastomers as "materials rubber, EPT, EPDM, PTFE(Teflon), ETFE, viton, vitril, neoprene, and silicone elastomer. Hardening and loss of strength of elastomers can be induced by elevated temperature (over about 95°F (35°C), and additional aging factors such as exposure to ozone, oxidation, and radiation." NUREG-1801, Chapter IX.D, has a definition for Air-indoor-uncontrolled (>95 degrees F). This definition discusses the temperature threshold for elastomer thermal aging, "If ambient is <95°F, then any resultant thermal aging of organic materials can be considered to be insignificant, over the 60-yr period of interest." The EPRI guideline, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Appendix D Section 2.1.8 states in part that, "synthetic rubbers are not affected by ozone and are typically much more resistant to sunlight (or other forms of ultraviolet radiation)."

Flexible hoses for Halon storage cylinders in areas other than the Control Building may exceed the temperature threshold for elastomer degradation. Thus, for Halon cylinder flexible hoses in the Auxiliary Building and Communications Corridor, thermal aging must be considered since it cannot be shown that the equipment spaces are below 95 degrees F.

Flexible hoses for Halon storage cylinders in the Control Building do not exceed the temperature threshold for elastomer degradation. NUREG-1801 states that if the elastomer temperature threshold is not exceeded, thermal aging is insignificant. The EPRI guide states that synthetic rubbers such as PTFE (Teflon) are not affected by ozone, sunlight or other forms of ultraviolet radiation. Thus, for Halon cylinder flexible hoses in the Control Building, thermal aging need not be considered and hardening - loss of strength is not expected.

Changes required:

(1) A generic component for flexible hoses will be added for Halon flexible hoses susceptible to thermal aging (Auxiliary Building/Communications Corridor). This generic flexible hose component will be assigned an environment of air-uncontrolled (external) and an aging effect of hardening - loss of strength. The Fire Protection AMP (XI.M26) will be the program used to manage aging. Note "E" will also be used in lieu of Note "J".

(2) A generic component for flexible hoses will be added for Halon flexible hoses in the Control Building. This generic flexible hose component will be assigned an environment of air-uncontrolled (external) and the aging effect and aging management programs will be changed to "None". Note "I" will be used in lieu of Note "J".

(3) Both new generic components will have an internal environment of dry gas. Note "G" will be assigned since the environment is not in NUREG-1801 for the component and material combination. The aging effect and aging management programs will be changed to "None".

The LRA will be amended as follows:

- LRA Table 3.3.2-14, Fire Protection System, Component Type "Flexible Hoses" (Control Building), environment "dry gas" will be amended to use Note "G,1" in lieu of note "J". Plant specific note #1 will be amended to state, "Ambient temperature in Control Building spaces is expected to be below 95 degrees. Below 95 degrees, thermal aging of elastomers is not considered significant."

- LRA Table 3.3.2-14, Fire Protection System, Component Type "Flexible Hoses" (Control Building), environment "plant indoor air" will be amended to use Note "G,1" in lieu of note "J". Plant specific note #1 will be amended to state, "Ambient temperature in Control Building spaces is expected to be below 95 degrees F. Below 95 degrees F, thermal aging of elastomers is not considered significant."

- LRA Table 3.3.2-14, Fire Protection System - A new generic component type will be added.
Component type: "Flexible Hoses" (Auxiliary Building/Communications Corridor)

Material: Elastomer
Environment: Plant indoor air (external)
Aging Effect: Hardening and loss of strength - elastomer degradation
Aging Management Program: XI.M26 - Fire Protection
NUREG-1801 Vol. 2 No.: VII.F2-7
Table 1 Item: 3.3.1.11
Note: E,3

Plant Specific Note: #3 - Thermal aging of Halon flexible hoses in the Auxiliary Building and Communication Corridor must be considered because it cannot be shown that these areas are below 95 F.

- LRA Table 3.3.2-14, Fire Protection System - A new generic component type will be added.
Component type: "Flexible Hoses" (Auxiliary Building/Communications Corridor)

Material: Elastomer
Environment: Dry gas (internal)
Aging Effect: Hardening and loss of strength - elastomer degradation
Aging Management Program: XI.M26 - Fire Protection

NUREG-1801 Vol. 2 No.: None
Table 1 Item: None
Note: G,3
Plant Specific Note: #3 - Thermal aging of Halon flexible hoses in the Auxiliary Building and Communication Corridor must be considered because it cannot be shown that these areas are below 95 degrees F.

- LRA Section B2.1.12 Fire Protection aging management program will be amended to include discussion of hardening - loss of strength for elastomers.

Staff Evaluation

By letter dated August 31, 2007, the applicant issued an LRA amendment to identify the aging effects and AMP for those flex hoses located in areas where the ambient temperature is greater than 95 degrees F. The applicant is crediting the Fire Protection Program to manage the aging effect of hardening - loss of strength. The applicant also stated that surveillance procedures will be enhanced to include visual inspection of these flexible hoses. On the basis that periodic inspection will be performed on these flex hoses, the staff finds the applicant's response acceptable.

Question No AMRA040 LRA Sec 3.4
Audit Question The GALL Report includes the extraction steam system as part of the steam and power conversion system. Explain why the extraction steam system is not included within the scope of LRA Section 3.4.
Final Response

The WCGS system that is equivalent to the NUREG 1801 extraction steam system is the Feedwater Heater Extraction, Drains and Vents (AF) System. The purpose of the WCGS AF System is to provide preheated feedwater to the steam generators to improve cycle efficiency and to minimize thermal stresses on the feedwater piping and steam generator feedwater nozzles. The AF System serves no safety function, has no safety design basis, and does not meet the criteria of 10CFR54.4(a)(1). It is not required to support the requirements of the criteria of 10CFR54.4(a)(3). The components of the AF System are located completely within the turbine building. There are no safety related systems or components located in the turbine building. Any failure of AF System components will not affect any safety related equipment of the plant, thus not meeting the criteria of 10CFR54.4(a)(2). Therefore, the Feedwater Heater Extraction, Drains and Vents System is not included in the scope of license renewal.

Staff Evaluation

The staff finds the applicant's response acceptable because the applicant has provided an explanation as to why the components of the AF System are excluded from the scope of license renewal.

Question No AMRA041 LRA Sec 3.4
Audit Question LRA Section 2.1.4.1 states "Thermal insulation was treated as a passive, long-lived component during the scoping and screening process. For systems where it has an intended function, insulation was considered in the scope of license renewal and subject to aging management review..."

Explain why there is no aging effect requiring management identified for insulation line items included in LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5.

Final Response

The piping insulation identified in LRA Tables 3.4.2-2 (main steam system), 3.4.2-3 (feedwater system) and 3.4.2-5 (steam generator blowdown system) is located indoors and is credited for limiting temperatures to containment building system containment penetrations. The insulation

also limits steam generator blowdown system piping overpressurization in the containment building during accident conditions. The plant indoor environment is a non-aggressive environment that does not promote aging of the foamglass or calcium silicate insulation materials.

There is no industry experience or WCGS operating experience that indicates insulation materials of calcium silicate sheathed in aluminum or foamglass sheathed in stainless steel in non-aggressive environments experience aging effects that require management. The following SERs identified insulation in the scope of license renewal and determined there were no aging effects:

- NUREG 1785 (H.B. Robinson)
- NUREG 1831 (D.C. Cook)
- NUREG 1838 (Millstone 2 and 3)
- NUREG 1839 (Point Beach 1 and 2)
- NUREG 1856 (Brunswick)

NUREG 1801 does not evaluate calcium silicate or foamglass insulation materials. NUREG 1801 does conclude there are no aging effects that require management for stainless steel (sheathing) and aluminum (sheathing) in plant indoor air. The calcium silicate and foamglass insulation materials in LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5 are jacketed with stainless steel or aluminum. Therefore, it is concluded that there are no aging effects requiring management for the insulation materials in LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5.

Staff Evaluation

The staff finds the applicant's response acceptable because it explains adequately as to why no aging effect requiring management was applicable to insulation (which is sheathed in aluminum or stainless steel) exposed to plant indoor air. See also the applicant's response to the staff's follow up question AMRA075.

Question No AMRA042 LRA Sec 3.4

Audit Question LRA Section 3.4.2.1.1 describes materials, environment, aging effects requiring management, and AMPs pertaining to the main turbine system. The environments listed in this section are the plant indoor air and the secondary water. The GALL Report, Section VIII. A, which covers the main turbine system, also includes components exposed to the steam and the lubricating oil environments. Explain why these environments are not addressed in the LRA description and the tables pertinent to the main turbine system.

Final Response

The purpose of the WCGS main turbine system is to convert steam thermal energy from the main steam system to mechanical energy to drive the main generator. The main turbine system serves no safety function, has no safety design basis, and does not meet the criteria of 10CFR54.4(a)(1). The components of the main turbine system are located completely within the turbine building. Any failure of main turbine system components will not affect any plant safety-related equipment and does not meet the criteria of 10CFR54.4(a)(2). Portions of the main turbine system are in-scope of license renewal to support the requirements of fire protection and ATWS based on the criteria of 10CFR54.4(a)(3). Fire protection requires the turbine to be tripped to support controlled depressurization of the secondary side systems. The fire protection trip function has no in-scope mechanical equipment. ATWS related mechanical equipment is turbine impulse piping and valves with an internal environment of secondary water and external environment of plant indoor air. Secondary water includes steam per LRA Table 3.0-1, Mechanical Environments. Therefore the only environments associated with the main turbine system are secondary water (includes steam) and plant indoor air.

Staff Evaluation

The staff finds the applicant's response acceptable because it provides adequate explanation as to why no main turbine system components exposed to steam and lubricating oil were in the scope of license renewal.

Question No AMRA043 LRA Sec 3.4

Audit Question LRA Table 3.4.2-5, steam generator blowdown system, includes stainless steel pumps exposed to secondary water environment. According to this table, the aging effect requiring management is loss of material. Clarify what is the temperature of the treated water to which these components are exposed to. Justify why cracking is not identified as the aging effect requiring management for these components.

Final Response

The pumps listed in Table 3.4.4-5 for the steam generator blowdown system are the steam generator drain pumps. The pump bodies are cast austenitic stainless steel (CASS) with an internal environment of secondary water when in use. These pumps are not used during normal plant operation and do not experience elevated temperatures above room ambient temperature during plant operation. The pumps are used for draining the steam generators after the steam generators have been cooled down to near ambient conditions. The pumps are in-scope for spacial interaction since the pumps and piping are not drained after use. The maximum temperature experienced by the pumps is well below the threshold temperature of 482 degrees F for thermal embrittlement of CASS. Cracking is not a consideration for the steam generator drain pumps since they are not normally used to drain the steam generators at fluid temperatures above 140 degrees F. However, WCGS Procedure SYS BM-201, Steam Generator Draining, has a precaution that fluid temperatures could be as high as 150 degrees F. Since steam generator draining is a limited duration evolution not accomplished during normal plant operations, cracking is not a consideration for the steam generator drain pumps.

Staff Evaluation

The staff finds the applicant's response acceptable because it explains why the pumps included in LRA Table 3.4.2-5 are not subject to cracking as an aging effect requiring management. The applicant explains that the pumps listed in the table are steam generator drain pumps which are not used during normal plant operation and are not exposed to fluid temperatures above 140°F.

Question No AMRA044 LRA Sec 3.4

Audit Question LRA Table 3.4.2-6, auxiliary feedwater system, includes several line items pertaining to heat exchangers.

a. Clarify what type of heat exchanger is HX # 154. If it is a shell and tube heat exchanger, explain what is flowing through the tubes and which line item addresses the aging management of tubes for this heat exchanger.

b. There is one item on tube sides for HX # 155, 156 and 157 exposed to lubricating oil. Reduction of heat transfer or fouling is only addressed for HX # 157. Explain why is the reduction in heat transfer not addressed for HX # 155 and 156. Justify why an aging management is not required for the shell sides of these three heat exchangers.

c. There are two line items addressing tube side of heat exchangers (HX # 155, 156, 157) exposed to secondary water (internal) and plant air (external). Clarify what type of heat exchangers are these.

d. Provide operating experience (including maintenance) for HX # 154, 155, 156 and 157.

Final Response

The line items in LRA Table 3.4.2-6 all relate to the turbine lube oil cooler which is a shell and tube heat exchanger. Multiple heat exchangers are not being addressed in the table only the turbine lube oil cooler. The heat exchanger (HX) numbers in LRA Table 3.4.2-6 apply to HX subcomponents of the turbine lube oil cooler. The terminology for HX # 154, # 155, # 156, and # 157 is explained in LRA Table 2.3.4-6. The HX shell (#154) is carbon steel, the HX head (#155) is carbon steel, the HX tube sheet (#156) is carbon steel, and the HX tubes (#157) are carbon steel.

Turbine lube oil flows into the inlet HX head, the turbine lube oil flows through the HX tubes, and out the outlet HX head. Secondary water from downstream of the auxiliary feedwater pump flows into the HX shell and returns to the auxiliary feedwater pump suction. The interior of the HX tubes have an environment of turbine lube oil and an external environment of secondary water. The HX heads have an internal environment of turbine lube oil. The HX shell has an internal environment of secondary water. The HX tube sheets have turbine lube oil on one side and secondary water on the other side. The external environment for both the heads and shell is plant indoor air.

Loss of heat transfer applies to the turbine lube oil cooler based on NUREG 1801 line VIII.G-15. Maintenance records and operating experience for the turbine lube oil cooler do not indicate any issues of note. Turbine lube oil sample analyses have been within specifications. Lube oil cooler inspections during turbine overhaul periods have identified no issues.

Staff Evaluation

The staff finds the applicant's response acceptable because it includes a clarification that the heat exchanger numbers listed in LRA Table 3.4.2-6 do not represent multiple heat exchangers.

All heat exchanger line items represent the subcomponents of just one heat exchanger, which is the turbine lube oil cooler. The applicant's response also confirms that this heat exchanger is a shell and tube type heat exchanger and provides information on the operating experience for this heat exchanger.

Question No AMRA045 LRA Sec 3.4
Audit Question LRA Table 3.4.2-6, auxiliary feedwater system, includes a line item for turbine exposed to lubricating oil. Explain which specific components of the turbine are subject to loss of material for exposure to lubricating oil. Confirm that the internal surfaces of these components are within the scope of the One Time Inspection Program.

Final Response

The auxiliary feedwater steam turbine is included as a component in the main steam system in LRA Table 3.4.2-2. The turbine component type listed in LRA Table 3.4.2-6 for the auxiliary feedwater system is for the auxiliary feedwater turbine lube oil support subcomponents. Included subcomponents are lube oil piping, lube oil sump and lube oil bearing reservoirs. The lube oil pump is a separate item in LRA Table 3.4.2-6. The internal surfaces of the auxiliary feedwater turbine lube oil subcomponents in the auxiliary feedwater system are included in the One Time Inspection Program.

Staff Evaluation

The staff finds the applicant's response acceptable because it provides adequate explanation that the line item listed in LRA Table 3.4.2-6, as the turbine exposed to lubricating oil, represents auxiliary feedwater turbine lube oil support subcomponents such as lube oil piping, sump, and bearing reservoirs and the lube oil pump is listed as a separate line item.

Question No AMRA046 LRA Sec 3.4
Audit Question LRA Table 3.4.2-3, feedwater system, includes several line items pertaining to tube sides of heat exchangers HX # 152 and HX # 153. Describe the type of these heat exchangers and flow conditions in tube and shell sides.

Final Response

The line items in LRA Table 3.4.2-3 all relate to the High Pressure (HP) feedwater heaters which are shell and tube heat exchangers. Multiple heat exchangers are not being addressed in the table only the HP feedwater heaters. The heat exchanger (HX) numbers in LRA Table 3.4.2-3 apply to HX subcomponents of the HP feedwater heaters. The terminology for HX # 152 and # 153 is explained in LRA Table 2.3.4-3. HX head (#151) is carbon steel, the HX tube sheet (#152) is carbon steel, the HX tubes (#153) are stainless steel, and the HX shell (#158) is carbon steel. HP secondary water going to the steam generators flows into the inlet HX head,

the secondary water flows through the HX tubes, and out the outlet HX head. Secondary water from extraction steam flows into and out of the HX shell. The interior of the HX tubes has an environment of HP secondary water (going to the steam generators) and an external environment of secondary water from extraction steam. The HX heads have an internal environment of secondary water going to the steam generators. The HX shell has an internal environment of secondary water from extraction steam. The HX tube sheets have secondary water on both sides. The external environment for both the heads and shell is plant indoor air.

Staff Evaluation

The staff finds the applicant's response acceptable because it includes a clarification that the heat exchanger numbers listed in LRA Table 3.4.2-3 do not represent multiple heat exchangers. All heat exchanger line items represent the subcomponents of just one heat exchanger, which is the high pressure feedwater heater. The applicant's response also confirms the type of this heat exchanger.

Question No AMRA047 LRA Sec 3.5

Audit Question LRA Table 3.5.1, item 3.5.1.33, Group 1-5: concrete, states that aging effect is reduction of strength and modulus of concrete due to elevated temperature. Identify which plant specific AMP is being used to manage this aging effect. Explain why Notes E and 3 were used for this item.

Final Response

As noted in the Discussion column of LRA Table 3.5.1, Item 3.5.1.33, the plant-specific aging management program used to manage this aging effect is the Structures Monitoring Program (B2.1.32).

[Note E: Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.] This note was used because NUREG-1801, item III.A4-1, specifies a plant-specific aging management program.

[Note 3: Concrete is monitored for visible signs of aging effects due to increased temperature by Structures Monitoring Program (B2.1.32).] This note was used to clarify the action to be performed by the Structures Monitoring Program as it pertains to this item.

Staff Evaluation

The staff finds the applicant's response acceptable because the applicant has provided an adequate explanation for using Notes E and 3 and the applicant also meets SRP Section 3.5.2.2.2.3 criteria, consistent with the GALL Report and WCGS Technical Specification.

Question No AMRA048 LRA Sec 3.5

Audit Question LRA Table 3.5.2-22, containments, structures, and component supports, lists a component type of "supports ASME 2 and 3" (page 3.5-166). The LRA references Table 1, item 3.5.1.42, and Notes I and 4. However, the table does not provide a definition for Note I. Provide the definition for Note I and explain why this Note was used.

Final Response

The list of Standard Notes for LRA Table 3.5.2-22 will be amended to add Note I: "Aging effect in NUREG-1801 for this component, material and environment combination is not applicable."

Staff Evaluation

The staff finds the applicant's response acceptable because by letter dated August 31, 2007, the applicant amended the LRA table 3.5.2-22 to add the missing Note I to the standard notes.

Question No AMRA049 LRA Sec 3.5
Audit Question LRA Table 3.5.1, item 3.5.1.43, corresponds to GALL Report, items III.A3-11 and III.A1-11, which state that masonry block walls are subject to cracking due to restraint shrinkage, creep, and aggressive environment. The GALL Report recommends the Masonry Wall Program to manage this aging effect. The lines referencing item 3.5.1.43 manage this aging effect with the Masonry Wall and the Fire Protection Programs, with no further evaluation recommended. Explain why Notes E and 1 were used for this line item.

Final Response

Some Masonry Walls at WCGS are credited as fire barriers, therefore, they must be inspected in accordance with the Fire Protection program (B2.1.12).

[Note 1: NUREG-1801 does not provide a line in which concrete masonry is inspected per the Fire Protection program (B2.1.12).] This note was used to explain the addition of the Fire Protection AMP to this line instead of using another line.

[Note E: Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.] This note was used because a different AMP (Fire Protection) is credited.

Staff Evaluation

The staff reviewed the AMR results lines which referenced to Note E and determined that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends AMP XI.S5, "Masonry Wall Program," the applicant has proposed using the Fire Protection Program. The GALL Report line item referenced is the masonry block wall, and therefore, the GALL Report recommends AMP XI.S5. However, the AMR results lines item that reference LRA table 3.5.1 item 3.5.1-43, are listed only as fire barrier that is in the scope for 10 CFR 54.4(a)(2) criterion and are not in the masonry wall system. The Fire Protection Program visually inspects and is therefore an acceptable program for this line item.

Question No AMRA050 LRA Sec 3.5

Audit Question In LRA Table 3.5.2-14, a line references to item 3.5.1.45. Explain why Notes E and 3 were used instead of Note A.

Final Response

LRA Table 3.5.1, Item 3.5.1.45, will be amended to revise the Aging Management Program entry to read: "Inspection of Water-Control Structures (B2.1.33)." This amendment to the LRA will correctly align this item with the SRP.

[Note E: Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.] This note was used because the Structures Monitoring Program is credited instead of Water-Control Structures.

[Note 3: WCGS inspects the submerged portions of the Circulating Water Screen House as part of the Structures Monitoring Program (B2.1.32).] This note was used to identify the AMP that is used at WCGS to inspect the CWSH.

Staff Evaluation

By the letter dated August 31, 2007, the applicant amended the LRA Table 3.5.1, item 3.5.1.45 aging management program entry to read: "Inspection of Water-Control Structures." This amendment to the LRA correctly aligns this item with the SRP. The applicant also indicated that WCGS inspects the submerged portions of the Circulating Water Screen House as part of the Structures Monitoring Program. Therefore, the Structures Monitoring Program is credited instead of Water Control Structures. The staff reviewed the AMR results for this line item and determined that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends AMP XI.S7, "Inspection of Water-Control Structures Program ," the applicant has proposed using the Structures Monitoring Program. Because, the submerged portions of the Circulating Water Screen House is part of the Structures Monitoring Program, the Structures Monitoring Program visually inspects to manage loss of material due crevice cavitation. Based on this, the applicant's response is acceptable.

Question No AMRA051 LRA Sec 3.5

Audit Question In LRA Section 3.5, Table 2s, there are several lines that reference Note E and GALL Report, item 3.5.1.47, for aging management of loss of material due to general (steel only), pitting and crevice corrosion. For this specific item, the GALL Report recommends the use of the Regulatory Guide 1.127, Inspection of Water Control Structures and a protective coating monitoring and maintenance program. Explain why the Structures Monitoring Program (Note E) was credited instead of the programs recommended by the GALL Report.

Final Response

NUREG 1801 line III.A6-11 specifies Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.33) as the aging management program for metal components in water-control structures. Regulatory Guide 1.127, does not address metal components, so the Structures Monitoring Program (B2.1.32) is used. WCGS does not rely upon protective coatings to manage the effects of aging.

Staff Evaluation

The staff finds the applicant's response acceptable because Regulatory Guide 1.127 does not address metal structural components and the specific line item in the LRA corresponds to metal components. The Structures Monitoring program visually inspects to manage loss of material due to general (steel only) pitting and crevice corrosion. Therefore, the use of Structures Monitoring program for this line item is considered adequate.

Question No AMRA052 LRA Sec 3.5
Audit Question For LRA Table 3.5.1, item 3.5.1.33, provide the maximum temperature that concrete experience in Group 1-5 structures.

Final Response

USAR Section 3.8.3.4.2 discusses loading on the primary shield wall. During normal plant operation, the primary shield wall concrete temperatures are limited to 150°F except for the area directly below the seal ring support which is limited to 220°F. High energy line containment penetrations have been designed with flued heads to dissipate the heat from these process pipes, and insulation has been installed to further limit the exposure of the concrete. WCGS Technical Specifications require that the containment average air temperature be less than or equal to 120 degrees F.

In the auxiliary building, concrete temperatures are limited to 150°F except for local areas, which are limited to 200 degrees F. These limits are maintained by insulation installed on high temperature lines and the plant ventilation system.

There are no other in-scope structures that house high temperature lines.

Staff Evaluation

The containment cooling system provides cooling to ensure temperature limits are not exceeded. The highest concrete temperature in the area directly below the seal ring support is not load bearing.

The staff determined through discussions with the applicant's technical staff that the reduction of strength and modulus of concrete structures due to elevated temperatures is not a plausible aging effect due to the nonexistence of these aging mechanisms. The applicant stated that to the aging effects due to elevated temperature are not expected at WCGS for the concrete associated with Groups 1-5 structures since general area temperatures within the primary containment do not exceed 150°F except for the area directly below the seal ring support which is limited to 220 °F and local area temperatures do not exceed 200°F. The staff finds the applicant's response that the accessible concrete components will be monitored by the

Structures Monitoring program to identify and manage any visible effects due to elevated temperatures to the WCGS Groups 1-5 structures concrete to be acceptable.

Question No AMRA053 LRA Sec 3.5

Audit Question In LRA Table 3.5.2-16, there is one line that references item 3.5.1.28 and states that crack and distortions will be managed by the Regulatory Guide 1.127, Inspection of Water - Control Structures Associated with Nuclear

Power Plants Program. Explain why this AMP is used instead of the Structures Monitoring Program recommended by the GALL Report.

Final Response

The ESW Discharge Structure is normally submerged and is inspected by divers. It is inspected under WCGS's program that is based on RG 1.127. The Structures Monitoring program credits this program for the ESW Discharge Structure.

LRA Table 3.5.2-16 line item that refers to Table 1 line item 3.5.1.28, will be amended to revise the Aging Management Program entry to read: "Structures Monitoring Program (B2.1.32)" and to reference Note A instead of Note E and delete reference to Note 1.

The list of Standard Notes for LRA Table 3.5.2-16 will be amended to delete note 1.

Staff Evaluation

By letter dated August 31, 2007, the applicant amended the Table 3.5.2-16 line item as stated in the response. The AMR results for this line item are now consistent with the corresponding line of the GALL Report. Based on this, the staff finds the applicant's response acceptable.

Question No AMRA054 LRA Sec 3.5

Audit Question Provide the following information regarding LRA Section 3.5.2.2.2.6:

a. Additional information about the bolting material used in structural applications, including group B1.1 application at WCGS:

(i) Clarify what is the bolting material.
(ii) Clarify what is the normal yield strength and upper-bound as received yield strength.
(iii) Describe the WCGS resolution of the bolting integrity generic issue as it relates to structural bolting.
(iv) Clarify if any structural bolting has been identified as potentially susceptible to cracking due to SCC. List any structural bolting replaced as part of the resolution.

b. Describe the scope and aging management review performed for class MC pressure retaining bolting. Explain how WCGS manages loss of pre-load.

Final Response

a. LRA Table 3.5.2-22 includes a line item for high strength bolting made from high strength, low alloy steel. These bolts are also addressed in LRA Table 3.5.1, Item 3.5.1.51. At WCGS, the maximum ultimate tensile strength for bolts was limited to 170 ksi. Specifications C-134A (Bechtel) and M-730 (Westinghouse), as well as USAR App. 3A, pg 3A-53, limit the bolting materials that can be used at WCGS. Of the bolting materials specified, only SA-540 Grade 21 has a specified minimum yield of equal to or greater than 150 ksi. All other bolting material used at WCGS has a yield strength less than 150 ksi.

For high strength bolting to be susceptible to SCC, material with an actual yield strength of greater than 150 ksi must be subjected to excessive bolt preload and contaminants, such as molybdenum sulfide in the thread lubricants. Bolt preload was managed by procedural controls, and lubricants containing detrimental contaminants were not used. Therefore, cracking due to SCC is not an aging effect requiring management for high strength bolting at WCGS.

A review of plant operating experience has not found any instances of SCC, and no structural bolting has been replaced due to this concern.

b. There is no class MC pressure retaining bolting at WCGS. Loss of preload is managed by the Bolting Integrity AMP (LRA Section B2.1.7)

Staff Evaluation

This question was for information (clarification) only. The applicant's response is acceptable as it provides the requested information.

Question No AMRA055 LRA Sec 3.5
Audit Question LRA Table 3.5.2-1, containments, structures, and component supports, lists a component type of penetration which makes reference to Note H. However, the table does not provide a definition for Note H. Provide a definition for this note and justify its use for this specific component.

Final Response

The list of Standard Notes for LRA Table 3.5.2-1 will be amended to add Note H: "Aging effect not in NUREG-1801 for this component, material and environment combination."

Staff Evaluation

The staff finds the applicant's response acceptable because by letter dated August 31, 2007, the applicant amended LRA Table 3.5.2-1 to include the missing definition of Note H.

Question No AMRA056 LRA Sec 3.5
Audit Question LRA Table 3.5.2-12, containments, structures, and component supports, lists a component type of liner spent fuel pool which makes reference to Note H. However, the table does not provide a definition for Note H. Provide a definition for this note and justify its use for this specific component.

Final Response

The list of Standard Notes for LRA Table 3.5.2-12 will be amended to add Note H: “Aging effect not in NUREG-1801 for this component, material and environment combination.”

Staff Evaluation

The staff finds the applicant’s response acceptable because by letter dated August 31, 2007, the applicant amended LRA Table 3.5.2-12 to include the missing definition of Note H.

Question No AMRA057 LRA Sec 3.6

Audit Question In LRA Table 3.6.1, item 3.6.1.6, the applicant stated that all fuse holders including the fuses installed for electrical penetration protection are part of larger assemblies, so the applicable GALL Report items were not used. In Interim Staff Guidance (ISG)-5, "Identification and Treatment of Electrical Fuse Holders for License Renewal," the staff provides examples of fuse holders that require an AMR. These are fuses that are installed in fuse holder panels which are used as protective devices to ensure the integrity of containment electrical penetration or as isolation devices between Class 1E and non-Class 1E electrical circuits.

a. List all components in an electrical containment protection assembly and explain why fuse holders installed in this assembly are considered part of a larger active assembly.

b. Identify fuse holders installed as isolation devices between Class 1E and non-Class 1E electrical circuits. Explain why these fuse holders do not require an AMR.

c. Provide a schematic diagram for electrical containment protection for review during the site visit.

Final Response

a) The electrical containment penetration assemblies at WCGS do not incorporate self-fusing characteristics and must be protected externally. The fuses that are used to protect the electrical containment penetrations are installed in larger assemblies (i.e. motor control center cubicles, main control boards, distribution panels, etc.).

b) The WCGS controlled fuse list does not identify which of the over 2500 fuses are used as isolation devices between Class 1E and non-Class 1E electrical circuits. The fuse list does identify the locations for all of the fuses. A review of this list determined that there are no fuses in the scope of license renewal that are not installed as part of a larger assemblies. The aging of the components including the fuse holders within these assemblies is managed as part of the active component. The WCGS does not install fuse in standalone fuse panels or cabinets.

c) Drawings E-13LF08, E-13BB03 and E-13EP02B show typical arrangements of the electrical containment penetration protection circuits.

Staff Evaluation

The staff finds the applicant's response acceptable because in accordance with 10 CFR 50.54, fuse holders installed in an active assembly are piece part of an active assembly and do not require an AMR.

Question No AMRA058 LRA Sec 3.6

Audit Question In LRA Table 3.6.1, item 3.6.1.12, the applicant takes an exception to the GALL Report for the transmission conductors and connections, and switchyard bus and connections. In addition, the applicant states that the aging effect in the GALL Report for this material and environment combination is not applicable. In LRA Section 3.6.2.2.3, the applicant further states that transmission conductor connections at the time of installation are treated with corrosion inhibitors to avoid connection oxidation and are torqued to avoid loss of pre-load.

SRP Section 3.6.2.2.3 states that increased resistance of connections due to oxidation or loss of pre-load could occurs in transmission conductors and connections, and in switchyard bus and connections. Further, EPRI document TR-104213, "Bolted Joint Maintenance & Application Guide," states that increased temperature difference in electrical bolted joints is due to high circuit rating or increased current duration. The temperature of an electrical bolted joint will rise and stress will increase with increasing current duration. If this temperature increase is not taken into consideration, loose or failure joints will result.

a. Explain why torque relaxation for bolted connections of switchyard bus and transmission conductors is not a concern at WCGS.

b. Provide a discussion about the qualified life of corrosion inhibitors. Explain why increased resistance of bolted connections due to oxidation is not a concern for switchyard bus and transmission connections.
Follow-up:
Question 58 - Provide thermographic data for startup XFMR high voltage connections.

Final Response

a) Torque relaxation for bolted connections of switchyard bus and transmission conductors is not a concern at WCGS because stainless steel bolts with stainless steel washers are used to maintain the proper torque and prevent loss of pre-load. The in-scope bolted transmission connections are at the startup transformer XMR01 and disconnect 345-163. These connections are periodically evaluated via thermography as part of the preventive maintenance activities performed on the startup transformer and disconnect. Based on temperature data in the USAR Chapter 2.3, the transmission connections do not experience thermal cycling. The transmission connections are subject to average

monthly temperatures ranging from 80 ºF in July and August to 29 ºF in January with minimal ohmic heating.

b) The corrosion inhibitors compound (a grease-type sealant) is a consumable which is used for initial assembly of bolted connections and is replaced as required when connections are taken apart and reassembled (e.g., during routine maintenance). The compound is weather resistant and adheres to the connection to ensure low contact resistance. Based on operating experience, this method of installation has been shown

to provide a corrosion resistant low electrical resistance connection. The WCGS outdoor environment is not subject to industry air pollution or saline environment. The connections do not experience any appreciable aging effects in this environment. Therefore, it is concluded that general corrosion resulting in the oxidation of transmission connection surface metals is not an aging effect requiring management at WCGS. The in-scope bolted connections are at the startup transformer XMR01 and disconnect 345-163. These connections are periodically evaluated via thermography as part of the preventive maintenance activities performed on the startup transformer and disconnect.

Periodic thermography will continue into the period of extended operation. A copy of the Infrared Thermography Report dated 10/23/03 for the Startup Transformer was provided along with a copy of the work order history. The thermography results show that based on the transmission line capacity vs the connected load these connections experience minimal to no ohmic heating. These electrical bolted joints do not experience high circuit rating or increased current duration as discussed in EPRI document TR-104213, "Bolted Joint Maintenance & Application Guide."

The last paragraph of LRA further evaluation 3.6.2.2.3 will be amended to read the following.

The WCGS outdoor environment is not subject to industry air pollution or saline environment. Aluminum bus material, galvanized steel support hardware and stainless steel connection material do not experience any appreciable aging effects in this environment. These connections are periodically evaluated via thermography as part of the preventive maintenance activities performed on the startup transformer and disconnect. The periodic thermography will continue into the period of extended operation.

Staff Evaluation

The staff reviewed the infrared thermography report data and verified that the startup transformer connections experienced minimal ohmic heating. Based on the data, the staff determined that these electrical bolted connections do not experience high temperature as a result of ohmic heating. Anti-oxidant compound is used in bolted connections to prevent the formation of oxides on the metal surface and to prevent moisture entering the connections thus reducing the chances of corrosion. Therefore, increased resistance fo bolted connections due to oxidation is not an aging effect requiring management at WCGS. Because startup transformer connections experienced minimal ohmic heating, bolt loosening due to ohmic heating is not an aging effect requiring management at WCGS. In addition, a periodic infrared thermography inspection on the startup transformer and disconnect is performed as part of preventive maintenance activities to maintain the integrity of in-scope switchyard connections. This inspection will continue into the period of extended operation. On the basis of its review, the staff finds the applicant’s response acceptable.

Question No AMRA059 LRA Sec 3.6

Audit Question GALL Report, Chapter VI, item VI.A-1, cable connections (metallic parts), lists air indoor and air outdoor as the environment. LRA Table 3.6.2-1, lists air indoor; however, it does not include air outdoor environment. Justify why oxidation of cable connections is not an aging effect for cable connections in an outdoor environment.

Final Response

LRA Table 3.6.2-1 will be amended to include electrical cable connections in outdoor air.

Staff Evaluation

The staff finds the applicant response acceptable because oxidation of cable connections is a potential aging mechanism in outdoor air environment. By letter dated August 31, 2007, the applicant amended LRA Table 3.6.2-1 to add a line item for cable connections exposed to atmosphere/weather. The environment is now consistent with GALL Report

Question No AMRA060 LRA Sec 3.6

Audit Question GALL Report, Chapter VI, item VI.B-1, identifies adverse localized environment due to heat, radiation, or moisture in the presence of oxygen. LRA Table 3.6.2-1 only lists adverse localized environment (ext). Justify why aging caused by heat, radiation, or moisture is not a concern at WCGS.

Final Response

LRA Table 3.0-3 defines an Adverse Localized Environment as follows:
Adverse localized environments can be due to any of the following: (1) exposure to moisture and voltage (2) heat, radiation, or moisture, in the presence of oxygen (3) heat, radiation, or moisture, in the presence of oxygen or >60-year service limiting temperature, or (4) adverse localized environment caused by heat, radiation, oxygen, moisture, or voltage. The term “>60-year service limiting temperature” refers to that temperature that exceeds the temperature below which the material has a 60-year or greater service lifetime.

Staff Evaluation

The staff finds the applicant response acceptable because the applicant already defines adverse localized environment in LRA Table 3.0-3.

Question No AMRA061 LRA Sec 3.3

Audit Question LRA Table 3.3.1, item 3.3.1.69, states that this line is consistent with the GALL Report except that a different AMP is credited for stainless steel piping, piping components, and piping elements exposed to raw water on the internal surfaces. The Fire Water System Program will be credited along with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components to manage the aging effects. This corresponds to

several line items in LRA Table 3.3.2-14, fire protection system, where Note E is referenced.

Describe how these two programs are used in conjunction to manage these aging effects.

Final Response

The Fire Water System program manages loss of material for water-based fire protection systems. Periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests considering National Fire Protection Association (NFPA) codes and standards ensure that the water-based fire protection systems are capable of performing their intended functions. The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler nozzle to verify that each open head spray/sprinkler nozzle is unobstructed. The Fire Water System program tests a representative sample of fire protection sprinkler heads or replaces those that have been in service for 50 years, using the guidance of NFPA 25 2002 Edition, and tests at 10 year intervals thereafter during the period of extended operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

Visual inspections evaluating wall thickness to identify evidence of loss of material due to corrosion, ensuring against catastrophic failure, are covered by the aging management program XI.M38 "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components". The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP manages cracking, loss of material and hardening - loss of strength for components whose internal inspections are not covered by other aging management programs. Thus, the Fire Water System program internal visual inspections are covered by the Internal Inspection program. Other inspections such as, fire detection and suppression testing and maintenance, yard fire hydrant inspections and flushing, powerblock fire hose testing, hose station gasket inspections and sprinkler/spray nozzle inspections are covered by the Fire Protection program.

Internal visual inspections will be conducted during periodic maintenance, surveillance testing and corrective maintenance to the fire protection system components in the program.

Staff Evaluation

The applicant provided information of how the Fire Water System program was used in conjunction with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effects. On the basis that periodic visual inspections are performed to evaluate wall thickness as recommended by the GALL AMP XI.M27, the staff finds the applicant response acceptable.

Question No AMRA062 LRA Sec 3.3

Audit Question LRA Table 3.3.1, item 3.3.1.70, states that this line is consistent with the GALL Report except that a different AMP is credited for copper alloy piping, piping components, and piping elements exposed to raw water on the internal surfaces. The Fire Water System Program will be credited along with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effects. This corresponds to several line items in LRA Table 3.3.2-14, fire protection system, where Note E is referenced.

Describe how these two programs are used in conjunction to manage these aging effects.

Final Response

The Fire Water System program manages loss of material for water-based fire protection

systems. Periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests considering National Fire Protection Association (NFPA) codes and standards ensure that the water-based fire protection systems are capable of performing their intended functions. The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler nozzle to verify that each open head spray/sprinkler nozzle is unobstructed. The Fire Water System program tests a representative sample of fire protection sprinkler heads or replaces those that have been in service for 50 years, using the guidance of NFPA 25 2002 Edition, and tests at 10 year intervals thereafter during the period of extended operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

Visual inspections evaluating wall thickness to identify evidence of loss of material due to corrosion, ensuring against catastrophic failure, are covered by the aging management program XI.M38 "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components". The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP manages cracking, loss of material and hardening - loss of strength for components whose internal inspections are not covered by other aging management programs. Thus, the Fire Water System program internal visual inspections are covered by the Internal Inspection program. Other inspections such as, fire detection and suppression testing and maintenance, yard fire hydrant inspections and flushing, powerblock fire hose testing, hose station gasket inspections and sprinkler/spray nozzle inspections are covered by the Fire Protection program.

Internal visual inspections will be conducted during periodic maintenance, surveillance testing and corrective maintenance to the fire protection system components in the program.

Staff Evaluation

The applicant provided information of how the Fire Water System program was used in conjunction with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effects. On the basis that periodic visual inspections are performed to evaluate wall thickness as recommended by the GALL AMP XI.M27, the staff finds the applicant response acceptable.

Question No AMRA063 LRA Sec 3.4
Audit Question LRA Tables 3.4.2-3 and 3.4.2-6 list several line items related to management of loss of material in steel heat exchanger components exposed to secondary water. These line items refer to LRA Table 3.4-1, item 3.4.1.04, with Note D.

LRA Table 3.4-1, item 3.4.1.04, addresses management of loss of material for steel piping, piping components, and piping elements exposed to treated water. LRA Table 3.4.1, item 3.4.1.03, however; covers loss of material for steel heat exchangers. Even though the line item in LRA

Table 3.4-1 is listed for condensate and steam generator blowdown systems, it has the same component, material, environment and aging effect as the line items in Table 3.4.2 3. Explain why LRA Table 3.4.1, item 3.4.1.03, has not been used instead of item 3.4.1.04.

Final Response

NUREG 1801 Table VIII.D for PWR Feedwater System has no HX lines, therefore Table line VIII.D1.8 (steel piping in a treated water environment) was used for steel heat exchanger in a treated water environment. NUREG 1801 Table VIII.G for PWR Auxiliary Feedwater System has HX lines but not for steel in treated water, therefore Table line VIII.G-38 was used for steel piping in a treated water environment. Lines VIII.D1.8 and VIII.G-38 provide aging effects/aging mechanism of loss of material/general, pitting, and crevice corrosion and aging management programs of water chemistry and one-time inspection.

LRA Table 3.4.1, item 3.4.1.03 addresses components in the condensate and blowdown system. NUREG 1801 lineVIII.E-37 for the condensate system and NUREG 1801 lineVIII.F-28 for the blowdown system evaluate steel HX components in a treated water environment. These lines provide aging effects/aging mechanism of loss of material/general, pitting, and crevice corrosion and aging management programs of water chemistry and one-time inspection.

The aging effects, aging mechanism, and aging management programs from NUREG 1801 lines VIII.D1.8 and VIII.G-38 (LRA Table 3.4.1, item 3.4.1.04) are the same as those associated with LRA Table 3.4.1, item 3.4.1.03.

Staff Evaluation

The staff finds the applicant's response acceptable because it provides an adequate rationale for using LRA Table 3.4.1, Item 3.4.1.04 with Note D, for management of loss of material aging effect for heat exchanger components exposed to secondary water.

Question No AMRA064 LRA Sec 3.4

Audit Question LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5 include several line items related to insulation materials exposed to the plant indoor air. These items reference Note J and state that there are no aging effects to be managed.

Degradation of the thermal insulation on piping and equipment can result in the loss of insulating capability which may cause the area temperature to increase.

a. Justify why the degradation of insulating properties is not an issue.

b. Provide plant specific and industry operating experience relative to this aspect.

c. Clarify if there is environmentally qualified equipment in the vicinity of the insulation and if the temperature rise been evaluated.

Final Response

The piping insulation identified in LRA Tables 3.4.2-2 (main steam system), 3.4.2-3 (feedwater system) and 3.4.2-5 steam generator blowdown system is located indoors and is credited for limiting temperatures to containment building system containment penetrations. The insulation also limits steam generator blowdown system piping overpressurization in the containment building during accident conditions. The plant indoor environment is a non-aggressive environment that does not promote aging of the foamglass or calcium silicate insulation materials.

There is no industry experience or WCGS operating experience that indicates insulation materials of calcium silicate sheathed in aluminum or foamglass sheathed in stainless steel in non-aggressive environments experience aging effects that require management. The following SERs identified insulation in the scope of license renewal and determined there were no aging effects:

- NUREG 1785 (H.B. Robinson)
- NUREG 1831 (D.C. Cook)
- NUREG 1838 (Millstone 2 and 3)
- NUREG 1839 (Point Beach 1 and 2)
- NUREG 1856 (Brunswick)

NUREG 1801 does not evaluate calcium silicate or foamglass insulation materials. NUREG 1801 does conclude there are no aging effects that require management for stainless steel (sheathing) and aluminum (sheathing) in plant indoor air. Therefore, it is concluded that there are no aging effects requiring management for the insulation materials in LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5.

WCGS calcium silicate and foamglass insulation have no aging effects that require aging management. Therefore, there is no loss of intended function and there are no impacts to room temperatures or nearby equipment or structures due to aging of insulation.

Staff Evaluation

The staff finds the applicant's response acceptable because it explains adequately as to why no aging effect requiring management was applicable to insulation (which is sheathed in aluminum or stainless steel) exposed to plant indoor air.

Question No AMRA065 LRA Sec 3.4

Audit Question LRA Table 3.4.2-4 includes a line item pertaining to stainless steel tank exposed to outside atmosphere and weather. The LRA references Note G and states that there are no aging effects requiring management.

a. Describe the location of the tank (e.g., above ground, partially buried, bottom touching the soil).

b. Justify why no aging effect requiring management is considered for the tank exterior.

Final Response

a.) The tank in LRA Table 3.4.2-4 is the Condensate Storage Tank (CST). The CST is constructed of stainless steel and is located above ground outside on a concrete foundation. The external environment is atmosphere/weather. Stainless steel exposed to atmosphere/weather has no aging effect or aging mechanism. Note G was selected since the atmosphere/weather environment is not in NUREG 1801 for stainless steel components.

b.) NUREG 1801 does not address this environment. The WCGS plant outdoor environment is not subject to industrial air pollution or saline environment. The CST is a Stainless Steel tank located in an outside air environment and are is not exposed to aggressive chemical species. Alternate wetting and drying resulting from rain has shown a tendency to "wash" the exterior surface material rather than concentrate contaminants. This is consistent with NUREG-1843, the Browns Ferry SER, section 3.5.2.3 (pages 3-303 and 3-304) that identifies stainless steel components exposed to an outside air environment are not subject to aging.

Staff Evaluation

The staff finds the applicant's response acceptable because it provides the location of the tank as required by the staff's question and adequately explains as to why no aging effect requiring management was applicable to the stainless steel tank exterior exposed to outside atmosphere and weather conditions.

Question No AMRA066 LRA Sec 3.4

Audit Question LRA Table 3.4.2-4 includes a line item pertaining to carbon steel closure bolting exposed to atmosphere and weather. The LRA states that loss of preload is an aging effect requiring management and references Notes H and 1.

Identify in which equipment these closure bolts are located on. Include a brief discussion as to how the AMP credited for aging management will address this specific aging effect.

Final Response

Closure bolting is a generic component that is created to cover closure bolting applications under applicable material and environment combinations. In this case closure bolting was created for applications that use carbon steel bolts or studs subject to an atmosphere/weather environment. Examples of plant components include valves and flanges exposed to atmosphere and weather.

NUREG 1801 does not have a loss of preload line for closure bolting using carbon steel in an atmosphere/weather environment. This condition resulted in the use of Standard Note H. Plant Specific Note 1 explains that loss of preload applies to this application even though NUREG 1801 does not evaluate steel closure bolting in atmosphere/weather environments. AMP XI.M.18, Bolting Integrity is credited for aging management of this loss of preload application. The requirements of the AMP apply completely for this loss of preload application. The AMP requires that bolting installation plant procedures control joint assembly and control of preload. This includes pre-assembly inspection and cleaning requirements, use of specific bolt torque

patterns, use of increased torque application through multiple passes, and verification of uniformity of gasket compression. Post-bolting inspections include verifying contact between the fastener and flange and proper flange alignment.

Staff Evaluation

The staff finds the applicant's response acceptable because it provides the description of the carbon steel bolting as required by the staff's question and adequately explains as to how the loss of preload aging effect will be managed for the closure bolts exposed to atmosphere and weather conditions.

Question No AMRA067 LRA Sec 3.4

Audit Question LRA Table 3.4.2-3 includes several heat exchanger components which are exposed to plant indoor air and secondary water. The LRA states that loss of material and cracking (in one case) are aging effects requiring management.

Justify why heat transfer is not stated as the intended function for these and why loss of heat transfer is not considered as an aging effect requiring management.

Final Response

The High Pressure (HP) feedwater heaters are in-scope for feedwater system pressure boundary integrity to support post fire safe shutdown requirements per 10CFR54.4(a)(3). Heat transfer is not an intended function for the HP feedwater heaters.

Staff Evaluation

The staff finds the applicant's response acceptable because it provides adequate explanation that the heat exchangers (high pressure feedwater heaters) listed in LRA Table 3.4.2-3 were in scope for feedwater system pressure boundary integrity to support requirements of fire safe shutdown and not for heat transfer as the intended function.

Question No AMRA068 LRA Sec 3.2

Audit Question SRP-LR Section 3.2.2.2.6 states that loss of material due to erosion may occur in the stainless steel high-pressure safety injection (HPSI) pump miniflow recirculation orifice exposed to treated borated water, LRA Section 3.2.2.2.6 addresses loss of material due to erosion. The applicant stated that this aging effect is not applicable because WCGS does not use the safety injection pumps for normal charging; therefore, the applicable GALL Report line item was not used. Provide procedures and/or other documentation that show infrequent use of the HPSI pumps.

Final Response

The High Pressure Safety Injection pumps are not used for normal charging. The normal and centrifugal charging pumps are part of the Chemical & Volume Control System. USAR Section 9.3.4.2.1.1 discusses the Chemical & Volume Control System Charging, Letdown and Seal Water subsystems. From USAR Section 9.3.4.2.1.1 - Three charging pumps (one "normal" pump and two standby pumps) are provided to take suction from the volume control tank and return the purified reactor coolant to the RCS. Normal charging flow is handled by the normal charging pump.

The HPSI mini-flow recirculation lines containing the flow orifices are only used during the Emergency Core Cooling System injection phase when RCS pressure is above pump shutoff head, or during safety injection pump testing. (ref. USAR Section 6.3.2.1)

Staff Evaluation

The staff found the applicant response acceptable because the applicant demonstrated that the HPSI mini-flow recirculation line containing flow orfices during actuation of the Emergency Core Cooling System or during testing and are not used during normal charging. Since loss of material due to erosion can only occur in these components if they are frequently operated, the staff finds that erosion is not plausible for WCGS HSPI pumps and flow orifices.

Question No AMRA069 LRA Sec 3.2

Audit Question SRP-LR Section 3.2.2.2.9 states that loss of material due to general, pitting, crevice, and MIC may occur in steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. Buried piping and tanks inspection programs rely on industry practice, frequency of pipe excavation, and operating experience to manage the aging effects of loss of material from general, pitting, and crevice corrosion, and MIC. The effectiveness of the buried piping and tanks inspection program should be verified by evaluation of an applicant's inspection frequency and operating experience with buried components to ensure that loss of material does not occur. LRA Section 3.2.2.2.9 addresses loss of material due to general, pitting, crevice, and MIC. The applicant stated that this aging effect is not applicable because WCGS is a PWR. Provide an explanation as to why buried piping is only found at BWRs.

Final Response

Section 3.2.2.2.9 is a roll-up of V.B-9 for Standby Gas Treatment Systems which is a BWR specific system. See NUREG-1800 Table 3.2-1 Item 17; NUREG-1801 Table 2 Item 17; NUREG-1801 line V.B-9. In addition, there is no buried carbon steel piping associated with ESF systems at WCGS.

Staff Evaluation

The staff found the applicant response acceptable because the Standby Gas Treatment Systems is a BWR specific system, and additionally there is no buried carbon steel piping associated with ESF systems at WCGS. As such, this aging effect not applicable to this component type.

Question No AMRA070 LRA Sec 3.3
Audit Question Table 3.3.2-16, page 3.3-163, includes a component item "Insulation" of ceramic fiber insulation material. Please explain where this insulation material is used. Also, note 2 at the bottom of Table 3.3.2-16 does not include ceramic fiber insulation materials. Does note 2 apply to this item?

Final Response

The ceramic fiber insulation is used for diesel generator exhaust line at the penetration of the diesel generation room to prevent overheat of the surrounding concrete. It is made of Kaowool ceramic fiber blanket.

The Note 2 of LRA Table 3.3.2-16 will be amended as follows:

2 "NUREG-1801 does not consider mechanical insulation. The in-scope thermal insulation is located in areas with non-aggressive environments (meaning the insulation is not exposed to contaminants). Based on the review of the site operating experience, it was determined that for stainless steel insulation, closed cell foam, quilted fiberglass insulation, calcium silicate, ceramic fiber and insulation jacketing in non-aggressive environments, there were no aging effects requiring management."

Staff Evaluation

The applicant response is acceptable because the applicant supplemented the LRA to revise Note 2 to add ceramic fiber insulation material. The discrepancy is resolved.

Question No AMRA071 LRA Sec 3.1
Audit Question Three line items in LRA Table 3.1.2-1, crediting Notes "I" and "2," address crack growth in carbon steel with stainless steel cladding in reactor coolant. Note 2 refers to LRA Section 3.1.2.2.5 for further evaluation. LRA Section 3.1.2.2.5 references Westinghouse WCAP 15338-A to support the statement (generic Note I) that the aging effect for this component, material and environment combination is not applicable at WCGS.

The staff approved the use of WCAP-15338-A as a reference in LRAs for Westinghouse 4 loop plants in an SER, dated September 25, 2002 (ML022690375). The subject SER includes the following license renewal action items:

The license renewal applicant is to verify that its plant is bounded by the WCAP-15338 report. Specifically, the renewal applicant is to indicate whether the number of design cycles and transients assumed in the WCAP-15388 analysis bounds the number of cycles for 60 years of operation of its RPV.

Section 54.21(d) of 10 CFR requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation. Those applicants for license renewal referencing the WCAP-15338 report for the RPV components shall ensure that the evaluation of the TLAA is summarily described in the FSAR supplement.
a) Clarify if WCGS has completed the action items as described in the WCAP 15338-A SER.

b) Provide documentation for staff review to support that these action items have been completed.

Final Response

The Nuclear Regulatory Commission (NRC)safety evaluation of WCAP-15338-A notes that "Underclad cracks … have been reported …only in SA-508, Class 2 reactor vessel forgings manufactured to a coarse grain practice and clad by high-heat-input submerged arc processes." In the WCGS vessel only the carbon steel forgings are SA-508 Class 2 or 3. The clad is stainless steel weld metal, Analysis A8; and Ni-Cr-Fe Weld Metal, F-Number 43. Although the vessel contains these SA-508 forgings clad by high-heat-input processes, the qualification of clad welding processes to avoid cracking is documented in WCGS USAR Section 5.3.1.2.g and Appendix 3A section on Reg. Guide 1.43, Revision 0, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components".

No underclad flaws have been detected or analyzed for the WCGS reactor vessel therefore WCAP-15338-A was not invoked. See License Renewal Application (LRA) Section 4.7.2 for additional details.

Staff Evaluation

In response to the questions, the applicant stated that although the reactor vessel contains carbon steel forgings made of SA-508, the cladding weld process was qualified in accordance with the recommendations of Regulatory Guide 1.43, Revision 0, “Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components,” and that no under clad flaws have been detected or analyzed for the WCGS reactor vessel. The staff notes that in LRA Section 4.7.2 the applicant stated that the cyclic and transient loads used in the WCAP analysis bound those expected for WCGS through the period of extended operation, and therefore the WCAP is applicable for WCGS. However, because no under clad flaws have been found, the applicant stated that WCAP-15338-A has not been invoked to support WCGS during the period of extended operation.

On the basis that no underclad flaws have been found in the WCGS reactor vessel and the WCAP report has not been invoked by WCGS to support acceptability of flaws during the period of extended operation, the staff finds that completion of action items required for crediting the WCAP during the period of extended operation is not required at WCGS and that the applicant’s response is acceptable.

Question No AMRA072 LRA Sec 3.1

Audit Question

SRP-LR Section 3.1.3.2.16.2 recommends a one-time inspection of the pressurizer spray head. However, the staff was unable to identify an AMR result line in LRA Table 3.1.2-2 related to the pressurizer spray head.

a) Identify where is the AMR result line for the pressurizer spray heads.
b) Clarify if there will be a one time inspection as recommended in the SRP LR.

Final Response

As indicated in LRA Section 3.1.2.2.16.2, the pressurizer spray head is not included in scope of license renewal. LRA Table 3.1.1 item 3.1.1-36 includes Reactor Coolant System (RCS) stainless steel pipes and valves in the scope of license renewal with a structural integrity (attached) intended function (Criterion (a)(2)). The RCS stainless steel components with the structural integrity (attached) intended function were evaluated as consistent with NUREG-1801 item IV.C2-17 which is included in LRA Table 3.1.1 item 3.1.1-36. The discussion column of LRA Table 3.1.1 item 3.1.1-36 and its associated further evaluation LRA section 3.1.2.2.16-2 (SRP-LR section 3.1.2.2.16-2) reflects the evaluation of these RCS Criterion (a)(2) components.

The pressurizer spray head is a non-pressure boundary subcomponent. The function of the spray head is to disperse the flow for maximizing condensation of the steam bubble. Failure of the spray head would not prohibit the spray water from entering the pressurizer for condensing the steam. The spray water would be still available as a stream instead of a fine spray. The intended function of pressurizer spray would not be impaired by the failure of the spray head. Thus, the pressurizer spray head is not relied on to provide the intended function for 10CFR54.4(a)(1).

According to Post-Fire Safe Shutdown Analysis, the pressurizer spray is isolated to prevent RCS pressure reduction. The steam generator atmospheric relief valves are used to control RCS cooldown. Thus the pressurizer spray head does not provide any intended function for 10CFR54.4(a)(3).

If the pressurizer spray head were to degrade and shed one or more pieces of the head, the postulated loose parts may affect the operation of the PORV or the code safety valve during pressurization transients. However, based on the operating experience and industry experience, the possibility of its hypothetical failure is not sufficient to include the pressurizer spray head in scope for 10CFR54.4(a)(2).

Staff Evaluation

In response to the question, the applicant stated that the pressurizer spray head is not included in the scope of license renewal. The applicant stated that the pressurizer spray head is not classified as a safety related component, it does not provide a pressure boundary function, and that its spray function is used in normal operation but is not credited in a design basis event or in the post-fire safe shutdown analysis.

The staff reviewed license topical report WCAP-14574-A, "License Renewal Evaluation: Aging Management Evaluation for Pressurizers," and its associated safety evaluation (ADAMS: ML010660292) and confirmed 1) that the license renewal evaluation is applicable for WCGS and 2) that the evaluation determined that the pressurizer spray head is not in scope for license renewal. On this basis the staff determined that the applicant's position with regard to the pressurizer spray head not being in scope for license renewal is consistent with a previously approved safety evaluation that is applicable for WCGS. The AMR reviewer also confirmed that the safety and screening reviewer has accepted the applicant's position that the pressurizer spray head is not in scope. On the basis of previous NRC approval as documented in an applicable SER, and acceptance of the applicant's position by the staff's scoping and screening reviewer, the staff finds the applicant's response acceptable.

Question No AMRA073 LRA Sec 3.3

Audit Question

In its response to audit question AMRA039, the applicant stated that the LRA would be amended to add two new generic items for flex hoses in the fire protection system for elastomer materials in dry gas internal and plant indoor air external environments with an aging effect of hardening and loss of strength. The Fire Protection Program will be credited to manage these aging effects. LRA Table 3.3.1, item 3.3.1-11, was also referenced. However, the response did not indicate if the discussion column of LRA Table 3.3.1-11 would be amended to add the Fire Protection Program. The response also stated that the Fire Protection Program would be amended, but did not indicate the changes.

a) Provide the proposed LRA changes for the Fire Protection Program.

b) Clarify if LRA Table 3.3.1, item 3.3.1-11, will be amended to add the Fire Protection Program in the discussion column. In addition, the response to audit question AMRA029 also amends the discussion column of item 3.3.1-11. Clarify how these two responses would change the discussion column.

c) Explain how the Fire Protection Program will manage the internal surfaces of the flexible hoses.

Final Response

a) Proposed LRA Changes:

LRA Appendix A1.12 - Amended first sentence of first paragraph: The Fire Protection program manages loss of material for fire rated doors, fire dampers, diesel-driven fire pump, and the halon fire suppression system; cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors; hardness and shrinkage due to weathering of fire barrier penetration seals; and hardness-loss of strength for halon fire suppression system flexible hoses.

LRA Appendix A1.12 - Added paragraph (at the end of A1.12): Prior to the period of extended operation, halon fire suppression system inspection procedures will be enhanced to include

visual inspections of halon tank flexible hoses for hardening-loss of strength. Visual inspections would not be required for flexible hoses that have scheduled periodic replacement intervals.

LRA Appendix B2.1.12 - Amended first sentence of first paragraph: identical to Appendix A1.12 first sentence first paragraph above.

LRA Appendix B2.1.12 - Subsection "Enhancements" - Added as enhancements to Elements 3 and 4: Prior to the period of extended operation, halon fire suppression system inspection procedures will be enhanced to include visual inspections of halon tank flexible hoses for hardening-loss of strength. Visual inspections would not be required for flexible hoses that have scheduled periodic replacement intervals.

LRA Table 3.3.2-14 will be amended to change existing standard Notes for Flexible Hoses in an environment with the ambient temperature of less than 95 degrees F, from "J" to "G".

LRA Table 3.3.2-14 will be amended to add the following two new lines for flexible hoses in an environment with ambient temperature greater than 95 degrees F:
Component Type: Flexible Hoses
Intended Function: PB
Material: Elastomer
Environment: Dry Gas (internal)
Aging Effect: Hardening and Loss of Strength
AMP: Fire Protection (B2.1.12)
NUREG-1801 Vol 2 Item: None
Table 1 Item: None
Note: G

Component Type: Flexible Hoses
Intended Function: PB
Material: Elastomer
Environment: Plant Indoor Air (external)
Aging Effect: Hardening and Loss of Strength
AMP: Fire Protection (B2.1.12)
NUREG-1801 Vol 2 Item: VII.F2-7
Table 1 Item: 3.3.1.11
Note: E

b) The discussion column for Table 3.3.1, Item 3.3.1.11 will be amended to add the Fire Protection program (B2.1.12)(note: exception in 3.3.1.11 for Control Bldg flex connectors was deleted in response to AMRA029). LRA Section 3.3.2.2.5.1 will be amended to insert the following as a new third paragraph: The Fire Protection program (B2.1.12) will manage the hardening and loss of strength from elastomer degradation for halon fire suppression system flexible hoses not periodically replaced in locations where the ambient temperature cannot be shown to be less than 950 F.

c) Halon Tank weight and pressure check surveillance tests are performed every 18 months and provide inspection opportunities for visual inspection of the halon tank flexible hoses. Procedures STN FP-404A and STN FP-404B will be enhanced to include visual inspection of halon tank flexible hoses.

Staff Evaluation

By letter dated August 31, 2007, the applicant has issued an LRA amendment to identify aging effects and AMP for those flex hoses located in areas where the ambient temperature is greater than 95 degrees F. The applicant is crediting the Fire Protection Program to manage the aging effect of hardening - loss of strength. The applicant also stated that surveillance procedures will be enhanced to include visual inspection of these flexible hoses. On the basis that periodic inspection will be performed on these flex hoses, the staff finds the applicant response acceptable.

Question No AMRA074 LRA Sec 3.3

Audit Question In its response to audit question AMRA021, the applicant stated that a

new commitment would be added to the LRA commitment list. Clarify if the Closed Cycle Cooling Water System Program and its FSAR supplement will be amended to add this enhancement and commitment. Provide the proposed LRA changes.

Final Response

WCNOC letter ET 07-0020, dated May 25, 2007 added commitment number 32 (RCMS 2007-253) to the License Renewal Application - List of Regulatory Commitments. Commitment number 32 states "WCNOC Procedure QCP-20-518, "Visual Examination of Heat Exchangers and Piping Components", will be revised to define cracking, provide additional guidance for detection of cracking and specific acceptance criteria relating to "as-found" cracking."

LRA Appendix A1.10 and Appendix B2.1.10 will be amended as follows:

Appendix A1.10 will be amended to include:
"Visual inspection procedures used for identification of stress corrosion cracking (SCC) will be enhanced to define cracking, provide additional guidance for detection of cracking and identify specific acceptance criteria relating to "as-found" cracking."
Appendix B2.1.10 will be amended to include:
"Detection of Aging Effects - Element 4
Visual inspection procedures used for identification of stress corrosion cracking (SCC) will be enhanced to define cracking, provide additional guidance for detection of cracking and identify specific acceptance criteria relating to "as-found" cracking."

Staff Evaluation

The applicant amended the LRA to include Commitment No. 32 to revise the procedure QCP-20-518 to define cracking, and provide additional guidance for cracking. The applicant also amended the LRA AMP B2.1.10, Closed-Cycle Cooling Water System Program to add an enhancement to revise the procedure. On this basis, the staff finds the response acceptable.

Question No AMRA075 LRA Sec 3.4

Audit Question In its response to audit question AMRA041, the applicant stated that the GALL Report concludes that there are no aging effects that require

agement for stainless steel (sheathing) and aluminum (sheathing) in plant indoor air.

a) LRA Tables 3.4.2-2 and 3.4.2-3, assign Note J to the line items pertaining to the stainless steel and aluminum jacketing exposed to plant indoor air. This note implies that neither the component nor the material and environment combination is addressed in the GALL Report. In light of the response provided in AMRA041, the staff believes that the Note needs to be revised to make these AMR line items consistent with the GALL Report. Clarify if the LRA will be amended to reflect this change.

b) The response provided in AMRA041 also states that all the insulation within the scope of license renewal is jacketed with either stainless steel or aluminum. Therefore, LRA Table 3.4.2-5 should include AMR line items for both stainless steel and aluminum exposed to plant indoor air similar to those in LRA Tables 3.4.2-2 and 3.4.2-3. Clarify this inconsistency.

Final Response

NUREG 1801 does conclude that there are no aging effects that require management for aluminum and stainless steel in plant indoor air as stated in the response to AMRA041. However, the NUREG 1801 lines are not specific to aluminum jacketing or stainless steel jacketing but apply to other component types. Therefore "Standard Note C" would be applicable to address the different component types.
a) LRA Tables 3.4.2-2 (main steam system) and 3.4.2-3 (feedwater system) assigned Note J to aluminum jacketing exposed to plant indoor air. The LRA will be amended to specify NUREG 1801 line V.F-2, Table 1 Item 3.2.1.50, and Note C for aluminum jacketing in plant indoor air in LRA Tables 3.4.2-2 and 3.4.2-3.

b) LRA Table 3.4.2-5 (steam generator blowdown system) does not include the aluminum jacketing and stainless steel jacketing that is used to protect the blowdown system piping insulation materials. The LRA will be amended to specify NUREG 1801 line V.F-2, Table 1 Item 3.2.1.50, and Note C for aluminum jacketing in plant indoor air and specify NUREG 1801 line VIII.I-10, Table 1 Item 3.4.1.41, and Note C for stainless steel jacketing in plant indoor air in LRA Table 3.4.2-5.

Staff Evaluation

This question was a follow up question on applicant's response to the staff's previous question AMRA041. The staff finds the applicant's response acceptable because by letter dated October 11, 2007, the applicant has amended the applicable lines in LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5 to incorporate the staff's comments.

Question No AMRA076 LRA Sec 3.5

Audit Question LRA Table 3.5.1, item 3.5.1-59, states that there is no aging effect for the component type of stainless steel support members, welds, bolted connections, and support anchorage to building structure. Identify the environment or location of this line item (e.g., exposed to air indoor uncontrolled).

Final Response

Line item 3.5.1.59 is linked to six lines in Table 3.5.2-22.

Three of those lines have an environment of "Plant Indoor Air (Structural)". The GALL lines for these refer to "Air - Indoor uncontrolled". These components are:

Component Type: Supports ASME 2 & 3
NUREG 1801 Item: III.B1.2-7

Component Type: Supports Mech Equip Non ASME
NUREG 1801 Item: III.B4-8

Component Type: Supports Non ASME
NUREG 1801 Item: III.B2-8

Three of the linked lines have an environment of "Borated Water Leakage". The GALL lines for these refer to "Air with borated water leakage". These components are:

Component Type: Supports ASME 1
NUREG 1801 Item: III.B1.1-10

Component Type: Supports ASME 2 & 3
NUREG 1801 Item: III.B1.2-8

Component Type: Supports Non ASME
NUREG 1801 Item: III.B2-9

Staff Evaluation

This question was for clarification purpose. The staff finds applicant's response acceptable as it provides the requested details.

Question No AMRA077 LRA Sec 3.5
Audit Question LRA Section 3.5.2.2.1.4 states that the Structure Monitoring Program will identify and manage any cracks in the concrete or degradation of the moister barrier that could potentially provide a pathway for water to reach inaccessible portions of the steel containment liner. SRP-LR Section 3.5.2.2.1.4 states that the existing program relies on ASME Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J to manage loss of material. LRA Table 3.5.2.1, item 3.5.1-06, assigns Note "B" and credits the ASME Section XI, Subsection IWE Program to manage loss of material in the containment liner. It seems that there is an inconsistency between the AMR result line and the text provided in the further

evaluation, as one is addressing cracking and the other loss of material. Please clarify.

Final Response

LRA Section 3.5.2.2.1.4 will be amended to note that the WCGS program relies on ASME Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J to manage loss of material. LRA Table 3.5.2-1 will be amended to add 10 CFR Part 50, Appendix J (B2.1.30) as one of the AMP's for component type "Liner Containment" in Plant Indoor Air (Structural).

The text in LRA Section 3.5.2.2.1.4 is intended to specifically address the conditions given in NUREG 1801, Item II.A1-11, in the AMP column. These conditions, if satisfied, allow the presumption that, for inaccessible areas (embedded containment steel shell or liner), loss of material due to corrosion is not significant. Therefore, further evaluation for corrosion in inaccessible areas of the steel containment liner is not required.

WCGS meets these criteria as follows:

1. Concrete meeting the requirements of ACI 318 or 349 and the guidance of 201.2R was used for the containment concrete in contact with the embedded containment shell or liner.

LRA Section 3.5.2.2.1.4 response:

Reinforced concrete structures at WCGS were designed, constructed, and inspected in accordance with applicable ACI and ASTM standards, which provide for a good quality, dense, well cured, and low permeability concrete. Design practices and procedural controls ensured that the concrete was consistent with the recommendations and guidance provided by ACI 201.2R. The mixes were designed with entrained air content between 3% and 6%, and the concrete slumps were controlled throughout the batching, mixing, and placement processes. USAR Section 3.8 discusses the design requirements for each major structure.

2. The concrete is monitored to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment shell or liner.

LRA Section 3.5.2.2.1.4 response:
The Structures Monitoring Program (B2.1.32) will identify and manage any cracks in the concrete (or degradation of the moister barrier) that could potentially provide a pathway for water to reach inaccessible portions of the steel containment liner.

3. The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with IWE requirements.

LRA Section 3.5.2.2.1.4 response:
The Structures Monitoring Program (B2.1.32) will identify and manage any (cracks in the concrete or) degradation of the moister barrier that could potentially provide a pathway for water to reach inaccessible portions of the steel containment liner.

4. Borated water spills and water ponding on the containment concrete floor are not common and when detected are cleaned up in a timely manner.

LRA Section 3.5.2.2.1.4 response:
Procedural controls will ensure that borated water spills are not common, and when detected are cleaned up in a timely manner.

Staff Evaluation

By letter dated August 31, 2007, the applicant amended LRA Table 3.5.2-1, line 3.5.1-06 to add 10 CFR Part 50, Appendix J (B.2.1.30) in the Aging Management Program column. This makes this AMR line item consistent with GALL Based on this, the staff finds the applicant's response to be acceptable.

Question No AMRA078 LRA Sec 3.1
Audit Question LRA Table 3.1.1, item 3.1.1.24, states that "Water Chemistry will be augmented with ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD because the CASS in the reactor coolant system piping at WCGS meets the NUREG-0313 requirements for ferrite content but not for carbon content."

a) Provide an expanded discussion on the use of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for detection of cracking due to SCC in CASS piping at WCGS. Address which examinations specified in ASME Section XI are credited and their capability to detect cracking due to SCC in CASS piping before a through-wall leak occurs.
b) Clarify what is the carbon content used for CASS piping in the reactor coolant system at WCGS.

Final Response

a) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD volumetrically inspect piping welds in the reactor coolant system. WCGS reactor coolant loop piping is CASS and the reactor coolant piping welds are ultrasonic tested (UT) as required by Table IWB-2500-1 Examination Category B-J, Items B9.10 and B.9.11. UT inspection is a proven industry ASME Code technique for detection of weld and adjacent base metal cracking caused by SCC.

b) The WCGS Certified Material Test Reports of CASS Class 1 piping indicate that the carbon content of the reactor coolant system CASS piping is 0.05% - 0.08%.

Staff Evaluation

In response to this question, the applicant stated that the carbon content of CASS piping at WCGS is in the range of 0.05 percent to 0.08 percent, which is above the 0.035 percent maximum carbon content specified in NUREG-0313. The applicant also stated that ASME Code Section XI examinations of CASS piping welds are performed in accordance with the examination requirements of ASME Code Section XI, Table IWB-2500-1, Examination Category B-J, Items B9.10 and B9.11, which require surface and volumetric examinations. The applicant stated that volumetric examination is performed using ultrasonic testing (UT) and that UT

inspection is a proven industry technique for detection of weld and adjacent base metal cracking caused by SCC.

The GALL Report recommends that the aging management program for CASS components is the Water Chemistry Program; and, if the carbon and ferrite content of the CASS does not meet the limits specified in NUREG-0313, the GALL Report recommends that the Water Chemistry Program be augmented by an inspection program. The staff's evaluation of the applicant's Water Chemistry program and of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program found both program to be acceptable. On the basis of its evaluations of these programs, the staff finds that the applicant's use of the Water

Chemistry Program augmented by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is consistent with the GALL Report's recommendation for a plant-specific program that includes adequate inspection methods to ensure detection of cracks; and the staff finds the applicant's response to be acceptable.

Question No AMRA079 LRA Sec 3.1

Audit Question In its response to audit question AMRA002, WCGS stated that the reactor vessel closure head (O ring leak monitoring tubes) described in LRA Table 2.3.1 1 is made of nickel alloy and is not associated with GALL Report Volume 2, item IV.A2 5, which is based on the material made of stainless steel. The response also stated that the reactor vessel closure head (O ring leak monitoring tubes) is evaluated with GALL Report, Volume 2, items IV.A2 14 and IV.A2 18 and is referenced to LRA Table 3.1.1, items 3.1.1.83 and 3.1.1.65, respectively.

The title of LRA Section 3.1.2.2.7.1, "PWR stainless steel reactor vessel flange leak detection line," and its associated description appear to be inconsistent with the response to AMRA002 because they imply that the WCGS vessel flange head detection lines are made of stainless steel. In addition, the title of LRA Section 3.1.2.2.7.1 does not mention the stainless steel bottom mounted instrument guide tubes (high pressure conduits) which are discussed in SRP LR Section 3.1.2.2.7.1 and which are referenced to LRA Table 3.1.1, item 3.1.1.23.

Explain the discrepancy between the description in LRA Subsection 3.1.2.2.7.1 and the response to Question AMRA002. Clarify which components referencing SRP LR Section 3.1.2.2.7.1 are addressed by this LRA Section. Revise the LRA Table 3.1.1 23 item accordingly.

Final Response

(a) Reactor Vessel Flange O-ring Leak Monitoring Tubes

The reactor vessel flange O-ring leak monitoring tubes are made of nickel alloy and are evaluated with GALL Report, Volume 2, items IV.A2-14 and IV.A2-18, which are referenced to LRA Table 3.1.1, items 3.1.1.83 and 3.1.1.65, respectively. For LRA Table 3.1.1, items 3.1.1.83 and 3.1.1.65, the GALL recommends no further evaluations of aging management. Thus, the evaluation of LRA Section 3.1.2.2.7.1 is not applicable to the reactor vessel flange O-ring leak monitoring tubes.

(b) LRA Section 3.1.2.2.7.1

LRA Section 3.1.2.2.7.1 will be amended to change the title to "PWR stainless steel reactor vessel instrument tubes and bottom-mounted flux thimble guide tubes." The Discussion column of LRA Table 3.1.1, item 3.1.1.23 will be amended to state that the reactor vessel O-ring leak monitoring tubes are made of nickel alloy.

(c) Bottom-Mounted Guide Tubes Aging Management

The components that reference LRA Section 3.1.2.2.7.1 and LRA Table 3.1.1, item 3.1.1.23 are stainless steel reactor vessel instrument tubes in the upper internals and the bottom-mounted flux thimble guide tubes (High Pressure Conduits), which are described in USAR 3.9(N).5.1. The aging management evaluations of these components are addressed in LRA Table 3.1.2-1, page 3.1-52. The WCGS ASME Section XI ISI AMP (B2.1.2) manages aging of bottom-mounted flux thimble guide tubes and they receive a VT-2 visual inspection as specified in ASME Section XI, Table 2500-1, Category BP.

Staff Evaluation

In response to the staff's questions, the applicant stated 1) that the O-ring leak monitoring tubes are made of nickel alloy (not stainless steel) and are evaluated with GALL Report, Volume 2, items IV.A2-14 and IV.A2-18, respectively; 2) that the LRA Section 3.1.2.2.7.1 will be amended to make the title of the section consistent with its discussion and that the Discussion column in LRA Table 3.1.1, item 3.1.1.23 will be amended to say that the O-ring leak monitoring tubes are made of nickel alloy; and 3) that the ASME Section XI inspection performed for the bottom-mounted flux thimble guide tubes and for the other instrument tubes connected to the reactor vessel is the VT-2 examination for leakage performed at every refueling outage, as specified in ASME Section XI, Table 2500-1, Category BP.

The staff compared the AMR results for the O-ring leak monitoring tubes against the GALL Report items identified by the applicant and found them to be consistent with the GALL Report. On this basis, the staff finds part 1) of the applicant's response to be acceptable.

On the basis that the proposed LRA changes will eliminate an inconsistency in the LRA and provide additional clarification, the staff finds part 2) of the applicant's response to be acceptable.

The aging effect of cracking in the stainless steel instrument tubes due to SSC is provided by the Water Chemistry Program and the ASME Section XI VT-2 inspections. On the basis that the Water Chemistry Program provides mitigation consistent with the GALL Report's recommendations, and the ASME Section XI VT-2 inspections provide on-going confirmation of effectiveness of the Water Chemistry Program, the staff finds part 3) of the applicant's response to be acceptable.

Question No AMRA080 LRA Sec 3.1

Audit Question In its response to audit question AMRA002, the applicant described the function and configuration of the high pressure conduits. The line in LRA Table 3.1.2-1 for reactor vessel penetrations (high pressure conduits), GALL Report, item IV.A2-1, references LRA Table 3.1.1, item 3.1.1.23, and LRA Section 3.1.2.2.7.1. The LRA credits the Water Chemistry and ASME Section XI, Subsections IWB, IWC and IWD Programs to manage

the aging effect of cracking due to SCC in the bottom mounted instrument guide tubes (high pressure conduits).

a) Clarify whether there are any nickel alloy welds associated with the bottom mounted instrument guide tubes. If there are nickel alloy welds, identify where the AMR results for those welds are presented in the LRA.

b) Provide an expanded discussion on the use of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for the detection of cracking due to SCC in the bottom mounted instrument guide tubes. Address which examinations specified in ASME Code Section XI are credited and their capability to detect cracking due to SCC in the bottom mounted instrument guide tubes before a through-wall leak occurs.

Final Response

(a) There are Alloy 82/182 welds associated with the bottom mounted instrument guide tubes. It includes J-groove welds of the Flux Thimble Guide Tube Penetrations to the vessel bottom and the welds of the Flux Thimble Guide Tube Penetrations to the thimble guide tubes (high pressure conduits).

The aging management of these welds is evaluated as part of the Flux Thimble Guide Tube Penetrations that are made of nickel alloys and are addressed in LRA Table 3.1.2-1, pages 3.1-50 and 3.1-51 as follows:

Component Type: RV Penetrations (Flux Thimble Guide Tube Penetrations)
Intended Function: PB
Material: Nickel Alloys
Environment: Reactor Coolant (Int)
Aging Effect: Cracking
AMP: Nickel Alloy Aging Management Program (B2.1.34)
ASME Section XI ISI, Subsections IWB, IWC, and IWD (B2.1.1)
Water Chemistry (B2.1.2)
Comply with applicable NRC Orders and FSAR Commitment (B2.1.35)
NUREG-1801 Vol 2 Item: IV.A2-9
Table 1 Item: 3.1.1.31 (No further evaluation required)
Note: E and Plant Specific Note 1

Component Type: RV Penetrations (Head vent pipe, flux Thimble Guide Tube Penetrations)
Intended Function: PB
Material: Nickel Alloys
Environment: Reactor Coolant (Int)
Aging Effect: Loss of Material
AMP: Water Chemistry (B2.1.2)
NUREG-1801 Vol 2 Item: IV.A2-14
Table 1 Item: 3.1.1.83 (No further evaluation required)
Note: B

(b) The discussion on the aging management for SCC in the bottom mounted instrument guide tubes is provided in the response to AMRA079.

Staff Evaluation

The applicant's response stated that the bottom-mounted instrument guide tubes do include nickel alloy welds (Alloy 82/182) and identified the AMR results that are applicable for these welds. The staff compared the WCGS AMR results with the corresponding recommendations in the GALL Report and found them to be consistent. On this basis, the staff found this part of the applicant's response to be acceptable.

The applicant's response to the staff's question about inspection of the bottom mounted instrument guide tubes was provided in the applicant's response to AMRA079 where the applicant stated that ASME Section XI VT-2 inspections will be used to augment the Water Chemistry Program for managing the aging effect of cracking due to SSC in the bottom-mounted instrument guide tubes. On the basis that the Water Chemistry Program provides mitigation consistent with the GALL Report's recommendations, and the ASME Section XI VT-2 inspections provide on-going confirmation of effectiveness of the Water Chemistry Program, the staff finds the applicant's response to be acceptable.

Question No AMRA081 LRA Sec 3.1

Audit Question In its response to audit question AMRA016, the applicant stated that LRA Section 3.1.2.2.16.1 will be revised to read, "These control rod drive mechanism housings are stainless steel for WCGS, therefore no additional commitments or further evaluation is required."

Clarify whether there are any nickel alloy welds associated with the control rod drive mechanism housings. If there are nickel alloy welds associated with the control rod drive mechanism housings, identify where the AMR results for those welds are presented in the LRA.

Final Response

There are Alloy 82/182 welds of the control rod drive mechanism (CRDM) housings to the CRDM penetration tubes. Also, there are Alloy 82/182 J-groove welds of the CRDM penetration tubes to the lower surface of the vessel head. The aging management of these welds is evaluated as part of the CRDM penetration tubes that are made of nickel alloys and are addressed in LRA Table 3.1.2-1, page 3.1-44 as follows:

Component Type: RV Control Rod Drive Head Penetration
(CRDM tubes)
Intended Function: PB
Material: Nickel Alloys
Environment: Reactor Coolant (Int)
Aging Effect: Cracking
AMP: ASME Section XI ISI, Subsections IWB, IWC, and IWD (B2.1.1)
Water Chemistry (B2.1.2)
Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of PWR (B2.1.5)

NUREG-1801 Vol 2 Item: IV.A2-9
Table 1 Item: 3.1.1.65 (No further evaluation required)
Note: B

Component Type: RV Control Rod Drive Head Penetration (CRDM tubes)
Intended Function: PB
Material: Nickel Alloys
Environment: Reactor Coolant (Int)
Aging Effect: Loss of Material
AMP: Water Chemistry (B2.1.2)
NUREG-1801 Vol 2 Item: IV.A2-14
Table 1 Item: 3.1.1.83 (No further evaluation required)
Note: B

Staff Evaluation

The applicant's response stated that the control rod drive mechanism (CRDM) housings to CRDM penetration tubes are Alloy 81/182 Welds (nickel alloy welds) and that there are Alloy 82/182 J-groove welds of the CRDM penetration tubes to the lower surface of the vessel head. The applicant's response also identified the AMR results that are applicable for these welds. The staff compared the WCGS AMR results with the corresponding recommendations in the GALL Report and found them to be consistent. On this basis, the staff finds the applicant's response acceptable.

Question No AMRA082 LRA Sec 3.2

Audit Question LRA Section 3.2.2.2.3.4 states that the Lubricating Oil Analysis and the One Time Inspection Programs will manage loss of material due to pitting and crevice corrosion for copper alloys, copper nickel, and stainless steel components exposed to lubricating oil, except for the RCP lube oil leakage collection system. Explain how is loss of material managed in the RCP lube oil leakage collection system.

Final Response

The Reator Coolant Pump (RCP) lube oil leakage collection system is part of Floor & Equipment Drains System. The aging management evaluation for Loss of Material in the RCP lube oil leakage collection system is addressed in LRA Table 3.3.2-17.

The environment is oil leakage from the RCP motor that may be contaminated oil. As indicated in the Plant Specific Note 2 of LRA Table 3.3.2-17, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22) manages Loss of Material on internal component surface exposed to contaminated oil environment instead of Lubricating Oil Analysis program (B2.1.23).

The inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component AMP (B2.1.22) will perform visual inspection during maintenance activities to manage Loss of Material of the internal surface of the RCP lube oil collection components.

Staff Evaluation

The staff finds the applicant's response acceptable because lube oil collection components will be visually inspected for Loss of Material through the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component AMP (B2.1.22).