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May 13, 2003

U.S. Nuclear Regulatory Commission
Document Control Desk
Attn: Mr. Russell Arrighi (Mail Stop O-12D-3)
Office of Nuclear Reactor Regulation
Washington, D.C. 20555-0001

Subject: Response to LRA Request for Additional Information (RAI)
R. E. Ginna Nuclear Power Plant
Docket No. 50-244

Dear Mr. Arrighi:

This letter is in response to the NRC's March 21, 2003 "Request for Additional Information for the Review of the R. E. Ginna Nuclear Power Plant, License Renewal Application".

We are responding to 133 of the 224 RAIs. The balance of the responses will be provided prior to June 12, 2003.

If you have any questions, please direct them to the Ginna License Renewal Project Manager, George Wrobel, at (585) 771-3535.

I declare under penalty of perjury under the laws of the United States of America that I am authorized by RG&E to make this submittal and that the foregoing is true and correct.

Very truly yours,

Executed on May 13, 2003

Robert C. Mecredy

Attachments

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List of Regulatory Commitments

The following table identifies those actions committed to by Rochester Gas & Electric (RG&E) in this document. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments. Please direct questions regarding these commits to Mr. George Wrobel, License Renewal Project Manager at (585) 771-3535.

REGULATORY COMMITMENT		DUE DATE
F-RAI 2.1-4	Add house heating boiler and associated components in screenhouse as requiring aging management review.	Prior to 9/2009
F-RAI 3.2.1-1	Locations judged to be potentially susceptible to thermal fatigue will be included in the sample population of small bore piping to be examined by an appropriate volumetric technique.	Prior to 9/2009
F-RAI 3.2.2-5	The pressurizer manway stainless steel insert will receive a visual and surface examination as part of our ISI program, to detect potential stress corrosion cracking.	Prior to 9/2009

R. E. GINNA
LICENSE RENEWAL APPLICATION
REQUEST FOR ADDITIONAL INFORMATION

F-RAI 2.1 -1

Based on a review of the license renewal application (LRA) and scoping and screening implementation procedures, the structures, system and components (SSC) functions identified in the applicant's safety classification program were used to provide preliminary scoping results. The staff has reviewed the safety classification rules contained in the applicants administrative procedure IP-QAP-1 and requires additional information to determine how the safety classification rules were specifically applied to preliminarily identify in-scope SSCs. For example, Section 2.1.5.3 of the LRA implies that non-safety SSCs credited for internal missiles were identified using the safety classification rules; however, it was not clear which safety classification rule contained in IP-QAP-1 would apply to this equipment. Please provide a mapping of the safety classification program rules as applied to the 10 CFR 54(a)(1), (2), and (3) license renewal (LR) scoping criteria. This information will expedite the staff's review of the LR scoping methodology.

Response

As indicated in LRA section 2.1.5, Application of License Renewal Scoping Criterion, the safety related criteria used in IP-QAP-1 encompasses the SSC inclusion requirements of 10 CFR 54 (a)(1). Specifically: Criterion 1 SSCs can be mapped to IP-QAP-1 rules 3.1.1 (beginning at safety class 1) and continuing through 3.1.3.21 (ending the SC-3 definitions) all-inclusive.

Criterion 2 SSCs, described in the analytical review process detailed in LRA section 2.1.5.3, are associated with IP-QAP-1 rules:
3.1.4.1 Support Hydrogen (H2) concentration control of the primary containment atmosphere with equipment outside the containment.

3.1.4.7 Safely handle heavy loads (NUREG-0612 definition) during planned normal operations.

3.1.4.19 Contain generated steam or feedwater under high energy conditions outside the containment. (Refer to Inservice Inspection Program.)

3.1.4.20 Prevent failure to safety-related civil structures from tornado or flooding effects.

3.1.4.32 Components whose structural failure during postulated seismic events could impair the capability of adjacent safety-related components from accomplishing their safety-related function. (Seismic II/I). These include the following:

Supports for non safety-related components whose hangers, supports and mounting hardware must be seismically designed to prevent non safety-related components from damaging adjacent safety-related components.

Non safety-related components and associated supports that can be considered a potential source of jeopardy (missile) for nearby safety-related components.

3.1.4.33 Prevent internal flooding due to failure of tanks or components in accordance with SEP Topic IX-3, Section 4.25.3 (NUREG-0821).

Criterion 3 SSCs, described in LRA section 2.1.5.5, Other Scoping Pursuant to 10 CFR 54 (a)(3), are associated with IP-QAP-1 rules:
3.1.4.2 Fire detection, suppression, principal barriers and mitigation systems and components used to protect safety-related or safe shutdown equipment. (See ND-FPP, "Fire Protection Program" for quality requirements). Refer to 3.1.4.18.

3.1.4.18 Systems or components whose specific function is to ensure alternative shutdown capability and are subject to the requirements of 10CFR50 Appendix R. (See RG&E Appendix R Alternative Shutdown Report.)

3.1.4.8 System/components required to respond to or mitigate anticipated transients without scram (ATWS) in accordance with 10CFR50.62 requirements. Systems/components which automatically actuate (using equipment diverse from the reactor trip system) auxiliary feedwater flow and main turbine trip under conditions indicative or an Anticipated Transient Without Scram (ATWS) event.

3.1.4.30 Systems/components required to respond to or mitigate the consequences of station black out in accordance with NUMARC 87-00 and 10CFR50.63 including the committed to portions of Reg. Guide 1.155.

Please note that the Station EQ master list was utilized for the scoping of Environmentally Qualified equipment. Additionally as described in LRA section 2.1.6, Interim Staff Guidance Discussion, some criterion 2 and 3 scoping boundaries have been expanded beyond the SSC boundaries established by the Q-list rules.

<u>F-RAI 2.1 -4</u>

By letters dated December 3, 2001, and March 15, 2002, the Nuclear Regulatory Commission (NRC) issued a staff position to the Nuclear Energy Institute (NEI) which described areas to be considered and options it expects licensees to use to determine what SSC meet the 10 CFR 54.4(a)(2) criterion (i.e., All non safety-related SSCs whose failure could prevent satisfactory accomplishment of any safety-related functions identified in paragraphs (a)(1)(i),(ii),(iii) of this section.)

The December 3rd letter provided specific examples of operating experience which identified pipe failure events (summarized in Information Notice (IN) 2001-09, "Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor") and the approaches the NRC considers acceptable to determine which piping systems should be included in scope based on the 54.4(a)(2) criterion.

The March 15th letter, further described the staff's expectations for the evaluation of non-piping SSCs to determine which additional non safety-related SSCs are within scope. The position states that applicants should not consider hypothetical failures, but rather should base their evaluation on the plant's current licensing basis (CLB), engineering judgement and analyses, and relevant operating experience. The paper further describes operating experience as all documented plant-specific and industry-wide experience which can be used to determine the plausibility of a failure. Documentation would include NRC generic communications and event

reports, plant-specific condition reports, industry reports such as SOERs, and engineering evaluations.

Based on a review of the LRA, the applicant's scoping and screening implementation procedures, and discussions with the applicant, the staff determined that additional information is required with respect to certain aspects of the applicant's evaluation of the 10 CFR 54.4(a)(2) criteria.

For example, the applicant noted that the auxiliary boiler in proximity to the service water pumps in the screen house was not included in scope because its failure had been analyzed as part of the Systematic Evaluation Program (SEP) and design features had been put in place to mitigate the effects of such a failure. Based on the applicant's evaluation, the design features were considered within scope. However, the SEP evaluations did not specifically consider the potential for age-related degradation and subsequent failure of these non-safety related SSCs affecting safety-related SSCs under conditions when those safety-related SSCs were required to function. Based on the staff's discussions with the applicant, it appears that under certain design basis scenarios where the primary mitigative system is considered affected by the age-related degradation of a non-safety related SSC, the standby system or mitigative feature would potentially not be capable of ensuring appropriate mitigation. Given this additional insight, the staff considers that those non-safety related SSCs such as the auxiliary boiler, meet the 10 CFR 54.4(a)(2) criteria and therefore be included in scope of LR.

a) Based on the aforementioned information and results of the scoping and screening methodology audit interactions with the staff, describe any additional scoping evaluations performed to address the 10 CFR 54.4(a)(2) criteria? As part of your response, list any additional SSCs included within scope as a result of your efforts, and list those SCs for which AMRs were conducted, and for each SC describe the aging management programs (AMPs), as applicable, to be credited for managing the identified aging effects?

b) Consistent with the staff position described in the March 15 letter, please describe your scoping methodology implemented for the evaluation of the 10 CFR 54.4(a)(2) criteria as it relates to the non-fluid-filled SSC of interest. As part of your response, indicate the non-fluid-filled SSCs evaluated and describe the site and industry operating experience relied on to determine the potential for failures of such non-fluid-filled SSC which could impact safety-related SSC within scope.

Response

a) RG&E reviewed our (a)(2) evaluations and concluded that the block walls in the intermediate building and the steam heating system in the screenhouse, including the boiler, met the criteria for (a)(2) inclusion. The block walls are already addressed by an aging management program, since they were already included in the scope of license renewal under (a)(3), fire protection. The steam heating system is already within the scope of license renewal. The house heating boiler and associated components located in the screen house will be included as components requiring aging management review. They will be managed by the Periodic Surveillance and preventive maintenance Program described in B2.1.23 of the application.

b) Non-fluid-filled system (a)(2) evaluations were performed in the same manner as fluid-filled system (a)(2) evaluations, as described in Sections 2.1.5.2 through 2.1.5.4 of the application. The affected systems are Containment Ventilation (2.3.3.9), Essential Ventilation (2.3.3.10), Non-Essential Ventilation (2.3.3.19), and Radiation Monitoring (2.3.3.13). The equipment in

scope of 10 CFR 54.4(a)(2) is described in each of these sections.There is no plant-specific operating experience that would indicate potential failure modes of these systems affecting safety-related SSCs; however, supports and hangers are in the scope of License Renewal as a Component Supports Commodity Group (2.4.2.12). As noted in that section, "...all supports for any equipment contained within a safety-related structure, regardless of the equipment's seismic classification, shall be considered in-scope to License Renewal unless a support is specifically excepted and that exception documented."

F-RAI 2.3 -1

On page 2-30 of the LRA, Table 2.1-1 describes system function code S as "Special Capability Class Function." The associated notes column for system function code S further explains that "Components within the system are safety significant (augmented quality). For the purposes of LR, components which are special capability class are treated under the Criterion 3 codes Z1 through Z5." However, in the subsections of LRA Section 2.3 that have components identified as code S, none of the adjacent system codes Z1-Z5 are check marked. Clarify the usage of system function code S. Specifically, are the components indicated as having augmented quality requirements by this system function code in the scope of LR? Identify the components and provide the basis for the augmented quality status for the containment spray system and hydrogen detectors system.

Response

As described in LRA section 2.3.1, System and Structure Function Determination, the plant process for functionally based classifications was used in the development of the application. The plant process includes a designation indicating when a system contains components that are not safety related but are subject to portions of the quality assurance program. In order to maintain fidelity with the plant process all function codes associated with components within a LRA system boundary are accurately reported, including the function S. This code broadly bounds a wide variety of components that are of interest to the plant and includes some rule based functional criteria that can be directly related to license renewal criterion 2 and 3. (See the response to RAI 2.1-1 for further clarification.) As indicated in Table 2.1-1, this system function code is never directly associated with any license renewal criterion. Specifically, there is no direct relationship between plant requirements for component inclusion in the augmented quality assurance program and inclusion within the scope of license renewal. For that reason, only if a Z function is indicated are there augmented quality components within a system boundary that are subject to license renewal review. The language describing the use of system function codes Z1-Z5 used in the comments section for systems descriptions, where a system contains an S function, is generic and meant to prompt the reviewer to look further down the list. The Z1-Z5 functions will only be check marked if the system under review actually contains components that perform those functions.

The components within the Containment Spay that warrant the S designation are associated with the spray additive tank level indication loop electronics (associated with LT-931 and LT-932). The components in Hydrogen Detector System are associated with piping heat trace circuits. The basis for the augmented quality status is described in our component classification procedure IP-QAP-1 by rule number 3.1.4.27 – Components or systems that do not perform a nuclear safety function, but are required to be operable by Ginna Station Technical Specification Limiting Conditions for Operation including the Technical Requirements Manual (TRM).

F-RAI 2.3 -2

The Ginna LR boundary drawings show numerous small pipe fittings without equipment identification numbers as being subject to an AMR. However, these components are not listed in many of the tables in LRA Section 2.3. Some tables have a component identified as "pipe" (for example, Table 2.3.2-2 for containment spray), while tables for other sections have components identified as "piping and fittings" (for example, reactor coolant, (class I). Clarify whether the component group "pipe" includes all fittings such as reducers, enlargers, flanges, and end caps, shown as part of a piping run on the LR boundary drawings, or if these components are uniquely identified if subject to an AMR.

Response

The component group "pipe" includes all fittings such as reducers, enlargers, flanges and end caps, shown as part of a piping run on the license renewal boundary drawings.

F-RAI 2.3.1 -1

Borated water leakage through the pressure boundary in pressurized water reactors (PWRs), and resulting borated water induced wastage of carbon steel is a potential aging degradation for the components. Reactor vessel head lifting lugs are considered to be such components requiring aging management. However, if the components are currently covered under Boric Acid Wastage Surveillance Program, then it may not require additional aging management. It appears that the subject components were not discussed in the LRA (Table 2.3.1-2), and therefore, the staff requests the applicant to verify whether the components are within the surveillance program; and if not, justify their omission.

Response

The reactor vessel head lifting lugs are included in the LRA in Table 2.3.1-2, under the subcomponent "Closure Head Dome". Reactor Vessel head lifting lugs are included in the Boric Acid Corrosion Program as are all carbon/low alloy steel external surfaces in the Reactor Coolant System. Application Table 3.2-1, line number (26) accounts for the head lifting lugs.

F-RAI 2.3.1 -2

The pressurizer surge and spray nozzle thermal sleeves were not identified in the LRA (Table 2.3.1-4) as within the scope of LR. The staff understands that the intended function of the thermal sleeves is to provide thermal shielding to the nozzles (pressure boundary), and that the failure of the sleeves may prevent the nozzles from performing their pressure boundary function during the extended period of operation. As such, thermal sleeves meet the criteria identified in 10 CFR 54.4(a)(2), and therefore, should be within the scope of LR. Furthermore, the Westinghouse Owners Group has committed in topical report WCAP-14574-A, "license Renewal Evaluation: Aging Management Evaluation for Pressurizers," and the staff has concurred that the pressurizer surge and spray nozzle thermal sleeves are within the scope of LR. However, the staff also understands that an in-scope component may not require an AMR if a time limited aging analysis (TLAA) was performed for the component, and the result was found to be acceptable for the extended period of operation. Based on the above discussion, the staff requests the applicant to provide the following additional information:

a) On the basis of the reason sited above, include the pressurizer surge and spray nozzle thermal sleeves within scope, or justify their omission.

b) Was a TLAA performed for the thermal sleeves as an integral part of the nozzles? If so, are the results of the TLAA also applicable to the sleeves (in addition to the nozzles), and are the results acceptable for the extended period of operation?

c) If the answers to (b) are not affirmative, then the staff requests the applicant to submit an AMR for the thermal sleeves which are in-scope components, or justify why an AMR is not required.

d) Are there other thermal sleeves which perform thermal shielding function for pressure boundary components; such as, the return line from the residual heat removal (RHR) loop, and the charging lines and the alternate charging line connections (refer to Ginna UFSAR Section 5.4.3.1.1), which may have been excluded from the scope of LR? If so, identify those thermal sleeves, and justify their exclusion from the scope.

Response

a) The Pressurizer surge and spray nozzle thermal sleeves are already accounted for in the License Renewal Application. They are within the scope of the rule and are evaluated as part of the constituent component nozzle assemblies.

b) The thermal sleeves are included within Metal Fatigue TLAA evaluations in LRA section 4.3 and are accounted for in LRA section B3.2, the Fatigue Monitoring Program. TLAA evaluation includes the nozzles and sleeves and the evaluation results indicate that the assemblies are acceptable for the period of extended operation, including accounting for the consequences of environmentally assisted fatigue.

c) Not applicable based on the above.

d) In addition to the Pressurizer surge line and spray nozzles, the return line from the residual heat removal loop, the charging and alternate charging lines, and the safety injection accumulator connections to the RCS all have nozzles containing thermal sleeves. These nozzles are within the scope of the LRA and have received TLAA evaluations. As with the Pressurizer nozzles, aging effects for these components are managed within the Fatigue Monitoring Program. Additionally, the steam generator feedwater nozzles contain thermal sleeves. The steam generators were replaced in 1996 and these components did not require TLAA evaluation because an explicit fatigue analysis was performed according to the requirements of ASME Section III, Subsection NB-3600 for the 40-year design life of the steam generators. Therefore these components do not require fatigue monitoring. They are, however, in scope to the rule and subject to other aging management programs as identified in the LRA.

F-RAI 2.3.2.3 -1

Screen assemblies and vortex suppressors are normally used in the containment sump which provides water for the emergency core cooling system (ECCS) recirculation phase, and one of the intended functions is to protect the ECCS pumps from debris and cavitation due to harmful vortex following a loss-of-coolant-accident (LOCA) (refer to Ginna UFSAR Section 5.4.5.4.3). Explain why the subject components were not identified as within scope in Table 2.3.2-3 of the LRA, which listed component groups for the RHR that require an AMR.

Response

The sump screens were not included in Table 2.3.2-3 of the LRA because they are considered civil/structural components rather than ECCS system components. The screens are within the scope of the rule and are evaluated within the Containment Structure. LRA section 2.4.1 provides a description confirming their inclusion. The screen is manufactured from stainless steel and as such is evaluated within the commodity group asset CV-SS(SS)-INT as described in Table 2.4.1-1. The Residual Heat Removal System design does not employ mechanical vortex suppressors. UFSAR section 5.4.5.4.3 describes the instrumentation used to verify vortexing has not occurred during reduced RCS inventory operations.

F-RAI 2.3.2.4 -2

The hydrogen recombiner system piping network branches with one path going to the hydrogen combustor and the other branch going to out-of-scope piping and components leading to the volume control tank. The branch leading to the volume control tank can be isolated at valve 1877, shown on LR boundary drawing 33013-1274-LR at location A9. This valve is shown as normally open; however, it forms the pressure boundary interface with an out-of-scope system. Although note 2 on drawing 33013-2241, "General Notes," states that the valve alignments are typical and the actual valve alignments are controlled by plant operating procedures, the staff is concerned that failure of the downstream, out-of-scope piping may affect the pressure boundary integrity intended function of this piping segment.

Provide additional information to support your determination that it is acceptable to terminate the in-scope portion of the hydrogen recombiner system piping at an open valve boundary. For example, discuss whether plant procedures specify closing this valve to mitigate hydrogen generation following a LOCA event, the amount of time required to complete these procedures, and the effect on system operation if the valves are not closed.

Response

The valve alignment to operate the Hydrogen Recombiner A and B, to maintain the hydrogen concentration in containment at a safe level, is included in Ginna Station procedure S-21.1 and S-21.2. It is important to note that hydrogen generation to a level which requires recombiners takes several days after a severe accident. Thus, sufficient time is available to perform manual valve alignments. Both procedures isolate the Volume Control Tank from the hydrogen manifold by closing valve 1877 and opening valve 1878. The failure of the downstream, out-of-scope piping would not affect the pressure boundary integrity intended function since this piping would be isolated when the hydrogen recombiner is in use. Also per Tech Spec Surveillance Requirement SR3.6.7.1, the hydrogen recombiner system is tested every 24 months.

F-RAI 2.3.2.4 -3

Pipe segments, connectors, and flexible hoses downstream of isolation valves 1868 A-D and 1867A-D, which connect to the mobile hydrogen tanks are not shown as subject to an AMR on LR boundary drawing 33013-1274-LR at locations E6, E7, E10, and E11. However, operability of these piping segments and connectors is necessary for the hydrogen recombiner system to preform its intended function. Justify the omission of these components from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

Response

The pipe segments, connectors and flexible hoses downstream of the isolation valves which connect to the mobile hydrogen tanks were not included in the scope of the LRA, since these components are isolated prior to the use of the hydrogen recombiners. See response to RAI 2.3.2.4-2.

F-RAI 2.3.2.5 -1

Containment penetrations are shown on the LR boundary drawings of multiple systems and discussed in several LRA sections (including containment spray, safety injection, chemical volume and control system (CVCS), ventilation, main steam, feedwater, auxiliary feedwater (AFW), and spent fuel pool cooling as well as containment isolation). Because of the large number of LR drawings and LRA sections that discuss penetrations, the staff are unable to determine with a reasonable assurance that all mechanical components of the containment penetrations shown in UFSAR Table 6.2-15a are within the scope of LR and subject to an AMR. Confirm that the mechanical portions of all containment penetrations are within the scope of LR and subject to an AMR, or identify and justify the exclusions.

Response

As stated in 2.3.2.5 of the application, all non-structural equipment detailed in the UFSAR performing a Containment Isolation (CI) boundary function, where the system containing that equipment has no other safety-related system function, are in scope of the Containment Isolation Component (CIC) system. All CI components in UFSAR Table 6.2-15a are in scope for license renewal either as a CIC component or as a component performing an intended function in the fluid system itself. As indicated in the LRA system descriptions, all containment penetrations are included within the scope of the LRA, with a system function K, "provide primary containment boundary".

F-RAI 2.3.2.5 -2

Unlike plants built after the introduction of the General Design Criteria, Appendix A to 10 CFR 50, some of the piping passing through containment penetrations at Ginna have both isolation valves outside the containment, and do not have inboard isolation valves. This situation was discussed as part of Topic VI-4, "Containment Isolation System," in the Ginna SEP (see page 4-19 of NUREG-0821). The LR boundary drawings show the boundary of some of the piping segments subject to an AMR immediately at the inside of the containment wall (for example, the piping runs through penetrations P123, P129, and P143 on LR boundary drawing 33013-1272, 1-LR at locations A11, B11, C11).

In such situations, piping and pipe restraints in close proximity to the containment structure adjacent to penetrations will not be subject to an AMR. In the event of a pipe break, dynamic effects, such as pipe whip and jet impingement from rupture of the out-of-scope piping segments could damage the containment structure or adjacent, in-scope piping and penetrations. This case is similar to non safety-related piping systems which are not connected to safety-related piping, but have a spatial relationship such that their failure could adversely impact the performance of piping and components with an intended safety function (Criteria A2 of 10 CFR 54.4). However, in this case, the concern is that the non safety-related piping has the potential for causing damage to the containment pressure boundary. Provide justification

for locating out-of-scope pipe segments in close proximity to containment penetrations instead of at some minimum distance.

Response

As described in UFSAR Section 3.1.1.2.5, all piping penetrations are solidly anchored to the containment wall. External guides, stops, increased pipe thickness, or other means are provided, where required, to limit motion and moments to prevent ruptures by making the penetration the strongest part of the system. In addition, all penetrations and anchorages are designed for forces and moments that might result from postulated pipe ruptures. Since by definition a containment boundary cannot be adversely affected by a dynamic effect calling for the boundary function to be maintained, the penetration design itself, as well as the Containment Isolation (CI) boundary on the other side of the 2-1/2 ft. thick reinforced concrete containment has been designed to withstand these forces.

F-RAI 2.3.3.3 -1

Spent fuel pool (SFP) heat exchanger "B" process monitor skid is shown on LR boundary drawing 33013-1250, 2-LR, as having radiation element RE-20B subject to an AMR. Clarify why the components of the SFP heat exchanger "A" process monitor skid and the associated piping and valves leading to radiation element RE-20A shown on LR boundary drawing 33013-1250, 2-LR, at location J6 are not within the scope of LR and subject to an AMR.

Response

The piping and components leading to RE-20A are only 3/4", and can also be isolated with valves 12520A and 12520B. RE-20B was included because it was a much larger size line (2 ½"), and its intended function is pressure boundary only. There is not an electrical function for RE-20A/B. This is consistent with footnote 1 in Table 2.3.3-5 which explains that selected instruments were conservatively included within the scope of the License Renewal. Where an instrument was unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail, that instrument is included for LR.

F-RAI 2.3.3.3 -2

Section 9.1.2.1.1 of the Ginna UFSAR states that the current criteria for the spent fuel storage system is defined, in part, by Regulatory Guide 1.13. Section C.8 of Regulatory Guide 1.13 states:

A seismic Category 1 makeup system should be provided to add coolant to the pool. Appropriate redundancy or a backup system for filling the pool from a reliable source, such as a lake, river, or onsite seismic Category 1 water-storage facility, should be provided.

Section 9.1.2.2.1 of the Ginna UFSAR states that water is supplied to the SFP from the refueling water storage tank (RWST) by the refueling water purification pump. Alternative sources of makeup water are available from the primary water treatment plant and the reactor makeup water tank or the monitor tanks. However, the refueling water purification pump and associated valves and piping to the RWST are shown as not subject to an AMR on LR boundary drawing 33013-1248-LR at location F5. The flow paths to the alternate makeup sources, the primary water treatment plant (location H1), the reactor makeup water tank (location H10) and the monitor tanks are also identified as not subject to an AMR. Justify the

exclusion of these piping runs and associated valves which provide the makeup water sources for the SFP from the scope of LR and being subject to an AMR.

Response

Ginna was built before RG 1.13 was issued - it is used as guidance, but not as a requirement. RG&E has calculated that it would take well over five hours to initiate boiling in the spent fuel pool following a complete loss of SFP cooling. With 26 feet of water over the top of the fuel assemblies, and a maximum boil off rate of 47 g.p.m., there are over 3000 minutes (well over 2 days) before water would have to be added to the pool. This is considered more than enough time to take corrective operator actions, using a wide variety of equipment not limited to Seismic Category I equipment.

F-RAI 2.3.3.3 -3

Section 2.3.3.3 of the LRA indicates that the stainless steel liner of the SFP and the transfer canal is included as a component within the spent fuel cooling and fuel storage system. However, on the basis of its review of Table 2.3.3-3 of the LRA, the staff is unable to locate a table entry for the stainless steel liner. Section 9.1.2.1.10 of the Ginna UFSAR states that the "SFP and refueling canal shall have provisions, such as a watertight liner, to prevent leakage of pool water," which appears to indicate that the liner serves a passive, pressure boundary intended function for LR. The staff notes that, although line number (19) of Table 3.6.1 of the LRA includes a description of an AMP that appears to apply to the stainless steel liner of the spent fuel pool and transfer canal, there is no traceable link between this entry and Table 2.3.3-3 of the LRA. Clarify the LRA's scoping and screening findings concerning the SFP and transfer canal liner, so that the staff may verify compliance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

Response

The SFP liner and transfer canal are in scope and subject to aging management review. The component group of "tank" in Table 2.3.3.3-3 describes the stainless steel SFP liner and transfer canal. Tank was utilized rather than a generic commodity materials group because the spent fuel pool carries a unique plant identification number (EIN) on drawing 33013-1248. In the plant configuration management system the SFP EIN is categorized as a component type of tank. In this case the link for tank in table 2.3.3.3-3 takes the user to Table 3.4-2, item 347 where the Water Chemistry Program is invoked. The Staff is correct that line number (19) of Table 3.6.1 could be appropriate. It also invokes Water Chemistry. This entry was included to maintain fidelity with the NUREG-1800, Standard Review Plan, system and component groupings.

F-RAI 2.3.3.5 -2

A portion of the SW system piping that is not subject to an AMR connects two parallel portions of the SW system piping that are subject to an AMR at valves 4733, 4651B, and 4562B that are shown as normally open (see LR boundary drawing 33013-1250, 3-LR, at locations I2, I7, and J7).

a) This piping run has two parallel trains containing air conditioning (AC) water chiller units SCI03A and SCI03B which cool the chilled water system. Drawing 33013-1920 for the chilled water system indicates that the chilled water system cools the control room ventilation

system. These components are all identified as augmented quality on the drawings. Section 9.4.3 of the Ginna UFSAR states that the function of the control room ventilation system is, in part, to ensure the operability of control room components during normal operating, anticipated operational transient, and design-basis accident conditions. This statement apparently applies to the cooling function of the system because the filtration and boundary integrity functions do not support control room equipment operability. Section 6.4 of the UFSAR states that the control room ventilation system cools the recirculated air as required using chilled water coils. Neither Section 2.3.3.5, Section 2.3.3.10, nor Section 2.3.3.15 of the LRA provide an adequate basis for excluding the associated systems and components from an AMR. Provide information identifying important-to-safety portions of the SW, chilled water, and control room ventilation systems as SCs subject to an AMR, or justify their exclusion from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

b) Failure of the piping not subject to an AMR may affect the pressure boundary intended function of the piping that is subject to an AMR. Section 2.3.3.5 of the LRA does not discuss why this approach is acceptable. Provide additional information to support the basis for this determination. For example, discuss the steps in the procedures for identifying the locations of breaks, for closing the valves, the amount of time required to complete these steps, and the consequences if the valves are not closed following a break of the piping that is not subject to an AMR.

Response

a) Those portions of the SW, chilled water, and control room ventilation systems that meet the requirements for being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) are identified in the LRA. While UFSAR sections 9.4.3 and 6.4 describe all the design functions of the Control Room Area Ventilation System, only some design functions meet the inclusionary criteria in 54.21 (a)(1). The staff observation that UFSAR section 9.4.3 "apparently applies to the cooling function of the system because the filtration and boundary integrity functions do not support control room equipment operability" seems to presume that the only cooling media is via chilled water with the heat ultimately rejected to service water. While this is the preferred method, it is not the only method and does not take into account cooling via radiant heat conduction into the surrounding building members nor the cooling provided by the exchange of air through the filtration and pressure boundary equipment. The components addressed in this question were reviewed under item III.D.3.4, Control Room Habitability, as part of NUREG-0737 (final docketed SER dated 11 April 1983). That review included the understanding that, under certain accident conditions, service water to the chiller units is automatically isolated thus rendering this heat removal media ineffective. NRC design bases inspection performed in 1997 (see docketed inspection report IR 50-244/ 97-201) also led to additional reviews to verify that the control room would not heat up to a temperature above acceptable limits. Additionally, plant operating experience supports the assessment that control room equipment remains functional and operable without the use of the chiller packages to condition the air. Thus the basis for exclusion from being subject to an AMR is that they are not important to safety and do not perform any functions listed in the scoping criteria requirements of 10 CFR 54.4.

b) The basis for the acceptability of the aging management review boundary stopping at an open valve is described in LRA section 2.1.7.1, Mechanical Systems. In this case motor operated valves 4733 and 4663 may receive an automatic closed signal isolating the downstream non-safety piping or they can be remotely closed should the need arise to perform service water leak isolation. Normally open manual valves 4651B and 4562B are also

accounted for in the LRA boundary description. For the valves under discussion each can be closed for leak isolation prior to deleterious affects on near by safety systems. With regard to valves 4651B and 4562B, the physical configuration and fluid dynamics in the SW discharge header where those lines connect make for very low-pressure conditions after the upstream MOVs are closed.

Plant procedure AP-SW.1, Service Water Leak, provides guidance for detecting and mitigating leaks. The procedure invokes an attached instruction set (ATT-2.1) whose very first step is to isolate the non-safety portion of the SW system from the safety portion. That step includes ensuring that at least one of the air conditioning SW loop isolation valves (MOVs 4733 and 4663) is closed. Additionally, the consequence of the piping failure in the area containing the system components under discussion, from the event onset to leak isolation has been evaluated. The evaluation contains a discussion of how much time is available for leak onset until safety related equipment might be affected as well as a description of detection methods. UFSAR section 3.6.2.4.8.1, Intermediate Building Flooding, provides summary of this evaluation.

F-RAI 2.3.3.5 -3

License renewal boundary drawing location listed below shows an isolated pipe section as not subject to an AMR, although the pipe connects to a piping section that is subject to an AMR. Clarify if the exclusion of this pipe section from the scope of LR was intentional, or the result of a drafting error. If the exclusion of this section is intentional, justify the exclusion from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

- A section of 14-inch piping connecting to line 16-SW-125-1 shown on drawing 33013-1250, 1-LR at location C8.

Response

The section of 14 inch piping connecting to line 16-SW-125-1 shown on drawing 33013-1250,1-LR at location C8, is a typographical error and is in scope.

F-RAI 2.3.3.5 -4

Major portions of the SW system discharge lines, shown on drawings 33013-1250, 1-LR, (downstream of expander at the end of pipe section 6-SW-125-1 at location I2), 33013-1250, 3-LR, (downstream of valve 4614 at location H2), 33013-1885, 1-LR, (beginning with pipe 14-SW-125-1 at location E12 and beginning with pipe section with identifier 125-9 at location J9), 33013-1885, 2-LR are identified as not being subject to an AMR. The drawings indicate that the discharge lines include sections of underground piping. Should these sections of piping fail to remove water from the SW system, the intended functions of the SW system will be impaired. Provide information identifying these sections of piping as components subject to an AMR or provide the basis for the determination that these piping sections should not be subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

For the cases cited above referencing LR drawings 33013-1885, 1-LR and 33013-1885, 2-LR, the transitions from piping sections requiring an AMR to those not subject to an AMR occur at

boundaries between drawings. If the boundaries are not changed, provide information to precisely locate these boundaries between piping sections subject to an AMR and piping sections not subject to an AMR.

Response

The piping shown on drawing 33013-1250,1-LR, downstream of expander at the end of pipe section 6-SW-125-1 at location I2 to the discharge header, including the discharge canal up to the lake, is in scope of license renewal. This piping is evaluated in SW Table 3.4-1 line number (16), and Table 3.4-2 line numbers (210) and (211).

The piping on drawing 33013-1250,3, downstream of valve 4614 at location H2, is correctly shown as being out of scope. There are several normally closed valves downstream of 4614 which could be used to isolate a break in the piping.

The 14" SW branch piping, shown on drawing 33013-1885,1 at location E12, is evaluated in the LRA, and the connecting discharge canal up to the lake is also evaluated in the LRA and should be shown on the drawings as requiring aging management review. This piping is evaluated in SW Table 3.4-1 line number (16), and Table 3.4-2 line numbers (210) and (211).

F-RAI 2.3.3.6 -1

On LR boundary drawing 33013-1990, 1-LR, the fire water storage tank is shown as subject to an AMR. However, the fire service water booster pumps and piping and valves back to the SW system are excluded. Justify the exclusion of the fire service water pumps, associated piping components, and valve bodies from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

Response

As described in the Fire Protection Safety Evaluation Report (SER) dated 14 February 1979; the tank and jockey (fire service water booster) pump configuration maintains system pressure above the loop fire pump starting pressures. In this way the components act to minimize motor driven or diesel driven fire pumps from automatic starts due to system leakage and maintenance and testing activities. It is important to note that the mere mention of a system, structure or component in a staff SER does automatically constitute a licensee commitment or requirement. The UFSAR section 9.5.1, Fire Protection Systems, along with the associated references describe in detail our commitments relative to the fire protection systems. In this case the commitment is to satisfy the requirements of Branch Technical Position 9.5-1 and the storage tank, jockey pump and associated appurtenances are not required by the current licensing basis to achieve compliance. Lake Ontario is the source of water for the motor and diesel driven fire pumps, not the storage tank. The fire water system can maintain full operability and compliance with the requirements of 10 CFR 50.48 and all other licensee fire protection commitments without the storage tank and jockey pump in service. Consequently those components and their associated piping and valve bodies are not subject to an AMR in accordance with the requirements of 10 CFR 54.4 (a) and 10 CFR 54.21(a)(1). That notwithstanding, RG&E has elected to perform aging management activities on the fire water storage tank for the simple fact that it is a pressurized tank in an occupied space.

F-RAI 2.3.3.6 -3

LRA Section 2.3.3.6 lists "fire proofing - a passive cementitious coating applied to steel to provide fire resistance." LRA Table 2.3.3-6 includes a component group, "structure," that references Tables 3.4-1 and 3.4-2 for aging management. None of these references address fire proofing of structural steel. No reference was found to the fire proofing of structural steel in Section 2.4, "Scoping and Screening Results Structures," or in Section 3.6, "Aging Management of Structures and Components Supports." Verify that fire proofing is used in the plant as part of fire barriers. If so, identify where the LRA addresses the aging management of these components, or justify their exclusion.

Response

Fire proofing of structural steel is used in the plant at selected locations. For each building that utilizes this feature the system description in LRA section 2.4.2 calls out that usage. For example, in section 2.4.2.3, Turbine Building, in the section describing features and appurtenances credited in the current licensing basis, item b states " Selected structural steel building members are coated with a protective material to resist the effects of fires". These material are evaluated in the fire protection system as part of fire barriers, and are evaluated for aging management in LRA Table 3.4-2 line numbers (322) - (329) component type "structure", material "grout".

F-RAI 2.3.3.6 -4

LRA Section 2.1.5.6 includes fire detection as part of the fire protection program necessary to meet the requirements of 10 CFR 50.48. LRA Section 2.3.3.6 includes the fire detection and alarm systems as in scope. Neither LRA Table 2.3.3-6 nor LRA Section 2.5, "Screening Results of Electrical and I&C Systems," includes any reference to the aging management of these systems. LRA Section 3.7, "Aging Management of Electrical and I&C Systems," contains no specific reference to the components of the fire detection and alarm systems. Confirm that these systems are in-scope and identify where the LRA addressed the AMR of these components.

Response

The aging management review of low voltage cables and connections is performed in LRA section 3.7 and is applicable to fire detection and alarm systems. The Aging Management Programs are listed in Table 3.7-1. The fire detection and alarm system components are in scope to license renewal, however all components are active with the exception of cables, connectors, and other passive electrical devices which are included in Table 3.7-1.

F-RAI 2.3.3.7 -1

In Section 2.3.3.7 of the LRA, the applicant states that portions of the heating steam system are considered within the scope of LR because they contain non safety components whose failure could prevent the accomplishment of a safety function. Those portions of the heating steam system are contained in the diesel generator rooms and the auxiliary building. In Table 2.3.3-7 of the LRA, the applicant identifies component groups that are subject to an AMR; however, the staff could not locate any of these components on the five drawings highlighted by the applicant as containing SCs subject to an AMR. The staff has identified some of the components as

appearing on LR boundary drawing 33013-1914, 1-LR, but is uncertain of the exact LR boundary. Provide the drawing numbers and equipment identification numbers for the components which comprise the component groups listed in Table 2.3.3-7.

Response

The affected components are shown on P&ID 33013-1914-LR, generally in locations B1 - B3 and F1 - F3 and should have been highlighted. This is a typographical error.

The specific components in component group "heater" in Table 2.3.3-7 are the Diesel Generator Unit Heaters ADU01, ADU02, ADU03, and ADU04. The component group "strainer housing" include HHS Strainers NHS02, NHS03, and NHS04. The component group "trap housing" includes house heating steam traps ZHS02, ZHS03, ZHS04, and ZHS05.

The component group "valve body" includes valves 7231F, 7231G, 6643, 6642, 6641, 6640, 6639, 6509, 6508, 6507, 6506, 6505, 6504, and 6638. The piping includes 1 ½", 1/4", 1/2", 1" and 3/4" carbon/low alloy steel piping.

Additional components in the screenhouse will be included within the scope of license renewal as referenced in RAI 2.1-4.

F-RAI 2.3.3.8 -1

Man ways associated with the diesel generator fuel oil storage tanks are shown to be subject to an AMR on LR boundary drawings 33013-1239-LR, sheets 1 and 2, at locations J2 and J10, respectively. A similar bolted access cover associated with the diesel generator cooling water expansion tanks are shown to be subject to an AMR on LR boundary drawings 33013-1239-LR, sheets 1 and 2, at locations A5 and A7, respectively. However, the Man ways and access covers have not been included in Table 2.3.3-8 or Tables 3.4-1 and 3.4-2. Furthermore, in Section 9.5.4 of the Ginna UFSAR, it states that watertight doors have been installed on the concrete Man ways of the underground diesel-oil storage tanks. The purpose of the doors is to prevent the accumulation of water in the Man ways. Water might seep into the oil through the flanged manhole on the top of each storage tank. Justify the exclusion of the Man ways, access covers, watertight doors, and bolting mechanisms from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

Response

The Man ways associated with the diesel generator fuel oil storage tank, and the bolted access cover associated with the diesel generator cooling water expansion tanks are grouped within the component group "tank". Line number (7) in Table 3.4.1 along with line numbers (335), (337), (340) and (341) in Table 3.4-2, are applicable to these components.

The concrete enclosure referred to in UFSAR section 9.5.4 is evaluated in the LRA within the Essential Yard Structures system in Table 2.4.2-11 under component groups YARD-C-BUR and YARD-CAPTION-EXT.

F-RAI 2.3.3.8 -2

Foot valves 5919 on LR boundary drawing 33013-1239, 1-LR, and 5920 on LR boundary drawing 33013-1239, 2-LR, are shown to be subject to an AMR. Note 4 on these drawings

indicate that the valve contains a screen. However, Table 2.3.3-8 does not list any screens as a component group subject to an AMR. Clarify if the screens associated with these valves are subject to an AMR. If not, justify the exclusion of these screen from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

Response

The screens associated with foot valves 5919 and 5920 are subject to an AMR. The applicable Aging Management Programs are listed in Table 3.4-1 line number (5) - Periodic Surveillance and Preventive Maintenance Program, Fuel Oil Chemistry Control Program as well as the One-Time Inspection Program. Currently there is a Reptask P301699 to inspect/clean D/G "A" Fuel Oil Storage Tank (TDG01A) which includes inspection of valve 5919 and associated screen. Reptask P301700 inspects "B" tank and valve 5920 and associated screen.

F-RAI Generic HVAC -1

The symbol for "air opening" (see "Symbol Legend", LR boundary drawing 33013-2242, 3-LR, location H4) appears at various air intakes and exhausts on the LR boundary drawings for the containment ventilation system. At many locations, these openings are highlighted to identify them as being subject to an AMR (for example; LR boundary drawing 33013-1864-LR, location F8). Since a different symbol has been used for air openings than for louvers, the nature of these air openings (e.g., screens, grillwork) is not clear to the staff. These components are not listed as a component group in LRA Tables 2.3.3-9 and 2.3.3.10. The staff requests that the applicant describe these air openings, through diagrams, textual description, or both, and justify the exclusion of these air openings from LRA Tables 2.3.3-9 and 2.3.3-10.

Response

The screens, grillwork, etc. associated with the air openings/louvers are part of the component group "ventilation ductwork" and where indicated on the drawings, are in scope to license renewal. This is consistent with the NUREG 1801.

F-RAI Generic HVAC -2

Cooling coils are shown on LR boundary drawings at the following locations for the containment ventilation system: 33013-1863-LR (locations A1, A4, A7, and I3), 33013-1864-LR (locations E5 and F5), and 33013-1866-LR (location D5). Similarly, cooling coils are shown on LR boundary drawings at the following locations for the essential ventilation systems: 33013-1867-LR (location A9) and 33013-1969-LR (locations B3, D3). In addition, an electric heating coil is shown on LR boundary drawing 33013-1867-LR (location A9).

Cooling coils have the intended function of transferring heat from return air or outside air to the cooling medium for the coil. Heating coils have the intended function of transferring heat to return air or outside air. In addition, both cooling and heating coils have the intended function of providing a pressure boundary.

Cooling coils are included as a component group in LRA Tables 2.3.3-9 and 2.3.3-10, with the listed passive function of providing a pressure boundary. Heating coils are considered as a separate component group in Table 2.3.3-10 with the listed passive function of providing a pressure boundary. Heat transfer; however, is not specified as an intended function for either cooling coils or heating coils in these tables. However, "heat exchangers" are listed as a

separate component group in LRA Tables 2.3.3-9 and 2.3.3-10 with the listed passive functions of both heat transfer and pressure boundary. The staff considers both cooling coils and heating coils to be heat exchangers. The above-cited cooling and heating coils appear to be the only heat exchangers shown within the LR boundary on the LR boundary drawings for the containment ventilation and essential ventilation systems. Therefore, it is not clear to the staff what differentiates the "heat exchangers" from the "cooling coils" and "heating coils" component groups in LRA Tables 2.3.3-9 and 2.3.3-10.

Identify any heat exchangers for all heating ventilation and air conditioning (HVAC) systems (other than the cooling coils and heating coils) that are within the scope of LR and have not been identified on the LR boundary drawings.

Response

All heat exchangers for all HVAC systems that are within the scope of license renewal have been identified on the license renewal boundary drawings. Component type "heat exchanger" is in scope for the intended function of pressure boundary, and not for the heat transfer function. The distinction between HVAC component types can be determined by using the symbol list on drawings 33013-2242 sheets 1-4. Specifically, drawing 33013-2242 sheet 1 shows the symbol for a u-tube heat exchanger, straight tube heat exchanger, and heat exchanger. Drawing 33013-2242 sheet 3 shows the symbol for a heating coil, and cooling coil.

F-RAI 2.3.3.9 -1

LR boundary drawing 33013-1866-LR shows flanged flexible hoses upstream of each of the fifteen containment penetrations indicated for the containment penetration cooling system. The drawing identifies these components as being subject to an AMR. However, flanged flexible hoses are not listed as a component group in LRA Table 2.3.3-9. Justify the exclusion of flexible hoses from LRA Table 2.3.3-9.

Response

The flanged flexible hoses were not excluded from evaluation. The 2 inch flanged flexible hoses were included in the component group "PIPE" on Table 2.3.3-9 of the LRA. The neoprene lining of the flanged flexible hoses received aging management evaluation as duct in accordance with NUREG 1801, Chapter VII, item F3.1-b. The link in the LRA to Table 3.4-1, line number (2) represents the flanged flexible hoses internal surfaces.

F-RAI 2.3.3.10 -1

LR boundary drawing 33013-1256-LR depicts the ventilation systems and components that serve the technical support center (TSC) diesel-generator room, the TSC un-interruptible power supply, and the TSC battery room as being in the scope of LR and subject to an AMR (see locations H1,2,3,4; I1,2,3,4,5; J1,2,3,4.). In order for the staff to confirm that all SCs that serve an intended function meeting the scoping criteria of 10 CFR 54.4(a) have been considered, identify the equipment (and the intended functions they perform) which rely on the functioning of these power supply components with justification of the omission of the ventilation components for the equipment from the scope of LR.

Response

The ventilation system for the entire TSC is not relied upon for the safe shutdown of the plant in Ginna's current licensing basis (CLB). The ventilation system components which are in scope of the LRA, shown on drawing 33013-1256, are correctly depicted. The ventilation components within the TSC that are included in the scope of the LRA, are used for post fire safe shutdown activities with a criterion 3 function. This meets the scoping criteria of 10 CFR 54.4(a).

The diesel generator, located in the TSC diesel generator room, is included in the scope of the LRA, under Emergency Power, section 2.3.3.8, with applicable components listed within Table 2.3.3-8. The TSC diesel generator can be used to supply a battery charger, located in the TSC battery room, in order to support vital DC for long term recovery following some fire scenarios, as described in the Emergency Power system description (section 2.3.3.8). These components are in scope of the LRA and can be found on drawing 33013-2288-LR.

F-RAI 2.3.3.10 -3

LR boundary drawing 33013-1869-LR depicts the ventilation systems that service the RHR, containment spray, charging, safety injection, and standby AFW pumps. In this drawing, only the ventilation system for the standby AFW pumps is shown to be within the LR boundary.

Two redundant cooling units each are provided for both the RHR pump pit and the charging pump room. Three cooling units, headered into common ductwork, are provided for the safety injection and containment spray pumps. A separate cooling unit is provided for each of the two standby AFW pump rooms. LRA Section 2.3.3.10 states that the fans for these cooling units are supplied by emergency diesel power.

The primary function of the safety injection system is to supply borated water to the reactor coolant system (RCS) to limit fuel rod cladding temperatures in the event of a LOCA. Safety injection is handled by two systems; a low-head system and a high-head system. The low-head system, which is activated for large breaks where there is rapid blowdown and depressurization, utilizes the RHR pumps for borated water injection. The high-head system, which is activated for small breaks, consists of two subsystems, one utilizing the chemical and volume control system charging pumps and the other utilizing the safety injection pumps for borated water injection.

Regarding the containment spray pumps, LRA Section 2.3.3.9 states that two of the containment recirculation fan coolers, plus one containment spray pump, are required to provide sufficient capacity to maintain the containment pressure within design limits after a LOCA or steam line break accident.

All of the pumps listed above are safety-related and are within the scope of LR, in accordance with 10 CFR 54(1), items (i) and (ii). The systems providing ventilation to the area's housing these pumps and associated pump motors have the function of maintaining an acceptable environment for operation of these components under accident conditions. Therefore, the staff considers these ventilation systems to be within the LR boundary.

Section 9.4.2.4.2 of the UFSAR states that the Reference 2 analysis, noted in Section 9.4.2.2.3, had errors that were correction in Reference 8, ALTRAN Technical Report 99124TR001. The assumption for the fans/coolers used in the Reference 8 analysis is unspecified.

Justify the exclusion of the ventilation systems servicing the RHR, containment spray, charging, and safety injection pumps from the scope of LR. If the justification is based on analysis, summarize the assumptions made and the resulting conclusions for each of these pumps.

Response

The RHR, SI, and CS pump motors have been analyzed to operate with no ventilation required following a design basis LOCA. All of the ECCS pump motors are in our EQ program. As stated in the conclusion of UFSAR 9.4.2.4.2, the EQ of all safety-related equipment (including these motors) in the auxiliary building was reviewed and it was still capable of performing the safety-related functions. The magnitude of the increase in peak temperatures combined with the short duration of the temperature increase resulted in negligible decrease in qualified life that did not affect the operability of the equipment.

The assumptions used in Altran Report 99124TR001 (Ref.8) are well-accounted for in UFSAR 9.4.2.4.2.

The charging pumps are not required to operate following a LOCA - they need only survive the environmental effects of a steam heating line break in the Auxiliary Building (calculated temperature of 150 F), in order to provide for inventory and reactivity control in the subsequent safe shutdown evolution. The pumps are assumed to be actuated in 8 hours, at which time Auxiliary Building environmental conditions are determined to have returned to pre-steam heating line break ambient conditions. Normal operation of the charging pumps produces a higher temperature in the motor windings than the 150 F environment the motor was exposed to in the steam heating line break. Therefore, the charging pump motors were removed from the Ginna EQ Master list (the motor temperature is no higher following "break" conditions than under normal operation), and therefore the cooling units are also not required to support a safety function. As stated in 9.4.2.2.3 of the UFSAR, the charging room cooling units are provided only to extend the commercial life of the equipment.

F-RAI 2.3.3.11 -2

Table 2.3.3-11 of the LRA lists "crane" as a component group within the scope of LR and subject to an AMR. The LRA does not define the component group crane. Listing "crane" as the structures and components subject to an AMR does not satisfy the requirement of 10 CFR 54.21(a)(1) because an entire crane is not subject to an AMR. List the structures and/or sub-components of the cranes, hoists, lifting devices, etc. that are within the scope of LR and subject to an AMR.

Response

As noted in Section 2.3.3.11 of the application, "cranes" include cables, hooks, and moving load-bearing elements (bridges and trolleys). Crane rails are evaluated as part of the structures that contain them.

F-RAI 2.3.3.12 -1

LR boundary drawing 33013-2681-LR shows six sump pumps and connecting piping and valves as being subject to an AMR. The six pumps are in diesel generator (DG) room "A" (location A6), DG room "B" (location A8), the control building ventilation room (location F6), and battery room "A" (location F7). The DG room vault sump pumps discharge to piping that is

subject to an AMR. The piping subject to an AMR; however, does not extend to the discharge canal, the final depository for the discharge flow. The sumps containing the DG "B" floor drain sump pump and the battery room "A" floor drain sump pump gravity drain through ball check valves. The discharge piping subject to an AMR extends only to the floor drain outside of the subject room.

It is not clear from the information provided in LR boundary drawing 33013-2681 where the three sump pumps PWT28, PWT29, and PWT30 (at locations B7, E7, and E6, respectively) discharge to, as the sumps all appear to be gravity drained. Clarify where these sump pumps discharge their respective flows.

In each of these cases, the intended system function of preventing flooding would appear to require that the complete discharge piping flow path, up to the final discharge point, be subject to an AMR. An exception could occur where the capacity of an interim storage location is sufficient to hold the maximum flood inventory. Explain why the entire treated water system discharge piping flow paths to a retention tank or the discharge canal is not subject to an AMR, or describe how the maximum flood inventory is accommodated.

Response

After initial construction the sump water boxes were modified to prevent potential back flow of oil into spaces containing safety related equipment. In some instances the modification consisted of installing a baffle, horizontally bisecting the water box. The sump pumps move the water that might collect on top of the baffle, through a check valve, to the bottom of the water boxes where the fluid flows by gravity through the drain header. The check valves and baffles prevent fluids from being forced from the common drains back into the space.

The reason why the entire treated water system discharge path is not subject to AMR lies in the configuration of the flow path. The drainage portion of the system outside the areas of concern is not a closed system. Numerous water boxes that are open to atmosphere exist in the drain system. Should the path to the retention tank be unavailable the water volume simply overspills these water boxes, with ultimate dewatering occurring though flow across the Turbine Building floor into the yard. Consequently the capacity of the interim storage volume can be viewed as infinite. Thus, the entire treated water system discharge piping flow paths are not subject to an AMR, only the piping and components which drain water from the rooms or prevent water from backing up into the rooms, which contain safety related equipment, are in the scope of the LRA.

F-RAI-2.3.3.12 -2

Location E8 of LR boundary drawing 33013-2681, 3-LR, shows the floor drain line for battery room "B" as not being within the scope of LR. However, at location E7 of this same drawing, the drainage line from battery room "A" is shown as being within scope. Document the basis for concluding that the floor drain line for battery room "B" is not within the scope of LR, so that the staff may verify compliance with 10 CFR 54.4(a).

Response

The referenced drawing inadequately depicts the "B" Battery room drainage configuration. The room does not contain a floor drain, rather the floor is sloped to provide gravity drainage to battery room "A". The configuration of the "A" Battery Room drainage is such that there is no possibility of back flow of oil or combustible liquids into the battery rooms from external sources.

There are no fluid systems in the battery rooms that could be internal flood sources. Therefore the Battery Room "B" drainage has no license renewal intended function and is not within the scope of License Renewal.

F-RAI 2.3.3.13 -1

LR boundary drawing 33013-1866-LR, shows piping, pumps, valves, flow elements, fittings, and radiation detectors in the containment ventilation process radiation monitor skid as being subject to an AMR. These components are necessary for the radiation monitoring system to perform the system function of providing process conditions and generating signals for reactor trip and engineered safety features actuation. Monitors included on the skid are the containment gas monitor, containment iodine monitor, and the containment particulate monitor. Piping and associated fittings and valves that transport the material to be monitored from the containment are subject to an AMR only up to the containment boundary. The piping which continues inside containment also appears to be needed for the system to perform its intended function. Discuss why those portions of the piping continuing inside containment (LR boundary drawing 33013-1866-LR, location G11) are not subject to an AMR.

Response

The piping which continues inside containment is not in scope because it does not provide an intended containment isolation boundary function. Isolation occurs outside of containment. The portion of piping, valve and components leading to the containment gas, iodine and particulate monitor skid were conservatively included in the scope of the LRA, although as stated in UFSAR section 6.2.4.3, the containment ventilation isolation signal serves as a backup to the containment isolation signal and is not specifically credited in the accident analysis.

F-RAI 2.3.3.13 -2

LR boundary drawing 33013-1867-LR shows the control room radiation monitor skid. The only components shown on this skid are radiation monitors. Confirm that the only components on these skids are the radiation monitors. If not, identify the other components and justify the exclusion of these components from the scope of LR and being subject to an AMR.

Response

Radiation Monitor System includes specific components on this skid such as valves, pumps, piping, tubing, flow meter, filter housings and detectors which were evaluated and determined to require aging management review. Drawing 33013-1867-LR shows a box around RE-36/37/38, which represent the skid.

F-RAI 2.3.3.15 -1

At location A9 on LR boundary drawing 33013-1867-LR, the chilled water cooling coil for the control room air handling unit is shown as being within the scope of LR. At location J7 on LR boundary drawing 33013-1920; however, a similar cooling coil is shown as not being within the scope of LR. Clarify whether or not this cooling coil is within the scope of LR, in accordance with 10 CFR 54.4(a).

Response

This is a typographical error. The control room air handling unit housing is in scope, not the coils. The letters should have been colored black on LR boundary drawing 33013-1867 at location A9. The housing is included for its pressure boundary function.

There are no components on drawing 33013-1920 which are within the scope of license renewal.

F-RAI 2.3.3.16 -1

Identify the components of the fuel handling system that comprise the fuel and reactor internals handling tools and control equipment for safety interlocks (including housings and support structures). Discuss whether the fail-safe feature of the spent fuel handling tool, the control rod drive shaft tool, the rod cluster control assembly changing fixture or other tools used to suspend fuel and reactor internals components above the reactor vessel and spent fuel pool could be compromised by wear, impact damage or other age-related degradation mechanisms. If so, justify the exclusion of this equipment from the scope of LR and being subject to and AMR.

Response

As stated in Section 2.3.3.16 of the LRA (Page 2-173), components within the Fuel Handling system which have intended functions are evaluated in the Cranes, Hoists and Lifting Devices system. The following components in scope of NUREG 0612 are included in Section 2.3.3.11 of the LRA:

Spent Fuel Pool Bridge Crane including rails and girders
Fuel Manipulator Crane including rails and girders
Containment Monorail on Fuel Manipulator Bridge including girders

The aging management review of these components is included in Tables 3.4-1 and 3.4-2 appropriately. The balance of the components in the Fuel Handling System do not perform any license renewal intended functions.

Technical Specification Surveillance Requirement TSR 3.9.3.1, verifies the refueling manipulator crane interlocks are OPERABLE, once prior to each refueling operation. UFSAR section 1.8.1.13 also discusses the Auxiliary Building Crane interlocks and the Spent Fuel Pool.

F-RAI 2.3.4.1 -1

Table 7.4-3 of the Ginna UFSAR identifies nitrogen bottles as a safe shutdown motive force for the atmospheric dump valves, also referred to as atmospheric relief valves (ARVs). Section 10.3.2.5 of the Ginna UFSAR states that "backup supply (to the ARVs) is provided by two non-seismic nitrogen supply systems in the event that a loss of offsite power causes loss of the instrument air system." LR boundary drawing 33013-1231-LR identifies nitrogen bottles, associated tubing, piping, and valves as subject to an AMR. However, Table 2.3.4-1 of the LRA does not list the nitrogen bottles of interest as requiring an AMR. It is noted that the associated tubing, piping and valves are listed in the table. Since the UFSAR identifies the nitrogen bottles as a power supply for the atmospheric dump valves, and the dump valves are required for safe shutdown, the nitrogen supply is within the scope of LR per 10 CFR 54.4(a) and is subject to an AMR per 10 CFR 54.21(a)(1). Explain the apparent omission of nitrogen bottles from being

subject to an AMR. If the nitrogen bottles are considered to be consumable, provide a description of the replacement program.

Response

These bottles are in the scope of license renewal with no aging management program required since they are a commodity item, replaced on condition. A daily operation log check, per Ginna procedure O-6.11 is performed and if the pressure is found to be less than 1000 psi the bottle is changed.

F-RAI 2.3.4.1 -2

The boundary of the portion of the main steam system that is within the scope of LR and subject to an AMR ends at valves that are shown as normally open (see LR boundary drawing 33013-1232-LR at locations E7 and F7 and 33013-1277, 1-LR, at locations C5 and H5). Failure of the downstream piping may affect the pressure boundary intended function. It is noted that piping downstream of these valves is classified as non safety-related, and the LRA page 2-19 states:

The LR evaluation markups for a system have typically been extended to the first normally closed manual valve, check valve or automatic valve that gets a signal to go closed. A normally open manual valve has also been used as a boundary in a few instances where a failure downstream of the valve has no short term effects, can be quickly detected, and the valve can be easily closed by operators to establish the pressure boundary prior to any adverse consequences. However, for station blackout (SBO), Appendix R, high energy line break (HELB), and flooding events, the LR boundaries for a system have been defined consistent with the boundaries established in the CLB evaluations. Those boundaries do not always coincide with an isolation device.

Provide a brief discussion on the steps to be taken during events such as HELBs, station blackout and fires for closing the valves, the amount of time required to complete these steps, and any other pertinent information to justify an open boundary at these valves.

Response

The explanation is included in note 3 of the drawing which states, "In accordance with EWR 5114, 30" and 24" main steam lines up to and including valves 3544 and 3545 as well as the 12" lines up to and including valves 3532 and 3533 are safety significant class for high energy consideration only. Class boundary for all branch lines is at the connection to the main piping". Ginna Station is designed to withstand the effects of HELB on all other piping segments and therefore no isolation is required. The NRC reviewed and accepted the analyses and facility design modifications for High Energy line breaks outside containment. The NRC acceptance is documented in letter to L. D. White, Jr., RG&E subject: Amendment No. 29 to License No. DPR-18, dated 8/24/79.

F-RAI 2.3.4.1 -3

On LR drawing 33013-1232-LR, several lines are shown branching from 24-MS- 600-1 (see locations B6 and E6). However, the branch lines up to a normally closed valve are not shown to be within the scope of LR or subject to an AMR. Failure of these branch lines may affect the

pressure boundary intended function of the main steam line. Justify the exclusion of these branch lines from being subject to an AMR.

Response

The High Energy line breaks outside containment were evaluated and accepted by the NRC (documented in NRC letter dated 8/24/79 from D.L. Ziemann, NRC, to L.D. White, Jr., RGE, Subject: Amendment No. 29 to License No. DPR-18). The High Energy Line breaks were subsequently identified on the Main Steam and Feedwater System P&ID's through EWR 5114.

The justification for excluding various branch lines from being subject to an AMR is provided in response to RAI 2.3.4.1-2.

F-RAI 2.3.4.1 -4

On LR drawing 33013-1231-LR, flanged flexible hose connections are shown to be subject to an AMR (see locations C7 and I7). However, Table 2.3.4-1 of the LRA does not contain an entry for this component type. Clarify if flanged flexible hose connections are considered to be part of the component group, "pipe," or some other component type listed in Table 2.3.4-1. If not, justify the exclusion of these components from the scope of LR.

Response

The flanged flexible hose connections are considered as part of the component group "Pipe". The links to Table 3.5-2, line numbers (33) and (35) apply. Asset ID MS-TUBING,8/2 includes this flexible hose.

F-RAI 2.3.4.1 -5

On LR drawing 33013-1231-LR at location E8, a screwed cap is shown as being subject to an AMR because it serves as a pressure boundary intended function. However, the screwed cap at location I8 is not shown as being subject to an AMR. Clarify if this is a drafting error or if this segment of piping was intentionally shown as not subject to an AMR.

Response

This is a typographical error. The screwed cap at location I8 is in scope, and is subject to aging management review.

F-RAI 2.3.4.1 -6

Table 2.3.4-1 of the LRA lists "operator" as a component group that requires an AMR. However, the referenced drawings for the main and auxiliary steam systems do not show any valve operators as requiring an AMR. Clarify whether the operator listed in Table 2.3.4-1 is associated with the atmospheric dump or relief valve (valves 3410 and 3411).

Response

The operator listed in Table 2.3.4-1 is associated with the atmospheric dump and relief valves 3410 and 3411. The operators should be shown as requiring aging management review on drawing 33013-1231-LR for these two valves. This is a typographical error.

F-RAI 2.3.4.2 -1

On LR boundary drawing 33013-1236, 2-LR, flow transmitter FT 466 at location B4 is shown to be subject to an AMR; however, FT 477 at location I4 is not. Additionally, flow transmitters FT 467 at location B1, FT 500 at location C2, FT 503 at location H1, and FT 476 at location I1 are not shown as subject to an AMR. Note 5 on the drawing indicates that these flow transmitters are considered "safety significant" class for pressure boundary considerations. Note 1 to Table 2.3.4-2 of the LRA indicates that selected instruments were conservatively included in the scope of LR if the instrument is unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail.

Although the transmitters in question appear to be isolable, the instrument line size is not indicated. Briefly discuss the justification for these specific transmitters as not subject to an AMR, that is, whether sufficient time exists to isolate the instruments, the line size is significantly small such that its failure would not degrade the pressure boundary, etc.

Response

Flow transmitter FT 466 at location B4 is shown to be subject to an aging management due to a typographical error. FT 466 is not within the scope of license renewal. FT 477, FT 467, FT 500, FT503 and FT476 are correctly shown as being out of scope on drawing 33013-1236,2-LR. Flow transmitters are considered active devices and do not require an aging management review.

F-RAI 2.3.4.2 -2

Clarify why the operator to the main feedwater regulating valve is not subject to AMR, while other operators are included in the scope of LR and subject to an AMR. This operator is credited for isolation in the CLB analysis presented in Section 15.1.1.1 of the UFSAR.

Response

The operator to the main feedwater regulating valves are not subject to aging management review because those valves fail to the safe position (closed) on loss of operator pressure boundary, thus providing the feed regulating valve isolation function. The steam generator atmospheric relief valves and pressurizer PORVs must operate both open and closed to satisfy their safety functions; thus the operators and their associated pressure boundaries provide a license renewal intended function and require aging management review.

F-RAI 2.3.4.3 -1

LR boundary drawing 33013-1234-LR shows Man ways on condensate storage tanks "A" and "B" to be subject to an AMR. However, the Man ways are not listed in Table 2.3.4-3. Explain why these passive, long-lived components are not included in the subject table.

Response

The Man ways on condensate storage tanks "A" and "B" which are shown in scope on drawing 33013-1234-LR are evaluated as part of the tank. All Man ways were evaluated as part of the associated tank with the exception of the Pressurizer, where the manway construction is unique

(bolted loose liner versus integral or weld overlay clad on vessel interior). This manway is evaluated in the LRA on Table 2.3.1-4.

F-RAI 2.3.4.3 -2

LR boundary drawing 33013-1234-LR shows a 6-inch vent on the top of condensate storage tanks "A" and "B". A class break is shown in the vent line. The vents are not shown to be subject to an AMR. Failure of the vent could potentially create a vacuum. Explain why the vent is not subject to an AMR, or indicate whether there is an alternate means to provide vacuum protection for this tank.

Response

The 6" vents on top of the condensate storage tanks "A" and "B", based on operating experience, were not included within the scope of the LRA. There is no credible aging effect, that would cause a large vent to fail in a manner which would create a tight seal on top of these tanks. Therefore the 6" vents were not included within the scope of the LRA.

F-RAI 2.3.4.3 -3

On LR boundary drawing 33013-1234-LR, the boundary for AMR is shown to end at valve 4047 (see location I5). This valve appears to be normally open. It is noted that a piping class change occurs at this valve. The note on page 2-19 of the LRA indicates that normally open manual valves are used as a boundary if failure of the downstream piping has no short term effects, can be quickly detected, and be easily closed by the operators to establish the pressure boundary prior to any adverse consequences. However, the staff is unable to determine which of these cases apply for this particular valve. Explain why it is acceptable to terminate the LR boundary at this normally open valve.

Response

As described in section 2.1.7.1 of the LRA, for SBO, Appendix R, high-energy line break (HELB), and flooding events, the LR boundaries for a system have been defined consistent with the boundaries established in the CLB evaluations. Those boundaries do not always coincide with a closed isolation device.

Valve 4047 is used to establish a Station Blackout (SBO) boundary that envelops the condensate storage tanks. Should the need arise, operating procedures reconfigure the valve to closed and establish a boundary so that the tanks can be refilled from various (in-scope to LR) sources. In this manner a steady supply source for the Turbine Driven Auxiliary Feedwater pump is maintained for the required SBO coping duration.

F-RAI 2.3.4.3 -4

On LR boundary drawing 33013-1237-LR at locations F9, I7, and J8, flow elements are shown to be subject to an AMR; however, flow element FE 2006 at location I10 is not. This component serves a pressure boundary function. Clarify if this is a typographical error, or justify its exclusion from an AMR.

Response

This is a typographical error. The flow element FE 2006, at location I10 is in the scope of license renewal and should have been shown on the drawing as requiring aging management review.

F-RAI 2.3.4.3 -5

Table 2.3.4-3 of the LRA indicates that a "governor" is subject to an AMR. After review of the various documents and drawings, the staff is unable to identify which "governor" or "governors" are those intended to be subject to an AMR. Clarify which valve governor(s) is/are intended by the component group listed in Table 2.3.4-3. It is noted that there are a few governors which are not shown to be subject to an AMR (see LR boundary drawings 33013-1231-LR, locations D2, C5, I5 and 33013-1236, 2-LR, locations D3 and G3).

Response

The governor for valve 9519E, should have been shown as requiring aging management review on drawing 33013-1231-LR, since it is in scope to license renewal. This is a typographical error. The governor for valve 9519E is the only component applicable to the group "governor" listed in Table 2.3.4-3.

F-RAI 2.3.4.3 -6

In Section 10.5.3.1.4 of the Ginna UFSAR, it states that connections have been provided allowing the use of the yard fire hydrant system to fill the condensate storage tanks as a source of water for the motor driven and turbine driven pumps. The staff could not identify these connections on the LR boundary drawings. Based on the statement in the UFSAR, it appears that the hydrant connections should be within the scope of LR and subject to an AMR. Explain why such connections do not require an AMR.

Response

This is a typographical error. The use of the yard fire hydrant system to fill the condensate storage tanks is documented in Ginna Emergency Response Procedure ER-AFW.1. Within this procedure it specifies to run the fire hose from hose reel #2 and connect at valve 4049C. Hose reel #2 (shown on drawing 33013-1990,2), along with the yard fire hydrant system piping is included in the scope of license renewal and is shown within the drawings listed for the Fire Protection System in LRA section 2.3.3.6. The fire system piping connection shown on drawing 33013-1234, at location H7, is shown incorrectly as black, and is a typographical error.

F-RAI 2.4 -1

In table 2.4.2-11, Essential Yard Structures, of the LRA, it states that the embedded portions of anchor bolts for three component groups (YARD-C-BUR, YARD-C-EXT, and YARD-C-INT) require an AMR. However, it does not address whether the exposed portions of anchor bolts require an AMR. If the exposed portion of anchor bolts requires an AMR, provide the information on component group, passive function, and aging management reference for the exposed portions. If not, provide a justification for their exclusion.

Response

Table 2.4.2-11, Essential Yard Structures should contain an entry for Yard-Fast(CS)-EXT. The absence of this component asset was a typographical omission. This generic asset includes the exposed portion of carbon steel threaded fasteners for Yard Structures that are exposed to the weather. The intended functions for these assets include Structural Support NSR Equipment, Cooling Water Source and Shelter/Protect Equipment. The AMR for the generic asset is contained in Table 3.6-1 line number (16).

F-RAI 2.4 -2

The terms "threaded fasteners" and "anchor bolts" have been used in several tables in Section 2.4 of the LRA as if they are interchangeable. Define what the terms threaded fasteners and anchor bolts consist of, and clarify whether the two terms mean the same item or different terms.

Response

Although the terms "threaded fasteners" and "anchor bolts" are different terms, the exposed portion of the structural anchor bolt receives the same evaluation as threaded fasteners. This is explained in the LRA within the descriptions for the component groups. For example: See the description for the component group "AB-C-EXT" in LRA Table 2.4.2-1.

F-RAI 2.4 -3

In Table 2.4.2-12, Component Supports Commodity Group, it indicates that the grout used for Hilti bolts requires an AMR, but the grout used for Drillco Maxi-Bolts is excluded from an AMR. Provide a justification for the exclusion of the grout used for Drillco Maxi-Bolts.

Response

All grout associated with supporting components that are within the scope of the rule, together with the grout in which Drillco Maxi-Bolts are embedded, is included for aging management review. The language used in Table 2.3.2-12 was meant to distinguish that Drillco Max-Bolts have a design installation technique different from other types of embedded anchor bolt configurations. That difference typically results in bolt shaft failure rather than grout failures when the component is over stressed.

F-RAI 2.4 -4

Drawing 33013-1250, 1-LR, note 9, states that a set of controlotron mounting tracks and transducers have been permanently installed and evaluated per PCR 2001-0009. At locations C5 and E5 of this drawing, these mounting tracks are shown as not subject to an AMR. Since these mounting tracks are passive and long-lived structural items, provide a basis to justify that they should not be subject to an AMR.

Response

The Controlotron mounting tracks and transducers are not included in the scope license renewal since they do not have an LR intended function. Controlotron ultrasonic flow measurement equipment, including transducers and mounting tracks were installed as a means

of measuring SW flow for testing purposes only. Additionally these devices were evaluated to determine if they were candidates for inclusion as non-safety components whose failure could affect a safety function. The results of that evaluation indicated that they were not within the scope of license renewal.

F-RAI 2.4 -5

The intake structure, intake canal, cable trays and supports, tube track, reactor vessel internals, pipe hangers and supports have been listed as items requiring an AMR in other plants submitted for LRA. The staff did not find these structures or structural components listed in Ginna LRA as requiring an AMR. If you determine that these structures or structural components require an AMR, provide the information on Component Group, Passive Function, and Aging Management Reference for them. If not, provide a justification for their exclusion.

Response

The intake structure and tunnel are not within the scope of license renewal. This is explained in Section 2.4.2.7 of the LRA. The Screen House and discharge canal have features which provide water intake from the discharge canal to the Service Water system should the Circulating Water intake tunnel become unavailable. The cable trays and supports are included in LRA section 2.4.2-12, and tube track in LRA Table 2.4.1-1 under component group CV-SS(SS)-INT. The reactor vessel internals are included in LRA 2.3.1.3. Pipe hangers and supports are included in LRA section 2.4.2-12.

F-RAI 3.1.2 -1

Programs identified in NUREG-1801 are generic programs. When components experience unusual aging effects, the programs identified in NUREG-1801 may not be applicable. Control rod drive (CRD) housings (LRA Table 3.2-1, item 23) are identified as being susceptible to SCC and primary water stress corrosion cracking (PWSCC) with aging management provided by the Water Chemistry (B2.1.37) and the Reactor Vessel Head Penetration (B2.1.26) programs. Cracking has been reported on CRD housings at Fort Calhoun (January 25, 2002, letter from OPPD) and Palisades (Nuclear Management Company letters to the NRC dated August 20, 2001, and March 14, 2002).

Identify the materials, the inspection history, and future inspection plans for the CRD housings to detect cracking of the type experienced at Palisades and Fort Calhoun. Identify the method of removing oxygen from the CRD housings and other corrective actions taken to prevent cracking of the type experienced at Palisades and Fort Calhoun.

Response

The materials of construction and design of the control rod drive (CRD) housings at Fort Calhoun and Palisades, which are both Combustion Engineering design plants, are different from those at Ginna Station, which is a Westinghouse design plant. The CRD housings at Fort Calhoun and Palisades are flanged and bolted. The upper housing assembly is fabricated from Type 347 stainless steel. The cracking observed at Fort Calhoun occurred at the upper housing assembly pipe-to-eccentric reducer weld. The through-wall crack was axially oriented and located in the weld. No such configuration or materials exist in the Ginna CRD housings.

The upper CRD housings on the Ginna reactor vessel are joined to the CRD nozzle adapters by a threaded connection which is the pressure boundary. The adapter and housing are both Type 304 stainless steel. The Type 304 adapter is welded to the Alloy 600 CRD nozzle by a full penetration single V-groove butt weld using Alloy 82/182 weld metal. These welds have been periodically examined on the peripheral CRD rows by both dye-penetrant (PT) and ultrasonic testing (UT). No evidence of leakage from these welds has ever been observed. The upper CRD housing contains no pressure-boundary welds, and therefore the combination of materials and design which resulted in the cracking observed at Fort Calhoun and Palisades does not exist at Ginna Station.

A replacement head is being fabricated for installation on the Ginna reactor vessel during the Fall 2003 refueling outage. The replacement head incorporates many enhancements in both design and materials of construction (see response to RAI B2.1.26-1). New CRD housings are also being fabricated for installation on the replacement head. The new CRD housings are like-for-like replacements.

F-RAI 3.1.2 -2

GALL AMP XI.M32 indicates the One-Time Inspection is to be utilized when an aging effect is not expected to occur but there is insufficient data to completely rule it out or an aging effect is expected to progress very slowly. The One-time inspection provides additional assurance that either aging is not occurring or the evidence of aging is so insignificant that an AMP is not warranted. In order to determine whether crack initiation and growth for the reactor vessel flange leak detection line is not expected to occur, the applicant must review its inspection records to determine whether this aging effect has previously occurred at Ginna. If it has not occurred the proposed program is acceptable. If a component has experienced this aging effect in the past, the applicant should identify when it occurred, the corrective action, and the reason for not expecting it to occur in the future. If this aging effect is expected to occur in the future, periodic examination is necessary.

Response

Review of plant specific operating experience reveals that there has been no age related degradation of the reactor vessel flange leak detection line. Therefore, the One-Time Inspection program is appropriate in managing the aging effect of crack initiation and growth.

F-RAI 3.1.2 -3

The applicant has identified fatigue as an aging effect for reactor coolant (Class 1) components. The applicant has not identified fatigue as an aging effect for the reactor vessel, reactor vessel internals, pressurizer, steam generator and reactor coolant (Non-Class 1) components. The GALL report identifies fatigue as an aging effect for many components in the reactor vessel, reactor vessel internals, pressurizer, and steam generator. The staff requests that the applicant explain for the components identified in NUREG-1801, Volume 2, Chapter IV, Section A2, B2, C2, and D1 as being susceptible to fatigue, why fatigue is not an applicable aging effect for the Ginna reactor vessel, reactor vessel internals, pressurizer, and steam generator components. In addition, the staff requests that the applicant explain why the components identified in reactor coolant (Class 1) as susceptible to fatigue, while similar components in reactor coolant (Non-Class 1) are not susceptible to fatigue.

Response

Table 3.2-1, Line number (1) in the LRA identifies cumulative fatigue damage as an applicable aging effect requiring management for the component grouping "Reactor Coolant Pressure Boundary Components". Table 1 in NUREG-1801, Volume 1, lists thirty-eight (38) individual PWR line items in Chapter 4, "Reactor Vessel, Internals, and Reactor Coolant System" under the component grouping "Reactor Coolant Pressure Boundary Components" as being subject to cumulative fatigue damage. These line items cover the reactor vessel (Section A2), the reactor vessel internals (Section B2), the reactor coolant system and connected lines (Section C2), the pressurizer (Section C2), and the steam generators (Section D1). In the "Discussion" column in Table 3.2-1, Line Number (1) of the LRA it is clearly stated that "Consistent with NUREG-1801, cumulative fatigue damage was identified as an aging effect requiring management during the period of extended operation for components listed in this component grouping." This statement refers to the component line items listed in Volume 1, Table 1, "Reactor Coolant Pressure Boundary Components" in NUREG-1801. Therefore, fatigue was identified as an aging effect requiring management for the Ginna reactor vessel, reactor vessel internals, pressurizer, and steam generators and is addressed as a TLAA in Chapter 4, Paragraph 4.3.1, "ASME Boiler and Pressure Vessel Code, Section III, Class 1" of the LRA.

Non-Class 1 piping systems at Ginna Station were designed to the requirements of ANSI/ASME B31.1. No explicit fatigue analyses were required for B31.1 components at the time Ginna Station was designed. However, metal fatigue of B31.1 piping systems is addressed as a TLAA in Chapter 4, Paragraph 4.3.2, "ANSI B31.1 Piping" of the LRA and NUREG-6260 locations are addressed in Paragraph 4.3.7.3, "USAS B31.1 Locations".

F-RAI 3.2.1 -1

Table 3.2-1 of the LRA, line number (6), states that small-bore RCS and connected systems piping are to be sampled using appropriate volumetric examinations techniques near, but prior to, the end of the current license period. This sample will be selected to include various piping sizes, configurations and flow conditions. The staff is concerned with SCC and thermal fatigue resulting from turbulent penetration and thermal stratification. Indicate how the applicant will identify how the inspection sample of pipes will be chosen such that pipes susceptible to SCC or thermal fatigue will be examined.

Response

The sample population of small-bore (< 4 inch nominal pipe size) Class 1 RCS and connected systems piping welds will be derived using ASME Section XI Code, 1995 Edition with 1996 Addenda, Category B-J. All locations are considered susceptible to cracking due to SCC. An assessment of small-bore piping for susceptibility to thermal fatigue has also been performed. This assessment included Class 1 piping systems that are connected to the reactor coolant pressure boundary and are normally stagnant and not isolable from the reactor coolant pressure boundary, including safety injection, residual heat removal, drain, alternate charging and auxiliary spray lines. The assessment addressed the potential for in leakage, stratification and turbulence penetration using interim thermal fatigue management guidelines developed by EPRI/MRP. Locations judged to be potentially susceptible to thermal fatigue will be included in the sample population of small bore piping to be examined by an appropriate volumetric technique.

F-RAI 3.2.1 -2

Table 3.2-1 of the LRA, line number (9), PWR core support pads, instrument tubes (bottom head penetrations), pressurizer spray heads, and nozzles for steam generator instruments and drains indicates that the core support pads and the bottom head instrument penetrations are fabricated from Alloy 600 and the Reactor Vessel Head Penetration Inspection Program is used to monitor crack initiation, SCC, and PWSCC. The Reactor Vessel Head Penetration Inspection Program is a plant-specific program which includes participation in industry initiatives related to management of Alloy 600 penetration cracking issues.

Confirm that all the components in this item (that perform a LR intended function) will be evaluated as part of the above specified industry initiative? If a component will not be evaluated as part of the industry initiative provide a plant specific program to manage the aging effects for these components.

Response

The core support pads and the bottom head instrumentation penetrations in the Ginna reactor vessel are fabricated from Alloy 600. Crack initiation and growth in these components due to PWSCC was identified as an aging effect requiring management during the aging management review process. The Ginna Station Reactor Vessel Head Penetration Inspection Program is a plant-specific program that includes participation in industry initiatives relative to management of Alloy 600 penetration cracking issues. The core support pads and bottom head instrumentation penetrations are included in the scope of the Reactor Vessel Head Penetration Inspection Program and will be evaluated as part of any industry initiatives related to management of cracking in Alloy 600 penetrations.

F-RAI 3.2.2 -1

Table 3.2-2 of the LRA, line number (1), bottom mounted instrument (BMI) guide tubes and seal table fittings identifies these components as being susceptible to cracking from SCC. The AMP for the BMI guide tubes includes Water Chemistry and ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Programs. The AMP for the seal table fittings is the Water Chemistry Program.

a) What is the basis for including stress corrosion cracking (SCC) as an aging effect for these components? Include the inspection history for these components in the justification.

b) Identify the scope, examination method, acceptance criteria, frequency of examination and personnel qualification to be utilized to detect SCC in BMI guide tubes.

c) GALL, typically, requires both mitigation (i.e. Water Chemistry Program) and monitoring (i.e. ISI) for aging management of cracking in stainless steel components in reactor coolant environment. The staff requests the applicant to identify the monitoring program to be utilized for detecting SCC in seal table fittings.

Response

(a) Stress corrosion cracking (SCC) is an aging effect requiring management for the BMI guide tubes because over some length they are exposed to primary water at temperatures above 140 degrees F. SCC was incorrectly identified as an aging effect requiring management for the seal

table fittings because the temperature at the seal table is ambient Containment temperature, i.e., less than 140 degrees F. The OD surface of the thimble tubes is exposed to the same environment as the ID surface of the guide tube. Only four thimble tubes have been replaced as a result of wear damage; the remaining tubes have therefore experienced the same service history as the guide tubes. No evidence of cracking has ever been detected in the thimble tubes, which have been periodically inspected over their full length by eddy current testing since 1988 under the Thimble Tube Inspection Program. In addition, no evidence of leakage has ever been detected from the guide tubes.

(b) Credit is taken for the thimble tube inspections performed under the Thimble Tube Inspection Program as managing cracking due to SCC of the guide tubes. Details of these inspections including scope, examination method, acceptance criteria, and examination frequencies are included in the Thimble Tube Inspection Program description in Section B2.1.36 of the LRA. All thimble tube inspections are performed by personnel qualified in accordance with the requirements of ASME Section XI, Article IWA-2300, SNT-TC-1A, and ANSI/ASNT CP-189. In addition to thimble tube inspections, the annular space between the thimble tubes and guide tubes is periodically flushed and water samples are analyzed for chloride, fluoride, and sulfate ion.

(c) The seal table fittings are not susceptible to cracking due to SCC because the temperature at the seal table is the ambient Containment temperature, i.e., less than 140 degrees F.

F-RAI 3.2.2 -2

Table 3.2-2 of the LRA, line number (2), primary nozzle safe ends, does not identify cracking due to flaw growth as an aging effect requiring management.

Since the V. C. Summer main coolant loop weld cracking event involving Alloy 82/182 weld material, the staff has been addressing the effect of PWSCC on Alloy 82/182 piping welds on a generic basis for all currently-operating PWR plants. To resolve this current operating issue, the industry is taking the initiative to (1) develop overall inspection and evaluation guidance, (2) assess the current inspection technology, and (3) assess the current repair and mitigation technology.

An interim industry report, "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plants (MRP-44), Part 1: Alloy 82/182 Pipe Butt Welds," was published in April 2001 to justify the continued operation of PWR plants while the industry completes the development of the final report. The staff documented its acceptance of this interim report in a safety evaluation issued June 14, 2001, which states "Should the industry not be timely in resolving inspection capabilities to identify PWSCC in Alloy 600 welds regulatory action may result." Although the final industry report on this issue has not yet been published, the staff is considering regulatory action to resolve this issue, pending receipt and review of the final industry report.

In view of the V. C. Summer event, there are concerns regarding the potential for PWSCC of Alloy 182/82 weld materials in PWR environment. To ensure that the effect of PWSCC in all Alloy 182/82 components are adequately managed during the extended period of operation, provide the following information:

a) Identify the locations in Ginna RCS piping that contains Alloy 82/182 welds or buttering.

b) Describe the actions you have taken to address this operating experience as it applies to Ginna. Include in your discussion the current inspection program implemented at Ginna station for components identified above including the inspection method/frequency and history of inspection results.

c) Provide the bases that support your conclusion that the existing programs implemented at Ginna station will provide adequate aging management of the PWSCC effect on the components with Alloy 182/82 weld or buttering. In the discussion of the adequacy of the program, the applicant should consider the following industry experiences:

- The inspections performed in accordance with current ASME Section XI ISI Program requirements failed to identify the cracking
- There is no reported deviation from the EPRI guidelines in the water chemistry of the reactor coolant in V. C. Summer, Davis-Besse and other plants where PWSCC was found.
- Industry experiences have shown that early detection of small leakage from insulated welds can not be assured.

Response

(a) There are no locations in the reactor coolant system (RCS) piping at Ginna Station which contain Alloy 82/182 welds or weld buttering. The only Alloy 600 and Alloy 82/182 materials in the RCS at Ginna Station are located in the reactor vessel and the replacement steam generators. The CRDM nozzles in the reactor vessel closure head and the BMI penetrations in the bottom head are Alloy 600 and are welded to the heads with partial penetration J-groove Alloy 82/182 welds. The radial core support lugs in the reactor vessel are Alloy 600 and are welded to the lower shell with Alloy 82/182 weld metal. The tubesheets in the replacement steam generators are overlaid with Alloy 82 weld metal (non-pressure boundary). The reactor vessel closure head is scheduled to be replaced at Ginna Station in Fall, 2003. The replacement head will have Alloy 690 penetrations welded to the head with partial penetration J-groove Alloy 52 welds.

(b) The operating experience reported at V.C. Summer and documented in NRC Information Notices 2000-17 and 2000-17, Supplement 1 was reviewed and determined not to be applicable at Ginna Station.

(c) Cracking due to PWSCC of Alloy 600 and Alloy 82/182 materials is managed by the Reactor Vessel Head Penetration Inspection Program. For additional information, see response to RAI 3.2.1-2 and RAI B2.1.26-1.

F-RAI 3.2.2 -3

Table 3.2-2 of the LRA, line number (11), secondary core support, diffuser plate, guide tube support pins, head vessel alignment pins, BMI columns and flux tubes, head cooling spray nozzles, upper instrumentation column, conduits, and supports, credits the Water Chemistry Control Program, but does not credit the ISI program for monitoring SCC.

GALL item IV B2.2.3 identifies rod cluster control assembly (RCCA) guide tube support pins constructed from stainless steel as being susceptible to crack initiation and growth, SCC, PWSCC, and irradiation-assisted stress corrosion cracking (IASCC). GALL requires the use of a PWR Vessel Internals AMP in addition to a Water Chemistry AMP.

Since components in line number (11) are from equivalent material and operate in equivalent environments as the RCCA guide tube support pins, provide a program to monitor the effects of SCC or justify why an AMP is not required.

Response

The Reactor Vessel Internals Program, which is implemented by a combination of Water Chemistry Control and ASME Section XI, Subsection IWB, was inadvertently omitted from Table 3.2-2 as an applicable aging management program for components susceptible to SCC listed in Line Number (11). The Reactor Vessel Internals Program will be applied to these components.

F-RAI 3.2.2 -4

Table 3.2.2-2 of the LRA, line number (12), upper and lower internals assembly, holddown spring, upper and lower support column bolts, and clevis insert bolts identifies these components as being susceptible to loss of preload due to stress relaxation. GALL items IV B2.1-d, IV B2.1-k, IV B2.5-h, and IV B2.5-i identify the upper internals assembly, holddown spring, lower internals assembly, and clevis insert bolts as being managed by ASME ISI and loose parts monitoring or neutron noise monitoring.

Provide justification for not including a Loose Parts Monitoring and/or a Neutron Noise Monitoring Program to manage loss of preload due to stress relaxation.

Response

Neutron noise or loose-parts monitoring methods are not employed at Ginna Station. Plant-specific operating experience demonstrates that in-service inspections performed under the ASME Section XI, Subsections IWB ISI Program have been effective in managing loss of preload due to stress relaxation. These inspections have revealed no missing or loose reactor vessel or internals parts since the inception of plant operation. See LRA sections B2.1.19 and B2.1.20 for additional information.

F-RAI 3.2.2 -5

a) Table 3.2.2-2 of the LRA, line number (18), pressurizer manway cover, is identified as being constructed of carbon steel with a stainless steel disc insert and being susceptible to SCC. The staff requests the applicant to specify if the stainless steel insert is a pressure boundary component that requires aging management.

b) GALL item IV C2.5-m identifies pressurizer manway and flanges constructed from low alloy steel with stainless steel cladding in a primary water environment as being susceptible to SCC. GALL requires an ASME Section XI Inservice Inspection Program in addition to a Water Chemistry Control Program. The staff requests the licencee to specify an inspection program to monitor the adequacy of the applicant's specified Water Chemistry Control Program or justify why an inspection program is not required.

Response

a) The stainless steel insert on the pressurizer manway cover is part of the manway pressure boundary joint in that it is a sealing surface. However, the design of the pressurizer manway cover according to the requirements of ASME Section III does not credit the presence of the insert. See RAI 2.3.4.3-1 for further discussion.

b) Inclusion of the ASME Section XI Inservice Inspection Program in addition to the Water Chemistry Program for the pressurizer manway stainless steel insert was mistakenly omitted from the LRA. A step will be added to section 7.2 of procedure GMM-47-01-05, "Removal and Installation of Pressurizer Manway Cover" to perform a visual and surface examination of the stainless steel insert. The step will include reference to the ISI program and aging mechanism of stress corrosion cracking.

F-RAI 3.3 -1

LRA Table 3.3-1, line number (7), for components serviced by open-cycle cooling system, the applicant states that the combination of components, material and environments identified in Items V.A.6-a, V.A.6-b, V.D1.6-b and V.D1.6-c of NUREG-1801, Vol. 2, are not applicable at Ginna Station. Discuss how the AMR is to be performed for the heat exchangers, and their associated components, in the containment spray and emergency core cooling systems.

Response

The containment spray and emergency core cooling systems at Ginna Station have no heat exchangers that are provided cooling by the service water (open cycle cooling water) system other than the safety injection pump thrust bearing coolers. These coolers are made of cast iron with a single once through passage of service water providing cooling to the oil supplying the thrust bearing (non forced fed oil supply). Neither the material of construction (cast iron), nor the environment of oil are included in Chapter V, "Engineered Safety Features", of NUREG 1801. These coolers are included in Table 2.3.2-1 of the LRA under component group of heat exchanger and are appropriately linked to Table 3.3.2 line numbers (23), (24), (25), (26), and (27).

F-RAI 3.3 -3

In LRA Table 3.3-2, line number (28), the Water Chemistry Control Program is utilized to manage the aging effect of loss of heat transfer for the HX-Nickel alloy heat exchanger from exposure to a treated water-other environment. The applicant is requested to discuss the basis for not supplementing with an inspection program to verify the effectiveness of the Water Chemistry Control Program.

Response

Table 3.3-2, line number (28) of the LRA denotes that the Water Chemistry Control Program is utilized to manage the aging effect of loss of heat transfer for the HX-Nickel alloy heat exchanger from exposure to a treated water borated < 140 - environment. Line number (29) of Table 3.3-2 denotes the treated water other environment and applies the Closed Cycle (Component) Cooling Water System program for managing the aging effects of loss of heat transfer. A one-time inspection of the applicable components is included in Table 3.3-2, line number (30).

F-RAI 3.3 -4

a) In LRA Table 3.3-2, line numbers (44), (45), (67), (88), and (89), for copper alloy (Zn < 15%) pipe, thermowell, and valve body exposed to containment or indoor (no air conditioning) environments, the applicant identified no AERM. This may not be supported by industry experience, as the copper alloy material may be susceptible to corrosion in a sheltered, moistured environment. Provide the basis for this determination.

b) LRA Table 3.4.-2, line number (167), identifies no aging effect/mechanism for copper alloy components in the service water systems that are exposed to indoor (no air condition) environment and; therefore, no AMP is required. However, the GALL report , Table VII Item F.1.2, identifies aging effect of loss of material due to pitting and crevice corrosion for copper alloy exposed to warm, moist air environment. Provide the technical basis for not identifying loss of material as an aging effect for these copper alloy components including a discussion of the plant specific operating experience related to copper alloy components that are exposed to indoor no air conditioning environment to support your conclusion.

Response

(a) Copper and copper alloy materials (brasses and bronzes) with Zn < 15% display excellent resistance to atmospheric corrosion in a variety of environments, including industrial, marine, and rural atmospheres. The ASM Metals Handbook, Volume 13, Corrosion, states that "Comprehensive tests conducted over a 20-year period under the supervision of ASTM, as well as many service records, have confirmed the suitability of copper and copper alloys for atmospheric exposure". Corrosion rate data published in Volume 13 of the ASM Metals Handbook indicates that corrosion rates range from .002 mils/yr in rural environments to approximately 0.1 mils/yr in industrial/marine environments. These rates are essentially negligible. Plant-specific operating experience at Ginna Station has revealed no evidence of corrosion-related degradation of copper alloy components exposed to indoor (no air conditioning) and Containment environments.

(b) As discussed in (a) above, copper and copper alloys display excellent resistance to a variety of atmospheric environments. Atmospheric conditions at Ginna Station are benign, and certainly less severe than industrial or marine environments where these materials display excellent resistance to corrosion, including pitting and crevice corrosion. As discussed in (a) above, plant-specific operating experience confirms the absence of aging effects for copper and copper alloys exposed to ambient atmospheric conditions at Ginna Station.

F-RAI 3.3 -5

In LRA Table 3.3-2, line numbers (97) and (98), for galvanized carbon steel ventilation duckwork, exposed to air and gas (wetted)<140 or containment environments, the applicant identified no AERM. This may not be supported by industry experience, as galvanized steel may be susceptible to galvanic corrosion or boric acid corrosion in a ventilation or sheltered environment. Provide the basis for this determination.

Response

The internal and external environments in the Containment ventilation ductwork are essentially equal in temperature, and therefore condensation necessary to support corrosion would not be

expected to occur on ductwork surfaces. The galvanized coating on carbon steel substrate is intended to behave as a sacrificial layer, thereby protecting the carbon steel. As indicated in Section 3.1.12 of the LRA, carbon steel components (including ventilation ductwork) may be susceptible to boric acid corrosion. The ventilation ductwork is evaluated for these effects as indicated in Table 2.3.3-9, CS COMPONENTS which is appropriately linked to Table 3.4-1 line number (13).

F-RAI 3.4 -3

Table 3.4-1, line number (5) of the LRA, credits the Periodic Surveillance and Preventive Maintenance Program (B2.1.23), among others, for managing aging effects for the internal surfaces of components in ventilation systems, diesel fuel oil systems, and the emergency diesel generator system; and credits the System Monitoring Program (B.2.1.33) for managing the aging effect of loss of material for external surfaces of carbon steel components. The staff notes that in Appendix B2.1.23 and B2.1.33, under "Parameters Monitored/Inspected", it includes leakage as an example of parameters monitored/inspected. The staff is of an opinion that the presence of leakage from a component would indicate that the component's ability to perform its intended function as a pressure boundary may have been compromised. Clarify whether any of the auxiliary systems components for which the Periodic Surveillance and Preventive Maintenance Program and System Monitoring Program are credited rely on the monitoring of leakage. Discuss why visual inspection technique alone is sufficient in detecting the aging effects described in Appendix B2.1.23 and B2.1.33, without including other NDE procedures, such as volumetric and/or surface techniques. In addition, discuss the operating history of the above components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions.

Response

PSPM initiated leakage inspections are just one of several methods used for detecting and monitoring the affects of aging. Other techniques include visual examinations, supplemental surface and volumetric examinations deemed necessary by engineering evaluation, volumetric (eddy current) examinations of heat exchanger tubing, and other periodic volumetric examinations including radiography and ultrasonic testing to verify wall thickness as required by the Open Cycle Cooling Water System program. The identification of leaks and the evaluation of the consequences of those leaks are the condition where leakage monitoring is an important technique utilized for component aging management.

F-RAI 3.4 -4

LRA Table 3.4-2, identifies no aging effect for numerous galvanized carbon steel components (e.g., line numbers (3), (4) ,(5), (6), (61), (62), (163), (164), ...etc.) that are exposed to the environments of air and gas, air and gas (wetted) <140 degree F, containment, or indoor (no air conditioning). The LRA states that no AMP is required and it cites site-specific review of standard industry guidance for aging evaluation of mechanical systems and components as the basis for making the conclusion. It indicates that galvanized carbon steel exposed to ventilation air (T<140 degree F) would be expected to exhibit minimal deterioration of the zinc coating.

Provide the documented evidence for the above stated site-specific reviews of the standard industry guidance. In line number (62), under "Discussion", the temperature criteria of "T<140 degree F" is not consistent with "T>140 degree F" as listed under "Environment". Clarify this

discrepancy. Similar additional information is also required for "Muffler" in line numbers (193) and (194).

Response

The ASM Metals Handbook, Volume 13, Corrosion, states that "The behavior of zinc coatings during atmospheric exposure has been closely examined in tests conducted throughout the world. Precise comparison of corrosion behavior in atmospheres is complex because of many factors involved. It is generally accepted that the corrosion rate of zinc is low; it ranges from .005 mils/yr in dry rural atmospheres to 0.5 mils/yr in most industrial atmospheres. Zinc owes its high degree of resistance to atmospheric corrosion to the formation of insoluble basic carbonate films."

Zinc is used as a protective coating for carbon steels because of its corrosion resistance in external environments and because it provides galvanic protection of the carbon steel base metal at discontinuities or areas of coating damage. The corrosion products of zinc tend to be alkaline and thereby neutralize normal acidic moisture that occurs in outdoor or industrial environments. In the pH range 6-12, zinc undergoes negligible corrosion under most environmental conditions. When exposed to water, the corrosion resistance of zinc is maintained in this pH range. Temperature also affects the corrosion rate of galvanized steel. Between 140 degrees F and 200 degrees F, the corrosion products are significantly more conductive than at temperatures outside this range, and therefore, degradation of the zinc coating can occur on wetted surfaces in this temperature range. However, below 140 degrees F, and certainly at normal ambient temperatures in air/gas, Containment and indoor (no air conditioning) environments, where typical temperatures range from 75-90 degrees F, minimal deterioration of the zinc coating would be expected on galvanized carbon steel components.

A review of plant-specific operating experience revealed no evidence of age-related degradation of galvanized steel components exposed to air/gas, air/gas wetted < 140 degrees F, Containment and indoor (no air conditioning) environments.

There is a typographical error in the environment description for Line Numbers (62) (Expansion Joint) and (193) (Muffler) in Table 3.4-2. The correct environment is "Air and Gas (wetted) < 140 degrees F".

F-RAI 3.4 -5

LRA Table 3.4-2, line number (79), identifies aging effect of cracking due to SCC for carbon/low alloy fasteners (bolting) in the containment ventilation, essential ventilation, and radiation monitoring systems from exposure to indoor (not air conditioning) environment and identified Bolting Integrity Program for managing this aging effect. However, in the "Discussion" column of that row, it indicates that SCC is not an applicable aging effect/mechanism. Clarify this discrepancy.

Response

LRA Table 3.4-2, Line number (79) identifies cracking due to SCC as an aging effect requiring management for carbon/low alloy steel fasteners (bolting) in the containment ventilation, essential ventilation and radiation monitoring systems exposed to an indoor (no air conditioning) environment. The basis for this identification lies in NUREG 1801, Chapter VII, Item I.2-b, "Closure Bolting in High Pressure or High Temperature Systems". LRA Table 3.4-2, Line

Number (79) is incorrectly associated with bolting in Tables 2.3.3-9, 2.3.3-10 and 2.3.3-13. These systems are not high pressure or high temperature systems.

F-RAI 3.4 -6

LRA Table 3.4-2, line numbers (65), and (225) through (228) of the LRA does not identify aging effects for neoprene pipes exposed to oil and fuel oil, raw water, and treated water other environments that require management. This determination may not be supported by industry experiences. Similar to being exposed to containment or indoor (no air conditioning) environment, as in line numbers (220) through (224), the neoprene material, when expose to the above environments, may be susceptible to changes in material properties and cracking as well. Provide the basis for not considering change in material properties and cracking as applicable aging effects for the neoprene piping components included in Table 3.4-2, line numbers (65), and (225) through (228).

Response

Line numbers (65) and (225) through (228) address aging effects due to exposure of neoprene to internal environments of oil and fuel oil, raw water, and treated water (other). Standard industry guidance indicates that neoprene exhibits excellent resistance to oils, raw and treated waters, chemicals, sunlight and ozone. Changes in material properties of neoprene rubber occur as a result of exposure to elevated temperatures and ionizing radiation. The threshold temperature for aging mechanisms which cause changes in material properties of neoprene is conservatively taken to be 95 degrees F. The threshold fluence value for changes in material properties of neoprene due to exposure to ionizing radiation is conservatively taken to be 10E6 rads. Therefore, there are no aging effects requiring management for neoprene exposed to internal environments of oil and fuel oil and raw and treated waters at temperatures below 95 degrees F and exposed to ionizing radiation fluence less than 10E6 rads. Furthermore, a review of plant-specific operating experience revealed no evidence of age-related degradation of neoprene exposed to these environments.

F-RAI 3.4 -7

LRA Section B2.1.21, "One Time Inspection", states that the Ginna Station One-Time Inspection Program will include measures to verify the effectiveness of an existing AMP and confirm the absence of an aging effect. In LRA Table 3.4-2, at various line numbers, the applicant properly uses the One-Time Inspection Program to verify the effectiveness of an existing program, such as Water Chemistry Control Program. In other cases, such as line number (395); however, the applicant simply proposed to use the One-Time Inspection Program to manage loss of material, without committing to an existing AMP. This practice may not be supported by industry experience, as One-Time Inspection alone may not be sufficient for an early detection of material degradation during the extended period of operation. Provide the basis of not utilizing an existing AMP prior to the supplemental One-Time Inspection Program, for the components included in the above stated line number.

Response

LRA Table 3.4-2, line number (395) refers to valves constructed of cast austenitic stainless steel in a lubricating oil environment with an aging effect requiring management of loss of material due to MIC. Loss of material due to MIC for cast austenitic stainless steel exposed to oil/fuel oil environments is an aging effect requiring management because microbes could potentially

survive in the oil in the presence of extremely small amounts of water. The oil provides the nutrient source for colonization. The reason a one-time inspection was chosen is due to the fact that loss of material due to MIC is improbable. In addition, this is the only valve that is in this material environment grouping. Therefore, it was determined that a one-time replacement and internal inspection of the diesel fire pump engine oil drain valve for evidence of loss of material due to MIC would be appropriate. The replacement/inspection will be performed in conjunction with the diesel fire pump engine oil change activities implemented by Reptask P300230.

Since no Ginna specific or industry operating experience could be found for this material/environment grouping, results of the internal inspection will be documented, evaluated, and appropriate corrective action taken as necessary.

F-RAI 3.4.1 -1

LRA Table 3.4-2, line numbers (16) and (32), identifies the Closed-Cycle (Component) Cooling Water System (CCCCWS) Program for managing the aging effect of loss of material for stainless steel under treated water and other environments for various components in the auxiliary systems (e.g., boric acid evaporator condensers and coolers). However, the CCCCWS program does not reference EPRI TR-10736 and takes many exceptions from the GALL recommendations. Clarify how the degradation of the components such as corrosion product buildup, calcium deposits, and other parameters supposed to be monitored as recommended in GALL report can be managed under these environments.

Response

The Ginna Station Closed-Cycle (Component) Cooling Water System Surveillance Program employs various methods to ensure that the components in the component cooling system will continue to perform their intended function. Periodic maintenance activities provide opportunities for visual inspections of the internal (wetted) and external surfaces of components in the system. Thermal performance testing of selected heat exchangers is used to verify that these components are capable of performing the heat removal intended function. The makeup water to CCW at Ginna Station is supplied from the Reactor Makeup Water Storage Tank, and, as such, is demineralized. Therefore calcium and other mineral deposits are not an issue in the Ginna CCW system. Corrosion is controlled in the CCW system at Ginna Station by maintaining chromate-based inhibitors (potassium dichromate) in solution. Potassium dichromate is used because it is an excellent corrosion inhibitor and, in addition, is toxic to microbiological organisms. Monitoring of the component cooling water chemistry and maintaining parameters within the specified limits ensures that the system is maintained free of corrosion and biofouling.

In addition to the activities described above, routine surveillances of system operating parameters are performed by operators during normal rounds. These include monitoring flows through heat exchangers, monitoring system pressures at various locations, monitoring pump suction and discharge pressures, monitoring CCW temperature and fluid temperatures in systems served by CCW. The summation of these activities ensures early detection of CCW system problems that require corrective actions.

Plant-specific operating experience indicates that the CCW system performance has been very satisfactory. No evidence of corrosion product build-up or corrosion-induced through-wall cracking in CCW piping has ever been identified at Ginna Station. Confirmation of the effectiveness of the CCW chemistry control was obtained during remote visual inspection of the internal surfaces of the carbon steel heat exchanger shell, tubesheet, and tube supports, as well

as piping connections during retubing of both CCW heat exchangers in 1999. All surfaces were clean, free of deposits and corrosion products, and in excellent condition. For additional information, see the response to RAI B2.1.9-1.

F-RAI 3.4.1 -2

In LRA Table 2.3.3-1, the AMR results indicated that line number (5) of Table 3.4-1 is applicable to tanks, heat exchangers, and transmitters in the CVCS. However, the "Discussion" column of Table 3.4-1, line number (5), does not include the CVCS components. Clarify whether Table 3.4-1, line number (5) is applicable to the tanks, heat exchangers, and transmitters in the CVCS.

Response

Table 3.4-1 line number (5) is applicable to external surfaces of tanks, heat exchangers and valve bodies in the CVCS system.

Note that Table 3.4-1 line number (5) is not applicable to transmitters.

F-RAI 3.4.2 -1

In LRA Table 2.3.3-2, the AMR results indicate that Table 3.4-1, line numbers (5) and (14), and Table 3.4-2, line numbers (120), (130), (132), (133), (151), (152), (153), (154) are applicable to heat exchangers in the CCW system. It identifies the Periodic Surveillance and Preventive Maintenance Program, One-Time Inspection Program, CCCCWS Program, and Water Chemistry Control Program for managing loss of material due to various aging mechanisms, and cracking due to SCC. However, the GALL report recommends that, in addition to the Open-Cycle Cooling Water System (OCCW) Program, the Selective Leaching of Materials AMP under raw water, treated water, and ground water environments be used to detect occurrence of selective leaching by hardness measurement. Confirm that parameters monitored/inspected as recommended by GALL report are adequately covered in the applicant's AMPs identified above.

Response

Table 3.4-1, line numbers (5) and (14) include the Emergency Diesel Generator (EDG) Lube Oil and Jacket Water heat exchangers. The tubes in these heat exchangers are arsenical (inhibited) admiralty brass. The presence of arsenic acts to inhibit the selective leaching mechanism (i.e., dezincification) in the admiralty brasses. The tubeside environment in both of these heat exchangers is service (raw) water. The tubes are periodically inspected by eddy current testing under the Periodic Surveillance and Preventive Maintenance (PSPM) Program. The eddy current inspections provide a very effective means of detecting any tube degradation resulting from dezincification. The shell and channel heads of these units are gray cast iron. The shellside environment of the lubricating oil heat exchanger is lubricating oil, which would not support the selective leaching mechanism (graphitic corrosion of gray iron). The shellside environment of the jacket water heat exchanger is chromated water. Potassium dichromate is an effective and reliable corrosion inhibitor and would also suppress the selective leaching mechanism. The concentration of potassium dichromate is controlled and maintained under the Water Chemistry Control Program at Ginna Station. The channel heads are removed and inspected when the tubes are inspected. The channel heads are fitted with sacrificial zinc anodes which are periodically replaced under the PSPM Program. The zinc anodes effectively suppress the selective leaching mechanism. Nevertheless, a sample of components potentially

susceptible to selective leaching in raw water environments will be inspected under the One-Time Inspection Program. The sample will include the EDG Jacket Water and Lube Oil heat exchanger channel heads. This inspection will be performed prior to the end of the current license period. The inspection will be conducted using an eddy current technique (pancake probe). Hardness tests may also be used if component configuration and geometry allows (see response to RAI B2.1.29-1).

Table 3.4-2, line numbers (120), (130), (132), (133), (151) through (154) include heat exchangers in a variety of environments, including raw and treated water. Line number (120) covers carbon steel components which are not susceptible to selective leaching. Line numbers (130), (132) and (133) refer to admiralty brass tubes which are inspected by eddy current testing under the PSPM Program and therefore any degradation due to selective leaching (i.e., dezincification) would be readily detected. Line numbers (151), (152), (153) and (154) include stainless steel heat exchanger components which are not susceptible to selective leaching.

F-RAI 3.4.3 -1

LRA Table 3.4-2, line number (430), indicates that, for valve body (copper alloy) in the spent fuel cooling and fuel storage system, under the indoor no air conditioning environment, there is no aging effect. However, the Periodic Surveillance and Preventive Maintenance Program was identified as the AMP. Clarify this apparent inconsistency.

Response

As denoted in LRA Table 3.4-2, line number (430), the subject valves are in the spent fuel cooling and fuel storage system. The Preventive Maintenance Program was properly applied to the internal environment of treated water borated < 140, but was mistakenly applied for the same valves to the external environment.

F-RAI 3.4.4 -1

LRA Table 3.4.-1 line number (14) and Table 3.4-2, line number (132), credits the CCCCWS Program (AMP B.2.1.9) to manage the aging effect of loss of material due to general, pitting, and crevice corrosion as well as MIC for heat exchangers in the waste disposal system. However, the program description for the CCCCWS Program (AMP B.2.1.9) does not include waste disposal system. Clarify this discrepancy between Table 2.3.3-4 and Appendix B2.1.9.

Response

The scope of the CCCCWS Program includes all components exposed to component cooling water and therefore includes components in the waste disposal system serviced by the component cooling water system, as well as components in the following systems:

Reactor Coolant System
Containment Spray System
Safety Injection System
Plant Sampling System

F-RAI 3.4.4 -2

LRA Table 3.4.-2, line number (199), identifies the loss of material as aging effects/mechanisms for stainless steel orifice in raw water drainage environment in the waste disposal system. It further indicates that the applicable AMP is the Ginna's One-Time Inspection Program (B2.1.21). However, GALL states in Table VII Item C1.4-a that the stainless steel orifice in raw water (untreated salt or fresh water) is subject to aging effect of loss of material due to pitting, crevice corrosion, MIC, and bio-fouling. Justify why the aging effects of MIC and biofouling are not required to be managed in this application. In addition, justify the adequacy of the One-Time Inspection Program for managing the aging effect including a discussion of the plant specific operating experience related to the components of concern to support its conclusion.

Response

The orifice under review was installed to restrict water flow into the Auxiliary Building sump such that a fire suppression system actuation would not overwhelm the sump pump capacity. Although the application considers the waste system as "raw water drainage" this component normally is only intermittently exposed to "waste" treated water (e.g. borated water and treated water). Thus, because the orifice is not normally exposed to untreated salt or fresh water, MIC and biofouling are considered improbable.

Plant operating experience has shown the need to periodically verify that the orifice has not been fouled from debris migrating though the floor drain system. These inspections have shown that the orifice is in good condition and is not experiencing any obvious aging effects. These inspections, although they provide confidence, are not considered sufficiently rigorous to be credited for license renewal. Thus a One-Time inspection detailed visual inspection by a qualified NDE inspector, to check for aging effects such as pitting, will be performed to confirm the results of these routine observations.

F-RAI 3.4.9 -1

LRA Table 3.4-2, line number (1), identifies loss of material as aging effect for cast iron air operated damper housing that are exposed to air and gas (wetted)<140 degree F and credits the One-Time Inspection Program for managing the aging effect. However, the staff noted that the scope of the One-Time Inspection Program as described on Pages B-38 and -39 of the LRA does not include components that are exposed to air and gas. Clarify this discrepancy. In addition, the applicant is requested to provide technical basis to justify why the One-Time Inspection alone is adequate to manage the aging effect including a discussion of the plant specific operating experience related to the component of concern to support its conclusion. Similarly, address the above staff's concerns for the HVAC equipment package (Table 3.4-2, line number (162)), and valve body (Table 3.4-2, line numbers (386), (413), and (426)).

Response

The scope of the One-Time Inspection Program description now includes components exposed to air/gas (wetted) < 140 degrees F environments.

Copper alloys and gray cast irons exhibit excellent resistance to atmospheric environments, including moist air. For a discussion of the atmospheric resistance of copper alloys, see the response to RAI 3.3-4. Gray cast irons are considerably more resistant to atmospheric corrosion and corrosion by natural waters than carbon and low/alloy steels. This is primarily a

consequence of the elevated silicon content (typically on the order to 2 - 2.5 %) in gray irons. A very dramatic example of this resistance was observed when the gray cast iron end bells on the circulating water pumps were removed and inspected in 1996. The end bells had been immersed in fresh, raw Lake Ontario water in the screen house bay for 26 years, and were found to be in excellent condition. This inspection was documented photographically.

Therefore, since it would be expected that gray cast irons and copper alloys should display very good resistance to moist air/gas environments at temperatures < 140 degrees F, a one-time inspection of the components identified in Table 3.4-2, line numbers (1), (413) and (426) should be sufficient to confirm the absence of potential aging effects, or to verify that age-related degradation is proceeding so slowly as to be negligible.

Line number (386) refers to carbon or low/alloy steel components that are exposed to an internal "air/gas" environment which is moisture free. Therefore no aging effects would be expected from exposure of carbon or low/alloy steel to this environment.

Line number (162) (HVAC equipment package) refers to the carbon steel Containment Recirc Fan Cooler housing. The temperature of the housing would be expected to be the same as that of the ambient Containment air on either side. Therefore no condensation would be expected to occur on the housing. Therefore aging effects, if any, from exposure of carbon steel to this environment would be expected to occur very slowly.

F-RAI 3.4.9 -2

LRA Table 3.4-2, line number (34), identifies loss of material as the aging effect for copper alloy (Zn < 15 %) cooling coil that are exposed to air and gas (wetted)<140 degree F and credited One-Time Inspection Program for managing the aging effect. However, the staff noted that the scope of the One-Time Inspection Program as described on Pages B-38 and -39 of the LRA does not include components that are exposed to air and gas. Clarify this discrepancy.

Response

As indicated in the response to RAI 3.4.9-1, the scope of the One-Time Inspection Program description now includes components exposed to air/gas (wetted) < 140 degrees F environments. Justification for including copper alloys exposed to air/gas (wetted) < 140 degrees F environments in the scope of the One-Time Inspection Program is also provided in the response to RAI 3.4.9-1.

F-RAI 3.4.10 -1

LRA Table 3.4-2, line number (9), identifies the material for blower casing component as galvanized carbon steel. However, in the "Discussion" column of the same row, it refers to stainless steel. The LRA states that stainless steel exposed to ventilation air (T<140 degree F) would not be expected to exhibit loss of material due to pitting and crevice corrosion. Clarify the discrepancy concerning the material of the component.

Response

LRA Table 3.4-2, line number (9), correctly identifies galvanized carbon steel. In the "Discussion" column of the same row, it should have read galvanized carbon steel rather than

stainless steel exposed to ventilation air (T<140 F). Galvanized carbon steel would also not be expected to exhibit loss of material due to pitting and crevice corrosion. Therefore no aging effects are applicable and no aging management program is required.

This was a typographical error.

F-RAI 3.4.11 -1

LRA Table 3.4-1, line number (13), under the "Discussion" column, indicates that the component of the cranes, hoists, and lifting devices has the potential for exposure to boric acid spillage and may be subject to the aging effect of loss of material due to boric acid corrosion. However, the AMR results of the cranes, hoists, and lifting devices as listed in the Table 2.3.3-11 of the LRA does not refer to Table 3.4-1, line number (13). Clarify this discrepancy.

Response

This is a typographical error. Table 2.3.3-11 should include under component group "fasteners (bolting)", aging management reference Table 3.4-1 Line Number (13).

F-RAI 3.4.12 -1

LRA Table 3.4.-2, line numbers (265) and (434), identifies the loss of material as aging effect/mechanism for aluminum, cast iron, or copper alloy components in raw water drainage environment in the treaded water system. It further indicates that the applicable AMP is the One-Time Inspection Program (AMP B.2.1.21). However, the One-Time Inspection Program is used to determine whether the loss of material, due to selective leaching for aluminum, cast iron or brass components, represents significant aging effects that require aging management. Justify why the One-Time Inspection alone is adequate to manage the aging effect including a discussion of the plant specific operating experience related to the components of concern to support its conclusion.

Response

LRA Table 3.4-2, line number (265) identifies loss of material as an aging effect for cast iron, and line number (434) for copper alloy (Zn<15 %) in raw water drainage environment, with the One-Time Inspection Program as the applicable program. A discussion of the corrosion resistance of gray cast iron and copper alloys in water environments is provided in the response to RAI 3.4-4 and 3.4.9-1. The scope of the One Time Inspection Program is described in LRA section B2.1.21.1. The program includes managing the loss of material and/or loss of structural integrity due to selective leaching on the internal surfaces of piping and components made of gray cast iron, bronze, or brass exposed to treated water or raw water environments. Copper Alloy (Zn<15%) may be considered to include either brasses or bronzes per ASME Metals Handbook, Volume 2, "Properties and Selection: Nonferrous Alloys and Pure Metals", Ninth Edition.

Plant specific operating experience as referenced in the responses to RAIs 3.4-4 and 3.4.9-1 supports a one-time inspection to verify the presence or absence of aging effects. If the results indicate a potential for loss of intended function during the period of extended operation, the corrective action program will be used to identify and implement any additional corrective actions, which may include further inspection.

F-RAI 3.4.12 -2

LRA Table 3.4-2, line number (443), identifies no aging effect for the plastic valve body exposed to raw water drainage environment and; therefore, no AMP is required. Clarify the type of plastic material of the valve body and provide the technical basis for not considering any aging effect for that specific material from exposure to raw water drainage environment including a discussion of the plant specific operating experience related to the component of concern to support its conclusion.

Response

As a result of recent plant initiatives to verify the functionality of back flow prevention devices there are no longer any plastic valve bodies within the scope of license renewal. The valves evaluated in Table 3.4-2 line numbers (441), (442) and (443) and shown on drawing 33013-2681-LR are now included in Table 3.4-2 line numbers (429) and (434) which are now the appropriate aging management references for the valves.

RAI 3.5-1

Table 3.5-1 of the LRA, line number (1) identifies the applicant's TLAA for cumulative fatigue damage for piping and fittings in the main feedwater line, steam line, and for AFW piping. In the discussion column for this item, the LRA states, "Consistent with NUREG-1801. Cumulative Fatigue Damage is addressed as a TLAA in Section 4.3." Since NUREG-1801 recommends aging management of cumulative fatigue for the main steam, feedwater, and AFW steam and power conversion system (SPCS) components and the LRA states it is consistent with NUREG-1801, Tables 2.3.4-1 thru 2.3.4-4 of the LRA should identify these components as being managed for cumulative fatigue. However, Tables 2.3.4-1 thru 2.3.4-4, do not identify any SPCS components that are managed for cumulative fatigue. Explain why Tables 2.3.4-1 thru 2.3.4-4 do not identify any SPCS components that are managed for cumulative fatigue. Also explain if the main steam, main feed, and AFW system piping are evaluated for thermal fatigue using the method described in Section 4.3.2 of the LRA.

Response

Links to Line Number (1) of Table 3.5-1 of the LRA were inadvertently omitted in Tables 2.3.4-1 through 2.3.4-4 to identify cumulative fatigue damage as an aging effect requiring management for piping and fittings in the main feedwater, main steam, and AFW steam and power conversion system (SPCS) components.

Section 4.3.2 of the LRA entitled "ANSI B31.1 Piping" states that the balance-of-plant piping was originally designed to the requirements of USAS B31.1, Power Piping Code. Balance-of-plant piping includes main steam, main feedwater, and AFW steam and power conversion components. Components in these systems were evaluated for thermal fatigue using the method described in Section 4.3.2, and the results of the evaluation demonstrate that the number of design thermal cycles (7000) will not be exceeded in 60 years of plant operation. Therefore, the analyses associated with ANSI B31.1 piping fatigue have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21, (c)(1)(I).

F-RAI 3.5 -3

Loss of material due to general corrosion, pitting and crevice corrosion, MIC, and biofouling could occur in carbon steel piping and fittings for untreated water from the backup water supply in the AFW system. In Table 3.5-1, line number (3), the LRA states, "the combination of component, materials and environments identified in Item VIII.G.1-d are evaluated in the SW system. The SW system components are reviewed under NUREG-1801, Chapter VII (Auxiliary Systems), Section C1." Based on this statement and the information contained in the LRA, staff could not make a reasonable assurance finding that these aging effects in the AFW piping connected to the backup water supply are adequately managed. The staff requests the applicant to describe the specific AFW system components exposed to untreated water from the backup water supply and describe plant specific AMP used to manage the loss of material for these components or provide operating experience to explain why aging management is not performed.

Response

There are no carbon steel components within the AFW evaluation boundary normally exposed to untreated water. Untreated water can be aligned to the auxiliary feedwater system during an emergency as a suction source, but those interface components are evaluated within the Service Water system. The potential interface between service water and auxiliary feed water is shown on drawing 33013-1237-LR at closed valves 4027 and 4020B (location D-2) and 4013 (location I-1) .

F-RAI 3.5 -5

In Table 3.5-1, line number (5), the LRA credits the Systems Monitoring Program to manage the loss of material for the external surface of carbon steel components and states, "Consistent with NUREG-1801. Since NUREG-1801 does not contain an approved AMP for loss of material due to general corrosion on the external surfaces of carbon steel components, explain why the Systems Monitoring Program is considered to be consistent with NUREG-1801.

Response

Table 3.5-1 is based on the table in the Steam and Power Conversion section of NUREG-1800 (SRP). The table indicates that a plant specific aging management program is appropriate and that program requires further evaluation. Section 3.5 of the LRA describes the criterion applied by the licensee in determining if an SRP line number is considered consistent with the GALL. In the final step of that process the programs credited in the GALL for managing an aging effect are compared to the programs invoked in our plant evaluations. If, using good engineering judgement, it could be reasonably concluded that the plant evaluation is in agreement with the GALL evaluation a line number was considered consistent with NUREG-1801.

In this case, although the aging management program invoked is plant specific, that program will comprise the 10 elements of a program as required by appendix A of NUREG-1800. This makes the program acceptable for consideration as if it were a pre-approved GALL program. Thus, because the program will detect loss of material on external surfaces of carbon steel components, and the program will be consistent with the required program elements, the applicant concluded that the Systems Monitoring Program is consistent with the guidance of NUREG-1801.

F-RAI 3.5 -7

LRA Tables 2.3.4-1, 2.3.4-2, 2.3.4-3, 2.3.4-4, 3.5-1, and 3.5-2, list "valve body" in the component column. NRC position is that the aging effects identified in these tables, except for wall thinning due to flow-accelerated corrosion, are applicable to both the valve body and bonnet. Explain why the valve bonnets are not affected by these aging effects or provide aging management for the bonnets.

Response

Bonnets are a part of the body and are included in the LRA in Table 3.6-1 and Table 3.6-2, under "valve body".

F-RAI 3.5 -9

Table 2.3.4-4 of the LRA for the turbine-generator and supporting systems does not list fasteners in the component group column. Are there any fasteners in these systems that require aging management review? Also, if it is determined that valve and bonnets are in scope of LR, would the body to bonnet fasteners require an AMR?

Response

Fasteners should have been included in LRA Table 2.3.4-4. These fasteners, however, were evaluated in Table 3.5-1 line number (8), and Table 3.5-2 line numbers (7) and (8) for aging management.

F-RAI 3.5 -10

LRA Table 3.5-2, line numbers (38) thru (41) and line numbers (72) thru (75) identify aging management of valve bodies and pipe for cracking due to SCC and loss of material using the Water Chemistry program. For these items, the One-Time Inspection program is identified to verify the effectiveness of the Water Chemistry Program. Table 3.5-2, line numbers (15) and (16) identify aging management of flow elements for cracking due to SCC and loss of material using the Water Chemistry program but does not identify the One-Time Inspection program to verify the effectiveness of the Water Chemistry Program. Explain why the One-Time Inspection Program is not used to verify the effectiveness of the Water Chemistry Program for the flow elements which have identical material and environment as the valve bodies and pipe.

Response

The Water Chemistry Control Program, as described in the LRA in section B2.1.37 relies on monitoring and control of water chemistry based on the EPRI guidelines in TR-105714 for primary systems chemistry and TR-102134 for secondary systems chemistry. For low-flow or stagnant portions of a system, a one-time inspection of selected components at susceptible locations provides verification of the effectiveness of the Water Chemistry Control Program. No verification inspections are required for intermediate and high flow regions.

Therefore, the One-Time Inspection Program is not listed in Table 3.5-2, line numbers (15) and (16), for the stainless steel flow elements in a treated water secondary >120 environment, since this is not stagnant or low flow. Table 3.5-2, conservatively shows the One-Time Inspection Program for valve bodies and piping in the identical environment, however this is not a

requirement based on the discussion of the Water Chemistry Program defined in LRA section B2.1.37.

F-RAI 3.6 -2

Section 2.4.1 of the LRA states that one of the elements associated with the tendon corrosion system is cathodic protection system (CPS). This important system does not appear either in the component grouping of Table 2.4.1-1, or in the line item in Table 3.6-2. The applicant is requested to provide information regarding the operating experience related to the CPS, and a description of a monitoring program that would ensure the continued functioning of the system during the extended period of operation.

Response

As described in UFSAR section 3.8.1.4.3.4, Corrosion Protection, section dd, at the time of containment construction, Durichlor anodes were installed around the perimeter of the vessel. Protective current can be applied from these anodes and regulated as needed to maintain a protective potential if cathodic protection is found necessary by measurements from the reference cells. The system was a construction feature installed because of a lack of operating experience involving the particular tendon design. The architect/engineers recognized that if unforeseen problems developed in the future the tendon design precludes easy repairs. To date voltage measurements, now incorporated into the Structures Monitoring program, have not indicated the need to employ cathodic protection measures. The containment tendon cathodic protection system is not used (no currents are impressed on the tendons) and is not relied upon to manage tendon aging. Operating experience has not indicated a current or future need for impressed current cathodic protection.

F-RAI 3.6 -3

In line number (2), Table 3.6-1 of the LRA, the applicant stated, "A review of plant-specific operating experience did not identify any occurrence of bellows failures due to SCC." The applicant is requested to provide the following information regarding aging of bellows in Ginna containment:

- Type of bellows, e.g., one ply, two-plies,
- accessibility for IWE inspection,
- ability to detect leakage from the bellows by (Appendix J) Type B testing,
- occurrences of excessive leakage through the bellows.

Response

(1)-(4) There are no penetration bellows at Ginna Station which perform a Containment isolation function. The bellows are single ply, ASTM A240, Type 304 stainless steel. The only function of the bellows is to accommodate lateral and axial pipe displacements.

F-RAI 3.6 -5

In line number (16), Table 3.6-1, the applicant discussed the aging mechanism related to "Elevated Temperature," and concludes that the temperatures are within the specified limits, therefore, loss of material, cracking, and change in material properties due to elevated temperature are not probable aging effects at Ginna, and has not been observed to date.

Normally established temperature limits for concrete components is 150°F. Research has shown that change in the concrete material properties is insignificant up to this limit. However, at sustained high temperatures, loss of material due to cracking and spalling are plausible aging effects. The applicant is requested to provide the following information regarding the concrete components inside Ginna containment:

- Sustained temperatures in the annulus between the primary shield wall and the reactor, and in the concrete components around the steam generators,
- Observed condition of the concrete (or liner, if applicable), in these components during the last inspection,
- Schedule for inspection of these components.

Response

The normal operating temperature of the air flowing through the annulus is approximately 80 degrees F. This air flows around the vessel, instrument ports, and vessel nozzles where air temperatures reach a normal maximum of approximately 130 degrees F. The air temperatures associated with the annulus, reactor vessel nozzles and the head shroud fan suctions and the water temperatures for the reactor vessel support pad cooling system are continuously recorded and displayed in the control room.

No permanent telemetry is installed that monitors the temperatures associated with the concrete around the steam generators; however, temporary RTDs were placed in the containment over a number of operating cycles to verify temperatures used in equipment environmental qualification calculations. Some of these RTDs were in the inside the shield walls and near the steam generator level indications. These RTDs indicate local area temperatures are normally below 100 degrees F.

No loss of material has been observed in the primary shield wall, the annulus region or in the vicinity of the steam generators. Some of these areas are routinely inspected where they interface with ASME component supports. The next general inspection is scheduled for the fall 2003 outage as part of the Structural Monitoring Program.

F-RAI 3.6 -8

The Structures Monitoring Program, Boric Acid Corrosion Program, and Bolting Integrity are all used to manage the aging of carbon steel structural fasteners (FAST(CS and HSLAS)). Describe the interaction of these three AMPs with regard to the aging management of this component group. Describe the differences between the inspection methods used by these three AMPs for this component group.

Response

The Bolting Integrity Program consists of four separate aging management programs, in addition to the Boric Acid Corrosion Program and Structures Monitoring Program, which manage the effects of aging associated with bolting. These four programs are: (1) ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program, (2) ASME Section XI, Subsection IWF Inservice Inspection Program, (3) Periodic Surveillance and Preventive Maintenance Program, and (4) Systems Monitoring Program. These six programs encompass the requirements for and attributes of the Bolting Integrity Program.

Structural bolting is inspected under two separate aging management programs: Structures Monitoring Program and Boric Acid Monitoring Program.

Visual inspections of bolting associated with structures within the scope of the Structures Monitoring Program are performed concurrent with the structure inspection. Structural bolting is inspected visually for evidence of corrosion, pitting, cracking, loose or missing hardware, evidence of boric acid buildup, physical damage or deformation, proper thread engagement of all nuts, proper bolt pattern, elongated or oversized bolt holes, proper washers, and proper stud alignment into the building structure.

The scope of the Boric Acid Corrosion Program includes visual examinations of structures, components and associated bolting in all areas and spaces that could potentially be wetted and damaged by leaking boric acid. The program relies on visual inspections conducted during normal plant walkdowns and while performing maintenance work, as well as VT-2 inspections performed at operating pressure and temperature of systems that contain boric acid. The program incorporates the guidelines in NRC GL 88-05 and thereby provides for timely detection of leakage by observance of boric acid crystals deposits.

The ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program, the ASME Section XI, Subsection IWF Inservice Inspection Program, the Periodic Surveillance and Preventive Maintenance Program, and the Systems Monitoring Program are described in Sections B2.1.2, B2.1.4, B2.1.23, and B2.1.33, respectively, of the LRA.

It is important to note that volumetric inspections (UT) are performed on high strength fasteners associated with Class 1 component supports under the ASME Section XI Subsection IWF ISI Program.

F-RAI 3.6 -10

The containment component group SPP02 for the moveable hatch and equipment hatch in Table 2.4.1-1 of the LRA does not reference table entry 4 in AMR Table 3.6-1. Line number (4) in Table 3.6-1 covers the aging effect loss of material due to corrosion through the Containment ISI and Containment leak rate test AMPS for the personnel airlock and equipment hatch. Explain this omission.

Response

The omission was due to a typographical error. Table 3.6-1, line number (4) is applicable and is associated with the moveable equipment and personnel hatches.

F-RAI 3.6 -11

The containment component group CV-SS(CS)-TENDONS in Table 2.4.1-1 of the LRA does not reference line number (11) in AMR Table 3.6-1. Line number (11) in Table 3.6-1 covers the aging effect loss of prestress due to relaxation, shrinkage, creep, and elevated temperature through a TLAA for containment tendons and anchorage components. Explain this omission.

Response

The omission was due to a typographical error. Table 3.6-1, line number (11) is associated with the containment tendons.

F-RAI 3.6 -12

The concrete containment component groups (CV-C-BUR, EXT, INT) in Table 2.4.1-1 of the LRA do not reference line number (15) in AMR Table 3.6-1. Line number (15) in Table 3.6-1 covers the aging effects of (1) scaling, cracking, and spalling due to freeze-thaw and (2) expansion and cracking due to reaction with aggregate through the Containment ISI AMP for concrete elements foundation, dome, and walls. Explain this omission.

Response

The omission was due to a typographical error. Table 3.6-1, line number (15) is applicable and is associated with the commodity groups (CV-C-BUR, EXT, INT).

F-RAI 3.6 -13

Line number (19), in Table 3.6-1 of the LRA is for Group 5: liners, and covers the spent fuel pool liner and refueling transfer canal liner. This table entry covers the aging effects crack initiation and growth from SCC and loss of material due to crevice corrosion through the Water Chemistry Program and monitoring of the spent fuel pool water level. However, line number (19) in Table 3.6-1 is not referenced for any of the component groups in Tables 2.4.2-1 through 2.4.2-12. Explain this omission.

Response

The spent fuel pool liner and refueling transfer canal is evaluated within the Spent Fuel Cooling system. The SFP liner and transfer canal are in scope and subject to aging management review. The component group of "tank" in Table 2.3.3.3-3 describes the stainless steel SFP liner and transfer canal. Tank was utilized rather then a generic commodity materials group because the spent fuel pool carries a unique plant identification number (EIN) on drawing 33013-1248. In the plant configuration management system the SFP EIN is categorized as a component type of tank. Thus, the lack of a generic commodity group to represent these liners was not an omission form Tables 2.4.2-1 through 2.4.2-12. In this case the link for tank in table 2.3.3.3-3 takes the user to Table 3.4-2, item 347 where the Water Chemistry Program is invoked. The Staff is correct that line number (19) of Table 3.6.1 could be appropriate. It also invokes Water Chemistry. This entry was included to maintain fidelity with the NUREG-1800, Standard Review Plan, system and component groupings.

F-RAI 3.6 -15

The Structural Monitoring Program and Boric Acid Corrosion AMPs are used to manage the aging of carbon steel expansion/grouted anchors (CSUPP-EXP(CS)). Neither of these AMPs in Appendix B of the LRA describe how the aging of this component group will be managed. In addition, the GALL AMPs XI.S6 "Structures Monitoring Program" and XI.M10 "Boric Acid Corrosion" do not describe the aging management of carbon steel expansion/grouted anchors. Please provide additional information regarding the aging management proposed for carbon steel expansion/grouted anchors.

Response

The commodity group CSUPP-EXP(CS) involves components exposed to the weather and, as indicated in the LRA, is not subject to the requirements of the Boric Acid Corrosion program.

That notwithstanding the question is appropriate for the commodity group CSUPP-INT(CS). Both the Structures Monitoring program and the Boric Acid Corrosion program visually evaluate carbon steels, including the exposed portions of expansion/grouted anchors, for signs of corrosion. In Table 3.6-1, line numbers (25) and (27), the discussion column provides a description of the applicable aging effects and the program selected to manage those effects.

For Structures Monitoring (see LRA section B2.1.32) the plant implementing procedure EP-2-P-0169, Structural Monitoring and Assessment Program has been modified to require visual inspection, evaluation and, if necessary corrective action, for accessible fasteners, including the exposed portions of expansion anchors used in equipment supports and restraints. The grouted connection is also visually inspected. In addition to in-scope equipment supports this evaluation is inclusive of all supports in areas containing safety related equipment with out regard or consideration if the supported equipment is within the scope of the rule.

For Boric Acid Corrosion (see LRA section B2.1.6) the plant implementing procedure IP-ITT-7. Boric Acid Corrosion Monitoring Program has been modified to ensure compliance with the GALL primarily through extending the applicability of the program scope beyond the reactor coolant system to include any carbon or low alloy steel structural or system components, including electrical and instrumentation, subject to borated water leaks. (The program previously only formally accounted for the equipment subject to Generic Letter 88-05.) Additionally changes were made to ensure that all potential boric acid leaks are entered into the corrective action process and receive an event investigation to determine the scope of equipment affected. If warranted, the procedure provides for technical evaluations for affected components in accordance with the guidance provided in the Boric Acid Corrosion Guidebook and GL 88-05.

F-RAI 4.2.1 -1

Section 4.2.1 of the LRA indicates that the upper shelf energy (USE) for the reactor vessel beltline weld material will be less than 50 ft-lbs at the end of the extended period of operation. Consequently, a low upper-shelf fracture mechanics analysis has been performed to evaluate the weld material for ASME Levels A, B, C, and D. To confirm the USE analysis meets the requirements of Appendix G of 10 CFR Part 50 at the end of the LR period:

a) For each beltline material that is projected to remain above 50 ft-lb at the end of the LR period provide the percentage copper, the unirradiated Charpy USE, the projected neutron fluence at 1/4 thickness, the projected Charpy USE at the end of the license LR, and whether the drop in Charpy USE was determined using the limit lines in Figure 2 of RG 1.99, Revision 2 or from surveillance data. If surveillance data was used, provide the surveillance data.

b) If an equivalent margins analysis was required to demonstrate compliance with the USE requirements in Appendix G of 10 CFR 50, provide the analysis or identify an approved topical report that contains the analysis. Information the staff will require to assess the equivalent margins analysis includes: the unirradiated USE (if available) for the limiting material, its copper content, the fluence (1/4T and at 1 inch depth), the end of extended license (EEOL) USE (if available), the operating temperature in the downcomer at full power, the vessel radius, the vessel wall thickness, the J-applied analysis for Service Levels C and D, the vessel accumulation pressure, and the vessel bounding heatup/cooldown rate during normal operation.

Response

An equivalent margins analysis has been performed to demonstrate compliance with the USE requirements in Appendix G of 10 CFR 50. This analysis is documented in Framatome ANP, Inc. document BAW-2425, dated May 2002. The information required by the staff to assess the analysis is contained in this document. This document has been provided to the staff under separate cover dated April 11, 2003.

F-RAI 4.2.2 -1

In Section 4.2, "Reactor Vessel Neutron Embrittlement," of the LRA it is stated that the methodology used to perform neutron fluence calculations is consistent with Regulatory Guide 1.190. Explain how the calculation adheres to the guidance of RG 1.190, i.e. what code(s) were used, how were they benchmarked, what approximations were used, what cross sections, how were the sources derived, were there any adjustments of the calculations with respect to measured surveillance capsule dosimetry, etc.

Response

Updated neutron fluence calculations were performed by Westinghouse to determine the neutron radiation environment within the reactor vessel and surveillance capsules at Ginna Station. Neutron dosimetry sensor sets from the first four surveillance capsules withdrawn from the Ginna reactor vessel were reanalyzed using current dosimetry evaluation methodology. Future fluence accumulations were projected through operating periods extending to 54 effective full power years. The results of these calculations are documented in WCAP-15885, "R.E. Ginna Heatup and Cooldown Curves for Normal Operation" , dated July 2002. This document has been provided to the staff under separate cover dated April 11, 2003.

F-RAI 4.3.1 -1

Section 4.3.1 of the LRA contains a discussion of the transients used in the design of the RCS components at the Ginna Station. The LRA indicates that a review concluded that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation. Provide the following information for each of the design transients reviewed:

a) The current number of operating cycles and a description of the method used to determine the number of the design transients from the plant operating history.

b) The number of operating cycles estimated for 60 years of plant operation and a description of the method used to estimate the number of cycles at 60 years.

c) A comparison of the design transients with the transients monitored by the Fatigue Monitoring Program (FMP) described in Section B.3.2 of the LRA. Identify any transients listed in the LRA that are not monitored by the FMP and explain why it is not necessary to monitor these transients.

Response

(a) Pre-operational testing and the first 19 years of plant operational history (June 1969 through July 1988) have been evaluated and documented in the Grove Report (Ref. 1). Annual reports were developed from the Transient Monitoring Program (Ref. 2) starting in 1996. The first Transient Monitoring Report (Ref. 3) issued in January 1996 covered the period from June 1969 through 1995. Subsequent annual reports were generated for the years of 1996 through 1999 (Refs. 4–7).

(b) Two methods were used for weighting: (1) a linear projection based on the full 30 years of operation and (2) a weighted projection based on the procedure described below.

(1) A linear projection was developed for each of the plant events counted in the Transient Monitoring Program on the basis of the first 30 years of operation. Results are shown in the "Linear Cycle Projection to 2029" column in Table 1.

(2) The first 19 years of plant operation represented by the Grove Report (Ref. 1) (1969-1988) was taken as a whole and given a weighting of 0.5. The next 6 years represented by the 1995 report (Ref. 3) (1989-1994) was given a weighting of 1. The next 5 years of operation represented by the annual reports (Ref. 4-7) (1995-1999) were given a weighting of 3. The basis for this weighting procedure relies upon the expectation that the most recent operating periods represent the method of future operation much better than the prior periods. Plant events projected to 60 years of operation utilizing the weighting procedure are shown in the "Weighted Cycle Projection through 2029" column in Table 1. The weighting projection uses the following equation:

$$\sum_{1}^{i} \frac{(Period\ n\ cycles)(Weight\ n)}{(Years\ n)}$$

(c) A comparison of the design transients with the transients monitored by the Ginna Fatigue Monitoring System are summarized in Table 2. As can be seen, all required transients, and more, are included in the Fatigue Monitoring System.

References: (all are located in Reactor Engineering "Transient Monitoring" folder)

1. Grove Engineering Report, "R.E. Ginna Nuclear Power Plant RCS Transient Validation Report," August 10, 1989

2. Transient Monitoring Program, Procedure Number RE-50.1, Revision 0

3. 1995 Transient Monitoring Report, dated January 18, 1996

4. 1996 Transient Monitoring Report, dated January 8, 1997

5. 1997 Transient Monitoring Report, dated January 6, 1998

6. 1998 Transient Monitoring Report, dated January 5, 1999

7. 1999 Transient Monitoring Report, dated January 29, 2000

Table 1
Plant Events and Projections

	Cycles									Linear	Weighted			Percentages		
Event	June 1969-July 1988 [1]	June 1969-1995	Aug 1988-1994	1995	1996	1997	1998	1999	Total Cycles through 1999	Linear Cycle Projection to 2029	Expected Cycles 2000- 2029	Weighted Cycle Projection through 2029	Design Cycles	Design Cycles at 30.5 years	Cycle Projection to 60 years (linear)	Cycle Projection to 60 years (weighted)
RCS Heatup	55	69	13	1	7	1	0	1	78	***153***	33	***111***	200	39%	***77%***	***55%***
RCS Cooldown	54	68	13	1	7	1	0	1	77	***153***	33	***111***	200	39%	***77%***	***55%***
Plant Loading	454	531	69	8	11	5	2	10	559	***1100***	128	***687***	14500	4%	***8%***	***5%***
Plant Unloading	256	321	58	7	10	5	2	8	346	***681***	110	***456***	14500	2%	***5%***	***3%***
Step Load Increase (10%)	4	4	0	0	0	0	0	0	4	***8***	0	***4***	2000	0.2%	***0.4%***	***0.2%***
Step Load Decrease (10%)	3	3	0	0	0	0	0	0	3	***6***	0	***3***	2000	0.2%	***0.3%***	***0.2%***
Step Load Reduction (50%)	8	13	5	0	0	0	0	1	14	***28***	4	***18***	200	7%	***14%***	***9%***
Refueling	19	25	5	1	1	1	0	1	28	***55***	13	***41***	80	35%	***69%***	***51%***
Loss of Load (w/o Rx Trip)	0	0	0	0	0	0	0	0	0	***1***	0	***1***	80	0%	***1%***	***1%***
Loss of Power	2	2	0	0	2	2	0	0	6	***12***	12	***18***	40	15%	***30%***	***45%***
Loss of Flow (One Pump)	2	2	0	0	0	0	0	0	2	***4***	0	***2***	80	3%	***5%***	***3%***
Reactor Trip	(2)	103	102	1	2	0	0	2	107	***210***	30	***137***	N/S			
Reactor Trip (>20% Power)	56	66	9	1	2	0	0	2	70	***138***	18	***88***	400	18%	***34%***	***22%***
Inadvertent RCS Depressurization	29	31	2	0	1	0	2	0	34	***67***	10	***44***	N/S			
Inadvertent Safety Injection [4]	3	4	1	0	0	0	0	0	4	***8***	0	***4***	10	40%	***80%***	***40%***
Turbine Roll Test	1	1	0	0	0	0	0	0	1	***1***	0	***1***	9	11%	***10%***	***10%***
Primary Hydro (3110 psig)	1	1	0	0	0	0	0	0	1	***1***	0	***1***	4	25%	***25%***	***25%***
Primary Hydro (2250/2352 psig)	7	9	2	0	1	0	0	0	10	***20***	3	***13***	40	25%	***50%***	***33%***
Stud Tension/Detension	20	26	5	1	1	1	0	1	29	***57***	13	***42***	80	36%	***71%***	***53%***
RHR Operation	73	83	9	1	5	1	0	1	90	***177***	27	***117***	200	45%	***89%***	***58%***
S/G Sec Side Pressure Test [3]					0	0	0	0	0	***1***	0	***1***	40	0%	***3%***	***3%***
S/G Leak Test [3]					0	0	0	0	0	***1***	0	***1***	200	0%	***1%***	***1%***
S/G Primary Manway Studs [3]					1	1	0	1	3	***26***	23	***26***	40	8%	***65%***	***65%***

Notes:

1. From Reference (1)
2. Not reported in Reference (1); total given in 1995 Operating Report (Reference 3)
3. Counting began with steam generator installations in 1996

Table 2
Design Transients Tracked by the Fatigue Monitoring Program for Ginna

Transients Monitored [1]	Design Cycles	Cycles from 6/69 through 12/31/99 [8]	Projected Cycles for 60-Years (Linear)		Projected Cycles for 60-Years (Weighted)	
			Cycles [4]	Percentage	Cycles [4]	Percentage
Reactor Coolant System Heatup	200	78	153	77%	111	55%
Reactor Coolant System Cooldown	200	77	153	77%	111	55%
Pressurizer Heatup	Not Specified	N/R	TBD [19]	TBD [19]	N/A	N/A
Pressurizer Cooldown	200 [2]	N/R	TBD [19]	TBD [19]	N/A	N/A
Plant Loading at 5% of Full Power/Minute [10]	14,500	559	1,100	8%	687	5%
Plant Unloading at 5% of Full Power/Minute [10]	14,500	346	681	5%	456	3%
Step Load Increase of 10% of full power	2,000	4	8	0.4%	4	0.2%
Step Load Decrease of 10% of full power	2,000	3	6	0.3%	3	0.2%
Large Step Load Decrease of 50% of full power	200	14	28	14%	18	9%
Reactor Trip at Power with No Cooldown [11]	230 [3]	70 [16]	138	34%	88	22%
Reactor Trip at Power with Cooldown and No SI [11]	160 [3]	0	1 [4]	1%	1 [4]	1%
Reactor Trip with Cooldown and SI [11]	10 [3]	0	1 [4]	10%	1 [4]	10%
RHR Initiation	200 [2]	90	177	89%	117	59%
Loss of Load (Turbine Trip) without Reactor Trip	80 [2]	0	1 [4]	1%	1 [4]	1%
Loss of Power	40 [2]	6	12	30%	18	45%
Loss of RC Flow (Partial)	80 [2]	2	4	5%	3	3%
Main Pressurizer Spray During High System ΔT	1,200 [5]	N/R	TBD [19]	TBD [19]	N/A	N/A
Auxiliary Spray Actuation During Cooldown	200 [2]	N/R	TBD [19]	TBD [19]	N/A	N/A
Inadvertent RCS Depressurization	Not Specified	34 [14]	67	N/A	44	N/A
Inadvertent Auxiliary Spray	10 [2]	[14]	TBD [19]	TBD [19]	N/A	N/A
High Head Safety Injection	10 [2]	5	8	80%	4	40%
Accumulator Safety Injection	4 [2]	N/R	1 [4]	25%	1 [4]	25%
Normal Charging and Letdown Flow Shutoff and Return to Service	80 [2] [6]	N/R	TBD [19]	TBD [19]	N/A	N/A
Letdown Flow Shutoff with Prompt Return to Service	200 [2]	N/R	TBD [19]	TBD [19]	N/A	N/A
Letdown Flow Shutoff with Delayed Return to Service	20 [2]	N/R	TBD [19]	TBD [19]	N/A	N/A

Transients Monitored [1]	Design Cycles	Cycles from 6/69 through 12/31/99 [8]	Projected Cycles for 60-Years (Linear)		Projected Cycles for 60-Years (Weighted)	
			Cycles [4]	Percentage	Cycles [4]	Percentage
Turbine Roll Test	10 [2]	1	1	10%	1	10%
Normal Pressurizer PORV Actuation	100 [2]	N/R	TBD [19]	TBD [19]	N/A	N/A
Low Pressure Pressurizer PORV Actuation	Not Specified	N/R	TBD [19]	TBD [19]	N/A	N/A
Pressurizer Code Safety Valve Operation	40 [2]	N/R	TBD [19]	TBD [19]	N/A	N/A
Primary Side Leak Test	40 [2]	10	20	50%	13	33%
Primary Side Hydrostatic Test	5 [2]	1	1	20%	1	20%
Secondary Side Leak Test [15]	200 [2]	0	1	3%	1	3%
Secondary Side Hydrostatic Test [15]	40 [2]	0	1	3%	1	3%
Steam Generator Manway Studs [15]	40 [2]	3	26	65%	26	65%
Operating Basis Earthquake	20 [2]	N/R	1	5%	1	5%

Notes for Table 3:

1. Plant Loading at 5% of full power per minute and Plant Unloading at 5% of full power per minute are not monitored due to the small rate of accumulation of cycles for the first 20 years of plant operation and the insignificant effects on the fatigue usage factor for any RCS component. Steady State Fluctuations are not monitored due to the insignificant effect on the fatigue usage factor of any RCS component.
2. Not included in FSAR Table 5.1-4 [8]
3. These three events are combined in FSAR Table 5.1-4 [8]
4. Plant cycles with zero cycles-to-date are conservatively set to 1 cycle.
5. This event is defined to address Low Temperature Over Pressurization (LTOP) concerns only and not due to fatigue concerns.
6. Loss of Charging and Letdown includes two sub-events;
   - Charging and letdown flow shutoff and return to service
   - Charging flow shutoff with delayed return to service
7. From [1]
8. N/R = Not reported in [1]
9. Reported as Reactor Trip from Greater than 20% Power. Review of records shows all events to be Reactor trip with no Cooldown and no SI.
10. Plant Loading and Unloading at 5% of Full Power / Minute not counted in Fatigue Monitoring Program due to very low accumulation rates and minimal fatigue effect.
11. 107 reactor trips from < 20% power have been counted through 1999. These project to 221 cycles in 60 years on a linear projection basis and 129 cycles on a weighted basis. However, these low power reactor trips have insignificant fatigue effect and are not counted in the Fatigue Monitoring Program.
12. Reported as Inadvertent SI Actuations by [1].
13. Reported as 7 Primary Side Hydro at 2250 psig (after opening) & ASME/ISI

Hydro at 2352 psig. Assumed as 7 RCS Leak Tests. Additionally, counting 1 ASME Pre-operational Hydro not recorded in [1].

14. Inadvertent RCS Depressurization is not monitored in the Fatigue Monitoring Program, however one of its component events is monitored (Inadvertent Auxiliary Spray).
15. Events counts started with installation of replacement steam generators in 1996.
16. Cycles determined from evaluation of transient operations log developed in [3-7].
17. Tabulated only Reactor Trips from Greater than 20% Power.
18. Reported as 1 Primary Side Hydro at 3110 psig and 10 Primary Hydros at 2250/2352 psig.
19. These cycles will be projected after two years of FatiguePro operation.

F-RAI 4.3.1 -2

The Westinghouse Owners Group issued Topical Report WCAP-14577, Revision 1-A, "Aging Management for Reactor Internals," to address the aging management of the reactor vessel internals (RVI). The staff review of WCAP-14577, Revision 1-A, identified a number of issues that should be addressed on a plant specific basis. Renewal Applicant Action Item 11 specified in WCAP -14577, Revision 1-A, indicates that the fatigue TLAA of the RVI should be addressed on a plant specific basis. In Table 3.2.0-2 of the LRA, RG&E indicates that a discussion of the RVI is contained in Section 4.3 of the LRA. Section 4.3 of the LRA indicates that the RVI were designed in accordance with Westinghouse criteria which were later incorporated into the ASME Code. Discuss the transients that contribute to the fatigue usage for each component listed in Table 3-3 of WCAP-14577, Revision 1-A, and discuss how the these transients were evaluated during the transient review discussed in F-RAI 4.3.1-1.

Response

The Ginna internals were designed in accordance with the requirements of Westinghouse internal criteria that were similar to the criteria described in Subsection NG of the ASME Section III Code. Fatigue usage factors for the critical locations in the Ginna RVIs were initially evaluated using design transients that were specified early in the plant design process. These design transients were intended to be conservative and bounding cases for all foreseeable plant operational conditions. A summary of the design transient cycles is as follows:

Normal Transients	Number of Cycles
Plant Heatup and Cooldown	200
Plant Loading @ 5% of Full Power / Min	14500
Plant Unloading @ 5% of Full Power / Min	14500
Step Load Increase	2000
Step Load Decrease	2000
Large Step Load Decrease with Steam Dump	200
Steady State Fluctuations	1.0E6

Upset Transients	Number of Cycles
Loss of Load	80
Loss of Power	40
Partial Loss of Flow	80
Reactor Trip	400

In 1995, Westinghouse performed an evaluation of the structural integrity of the reactor vessel internals in support of the proposed reduction of Tavg after installation of the replacement steam generators at Ginna Station. This evaluation was necessary to demonstrate that the structural integrity of the reactor components was not adversely affected by the change in RCS conditions and transients and/or by secondary effects of the change in reactor thermal hydraulic or structural performance. New envelope plots were established for the normal and upset transients. The peak stress intensity ranges and corresponding alternating stresses (Sa) were calculated according to the rules of ASME Section III, Subsection NB for the following reactor vessel internals components:

- Lower core plate - all normal and upset transients considered
- Baffle plates and baffle/barrel former bolts - all normal and upset transients considered; governing conditions were upset/up transients
- Thermal shield flexure supports - Step increase/step decrease (Normal up); Step reduction/Reactor trip (Normal Down); Loss of flow (Upset Up); Loss of Load (Upset Down)
- Lower core support plate - all normal and upset transients considered; governing conditions were thermal, vibration, OBE, insertion, friction
- Lower support columns - all normal and upset transients considered; governing conditions were thermal, vibration and OBE transients
- Core barrel outlet nozzle projection - all normal and upset transients considered; governing conditions were upset down, upset up and OBE transients
- Core barrel flange - all normal and upset transients considered; governing condition was loss of flow
- Lower radial restraints - all normal and upset transients considered; governing conditions were upset up and upset down transients
- Upper core plate alignment pin - all normal and upset transients considered; governing conditions were thermal, vibration, OBE, blow down accident
- Upper support columns - all normal and upset transients considered; governing conditions were inadvertent depressurization, upset down, and refueling transients
- Upper support plate - all normal and upset transients were considered; governing conditions were OBE, inadvertent depressurization, loss of flow, normal up transients
- Guide tubes and support pins - all normal and upset transients considered; governing condition was upset down transients

Fatigue usage factors (CUF's) were calculated for these components (which include the set of components identified in Table 3-3 of WCAP 14577, Revision 1-A as fatigue sensitive) for the current licensing period. The CUF's at all locations were verified to be less than one for plant operation within the design transient envelope at reduced Tavg.

Experience has shown that actual plant operation is bounded by these design transients. The use of actual operating history and transient monitoring data acquired by the FatigueProTM Automatic Cycle Counting and Fatigue Monitoring System installed at Ginna Station will allow quantification of the conservatism in the existing fatigue analysis and demonstrate that the design fatigue analyses will bound the extended period of operation. Projections to 60 years of plant operation have been made using both a conservative linear cycle projection and a more realistic weighted projection, which assumes that the more recent plant operating history is more representative of future operation than earlier plant history. This assessment of the frequency and severity of actual plant transients demonstrates that there is sufficient conservatism in the original design basis transient set, based on either method of projection (linear or weighted), to adequately bound the period of extended operation (see response to RAI 4.3.1-1).

F-RAI 4.3.5 -1

In Section 4.3.5 of the LRA it is stated that using a 15° focused beam search unit, the indication was resolved into two separate indications which met the criteria for acceptance by examination in ASME Section XI, 1974 with Summer 1995 Addenda. However, according to the Staff Evaluation section of the referenced document, USNRC Letter Johson to Mecredy, "Ginna Flaw Indication in the Reactor Vessel Inlet Nozzle Weld - 1989 Reactor Vessel Examination (TAC No. 71906)," July 7, 1989, "The staff's evaluation determined that the licensee's final

dimensions of 4.94" x .48" is a realistic representation of the actual flaw size. If the flaw length were assumed constant, a reduction of .036" in the depth dimension (.480" - .44") would result in a flaw indication that meets the ASME Section XI acceptance standard." Consequently, according to the staff SER, the dimensions of the flaw are not within ASME Section XI acceptance standards. Therefore a fatigue analysis for the extended period of operation for this flaw is a TLAA and its results must be provided in accordance with 10 CFR 54.21(c) and must be described in the UFSAR Supplement.

Response

Section 4.3.5 of the LRA described examinations and analyses performed on indications in nozzle N2B during 1979 and 1989. Additional examinations were performed in 1999. During the third-interval Inservice inspections of the reactor vessel performed by Framatome Technologies in 1999, two indications were detected in Nozzle N2B while scanning from the nozzle bore using a 15 degree transducer. These indications were subsurface along the fusion line near the weld root. Indication N2B-1 was the same indication previously recorded in 1979 and 1989 and found to be unacceptable in size according to the acceptance criteria for examination in ASME Section XI, 1986 edition (with no Addenda). Indication N2B-2 was not recorded previously and was evaluated as acceptable to the ASME acceptance criteria. Indication N2B-1 was characterized as a grouping of slag inclusions that were combined using the proximity rules of ASME, Section XI, and IWA-3000. The combined size of the indications resulted in an unacceptable total flaw size when compared to the IWB-3512-1 acceptance standard. This indication was also sized using 15 degree focused beam search units. A small indication in the grouping which aligned in the through-wall direction only and did not affect the length measurement was determined to be only 34% Distance Amplitude Correction (DAC) and therefore did not need to be considered when determining the total flaw dimension. Based on this analysis, indication N2B-1 was determined to be acceptable according to Section XI acceptance standard IWB-3512-1.

F-RAI 4.5 -1

In order for the staff understand the quantitative aspect of the analysis, the applicant is requested to provide the following information:

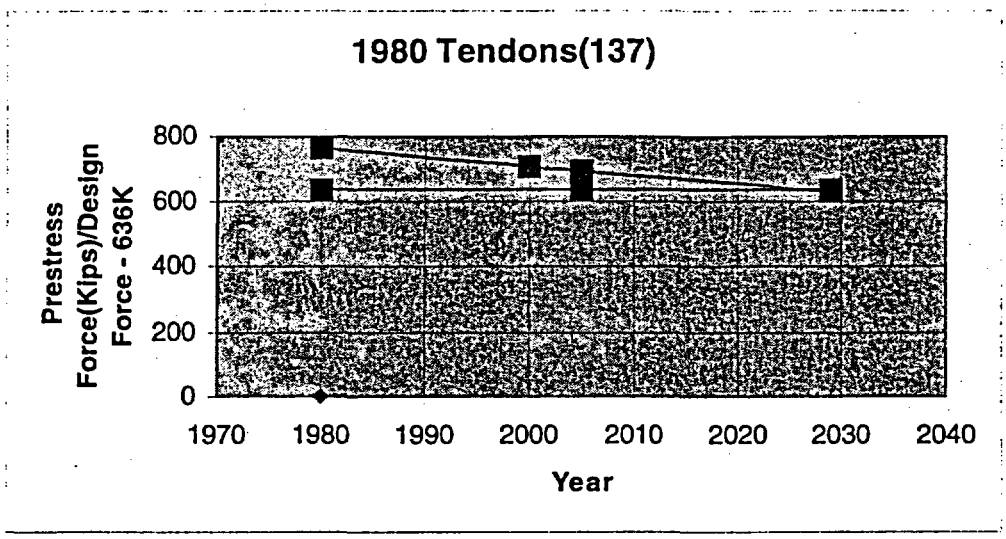
a) For the 23 tendons which were retensioned in 1969, the applicant is requested to provide the predicted lower limit line, MRV expected in 2005 and at 60 years (if not retensioned in 2005), a trend line for this group of tendons, and prestressing force values as points above and below the trend line measured during prior inspections.

b) The applicant is requested to provide the same information for the remaining 137 tendons, for the inspections performed after 1980 retensioning.

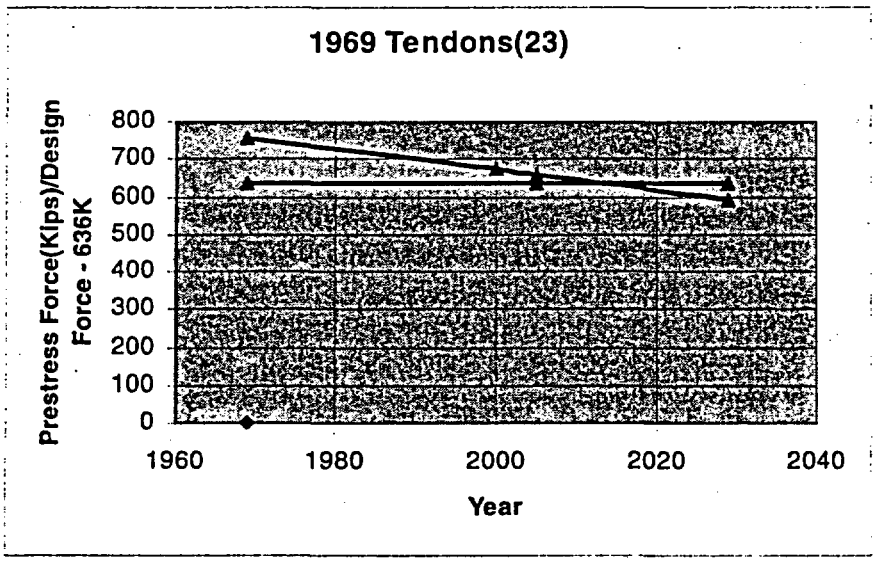
c) In the operating experience element of Section B3.3 of the LRA, it indicates that 23 tendons out of 160 tendons were retensioned 1000 hours after initial prestressing. It is not clear if the 23 tendons retensioned after initial prestressing were parts of the randomly selected tendons in the subsequent surveillance of tendons performed as per Regulatory Guide 1.35, or IWL-2520. The applicant is requested to provide information regarding the trending of prestressing forces in these 23 tendons.

Response

a) Based on the available test information for this set of 23 tendons that were retensioned in 1969, the below graph shows the trend line from 1969 projected through 2005, and out to 2029. The graph also includes a constant line at 636 kips, which is the minimum design prestress force.



b) Based on the available test information for this set of 137 tendons that were retensioned in 1980, the below graph shows the trend line from 1980 projected through 2005, and out to 2029. The graph also includes a constant line at 636 kips, which is the minimum design prestress force.



c) Following the initial installation and retensioning of those 23 tendons in 1969, they were then included into the total population of tendons for the structure(160), which were subsequently randomly sampled and tested per Regulatory Guide 1.35 through the year 2000. The next scheduled tendon surveillance will be performed in the year 2005 and will be tested per the requirements of IWL - 2520.

Since their retensioning in 1969, there have been 22 lift off tests performed on that population of 23 tendons.

F-RAI 4.5 -2

Section A4.1 of the LRA (UFSAR Supplement) gives a qualitative description regarding the prestressing forces in Ginna containment. The staff believes that the applicant should, as a minimum, provide target prestressing forces that will be maintained at 40 years and 60 years. The applicant is requested to supplement the present description in A4.1 with the basic quantitative description.

Response

The required minimum design prestress force for the containment structure of Ginna Station is 636 Kips. Based on data compiled for all tendons since 1969, the graphs presented in response to RAI 4.5.1 a) and 4.5.1 b) above, show the projected values for the 1969 and 1980 populations of tendon out to years 2005 and 2029. The prestress values for those two groups of tendons will provide a 4% and 8% margin above the minimum design force in 2005, and would fall below the minimum force if projected out to 2029. The tendons in the 1969 population will be retensioned in the 2005 surveillance and those in the 1980 population will be done in subsequent surveillances.

F-RAI 4.6 -3

Indicate if the hot piping penetration assemblies contain bellows. If yes, provide the basis for not identifying fatigue of these bellows as TLAAs, in accordance with 10 CFR 54.3.

Response

Hot and cold mechanical penetrations at Ginna Station contain bellows. However, by design, the bellows do not perform a Containment isolation function. The only function of the bellows is to accommodate lateral and axial pipe movements (see response to RAI 3.6-3).

F-RAI 4.7.3 -2

Indicate the design code to which the fatigue analysis of the fillet welds attaching the channel anchors to the liner was performed.

Response

The design codes employed for the fatigue analysis of the fillet welds attaching the channel anchors to the liner are as follows:

(1) AISC Specification, Sect. 1.7.2
(2) AWS Specification D2.0-63

(3) AASHO, Highway Structures Design Handbook I

F-RAI 4.7.4 -1

The applicant is requested to provide the UFSAR Section numbers where the staff can find information regarding the allowable radial and vertical displacements of the containment stainless steel tendon bellows, and calculations showing the fatigue usage factor less than 0.01.

Response

The containment stainless steel tendon bellows were designed to the requirements of USAS B31.1 Code for pressure piping. Figure 3.8-18 is referenced in UFSAR Section 3.8.1.4.4.1. Figure 3.8-18 contains the following information:

(1) Movements:
Case (1) - From undeflected position vertically downward 0.14 inches
Case (2) - From above position vertically upward 0.10 inches and simultaneous laterally 0.16 inches
(2) Fatigue: Two cycles per year
(3) Working Pressure: 60 psig
Test Pressure: Hydrostatic at 150% of working pressure
Pneumatic at 125% of Working Pressure
(4) Maximum working temperature: 160°F
(5) Standard Specification: ASA B31.1 Code for Pressure Piping
(6) Test two random assemblies for specified movements

Based on this information, the total number of thermal cycles including those accumulated during the period of extended operation would not exceed the allowable number of cycles (7000) for a stress range reduction factor of 1.0 in the USAS B31.1 pressure piping code.

A calculation of CUF for the tendon bellows for the period of extended operation was also performed as a TLAA in DA-CE-2002-016-07. This calculation is presented below:

The allowable radial and vertical displacements of the containment stainless steel tendon bellows are given in UFSAR Figure 3.8-18 and are limited to two cycles per year for the 40 year life of the plant. This limits the total number of allowable displacement cycles to 80. Assume that 80 cycles of allowable displacement results in a fatigue usage factor of 1.0.

From ASME Code Figure N-415(B) for stainless steel, the allowable alternating stress amplitude, Sa, for 80 cycles is 260 ksi. Assume that this is the peak stress produced in the bellows due to the combined effect of design basis vertical and radial displacements of 0.10" and 0.16" given in UFSAR Figure 3.8-18, and that this stress is directly proportional to the absolute sum of the displacements. Thus, Sa = 260 ksi is produced at an absolute displacement of 0.26".

The absolute magnitude of the combined vertical and radial displacements that actually occur is 0.030" + 0.014" = 0.044". This displacement corresponds to a bellows stress level of (0.044/0.26)(260) = 44 ksi.

The alternating stress intensity amplitude of 44 ksi corresponds to 40,000 cycles. The fatigue usage factor is 144/40,000 = 0.004.

Therefore, the structural integrity of the tendon bellows will be maintained through the period of extended operation.

F-RAI B2.1.3 -1

Regarding the overall loss of prestressing forces in majority of the containment tendons, the applicant is requested to provide a summary of the corrective actions taken, including the root cause determination, and the results of subsequent inspections.

Response

During lift-off surveillance testing in 1977 it was discovered that the average compressive force of the tendons had decreased to a value marginally above the design requirement of 636 kips. A 10-year retest was performed in 1979 and the marginal force values confirmed. In 1980, a total of 137 tendons were retensioned. In 1981, lift-off surveillance tests were performed, and witnessed by NRC inspectors (see Inspection Report 81-14). Subsequent surveillance testing has demonstrated that all tendons have met operability criteria. Investigation of the cause of the loss of prestress was undertaken at the Fritz Engineering Laboratory of Lehigh University. An extensive testing program was conducted with two primary objectives. The first objective was to determine the root cause of the loss of prestress, and the second was to determine the effect of retensioning at various times after initial stressing on subsequent loss of prestress. The results of the testing program can generally be summarized as follows (Refs. 1 and 2):

(1) The principal cause of the loss of prestress in the wall tendons was stress-relaxation;

(2) An increase in temperature from ambient conditions to operating conditions significantly increases the amount of stress relaxation over time. For example, at a temperature of 104 degrees F after 40 years the stress relaxation in the tendon would be expected to be as high as 21% as opposed to 12% as originally predicted;

(3) Retensioned tendons exhibit considerably less stress relaxation than initially tensioned tendons.

The results of the Lehigh University testing program were reviewed by Franklin Research Center (FRC) and Geotechnical Engineers, Inc. The reviews included assessment of other potential contributions to loss of tendon prestress, such as rock anchor slippage, bedrock creep, creep in concrete Containment walls, elastic shortening of the Containment concrete, tendon stress relaxation, and tendon wire corrosion. It was concluded that stress relaxation was the most reasonable and probable cause of the loss of prestress (Refs. 3 and 4). The review concluded that contributions from rock anchor slippage and creep of concrete Containment walls were significantly less than the contribution from stress relaxation. The NRC agreed with this analysis (Ref. 5) and concluded that the tendon lift-off surveillance program should be continued.

Tendon lift-off surveillance tests were performed in 1981, 1983, and 1985, and, thereafter, every five years (1990, 1995 and 2000). Regulatory Guide 1.35 requires that at least 4% of the population of each tendon group be randomly sampled during each surveillance. The tendon group for Ginna Station consists of 160 vertical tendons, and 4% amounts to a sample size of 7 per surveillance. The actual test sample size during each lift-off surveillance testing activity since retensioning has ranged from 14 to 21, well in excess of the minimum required by the

Regulatory Guide. The measured lift-off forces in all surveillance tests performed to date have exceeded the minimum required prestress force.

References:

1. "Containment Building Tendon Investigation", GAI Report 2347, Doc. No. GC 20224, EWR 1900, Record ID GC20224, 1981
2. "Evaluation of Lehigh Retension Tendon Stress Relaxation Data to Predict Tendon Surveillance Forces", Doc. No. GC20250, EWR 1900, Record ID GC20250, 1983
3. Tendon Evaluation, Rochester Gas and Electric Corp., R. E. Ginna Nuclear Power Station, Technical Evaluation Report C5506-551, Franklin Research Center, March 29, 1985
4. Review of Rock Anchor Evaluation, R. E. Ginna Nuclear Power Plant, Geotechnical Engineers, Inc., January 10, 1985
5. U. S. NRC Letter dated August 19, 1985 from John A. Zwolinski to R. W. Kober

F-RAI B2.1.3 -2

As described in Section 2.4.1 of the LRA, the support system of the Ginna containment is unique, and its inspection requirements are not specifically addressed in Subsections IWE and IWL of Section XI of the ASME Code. Provide information regarding the inspection and evaluation of the support system.

Response

As of September 2000, the containment system at Ginna Station is inspected and monitored according to the provisions of the ASME Code, Section XI, Subsections IWE and IWL as implemented by the Ginna Station "Containment Program".

The functionality of the structure will be monitored for structural adequacy of its unique support system by successful completion of testing performed under the containment "Tendon Surveillance Program", as defined in plant procedure PT 27.2, "Tendon Surveillance Program". The material condition and functionality of the containment structure is also evaluated under the provisions defined in Engineering Procedure EP-2-P-0169, "Structural Assessment and Monitoring Program" which provides guidance for evaluating galvanic potential measurements for the rock anchor tendons.

F-RAI B2.1.3 -3

Moisture barrier degradation and minor corrosion of the liner has been detected during prior inspections. The applicant is requested to provide, (a) the acceptance criteria used for repairing the liner plate, (b) the successive (IWE-2420), additional (IWE-2430), and augmented [IWE-2500(c)] liner inspections performed (and will be performed), and (c) sampling plans (if any) for removing the insulation for the purpose of inspection.

Response

(a) & (b) During scheduled ASME Section XI Subsections IWE inspections of the Containment circumference at the intersection of the basement concrete floor with the Containment steel liner, one area was discovered where the sealing (caulking) detail of the concrete floor to liner plate did not conform to drawings. The caulking seals the gap between the foam insulation on the containment walls and the concrete floor. As a result of this discovery, the inspection scope

was increased to include a visual inspection of the caulking detail around the entire circumference of the Containment concrete/liner interface. The caulking was found to be continuous with no visible gaps or discontinuities.

As a result of the discovery of the non-conforming caulking detail, insulation in two areas (one on the north side and one on the west side of the Containment) was removed and the Containment liner was visually inspected. Evidence of minor surface corrosion was visible in the area of non-conforming caulking detail (north side). Ultrasonic thickness readings were taken in both areas. The thickness readings ranged from .346" to .404" on the north side, and .388" to .404" on the west side. The minimum required thickness was determined by engineering analysis and documented in EWR 5190 to be 0.281". Therefore the minimum liner thickness requirements were met.

The Containment liner surface had been coated with a layer of zinc-rich paint during construction. The area of the liner which exhibited minor surface corrosion was cleaned and restored with a new coating of zinc-rich paint. The foam insulation was restored in both areas and new caulking installed in conformance with engineering specifications.

(c) Additional inspections of the caulking and Containment liner are scheduled during the second and third periods of the Fourth Ten-Year Inservice Inspection Interval which commenced January 1, 2000.

F-RAI B2.1.4 -1

In Section B2.1.4, "ASME Section XI, Subsection IWF Inservice Inspection", of the LRA it states that industry operating experience was incorporated into the LR process through a review of industry documents to identify aging effects and mechanisms that could challenge the intended function of systems and structures within the scope of LR. Review of plant specific operating experience was performed to identify aging effects. The staff noted that there are instances where industry operating experience is not included in the Ginna IWF Program; for instance, loss of material due to general corrosion for the bolts and anchorage; stress corrosion cracking due to improperly heat-treated anchor bolts; deformation or structural degradations of fasteners, springs, clamps; loss of hanger mechanical function; and improper clearances of guides and stops. The GALL program, Section XI.S3, "ASME Section XI, Subsection IWF," under "Parameters Monitored or Inspected," states that VT-3 visual examination will be used to monitor or inspect component supports for corrosion; deformation; misalignment; improper clearances; improper spring settings; damage to close tolerance machined or sliding surfaces; and missing, detached, or loosened support items. The applicant is requested to discuss how its IWF program was considered to be consistent with the GALL IWF program, considering conformance of all the relevant program elements.

Response

The ASME Section XI Subsection IWF Inservice Inspection Program is an existing program that is consistent with NUREG 1801 (Generic Aging Lessons Learned (GALL) Report), Section XI.S3, "ASME Section XI, Subsection IWF". The ten program attributes have been reviewed and found to be consistent with the corresponding attributes in NUREG-1801.

The parameters monitored or inspected under the ASME Section XI Subsection IWF Inservice Inspection Program include corrosion, deformation, misalignment, improper clearances, improper spring settings, damage to close- tolerance machined or sliding surfaces, and missing,

detached, or loosened support items. Component bolting is inspected for indication of potential degradation including loss of coating integrity, cracking and obvious evidence of corrosion.

A review of industry and plant-specific operating experience related to supports was conducted and is documented on-site, but only a summary was provided in Paragraph B2.1.4 of the LRA. Additional detail is provided in this response. Review of industry operating experience identified NRC Information Notice 80-36 which notified utilities of the potential for stress corrosion cracking (SCC) of high-strength component support bolting. In addition, corrosion of supports has been identified by inspections conducted under the ASME Section XI, Subsection IWF ISI Program at other nuclear plants, particularly on supports located outdoors at saltwater-cooled plants.

A review of plant-specific operating experience revealed the following:
(1) Failure of Anchor Bolts

During a scheduled shutdown from September 30 to October 15, 1970, a stud on the B Loop reactor coolant pump base plate that anchored the pump to the floor, was observed to have fractured in the upper thread. Subsequent inspections showed that a total of four anchor-bolts for the steam generator and reactor coolant pump had broken or cracked sections. Detailed testing, investigation, and evaluation revealed that the most probable root cause was the application of an excessively high initial (installation) torque that caused a bolt stress of approximately 160,000 psi and the exposure of the bolts to borated water. On several occasions, borated water had spilled on the floor near the bolts and had been washed or hosed down during clean up. Consequently, the highly stressed bolts were exposed to borated water resulting in a classic case of stress corrosion cracking.

All of the 56 anchor bolts that are used in the steam generators and reactor coolant pumps were replaced with bolts of the same material (A490). However, the bolts were tightened using a standard stud wrench, which eliminated the excessively high pre-load. Inspections during subsequent outages revealed no evidence of bolt distress, corrosion or cracking.

(2) Non-Conformance Report No. 94 - 056; "Westinghouse Reactor Coolant Pump B Anchor Bolt N-2 Rejected During ISI Examination"

During the 1994 refueling outage, inspection of anchor bolts for the B RCP revealed an indication at length 19.3" in a 23 ½" long stud. The indication appears to extend approximately 1/4" into the 1 3/8" diameter stud around 180 degrees of the stud perimeter. A strength and stiffness analysis of the structure revealed that the affected bolt is redundant. The remaining 11 can carry the total design loads such that code requirements are still satisfied. The remaining 11 bolts were thoroughly inspected and no indications were found. Consequently, the disposition for the bolt non-conformance was "use as is".

(3) Action Report 97-1773; "Misaligned Ears on Steam Generator Side of Snubber Bracket"

The ear that holds the pin for installation of a steam generator snubber was observed to be misaligned, preventing the free and effortless removal of the pin. This pin holds Snubber S.B.-4, and had to be cut to remove the snubber for functional testing. Investigations showed that the pin joints associated with the steam generator snubbers are subjected to effects of heat-up and cool-down of the RCS. The design of the RCS is such that the steam generators are allowed to float during these heat-up and cool-down cycles to minimize thermal stresses and nozzle loads in the system. These movements of the generators cause the upper support ring to experience

a small amount of rifling, that is the ring may rotate slightly due to bolt hole tolerance, causing the snubbers and bumper pins to be wedged in the holes, making the pins difficult to remove. This occurred during the shakedown process of the replacement steam generators during the first heat-up and cool-down exposure. The event did not cause any safety issue on plant operation. After replacement of the pin, the problem has not been noted since.

(4) Work Order No. 19604750; "Pressurizer Skirt Support"

This work order required a visual examination on two loose bolts in the pressurizer skirt support. The examination found no indications on the bolts. The bolts were subsequently tightened.

Other conditions discovered during ISI examinations included out-of-specification snubber settings, broken spring cans, damaged hangers, general corrosion, etc., all of which were addressed by engineering evaluation and subsequent repair/refurbishment in accordance with the Corrective Action Program. For additional information see the response to RAI B2.1.4-2.

F-RAI B2.1.4 -2

In the LRA Section B2.1.4, "ASME Section XI, Subsection IWF Inservice Inspection", it states that discovery of deficiencies during regularly scheduled inspections results in an expansion of inspection scope to assure that the full extent of the deficiencies is identified. Degradation that potentially compromises the support function or load capacity is identified for evaluation. The deficient incidents for pipe and component supports and anchorages have been corrected in accordance with the requirements of Subsection IWF. Provide a discussion and examples of expanding inspection scope when discovering deficiencies in supports and anchorage and evaluating the identified degradation of supports and anchorages at Ginna.

Response

During the scheduled Fall 2000 refueling outage at Ginna Station, inspections of main steam piping supports were being conducted. One support (MAU-23) was identified with a broken spring. Review of previous examination history indicated that an ISI examination had been performed in 1991 and the support was structurally sound at that time with an acceptable setting. The broken spring was considered to be service-induced. In accordance with the requirements of ASME Section XI, Subsection IWF, Paragraph IWF-2430(a), additional examinations were performed as follows:

(1) The component supports immediately adjacent to the support for which corrective action is required were examined, and
(2) Additional supports within the system, equal in number and of the same type and function to those scheduled for examination during the inspection period, were also examined.

The rejected component support MAU-23 was determined to be a Section XI Category F-A and Item number FI.20C. A total of 7 component supports were scheduled for examination during the first period outages. A total of nine supports were examined, two more than the minimum number required by ASME Code. Of these nine supports, one was identified with a service-induced repeatable condition reported as unacceptable corrosion. As a result, a second expansion was required. This expansion consisted of all remaining supports within the system of the same type and function as required by Paragraph IWF-2430(b). There were five

remaining supports within the system of the same type and function. These supports were examined and found to be acceptable.

A second example of an expansion of inspection scope and evaluation of an identified deficiency also occurred during the Fall 2000 refueling outage. During a WALKDOWNS of the main steam piping, a snubber support (MAU-26) was identified with a bent extension arm. Upon further investigation, it was determined that the settings were within tolerance. A review of past examination history revealed that in 1992 the indicator tube was loose, but no other deficiencies were noted. In 1999, a visual examination was performed and the snubber was found to be acceptable. The bent extension arm was considered to be service induced and the snubber was replaced. Additional examinations in accordance with the requirements of Paragraph IWF-2430(a) were performed. This expansion involved visual examinations of nine additional snubbers and surface examinations on the integral attachments. No deficiencies were identified. However, as a result of engineering evaluation, a significant number of additional examinations were performed to verify the structural integrity of additional snubbers as well as main steam piping welds. This "engineering expansion" encompassed three additional snubbers and their integral attachments and six piping welds. The examination of piping welds included visual examination, surface examination by MT, and volumetric examination by UT and RT. None of these examinations revealed any deficiencies.

F-RAI B2.1.6 -1

Section B.2.1.6 of the LRA indicates that Boric Acid Program will be consistent with the GALL.

a) Identify when this program will be consistent with GALL.

b) Describe the changes that must be incorporated to make the Ginna Boric Acid Program consistent with the GALL program.

Response

a) Consistency with the Gall program elements was achieved March 13, 2003 with the issuance of procedure IP-IIT-7, Boric Acid Corrosion Monitoring Program.

b) The changes made to ensure compliance primarily included extending the applicability of the program scope beyond the reactor coolant system to include any carbon or low alloy steel structural or system components, including electrical and instrumentation, subject to borated water leaks. (The program previously only formally accounted for the equipment subject to the requirements of Generic Letter 88-05.) Additionally changes were made to ensure that all potential boric acid leaks are entered into the corrective action process and receive an event investigation to determine the scope of equipment affected. If warranted, the procedure provides for technical evaluations for affected components in accordance with the guidance provided in the Boric Acid Corrosion Guidebook and GL 88-05.

F-RAI B2.1.6 -2

As a result of the insights gained from the recent discovery of boric acid-induced corrosion of the Davis-Besse vessel, the staff requests that the applicant address the changes that were made to its boric acid corrosion prevention program in response to the Davis-Besse event.

Response

Information provided to licensees in NRC Bulletins 2002-01, Reactor Pressure Vessel Head Degradation and RCS Pressure Boundary Integrity, and 2002-02, Reactor Pressure Vessel Head Penetration Nozzle Inspection Programs were direct contributors to new procedure IP-IIT-7, Boric Acid Corrosion Monitoring Program.

Specific changes to the Boric Acid Corrosion Monitoring Program resulting from the David-Besse operating experience include the identification of RCS locations containing Alloy 600 and Inconel 82/182 weld materials (materials that are susceptible to cracking in a primary water environment and may become sources of borated water leaks.) Moreover, the control rod penetrations are specifically called out for inspection. Additionally, during leak evaluations any identified boric acid residue will be evaluated to ensure is does not contain rust-like coloring and, when a leak is identified in containment or in an area with enclosed ventilation units, the ventilation units will be evaluated for evidence of boron precipitation.

F-RAI B2.1.9 -1

Section B2.1.9 of the LRA does not conclude if this AMP is/is not consistent with the GALL, but identifies some areas where the program differs from the GALL. Tables 3.3-1, 3.4-1 and 3.5-1 indicate the CCW Program is consistent with the GALL and requires no further evaluation.

Resolve the potential discrepancy regarding if the program is intended to be consistent with the GALL. If the applicant determines the program is not consistent with the GALL discuss how the CCW program meets the ten elements of an AMP.

If the program is intended to be consistent with the GALL, discuss the following:

a) System chemistry sampling will not permit detection of aging effects. Discuss operating experience or information regarding monitoring, testing and inspections performed on the system/components to ensure aging effects are identified prior to a loss of function.

b) Maintaining and monitoring system chemistry alone does not ensure that heat transfer capabilities are maintained. Loss of Heat Transfer is identified as an AERM that will be monitored by the Closed Cycle Cooling Water System. Discuss operating experience and/or testing and monitoring attributes of the program that prevent loss of heat transfer.

c) The applicant samples for pH, chromates, and radioactivity and indicates sampling for corrosion products, calcium, potassium and refrigerant chemicals is not performed based on plant operating experience. Discuss the operating experience and past samples taken (if any) that support not testing for corrosion products, calcium, potassium, and refrigerant chemicals.

d) EPRI TR 107396 (Closed Cooling Water Chemistry Guideline) recommends that conductivity, chlorides, and sulfates should be monitored in a chromated water system. EPRI TR 107396
indicates that chlorides and sulfates may reduced the efficacy of chromate inhibitors. Further, chlorides and sulfates may negatively impact the corrosion resistance of some alloys in the CCW system. Discuss the program bases for not monitoring these (chlorides and sulfates) parameters as outlined in TR107396 for chromated systems.

e) It may be difficult to establish and maintain chemistry controls in stagnant and low flow sections of systems. Describe how the CCW Program addresses aging effects in these areas.

f) The applicant indicates that due to condensation, external corrosion affected the surface of some CCW piping. Ultrasonic test (UT) readings were taken and no significant wall thinning was noted. Discuss how much of the system was affected, the extent of the UT inspections, how long the affected piping had been in service and how any indicated wall thinning was attributed to internal or external corrosion.

g) The applicant indicates that non destructive examinations (NDE) are used at locations were material loss may occur. Discuss how the CCW Program identifies areas for NDE inspection, the frequency of inspection, acceptance criteria and how the data are trended to ensure detection of aging effects.

Response

The Closed-Cycle (Component) Cooling Water System Surveillance Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801 (Generic Aging Lessons Learned (GALL) Report), Section XI.21, Closed-Cycle Cooling Water System. Exceptions were evaluated and determined to be minor in terms of assuring proper functionality of system components (see LRA section B2.1.9).

(a) & (b) The Closed-Cycle (Component) Cooling Water System Surveillance Program employs various methods to ensure that components in the component cooling system will continue to perform their intended function. Periodic maintenance activities performed under the Periodic Surveillance and Preventive Maintenance (PSPM) Program provide opportunities for visual inspections of the internal (wetted) and external surfaces of components such as motor-operated valves, check valves, relief valves and pumps in the system. Thermal performance testing of selected heat exchangers is used to verify that these components are capable of performing the heat removal intended function. Monitoring of the component cooling water chemistry and maintaining parameters within the specified limits ensures that the system is maintained free of corrosion and biofouling.

In addition to the activities described above, routine surveillances of system operating parameters are performed by operators during normal rounds. These include monitoring flows through heat exchangers, monitoring system pressures at various locations, monitoring pump suction and discharge pressures, monitoring CCW temperature and fluid temperatures in systems served by CCW. The summation of these activities ensures early detection of CCW system problems that require corrective actions.

Plant-specific operating experience indicates that the CCW system performance has been very satisfactory. No evidence of corrosion product build-up or corrosion-induced degradation in CCW piping or components has ever been identified at Ginna Station. Destructive metallurgical examination of a leaking pipe-to-elbow weld performed in 1991 revealed no evidence of corrosion or degradation of the internal surfaces of the pipe and elbow exposed to the CCW environment. The leak was determined to be the result of a large slag inclusion in the weld which was an original fabrication defect. Further confirmation of the effectiveness of CCW chemistry control was obtained during remote visual inspection of the internal surfaces of the carbon steel heat exchanger shell, tubesheet, and tube supports, as well as piping connections during retubing of both CCW heat exchangers in 1999. All surfaces were clean and in excellent condition.

(c) The makeup water to CCW at Ginna Station is supplied from the Reactor Makeup Water Storage Tank, and, as such, is demineralized. Therefore calcium and other mineral deposits are not an issue in the Ginna CCW system. Chromate is added to CCW water as potassium dichromate (K2CrO4). Therefore, analysis of potassium is not necessary. There are no components containing refrigerant chemicals that are serviced by CCW water at Ginna Station. Therefore monitoring for refrigerant chemicals is not necessary.

(d) The makeup water to CCW at Ginna Station is demineralized water. In addition, Ginna Station is located on the shore of Lake Ontario, which is a fresh water lake. As a result, there is no significant source of chloride and sulfate contaminants to enter the water. Furthermore, plant-specific operating experience confirms the effectiveness of the chromate inhibitor in suppressing corrosion of system piping and components fabricated from carbon steel.

(e) Relief valves connected to CCW piping are periodically inspected under the PSPM Program. These valves are exposed to stagnant CCW water. No evidence of degradation has ever been reported on these valves.

(f) Ultrasonic thickness readings were taken on 3", 2" and 1" diameter pipe at locations where minor rusting was observed on the exterior surface of the pipe. Each location was scanned around the circumference of the pipe over several inches of pipe length to determine minimum and maximum wall thickness. All thickness readings were acceptable. Insulation was subsequently installed on approximately 2000 feet of pipe. The piping which was insulated had been in service since original plant construction.

(g) Locations where material loss might be expected include dead legs at relief valve connections. A significant number of relief valves are periodically disassembled and inspected under the PSPM Program. No evidence of degradation has ever been found.

F-RAI B2.1.10 -1

a) Section 2.3.3.18 of the LRA states that the plant air system is not safety-related and does not perform a safety-related function and, as such, the plant air systems are not within the scope of LR. It further states that portions of plant air act as containment isolation devices and those portions are evaluated in the containment isolation system. Clarify and provide the basis of the LR intended functions of the plant air system for containment isolation devices. Also, identify the aging mechanisms and the AMPs required for this system or justify why an AMP is not required.

b) Provide the UFSAR Supplements related to this program, as applicable.

Response

LRA section 2.3.2.5, Containment Isolation Components identifies those portions of Plant Air that act as containment isolation boundaries. This section also identifies "Provide Primary Containment Boundary" as the applicable system level function.

As indicated in the section, the Plant Air System containment isolation components are shown as being encompassed by safety class 2 flags on drawings 33013-1882-LR, 33013- 1884,1-LR, 33013-1884,2-LR, 33013-1889,2-LR and 33013-1893-LR. The aging mechanisms of specific components types within the system can be identified by following the links provided in Table

2.3.2-5 and the inclusion of plant specific components can be confirmed using the review tools previously provided to the staff.

As the staff is aware, aging management programs are generally assigned based on the aging effects associated with material/environment combinations not system designations. The plant air component types that act to provide the pressure boundary for the primary containment are pipes and valve bodies. Additionally, there are fasteners (bolting) associated with these components.

The pipes and valves are comprised of two material type/ internal environment combinations: Carbon/low alloy steels in air and gas (wetted) <140 which could exhibit loss of material, and Copper Alloys (Zn<15%) in dry Air and Gas which is not expected to have any aging effects requiring management. The loss of material internal aging effect for the carbon steel components is managed by the One-Time Inspection Program and the Periodic Surveillance and Preventive Maintenance program.

The external surfaces of the pipes, valve bodies, and fasteners are managed by the Systems Monitoring Program with the carbon steel components also subject to the requirements of the Boric Acid Corrosion program where those components are susceptible to loss of material due to borated water leaks.

Additionally, all mechanical containment penetrations are subject to the ASME Section XI, IWE&IWL Inservice inspection program.

All UFSAR supplements related to the above programs are contained in Appendix A of the LRA.

F-RAI B2.1.16 -1

In Section B2.1.16 of the LRA the applicant does not specify if its Fuel Oil Chemistry Program is consistent with the program in GALL. The staff does not know, therefore, to what extent the program described in the Section B2.1.16 of the LRA deviates from the program specified the GALL. The applicant is requested to specify whether the program described in Section B2.1.16 of the LRA is consistent with the XI.M30 program in GALL. The applicant should also evaluate any deviations which may exist between the applicant's and the GALL programs, including not testing for biological activity, not adding biocide to the fuel oil, and not conducting particulate sampling in accordance with the modified ASTM D2276 standard.

Response

The Fuel Oil Chemistry Program is an existing program that is consistent with, but includes exceptions to, NUREG 1801 (Generic Aging Lessons Learned (GALL) report), Section XI.M30, "Fuel Oil Chemistry". The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with ASTM Standards D975, 1796, 4057, and 4176, and (b) periodic draining cleaning and visual inspection of internal surfaces of storage tanks as directed by the Periodic Surveillance and Preventive Maintenance Program (PSPM). Supplemental wall thickness measurements (i.e., by UT) will be performed periodically during internal inspections of underground storage tanks (starting in 2003) at locations where contaminants might accumulate, such as tank bottoms, and on a grid pattern to verify that wall loss due to external corrosion is not occurring.

Exceptions to NUREG-1801, Section XI.M30, "Fuel Oil Chemistry" are as follows:

(1) Corrosion inhibitors, oil stabilizers, or biocides are not added to fuel oil at Ginna Station. A review of plant-specific operating experience indicates that no evidence of oil degradation or MIC has ever been observed, and addition of inhibitors, stabilizers or biocides has not been necessary to date. The "A" and "B" storage tanks are scheduled to be drained, cleaned and inspected by ultrasonic (UT) testing during the Fall, 2003 refueling outage. The results of these inspections will be evaluated to determine the effectiveness of the current Program.

(2) NUREG-1801 refers to several ASTM Standards: D 4057 for guidance on oil sampling, D 1796 and D 2709 for determination of water and sediment contaminants in diesel fuel, and modified D 2276 Method A for determination of particulates. The methodology in D 4057 is used at Ginna Station for guidance on oil sampling. Determination of water and sediment contaminants is performed in accordance with D 1796, as required by D 975. The method described in D 2276 is not used by Ginna Station. D 2276 was developed for aviation fuels and not middle distillate fuels used in diesel engines for emergency generators. NUREG-1801 identifies two standards for analyzing water and sediment content, D 1796 and D 2709. The method described in D 1796 is used exclusively at Ginna Station; both methods provide results as % of total contaminants. D 1796 requires that a solvent be added to the sample, whereas D 2709 does not. Plant-specific operating experience indicates that testing diesel fuel oil in accordance with ASTM Standards D975, 1796, 4057, and 4176 has been effective in managing the effects of aging due to contaminants in the diesel fuel oil system.

(3) Plant-specific operating experience to date has indicated that there is no evidence of biological activity in the fuel oil system. Therefore no testing for microbes in fuel oil is presently performed at Ginna Station. However, should evidence of MIC be discovered during future inspections, appropriate testing will be commenced.

F-RAI B2.1.22 -1

The LRA indicates that the service water system is consistent with the GALL with two minor differences: 1) heat transfer tests are not performed on selected small heat exchangers which are periodically cleaned and inspected in accordance with the Periodic Surveillance and Preventive Maintenance Program, 2) the Service Water System Reliability and Optimization Program (SWSROP) does not address protective coatings which are not credited for aging management in the Ginna service water system.

With regards to the first difference; discuss the following:

a) How and what criteria are used to scope heat exchangers into the service water system or the Periodic Surveillance and Preventive Maintenance Program?

b) What parameters are monitored/ inspected during the preventive maintenance action, what method is used to detect aging?

c) How is heat exchanger maintenance periodicity established?

d) What and how are results trended with respect to applicable aging mechanisms?

e) What acceptance criteria are incorporated into the preventive maintenance action?

Also, the LRA indicates in the conclusion section of the Periodic Surveillance and Preventive Maintenance Program that the program must be enhanced to address aging mechanisms and

monitoring. Discuss if and how this is applicable to the small heat exchangers within the Service Water System Program and when actions will be complete. Describe the enhancements to the program; i.e. change in scope, procedures and/or methods applied to small heat exchangers.

Response

a) All Safety Related heat exchangers cooled by Service Water are included within the scope of the SWSROP program. RG&E, in its' January 29, 1990 response to NRC Generic Letter 89-13, made a commitment for the scheduling and routine inspections of safety-related heat exchangers, along with the initiation of a Reliability Centered Maintenance Program (RCM). This was considered an acceptable level of inspection and maintenance per the NRC, to meet the recommendations of Generic Letter 89-13.

b) Based on the specific component, the parameters monitored/inspected during the preventive maintenance action, are not limited to but may include: pressure, flow, and temperature. These tests are effective in detecting performance degradation that may be indicative of aging effects, as stated in the LRA section B2.1.23. The methods used to detect aging is not limited to but may include visual inspection and cleaning, eddy current testing, thermal performance testing, bench marking, and differential pressure testing,

c) The periodicity for heat exchanger maintenance is established based on specific Ginna operating plant experience. The frequency of testing is adjusted based on the conditions found.

d) The results of the Thermal Performance Testing, are analyzed to evaluate the specific heat exchanger function. Heat transfer tests are not as accurate when performed on air cooled heat exchangers, and therefore thermal performance testing is not routinely performed. An alternative method to determine the condition of a heat exchanger is through regular scheduled inspections and cleaning. Eddy current tests are also used to determine the condition of heat exchanger tubing. Eddy current examination assesses any corrosion degradation or mechanical damage that may have occurred since the previous inspection with particular attention to fretting at tube support plates/structures, outside diameter pitting and/or stress corrosion cracking, and inside diameter pitting and erosion.

e) The data obtained in the thermal performance testing procedure, PT-60 series, is analyzed by Engineering through a formal design analysis. The design analysis number is recorded within the PT procedure. The analysis determines the extent of fouling, with uncertainty, at the time of the test, along with the maximum fouling compared to the acceptance criteria and verifies that actual fouling is less than or equal to the design fouling. If the fouling exceeds the acceptance criteria, further action is taken to justify the ability of the heat exchanger to perform it's safety-related function. The service water flow is also computed by the use of a heat balance calculation.

There is also a heat exchanger tube plugging criteria summary table which is used for eddy current testing, within Ginna Station SF EWR 10111 document. This table indicates the maximum recommended wall thinning/defect as a percentage of nominal wall, along with the maximum recommended number of tubes which can be plugged, and the effect on power generation if the maximum number of tubes are plugged.

F-RAI B2.1.22 -2

The LRA indicates that the service water system is consistent with the GALL with two minor differences: 1) heat transfer tests are not performed on selected small heat exchangers which are periodically cleaned and inspected in accordance with the Periodic Surveillance and Preventive Maintenance Program, 2) the SWSROP does not address protective coatings which are not credited for aging management in the Ginna service water system.

With regards to the second difference, the program attributes of GL-89-13 and GALL identify inspection, monitoring and corrective action for failed internal coatings that could adversely impact heat transfer capability or lead to corrosion in service water systems. Not crediting the protective coatings does not eliminate the possibility that coating failure could have an adverse impact on heat transfer capabilities or corrosion.

Discuss how the Ginna SWSROP ensures internal coating (if any coatings are used) failure will not adversely impact heat transfer capability or corrosion of system components and provide operating experience supporting the applicants position.

Response

The interior surfaces of the service water pump bowls are coated with Plasguard 7122 HAR, which is an abrasion resistant coating. There are no other coatings on the internal surfaces of service water system piping and components at Ginna Station. The pump bowls were first coated in 1999. The service water pumps are pulled and inspected on a four-year frequency under the Periodic Surveillance and Preventive Maintenance Program. The first bowl inspection will be performed in Fall, 2003. Other routine inspections specified by the Service Water System Reliability Optimization program (SWSROP) include periodic opening, cleaning and inspection of heat exchangers for evidence of wall loss, fouling and blockage due to silting or coating failure. Heat transfer, flow and differential pressure tests are also monitored and trended at various locations in the system to detect blockage due to biofouling, coating failure, or silt accumulation. Should coating failure be detected, timely corrective actions are carried out in accordance with Ginna Station Corrective Action Program. The summation of these activities ensures that coating failure will not adversely affect heat transfer capability or degrade system components.

Review of recent plant-specific operating experience has shown no evidence of pump bowl coating failures.

F-RAI B2.1.23 -1

Section B2.1.23 of the LRA states that cracking and material thinning will be detected by performing visual inspections and surface examinations. Since cracking and thinning on the interior surfaces (for example, interior surfaces of pipe walls), cannot be detected by such methods, indicate the methods which will be employed to detect such defects.

Response

The Periodic Surveillance and Preventive Maintenance Program manages aging effects for SSCs within the scope of license renewal. Aging effects such as loss of material due to various corrosion mechanisms and wear are detected by visual examinations of surfaces for evidence of general or localized material thinning, presence of corrosion products, deposit accumulation,

etc. Supplemental inspections using other NDE techniques such as surface (e.g., dye penetrant or magnetic particle) and volumetric (e.g., ultrasonic or radiographic) examinations are performed as necessary based on engineering evaluation. Change in material properties of polymeric seals and gaskets is detected by visual examination for evidence of cracking and crazing, evaluation of resilience and indentation recovery, evidence of swelling, tackiness, etc. Degradation of heat exchanger tubing is detected by eddy current testing, which provides the capability of detecting both ID and OD initiated tube-wall degradation such as thinning due to general, pitting and under-deposit (crevice) corrosion, MIC, fretting wear, fouling and cracking.

A review of plant-specific operating experience indicates that the Periodic Surveillance and Preventive Maintenance Program has been effective in maintaining the material condition and intended function(s) of long-lived passive SSCs at Ginna Station.

F-RAI B2.1.23 -2

Section B2.1.23 of the LRA states that inspection for leakage may be utilized for managing aging effects in selected piping and components. It is the staffs position that actual leakage is indicative of piping or component failure; therefore, the AMP should be aimed at detecting and preventing loss of material so that corrective actions can be taken prior to the occurrence of leakage. Identify the specific circumstances where leakage inspection is proposed to be utilized for aging management.

Response

RG&E acknowledges that actual leakage is indicative of some type of degradation. However In-Service Inspection (ISI) regulations require that leak inspections be performed. The PSPM program implements surveillance activities including ASME Section XI required leakage examinations for borated water systems and other leakage examinations inside and outside of Containment. Thus the program must contain reference to leakage inspections even though those inspections may not be directly credited with managing the effects of aging of the SSC being inspected. Moreover, the leak inspections initiated by the PSPM program are an important element of the Boric Acid Corrosion program. The identification of leaks and the evaluation of the consequences of those leaks are the condition where leakage monitoring is an important technique utilized for component aging management. It is important to note that PSPM initiated leakage inspections are just one of several methods used for detecting and monitoring the affects of aging. Other techniques include visual examinations, supplemental surface and volumetric examinations deemed necessary by engineering evaluation, volumetric (eddy current) examinations of heat exchanger tubing, and other periodic volumetric examinations including radiography and ultrasonic testing to verify wall thickness as required by the Open Cycle Cooling Water System program.

F-RAI B2.1.25 -1

Section B2.1.25 of the LRA indicates that the reactor head closure studs are fabricated from ASME SA-320 Grade L43 (AISI 4340) low-alloys steel and are not susceptible to SCC (specified minimum yield strength of 105 ksi).

a) Provide plant experience regarding the number and results of the inspections of the reactor head closure studs and the basis for concluding that the reactor head closure studs are not susceptible to SCC.

b) Bolting is susceptible to SCC when heat treated to a maximum tensile strength limited greater than 1,172 MPa (170 ksi). What controls are in place at Ginna to ensure that no reactor head closure studs were heat treated to a tensile strength greater than 170 ksi?

Response

(a) The reactor head closure studs have been periodically inspected under the ASME Section XI ISI Program. All 48 studs have been inspected during each Ten-Year ISI Interval. The examination schedule during the most recent Third Ten-Year Interval (ending December 31, 1999) required one-third of the studs (16) to be inspected during each inspection period. Both surface (magnetic particle) and volumetric (ultrasonic) inspections were performed on each stud. No evidence of degradation has ever been reported on any of the studs. Review of plant-specific operating experience has revealed no incidents of boric acid leakage onto the studs.

The studs are fabricated from SA-320 Grade L43 (AISI 4340) material with a specified minimum yield strength of 105 Ksi. EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants" indicates that for bolting materials with specified minimum yield strength less than 150 ksi, susceptibility to SCC should not be considered a problem provided lubricants containing molybdenum disulfide are not used. Use of such lubricants is specifically prohibited under the Ginna Station Quality Assurance Program. Therefore the reactor closure head studs should not be considered susceptible to SCC.

(b) Original material test reports for the reactor head closure studs are not available. Since the studs are periodically examined using both surface and volumetric examination techniques, any evidence of cracking due to SCC would be detected and appropriate corrective action taken under the Ginna Station Corrective Action Program.

F-RAI B2.1.26 -1

The Reactor Vessel Head Penetration Inspection Program consists of (1) performing primary water stress corrosion cracking (PWSCC) susceptibility assessment to identify susceptible components, (2) monitoring and control of reactor coolant water chemistry to mitigate PWSCC and (3) performing ASME Code, Section XI Inservice inspection of reactor vessel head penetrations and bottom-mounted instrument tube penetrations. The applicant plans to replace the reactor vessel head and control rod drive mechanism (CRDM) penetrations during the fall 2003 refueling outage.

a) Confirm and discuss whether this program is consistent with the guidelines provided in AMP XI.M11,"Nickel Alloy Nozzles and Penetrations" of NUREG-1801. Discuss all the deviations from AMP XI.M11 and provide justification for each.

b) Describe in detail the parameters and criteria used in the susceptibility assessment for PWSCC to identify susceptible components. Based on your susceptibility assessment, what components are determined to be not susceptible to PWSCC.

c) The LRA states that the reactor vessel head is planned to be replaced in the fall of 2003 using Alloy 690TT material. Describe in detail the Alloy 690TT material, including its chemical composition, heat-treatment, process of fabrication and its susceptibility to PWSCC. Also discuss the differences between Alloy 690TT and Alloy 690.

d) PWSCC is a time-dependent material degradation process and its initiation and growth depends on a number of factors such as: susceptibility of materials, stress conditions, environmental condition, and operational temperature. Even if there is no PWSCC found in the susceptible components in the first 40 years of operation, there is no assurance that PWSCC will not occur in the next 20 years unless it is adequately mitigated and periodically verified. Provide the bases for not performing augmented inspection such as volumetric and eddy current examinations of the bottom-mounted instrumentation penetrations to verify that PWSCC is not occurring in those components during the extended period of operation.

e) Discuss in detail the conclusion that the Ginna station ASME Section XI ISI Program has been effective in maintaining the intended function of the current reactor vessel upper and lower head penetrations. The current industry experience does not support the applicant's conclusion. Describe in detail the ASME Section XI ISI Program implemented in Ginna station for reactor vessel upper and lower head penetrations, particularly regarding the method and frequency of inspection and the capability of detecting the PWSCC when cracks in susceptible components are not yet through-wall.

Response

(a) The Reactor Vessel Head Penetration Inspection Program is consistent with the guidelines provided in NUREG-1801 (Generic Aging Lessons Learned (GALL) Report), Section XI.M11, "Nickel-Alloy Nozzles and Penetrations" (Ref. 9.1), and complies with NRC Order EA-03-009 "Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors" issued on February 11, 2003 which is the latest NRC guidance document and not referenced in NUREG 1801.

(b) Ginna Station has participated in previous industry initiatives related to development of primary water stress corrosion cracking (PWSCC) susceptibility models for Alloy 600 CRDM penetrations. A probabilistic model was developed by Westinghouse for WOG plants to assess the susceptibility to PWSCC of reactor vessel head penetrations. This model was applicable to inner-diameter initiated PWSCC of reactor vessel closure head penetrations at Ginna Station, consisting of control rod drive mechanism (CRDM) nozzles. The model was used to support the Ginna Station response to GL 97-01 and the related RAI. Rankings generated by the model were used to determine the category for each plant in the industry histogram. Ginna Station fell into the <15 EFPY category, representing moderate susceptibility.

The NRC Order of February 11, 2003 modifies the operating licenses of pressurized water reactor nuclear power plants to include periodic RPV top head inspections based on the calculated susceptibility category of each RPV head to PWSCC-related degradation. The susceptibility categories are based on calculation of Effective Degradation Years (EDY) which is a function of the head temperature(s) at 100% power and the operating time at each specific head temperature. The susceptibility ranking for the present reactor pressure vessel (RPV) closure head has been calculated according to the requirements of the NRC Order. The total effective degradation years (EDY) for the present RPV closure head containing Alloy 600 penetrations and Alloy 82/182 weld metal is 16.182, which is in Category "High".

Susceptibility models for other Alloy 600 and 82/182 pressure boundary components in the RCS have not been developed to date. As these models become available, appropriate susceptibility assessments will be made.

As a result of recent industry experience, Ginna Station decided in 2001 to pursue preemptive replacement of the present reactor vessel closure head with a new head, incorporating enhancements in both materials and design (see Paragraph (c) below). The new head is scheduled to be installed on the reactor vessel during the Fall 2003 refueling outage.

(c) The replacement head for the Ginna Station reactor vessel is fabricated to the requirements of ASME Section III Code Class 1 (1995 Edition, 1996 Addenda) and incorporates Alloy 690TT (UNS N06690 thermally treated) penetrations and Alloy 52 (UNS 06052) weld buttering and J-groove welds. The Alloy 690TT CRDM guide tubes, instrumentation columns, and vent pipes comply with the requirements of ASME Section II (1995 Edition, 1996 Addenda), Part B, SB-167 "Specification for Nickel-Chromium-Iron Alloys, Seamless Pipe and Tube", UNS N06690. The manufacturing process for the CRDM guide tubes and instrumentation columns produced electroslag remelted, seamless hot extruded (and/or annealed) thermally-treated tubing. The thermal treatment process produces a microstructure with enhanced resistance to PWSCC. Additional metallurgical information regarding chemical, mechanical, heat treatment, microstructural and processing requirements is retained as lifetime records in accordance with the Ginna Station Quality Assurance program.

The replacement head will be insulated with mirror insulation, allowing full access to the exterior surface and the interface of each penetration with the head for bare metal visual inspections. The use of Alloy 690TT material, as well as incorporation of other design enhancements are expected to substantially improve the resistance of the nickel-alloy penetrations and weld metal to PWSCC.

(d) As previously discussed in NRC Bulletins 2002-01 and 2002-02, susceptibility to primary water stress corrosion cracking is related to "operating conditions (in particular operating temperature and time)" and the presence of "high residual stresses resulting from initial manufacture and the impact of tube straightening that may have been needed after welding". As documented in the Ginna response to an RAI related to NRC Bulletin 2002-01 (see Reference 1), the RPV bottom head penetrations in the Ginna reactor vessel are expected to be much less susceptible to PWSCC than the CRDM penetrations in the top (closure) head for the following reasons:

(1)The operating temperature is much lower (Tcold at Ginna Station is 533 degrees F).
(2)The penetrations are much smaller, requiring less weld material and therefore resulting is lower residual stresses.
(3)The verticality requirements for the lower head penetrations are less stringent than those for the CRDM penetrations. Therefore it is not expected that straightening operations would have been necessary for these penetrations.
(4)The bottom reactor vessel head was stress-relieved after these penetrations were installed and welded in place, thereby further lowering residual stress levels.

At present, no industry-accepted PWSCC susceptibility models for bottom head penetrations have been developed. However, Ginna Station is committed to participate in industry initiatives and closely follow relevant industry operating experience related to bottom head penetration degradation. As new models become available, appropriate susceptibility assessments will be made.

(e) The combination of ISI examinations (including VT-2 examinations) performed under the ASME Section XI, Subsections IWB, IWC & IWD Program, augmented volumetric inspections of all CRDM nozzles performed in 1999, and enhanced visual examinations of all CRDM

penetrations from above the head in 2002 have verified the absence of aging effects and leakage from CRDM penetrations to date. Detailed information on the effectiveness of programmatic activities at Ginna Station related to vessel head penetrations have been provided in the 15-day, 30-day and 60-day responses to Bulletin 2002-01, as well as in the response to the RAI on the 60-day response.

F-RAI B2.1.27 -1

Section B2.1.27 of the LRA identifies the following reactor vessel internals (RVI) components to be most susceptible to crack initiation and growth due to IASCC and loss of fracture toughness due to neutron irradiation embrittlement and/or void swelling:

- Lower core plate and fuel alignment pins;
- Lower support columns;
- Core barrel and core barrel flange in active core region;
- Thermal shield and neutron panels;
- Bolting - lower support column, baffle-former, and barrel former

Provide the criteria for choosing these locations.

Response

The reactor vessel internals components identified in Section B2.1.27 of the LRA as most susceptible IASCC and neutron irradiation embrittlement and/or void swelling were selected based on being exposed to the highest in-core neutron radiation fields.

F-RAI B2.1.27 -2

The applicant has described the 10 elements of the Reactor Vessel Internals Program but has not identified whether all 10 elements of the program are in accordance with GALL Program XI.M16 and whether the applicant's program contains any exceptions or enhancements to the 10 elements in GALL Program XI.M16. The applicant is requested to identify whether all 10 elements of the program are in accordance with GALL Program XI.M16 and whether the applicant's program contains any exceptions or enhancements to the 10 elements in GALL program XI.M16.

Response

The Reactor Vessel Internals Program is a new program that is consistent with, but includes one exception to, NUREG-1801 (Generic Aging Lessons Learned (GALL) Report), Section XI.M16, "PWR Vessel Internals". The only exception is that NUREG-1801, Section XI.M16 specifies examination schedules in accordance with IWB-2400, which requires core support structures to be inspected once during each 10-year interval. While this applies to the VT-3 examinations, some augmented examinations may be performed only once, unless degradation is detected.

F-RAI B2.1.29 -1

As stated in the LRA Section B2.1.29, the applicant has removed the hardness testing from its inspection program. The Selective Leaching Program in GALL identifies hardness measurements in addition to visual inspections as a method for determining whether there is a

degradation of material on select components due to selective leaching. Hardness test measurements are helpful in evaluating degradation of material in a component due to leaching, where visual inspection may be ineffective. The LRA states that an assessment of the feasibility of performing hardness tests and the value of hardness data is made on a component specific basis. Therefore, the staff requests the applicant to justify the deviation from hardness testing and to describe how the applicant will determine if selective leaching is occurring without hardness measurements, particularly on the components where visual inspection cannot be effective. Additionally, the staff requests the applicant to provide more detailed information concerning the assessment of determining the need for a hardness evaluation, list the components that will be assessed, and how the hardness testing will be performed.

Response

Hardness testing on components susceptible to selective leaching may be appropriate if the component configuration and geometry allows. Tubing and other components with complex internal geometry do not provide adequate physical access to internal surfaces requiring examination to allow accurate measurements to be made. Hardness measurements on suitably configured surfaces would typically be made using an Equotip hardness tester.

Gray cast irons are susceptible to selective leaching (graphitic corrosion) in natural waters and soils of high conductivity. Graphitic corrosion occurs at a low rate and manifests itself as either "uniform" or "plug" type. Uniform graphitic corrosion occurs over the entire surface, whereas "plug" type is more localized. In both cases, the mechanism involves oxidation of the ferrite (alpha iron) to form iron oxide, creating a soft, spongy porous mass consisting of graphite flakes and corrosion products of iron (References 1 and 2). This porous mass is a dark, brown/black color which is readily distinguishable visually from the surrounding sound gray iron material after the surface is appropriately cleaned and prepared by removing surface deposits and debris. In addition, probing the surface of the cast iron with a sharp object readily identifies soft, spongy areas which have undergone graphitic corrosion. Years of experience examining buried gray cast iron gas pipe at RG&E has confirmed that detection of graphitic corrosion may be effectively performed by these means. Supplemental tests such as hardness tests or eddy current testing using appropriate probes may also be performed to confirm the presence of graphitic corrosion if the surfaces to be examined are suitably configured. A review of plant-specific operating experience has revealed no occurrences of graphitic corrosion of gray cast iron at Ginna Station.

Selective leaching (dezincification) in high-zinc brasses (Zn > 15%) may also occur, predominantly after prolonged contact with highly oxygenated natural waters containing CO_2 under stagnant or low flow conditions (Reference 1). The selective leaching mechanism in brasses and bronzes also manifests itself as either "uniform" or "plug" type, producing a relatively porous and soft layer of copper and copper oxide. The only components within the scope of license renewal identified by the aging management review process as susceptible to dezincification are admiralty brass tubes in certain heat exchangers. These heat exchanger tubes are examined by eddy current testing, which effectively detects degradation due to selective leaching, and therefore other confirmatory tests such as hardness tests are not required. A review of plant-specific operating experience has also revealed that the only evidence of dezincification at Ginna Station occurred in admiralty brass tubing in heat exchangers exposed to stagnant or low-flow raw (service) water.

Selective leaching in high-aluminum bronzes (Al > 8%) has also been reported in acidic aqueous environments containing elevated chloride content (Reference 1). These environments do not exist for SSCs in scope to license renewal at Ginna Station.

References:

1. ASM Metals Handbook, Volume 13, "Corrosion", Ninth Edition
2. M. G. Fontana and N. D. Greene, "Corrosion Engineering", McGraw Hill, 1967

F-RAI B2.1.31 -1

The LRA states that the Steam Generator Tube Integrity (SGTI) AMP is credited for maintaining the integrity of the steam generator tubes and is consistent with XI.M19, "Steam Generator Tube Integrity," in the GALL report. However, Tables 3.2-1 and 3.2-2 identifies additional components for which the SGTI AMP (B2.1.31) is credited. In addition, the GALL report states that the scope of XI.M19 is specific to steam generator tubes. Therefore, the staff requests responses to the following questions:

a) Table 3.2-1, line number (2), "Steam Generator Shell Assembly", states that the aging effect for this component (i.e., loss of material due to pitting and crevice corrosion) is managed, in part, by the Steam Generator Tube Integrity Program (B2.1.31). It is not clear to the staff how the SGTI AMP manages this component and aging effect. The GALL report and the applicant's SGTI AMP state that the scope of XI.M19 is specific to steam generator tubes; therefore, provide details for the following attributes for this component: preventive actions; parameters monitored/inspected; detection of aging effects; monitoring and trending; and acceptance criteria. Ensure that your discussion identifies how the steam generator program manages this aging effect (e.g., the part of this component that is managed by the steam generator tube integrity program and how it is managed by the Steam Generator Tube Integrity Program).

b) Table 3.2-1, line number (15), "(Alloy 600) Steam generator tubes, repair sleeves, and plugs," states that the aging effects for these components are managed, in part, by the SGTI AMP (B2.1.31). The GALL report and the applicant's SGTI AMP state that the scope of XI.M19 is specific to steam generator tubes; therefore, provide details for the following attributes for the repair sleeves and plugs: preventive actions; parameters monitored/inspected; detection of aging effects; monitoring and trending; and acceptance criteria.

c) Table 3.2-2, line number (25), "SG Lattice Grid Tube Supports, U-Bend Fan Bar Restraints" and Table 3.2-1, line number (17), "Carbon Steel Tube Support Plate," state that the aging effect for these components is managed by the SGTI AMP (B2.1.31). The GALL report and the applicant's SGTI AMP state that the scope of XI.M19 is specific to steam generator tubes; therefore, provide details for the following attributes for this component: preventive actions; parameters monitored/inspected; detection of aging effects; monitoring and trending; and acceptance criteria.

Response

(a) The LRA incorrectly identified AMP B2.1.31 as "Steam Generator Tube Integrity Program". The Program should have been identified as "Steam Generator Integrity Program", which includes tubes, plugs and repair sleeves and secondary-side components within its scope.

(1) Preventive Actions

The program includes measures to mitigate degradation related to corrosion of primary-side components such as tubes, repair plugs and sleeves by controlling primary water chemistry. Mitigative measures for secondary side components such as the tube support structure (including lattice grid tube supports and U-bend fan bar restraints), wrapper, accessible areas of the shell, and upper internals are provided by controlling secondary water chemistry as described in the Water Chemistry Control Program. The guidelines in NEI 97-06 include foreign material exclusion and means to inhibit degradation due to fretting and wear.

(2) Parameters Monitored, Inspected, and/or Tested

The steam generator tube volumetric inspection technique (eddy current testing) detects ID and OD flaws caused by wall thinning, cracking and mechanical damage or deformation. Aging effects specific to tubes which are tested and monitored include loss of material due to wastage, pitting corrosion and wear, cracking due to PWSCC, IGA/IGSCC and high cycle fatigue, mechanical damage due to impingement of foreign objects on either the primary or secondary sides, and mechanical deformation (denting) due to corrosion or vibration at tube support structural members. Tube inspections are performed in accordance with the requirements of the EPRI PWR Steam Generator Examination Guidelines which are incorporated into Plant Technical Specifications. Inspection activities include visual examinations of repair plugs and sleeves for evidence of leakage.

Secondary side visual inspections are performed to identify aging effects such as loss of material due to general, pitting and crevice corrosion, fouling, and presence of foreign objects which could degrade secondary side components. Foreign Object Surveys and Retrieval (FOSAR) inspections, tubesheet visual inspections, and mid and upper bundle visual inspections are performed to assure that no degradation of the steam generator tube support structure (including lattice grid tube supports and U-bend fan bar restraints), wrapper, accessible areas of the shell, and upper internals is occurring which could lead to loss of intended function(s).

(3) Detection of Aging Effects

The primary method for detection of tube aging effects is by eddy current testing in accordance with Revision 5 of the EPRI Steam Generator Examination Guidelines. The extent and schedule of the inspections prescribed by the program are designed to ensure that flaws do not exceed established performance criteria. The extent and schedule of the inspections prescribed by the program are designed to ensure timely detection and replacement of leaking repair plugs and sleeves. Periodic visual inspections of the secondary side, including mid and upper bundle, tube support structure such as lattice grid tube supports and U-bend fan bar restraints, accessible areas of the shell, and upper internals, provide assurance for early detection of age-related degradation of secondary side structural components.

(4) Monitoring and Trending

Required inspection intervals based on Technical Specifications requirements and NEI 97-06 are expected to provide timely detection of stress corrosion cracking, loss of material, fouling, mechanical degradation or deformation, and fatigue cracking of tubes and leakage of tube plugs and repair sleeves. Monitoring of primary to secondary leakage will also identify degradation of

the SG tubing. Secondary side visual inspections provide for timely detection of any degradation of secondary side components, including tube support structure such as lattice grid tube supports and U-bend fan bar restraints, accessible areas of the shell, and upper internals. Condition-monitoring assessments are performed after each inspection to determine whether structural and accidental leakage criteria have been satisfied. Operational assessments are performed to verify that structural and leakage integrity are maintained during the operating interval until the next required inspection. Comparison of the results of the condition-monitoring assessment with the predictions of the previous operational assessment provides feedback for evaluation of the adequacy of the operational assessment and additional insights that can be incorporated into the next operation assessment.

(5) Acceptance Criteria

The acceptance criteria for the Ginna Station replacement steam generator (RSG) tubes, plugs and sleeves are in accordance with plant Technical Specifications and NEI 97-06. Loose parts or foreign objects that are found are removed from the RSGs unless it is shown by technical evaluation that these objects will not cause unacceptable tube damage. Any evidence of secondary side degradation such as general, crevice or pitting corrosion is dispositioned by engineering evaluation, including design reviews, assessment of potential degradation mechanisms, and industry operating experience reviews.

Tube inspections are followed by assessments of tube integrity relative to performance criteria. These performance criteria address three areas of tube integrity performance: structural integrity, operational leakage integrity, and accident induced leakage integrity. These performance criteria are expressed in terms of parameters that are directly measurable or that may be calculated on the basis of direct measurements.

When RSG tubes do not meet the acceptance criteria specified in plant Technical Specifications or NEI 97-06 they are removed from service by plugging the tube or repaired by sleeving. In addition, any tube plug leakage detected requires replacement of the leaking plug(s).

The acceptance criteria for allowable primary to secondary leakage are in accordance with plant Technical Specifications.

(b) See response in (a) above. It should be noted that the replacement Steam Generators have one plug installed in each channel head. These plugs were installed during manufacture; no other repair sleeves or plugs are installed in the generators at this time.

(c) See response in (a) above. As stated in the discussion column for Table 3.2-1, Line Number (17), there are no carbon steel tube support plates in the Ginna Station Replacement Steam Generators.

F-RAI B2.1.34 -1

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is to manage the loss of fracture toughness (embrittlement) in the CASS components in the reactor coolant system due to thermal aging. The LRA provides only a brief description of this program without a detailed discussion of the ten program elements/attributes as delineated in Appendix A of the SRP, and also does not state whether this program is consistent with AMP XI.M12 in NUREG-1801. However, the staff notes that in line number (20) of Table 3.2.1, the subject program is credited with managing loss of fracture toughness in CASS piping due to thermal

aging embrittlement. The credited management programs are described as consistent with NUREG-1801.

a) Discuss whether the subject AMP is consistent with the guidelines provided in AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)" of NUREG-1801. Also identify all deviations from the guidelines in AMP XI.M12 and provide justification for each deviation.

b) Confirm that this program covers the following CASS components: (1) valves bodies equal to or larger than 4 inches in size, (2) pump casings and main flanges and (3) RCS elbows.

c) Provide the service experience, previous inspection and leakage test results of CASS components at Ginna.

d) Provide the industry-wide service experience of CASS components.

Response

(a) The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is consistent with the guidelines in NUREG-1801, Section XI.M12. Flaw tolerance evaluations were performed for the reactor coolant system (RCS) piping which included the effects of thermal aging embrittlement of CASS elbows and CASS reactor coolant pump (RCP) casings in the RCS. These evaluations are contained in WCAP-15837, "Technical Justification for Eliminating Large Primary Loop Rupture as the Structural Design Basis for the R. E. Ginna Nuclear Power Plant for the License Renewal Program", April, 2002 and WCAP-15873, "A Demonstration of the Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of R. E. Ginna Nuclear Power Plant for the License Renewal Program", May, 2002. These documents will be submitted to the staff for review as a separate transmittal.

(b) The program covers CASS valves equal or larger than 4 inches in nominal pipe size, reactor coolant pump casings and flanges, and RCS elbows.

(c) CASS elbow-to-pipe welds in the RCS have been examined by ultrasonic testing (UT) and radiography (RT) under the ASME Section XI ISI Program. No recordable indications have ever been reported. Review of plant-specific operating experience has revealed no service-related degradation or leakage from CASS components at Ginna Station.

(d) Industry-wide service experience of CASS components is described in the following reference:

Letter from William H. Bateman, Chief, Chemical and Materials Engineering Branch, Division of Engineering, NRR to Michael E Mayfield, Chief, Materials Engineering Branch, Division of Engineering Technology, RES, "Integrity of < 4 inch NPS Valve Bodies Made from Cast Austenitic Stainless Steel", October 6, 1999.

This letter was enclosed with the following letter from C.I. Grimes:

Letter from Christopher I. Grimes, U.S. Nuclear Regulatory Commission, License Renewal and Standardization Branch, to Douglas J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Stainless Steel Components", May 19, 2000

F-RAI B2.1.36 -1

Section B2.1.36 of the LRA indicates that eddy current examinations are performed on a periodicity consistent with the severity of wear damage for each thimble tube. When wall loss in a tube exceeds 55%, but less than 65%, the tube is repositioned such that wear is redistributed, or other corrective action is taken.

Based on the results of a plant-specific analysis, examination results are compared to an upper allowable limit of 65% through-wall wear.

Eddy current examinations performed in 1988, 1989, 1990, 1991, and 1992 provided a basis for establishing the wear rates, and thus the inspection intervals, for thimble tubes. Based on those results, the inspection frequency and acceptance criteria are:

- Previous indication 10% to less than 45% - every third refueling outage (approximately once every 4.2 years)
- Previous indication 45% to less than 55% - every other refueling outage (approximately once every 3 years)
- Previous indication 55% or greater - perform corrective action, if support plate wear is the suspected cause. For other indications, corrective action will be taken at 65% or greater. Future inspection frequency will be every other or every third outage, as stated above.
- Previous inspection never exceeded 10% through-wall - no specified frequency. Future inspections will be based on a Ginna Station periodic assessment.

a) Identify the wear rate that was determined from the 1988 through 1992 inspections. Based on this wear rate, how were the inspection intervals determined to ensure that wear resulting from flow induced vibration does not result in the wall thickness below the minimum required for thimble tube integrity?

b) Provide the results (the amount of wear observed) from all inspection performed after 1992 and identify whether the amount of wear exceeded the amount identified in question a).

c) How will the applicant evaluate future inspection results to determine their impact on the inspection frequency of thimble tubes during the license renewal period?

Response

(a) In a letter dated April 8, 1993 (Reference 1) RG&E communicated to the NRC the results of eddy current inspections of thimble tubes performed at Ginna Station during refueling outages between 1988 and 1992. It was concluded that "none of the 36 thimble tubes have indicated a discernible increasing wear trend outside of the band of uncertainty (10%) assumed for the Eddy Current measurement technique" and that "the cumulative test results show that a conservatively predicted annual increase in wear is less than 5%. Therefore, for a tube whose inspection indicated less than 45%, there is adequate assurance that the 65% criterion would not be exceeded in four years." Similarly, for a tube with a previous indication between 45% and 55%, an inspection interval of 2 years would assure that the 65% criterion would not be exceeded.

(b) Annual wear rates determined from inspections performed on all thimble tubes in 1995,1997 and 1999 were within the predicted wear rate (5%) reported in 1993. Four tubes were replaced in 1999, three due to indications outside of the vessel and one (tube G-6) due to a wear indication which was sized at 59% through wall.

All thimble tubes were again inspected in 2000. Wear rates determined from the 2000 inspections were within the 5% rate for all tubes except for the four tubes which had been replaced in 1999. Three of these four tubes exhibited wear indications ranging from 16% to 22% through wall. One tube (G-6) exhibited a wear indication measuring 69% through wall. Corrective action was taken on tube G-6 by repositioning and isolating the tube at the seal table. The unusual wear on this tube was attributed to the absence of chromium plating on the tube in the lower core plate region prone to wear.

All thimble tubes were again inspected during the refueling outage in April 2002. Tube G-6 was again replaced during this outage with a new chromium-plated tube. All other tubes exhibited wear rates within the predicted 5% rate except for one tube, B-6, which exhibited an increase in wall loss from 22% to 37%, for a total of 15%.

(c) Thimble tube inspections will be performed every refueling outage during the period of extended operation unless inspections on a reduced frequency can be justified by engineering evaluation.

F-RAI B2.1.37 -1

In Section B2.1.37 of the LRA, the Water Chemistry Control Program specifies a one-time inspection for only those components exposed to low flow or stagnant water. The components exposed to high velocity water were excluded from the one-time inspection. Since, in general, high velocity water provide a more corrosive environment, explain the rationale for excluding these components which, in some instances, may also be exposed to degradation mechanisms.

Response

Stainless steel components exposed to high-velocity treated primary water environments such as in the RCS are unaffected by the erosion/corrosion or flow-accelerated corrosion mechanism. Therefore no one-time inspections should be necessary to verify the effectiveness of the Water Chemistry Control Program. Carbon or low-alloy steel components which are exposed to high-velocity treated secondary water are susceptible to loss of material due to flow-accelerated corrosion and these components are within the scope of, and inspected under, the Flow-Accelerated Corrosion Program.