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July 11, 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: RAI Response Clarifications
R. E. Ginna Nuclear Power Plant
Docket No. 50-244

Dear Mr. Arrighi:

As a result of NRC staff review of RG&E's RAI responses, several clarifications were requested by telecon. Attached are the majority of the requested clarification responses. The balance of the responses are scheduled to be provided on July 15, 2003.

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 July 11, 2003

Robert C. Mecredy

Attachments

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Tom Yurik

## R. E. Ginna License Renewal Application
## Clarifications Requested

### C-RAI 2.1 -4

The added component, Pipe, in Table 2.3.3.-7, was linked to the Aging Management Reference: Table 3.4-2 Line Number (474). However, the information for this link is missing. Provide this information. Furthermore, explain why Table 3.4-1 Line Number (5) is not applicable to the added "Pipe."

Response

The information for line number (474) on Table 3.4-2 was inadvertently deleted from the RAI response submittal. Below please find the information:

| Component Type | Material | Environment | AERMs | Program /Activity | Discussion |
|---|---|---|---|---|---|
| (474) Pipe | Carbon Steel | Air and Gas | No Aging Effects | No Aging Management Program Required | Material and environment grouping are not included in NUREG-1801. |

Table 3.4-1 Line number (5) is applicable to exterior surfaces of the carbon steel piping being added into the scope of LR based on this RAI response. However, because the material/environment combination for these pipes was already accounted for in the application no new table references (links) needed to be added.

### C-RAI 2.3.2.5 -2

Clarify the phrase, "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."

a) What is meant by "by definition"?

b) How does this definition assure that out-of-scope piping will not age to the point that it could potentially threaten the containment boundary in an accident?

Response

a) The Ginna Station UFSAR provides criteria which must be met for containment boundaries, such as containment isolation valves. In order to be considered a containment boundary, qualification for all post-accident conditions, such as pressure and temperature, missiles, jet impingement, spray, etc. must be met. For example, Section 6.2.4.3.2 states:

"All containment isolation valves, actuators, and controls are located so as to be protected against missiles which could be generated as the result of a LOCA. Only valves so protected are considered to qualify as containment isolation valves."

Therefore containment boundary definitions are those as described in the UFSAR.

b) For containment penetrations which have two containment isolation valves, both outside containment, the containment boundary extends through the containment, and terminates at the weld to the containment liner inside containment. Penetration and containment design is such that no damage could occur at these locations due to dynamic effects of an accident, or due to aging degradation of the not-in-scope process piping, since the penetration is protected from or qualified to withstand post-accident conditions.

C-RAI-2.3.3.3-2

Regulatory Guide (RG) 1.13 recommendation that seismically qualified redundant makeup water supplies be provided to the spent fuel pool was published in March of 1971, after the Ginna operating license was issued in 1969. However, paragraph C.8 was included with nearly identical wording in Safety Guide 13, which preceded RG 1.13.

Irrespective of the issue date of the Safety Guide, Section 9.1.2.1.1 of the Ginna UFSAR commits to the guidance of RG 1.13, by stating that "Criteria for the design and performance of the current spent fuel storage system are defined by ANSI/ANS Standard 57.2-1983 and Regulatory Guide 1.13."

Loss of water in excess of 47 gpm from a leaking spent fuel storage pool could result in overheating and damage to the stored spent fuel in less than 3000 minutes.

The NRC staff's SER for re-racking the spent fuel pool at Ginna, dated July 30, 1998, specifically cites the RWST and the CVCS holdup tanks as alternate sources of spent fuel pool makeup water following a loss of forced cooling. The applicant identified these sources of alternate spent fuel pool makeup water in a supplementary submittal dated November 11, 1997.

Taking the above information into account, identify the makeup sources, structures, and components within the scope of license renewal or justify their exclusion.

Response

Ginna Station was designed and licensed prior to the publication of Safety Guide 13, issued March 10, 1971. RG&Es comparison to that guide is provided in paragraph 1.8.1.13 of the UFSAR. There is no commitment to provide redundant seismic makeup sources.

The UFSAR Section 9.1.2.1.1 does state that "criteria for the design and performance of the current spent fuel storage system are defined by ANSI/ANS Standard 57.2-1983 and Regulatory Guide 1.13". This is a true statement, however, these documents are used for guidance, not as absolute commitments. UFSAR Section 9.1.2.1.1 further goes on to state "...the spent fuel racks satisfy these criteria as described below...". Nowhere in the ensuing 9.1.2 discussion is there mention of the makeup system being addressed in this clarification.

In Section 9.1.3.4.3 of the UFSAR, "Interruption of Spent Fuel Pool (SFP) Cooling", it is noted that the structural design temperature of the pool is 180°F. As part of the NRC review of the (1998) RG&E rerack modification, the NRC specifically requested that the time from 150°F to boiling of the SFP water at 212°F be provided along with the water boil-off rate. Although a pool heatup to 212°F would cause the pool water temperature to exceed the SFP structural design limit of 180°F, RG&E provided the NRC with the requested information. Although times to 212°F have been calculated, the 180°F heatup times are controlling for Ginna since they correspond to the SFP design temperature of 180°F.

It should be noted in Regulatory Position C.8 of Regulatory Guide 1.13 that the capacity of the makeup systems should be such that water can be supplied at a rate determined by the consideration of the leakage rate that would be expected as a result of damage to the fuel storage pool from the dropping of loads, from earthquakes, or from missiles originating in high winds. Since the Ginna spent fuel pool is designed to withstand these phenomena without being damaged, the capacity requirement is not applicable.

Thus, although as noted in the staff's SER for the reracking of the spent fuel pool, makeup capacity from the RWST and the CVCS holdup tanks does exist, these SSCs do not perform any license renewal intended functions, and are thus not within the scope of license renewal.

**C-RAI 2.3.3.5 -4**

The applicant's statement that there are several normally closed valves downstream of 4614 which could be used to isolate a break in the piping is too imprecise for use in future audits. The applicant should specify the exact location of the interface between the in-scope and out-of-scope piping segments, and whether all of the piping and components within the in-scope boundaries are subject to an AMR.

Response

The exact location where the change occurs from in-scope to out-of-scope is at, and includes, valve 4614. Downstream, the service water piping and components are non-safety related and do not meet any of the three criteria for inclusion within the rule. The upstream piping and components are subject to AMR as indicated on the service water drawings provided with the application. To specifically answer whether all the piping and components within the in-scope boundary are subject to an AMR: No. Only the passive, long-lived components screened into the AMR process. Active components (i.e. flow transmitters, etc.) are not highlighted on the drawings and are not typically subject to AMR.

**C-RAI 2.3.3.11 -1**

Are all of the following within the scope of LR: the Reactor Head Lifting Device, the Reactor Internals Lifting Device, and the load carrying elements of the Containment Main Crane, the Auxiliary Building Main Crane, and the Spent Fuel and Containment Refueling Bridge Cranes as well as selected jib and monorail hoists?

Response

Yes. All of the cranes, hoists and lifting devices required for NUREG 0612, as identified in Section 2.3.3.11 of the application, are within the scope of license renewal.

**C-RAI 2.3.3.11 -2(a)**

Does the component group "cranes" include the Reactor Head Lifting Device and the Reactor Internals Lifting Device? Or, are these two lifting devices not subject to an AMR?

Response

Yes. These lifting devices are within the scope of license renewal and subject to AMR. They are managed by the "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, described in Section B2.1.18 of the application.

**C-RAI 2.5 -1**

The response to F-RAI 2.5-1 states that credible failures of cables M0089 and M0108 do not result in the loss of an intended function, and the cables are not required to recover from a SBO event. Additionally, the figure provided in response to F-RAI 2.5-2 does not identify any of the circuits from 4160 V buses 12B and 12A to 480 V safety buses 16, 17, 14, and 18 as part of the offsite power circuits that are included within the scope of license renewal. These circuits are part of the offsite power path that bring offsite power into the safety buses. It's not clear why these circuits are not included within the scope of license renewal. Clarify how the Ginna plant can be brought to a shutdown condition from the offsite power supply if these circuits to the safety-related shutdown buses are not included within the scope of license renewal.

Response

All passive, long-lived Electrical/I&C components/commodities are included in the scope of license renewal unless otherwise specified. Therefore the 4160 V power paths to 480 V safety busses 14, and 16 are included in the scope of license renewal by default. Cables M0089 and M0108 provide the normal source of 4160V power to step down transformers, which in turn provide normal power for 480V Class-1E busses 17 and 18 respectively. Based on the scope of license renewal as defined in 10CFR54, cables M0089 and M0108 are not within the scope of license renewal. Circuits M0089 and M0108 are not relied upon to cope with, or recover from a Station Blackout. The entry conditions for plant procedure ECA-0.0, Loss of All AC Power, is the loss of bus 14 and bus 16. This procedure is not entered when bus 17 and bus 18 are lost. Upon restoration of Bus 14 and/or Bus 16, recovery actions are taken. These recovery actions do not rely upon bus 17 or bus 18, although they may be used if available. This procedure directs activities required to achieve shutdown conditions.

C-RAI 2.5 -2

The figure provided in response to F-RAI 2.5-2 does not identify the nature of the blue color-coded circuits from PPSB and PPSA to dummy breakers DX/12B and DX/12A respectively. Please identify the component/commodity group that applies to these portions of the offsite power circuits.

Response

The phase bus component/commodity group connects PPSA and PPSB to dummy breakers DX/12B and DX/12A. This is similar to the 3000A bus duct identified between the station auxiliary transformers and the switchgear.

C-RAI 3.4 - 1

Address the "operating experience" in responses to F-RAI 3.4 -1.

Response

A review of plant-specific operating experience has revealed that a number of maintenance work orders were released during the period 2001 to 2003 for repair of cracks, tears, splits and other degraded conditions in elastomeric components in ventilation ductwork such as flexible collars, expansion joints, rubber boots, etc. The recent identification of these conditions led to the conclusion that these components be included in the scope of the Periodic Surveillance and Preventive Maintenance program. However, operating experience indicates there are other elastomeric components in ventilation systems such as gasket seals that have not exhibited degradation. These components are appropriately included under the scope of the One-Time Inspection program.

C-RAI 3.4 -2

(1)The applicant did not respond to each of the three questions asked for internal environments; (2) For external surfaces, the LRA states that the System Monitoring Program will be credited for

managing the aging effects of loss of material. However, in the response to F-RAI 3.4-2, the applicant stated that the Periodic Surveillance and Preventive Maintenance Program will be used if age-related degradation is revealed. Are both AMPs to be used together with the One-Time inspection Program?
(3) no plant-specific operating experience related to the components of concern was provided. The applicant is requested to provide clarifications concerning these issues.

Response

(1) The One-Time Inspection program is credited for managing the effects of aging **only** for the components in the two ventilation systems that are included in Table 3.4-1. These components include carbon steel fan housings, damper housings, and filter housings in the Containment and Essential Ventilation systems. The internal environment of these components is "air and gas (wetted) <140 degrees F" and the external environment is "Containment air" which is the same as the internal environment. The temperature of these housings would be expected to be the same as that of the ambient air on either side. Therefore no condensation would be expected to occur on the housing surfaces. Therefore aging effects, if any, from exposure of carbon steel to this environment would be expected to occur very slowly. A commitment was made to perform a one-time inspection of the internal surfaces of these components and evaluate the inspection results. If no evidence of age-related degradation is found, no further inspections are planned. However, as stated in the response to the RAI, a further commitment was made to take appropriate corrective action and include these components in the scope of the Periodic Surveillance and Preventive Maintenance program only if evidence of age-related degradation was found.

For components in the diesel fuel oil system, the Fuel Oil Chemistry program and the Periodic Surveillance and Preventive Maintenance program are credited for managing the effects of aging for components exposed to the fuel oil environment.

For components exposed to service water and lubricating oil in the emergency diesel generator system, the Periodic Surveillance and Preventive Maintenance program is credited for managing the effects of aging. For components in the emergency diesel generator system that are exposed to component cooling water, the Periodic Surveillance and Preventive Maintenance program and the Closed-Cycle (Component) Cooling Water System program are credited for managing the effects of aging.

(2) For external surfaces of all components, the Systems Monitoring program is credited for managing the aging effect "loss of material".

A review of plant-specific operating experience revealed that no evidence of age-related degradation has ever been reported for carbon steel components such as fan housings, damper housings, and filter housings in the Containment and Essential Ventilation systems.

**C-RAI 3.4 -3**

Address the "operating experience" in responses to F-RAI 3.4 -3.

Response

A review of plant-specific operating experience was performed during the aging management review process and was documented in Aging Management Review Reports and in Aging Management Program Basis Documents. This review indicated that evidence of minor leakage at bolted closures has been identified by inspections performed during system engineer walkdowns under the Systems Monitoring program, during maintenance activities performed under the Periodic Surveillance and Preventive Maintenance program, and during leakage examinations performed under the ASME Section XI ISI program. The identification of these leaks and the evaluation of the consequences of those leaks under the Corrective Action Program have been an effective element of component aging management and, therefore, in maintaining component integrity before loss of intended function occurred.

**C-RAI 3.4.8 -2**

The response to F-RAI 3.4.8 -2 requested that the applicant to explain the apparent discrepancy for the link between Table 3.4 -1 line number (17) and Table 2.3.3-8 (the link to the AMR for pipe or tank covered in the emergency power system). The applicant response covered only "tank" and did not provide an explanation for "pipe". Explain the discrepance for pipe.

Response

The word "pipe" was omitted from the RAI response. Table 3.4-1 line number (17) is an appropriate link for pipe in Table 2.3.3-8.

**C-RAI 3.5 -3**

Are there any locations in the boundary between the AFW system and the service water system where residual raw water could collect; therefore requiring aging management? Are the drains located a low point in the system where they verify no raw water is present?

Response

There are no locations in the boundary between the two systems where raw water could collect. Drains are at low points. The piping from the service water discharge from the oil coolers and bearing coolers discharge into "funnels" located at selected floor drains. A review of operating experience showed no instances where flow was blocked or diverted from the normal path. There is not a possibility that the exterior surfaces of piping or equipment will be exposed to pooling raw water. As described in section 2.4.2.2 of the LRA, portions of the Intermediate Building structure contains features that are designed to resist flooding. Specifically, grating versus solid man way covers in the access holes separating the Intermediate Building sub-basement from the Intermediate building provide a de-watering path. This feature is also described in UFSAR section 3.6.2.1.1.

C-RAI 3.5 -4

Do responses 1 & 2 to RAI F-RAI 3.5 -4 refer to the same oil coolers?

Response

Responses (1) and (2) refer to two different heat exchangers. Response (1) refers to the stainless steel shell-and-tube lube oil coolers for the motor-driven and turbine-driven auxiliary feedwater pumps. Service water flows through the tube side of these units, and lubricating oil through the shell side. Response (2) refers to the outboard-bearing lube oil coolers for the motor-driven and turbine-driven auxiliary feedwater pumps. See the response to RAI 3.5-11 for additional discussion on the outboard-bearing oil coolers for these pumps.

C-RAI 3.5 -8

As described in the GALL report, the One-time Inspection program is used to verify the effectiveness of an aging management program (AMP) and confirm the absence of an aging effect expected to occur very slowly or not at all. For example, the Water Chemistry Program manages aging effects for piping internals and the One-time Inspection Program verifies effectiveness of the Water Chemistry AMP by confirming that unacceptable degradation is not occurring and the intended function will be maintained during the period of extended operation. In a raw water environment, galvanic corrosion is likely to occur; therefore, periodic inspections are more appropriate for managing these aging effects. Explain the basis for performing One-time Inspections to manage galvanic corrosion is raw water or provide periodic inspections to manage this aging effect.

Response

The severity of galvanic corrosion is directly related to the following factors: 1) the galvanic potential difference between the alloys in electrical contact; 2) the conductivity/corrosivity of the environment; and 3) the cathode-to-anode (noble/active member) surface area ratio. Raw water at Ginna Station is fresh Lake Ontario water and is not aggressive. Typical chloride levels are 20-25 ppm; sulfate levels are 25-30 ppm and the pH is near neutral. Based on these facts, as well as plant-specific operating experience, the raw water environment at Ginna Station would not be expected to support significant galvanic corrosion. As a result, inspections will be performed under the One-Time Inspection program to evaluate galvanic corrosion in "susceptible" components prior to the end of the current license period. If the results of these inspections indicate that degradation due to galvanic corrosion has occurred in any component, then a repetitive inspection task will be created under the Periodic Surveillance and Preventive Maintenance program and the component will be periodically inspected.

C-RAI 3.6-1 **(Related to responses to RAI 3.6-1 and RAI B2.1.3-2)**

The staff recognizes that the applicant is aggressive in performing tendon inspections, and the tendon inspections provide certain degree of confidence in the integrity of rock anchor system coupled to the tendons. However, it is the other inaccessible features of the containment, where the staff needs additional assurance for the extended period of operation. Inspections performed in accordance with the requirements of subsection IWL of Section XI of the ASME

Code will not be able to detect problems with the (1) tendon bellows, (2) elastomer pads, (3) radial tension bars. Moreover, the areas of the containment where these components are located are below the ground water level, and the staff had identified water related problems around the elastomer pads in the early 1990s. The applicant needs to develop an aging management program (or periodic functional tests) that would verify the containment functionality at the location of the containment hinge.

Response

RG&E understands the limitations related to detection of certain age related degradation as identified above. Therefore indirect observations are the most practical course of action. With respect to (1) tendon bellows our best course of action is to ensure that the tendon grease cans remain filled. To that end the Periodic Surveillance and Preventive Maintenance Program was modified to perform more frequent inspections and grease will be added as necessary to compensate for the possibility of bellows leakage. For item (2) the elastomer pads are under significant compression (the weight of containment) and largely inaccessible. No meaningful program could be identified to manage aging of the pads other than that done as part of ILRT and SIT. It is important to note that exposure of the elastomer pads to ground water does not constitute an aggressive material/environment combination that would be expected to have deleterious effects. What is lacking is the ability to directly confirm the absence of aging effects. For all items (1),(2) and (3) the Staff and RG&E have had numerous discussions which culminated in a safety evaluation report that concluded the best way to assure the structural integrity of the containment is through a well-planned tendon surveillance program. (See letter dated May 27, 1994, Allen Johnson ,NRC to Robert Mecredy, RG&E. Subject: GINNA CONTAINMENT STRUCTURAL INTEGRITY- TECHNICAL REPORT NO. 500167-7 "RADIAL DISPLACEMENT AND REBAR STRAIN MEASUREMENT FOR EWR 5181," MAY 17,1993 (TAC NO.M80494) and followup letter dated July12, 1994, Robert Mecredy, RG&E to Allen Johnson, NRC. Subject: Ginna Containment Structural Integrity R.E. Ginna Nuclear Power Plant.).

**C-RAI 3.6 -8**

Is loss of preload managed by the Bolting Integrity Program?

Response

Loss of preload is managed by the Bolting Integrity program.

**C-RAI 3.7 -2**

The response to F-RAI 3.7-2 states that the scope does not limit the program to adverse localized equipment environments, but is structured to identify any such areas that may exist within the plant space. The UFSAR supplement identified in Section A2.1.9 of the LRA, however, still states: "The program requires that cables and connections in accessible areas exposed to adverse localized environments caused by heat, radiation, or moisture are inspected on a periodic basis." This will need revision to make it consistent with how the program is actually conducted.

The response to F-RAI 3.7-2 goes on to say all cables identified with high loading or less than optimal cable tray fill are installed in plant spaces included in the scope of the aging management program. The plant spaces included in the scope of the aging management program are not limited to only those with highly loaded cables or less than optimal tray fill, are they?

The response also states that: "The aging management program allows for a graded approach to examination based on operating experience and the specific environment . Therefore it is not the intent to imply that all the accessible cable and connections within the identified plant building/areas will be visually inspected. When it is clear during the implementation of the program that a plant space contains no significant stressors and is within the analyzed assumptions for limiting materials of construction, then detailed inspections are not likely to occur. However, this does not eliminate the plant space from review for future inspections." This approach seems reasonable. I assume that the statement, "this does not eliminate the plant space from review for future inspections," indicates that at least a general inspection of the space will be performed in the future, to check that no changes have been made since the last inspection that could add significant stressors or adverse localized environments in the space. Is this accurate?

Response

(a) Appendix A of the LRA is supplemented by the following description of how Ginna Station manages: Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

> The program requires that cables and connections in selected plant spaces are inspected on a periodic basis. The program relies on the identification of adverse localized environments caused by heat, radiation, or moisture, which are known to accelerate degradation of insulated cables and connections. Visual inspections for cable and connector jacket surface anomalies such as embrittlement, discoloration, cracking, and surface contamination are performed at least once every ten years.

(b) The scope of the program includes all plant spaces identified in the scope "attribute" of the program as described in response to RAI 3.7-2. These spaces are defined by their structural boundaries, not by sub-areas that contain specific cables or cable trays.

(c) The described interpretation of how the program will be implemented is accurate.

**C-RAI 3.7-3**

The response to F-RAI 3.7-3 proposes an AMP for radiation monitoring and nuclear instrumentation cables that is based on measurement of insulation resistance. Is this AMP intended for both EQ and non-EQ cables? If intended for only non-EQ cables, the program description should clarify that this AMP is limited to non-EQ cables.

Response

The title of the program indicates that the AMP is for non-EQ cables. To clarify this, the scope will be changed as follows (revision in italics):

Scope of Program

This program applies to electrical cables used in circuits with sensitive, high voltage, low-level signals such as radiation monitoring and nuclear instrumentation that are within the scope of license renewal *and not included in the Environmental Qualification Program.*

C-RAI 3.7 -6(a)

The response to F-RAI 3.7-6 states that plant operating experience has not identified that aging effects for copper and stainless steels in non-marine atmospheric environments results in degradation requiring aging management. The response to F-RAI 3.7-6 also states that: "Because those portions of the switchyard bus that are in-scope to the rule have not exhibited any aging effect requiring management and because any detrimental effect of aging on their functionality is monitored by the maintenance rule, no further License Renewal Programs need be applied."

Plant operating experience and lack of exhibited aging effects prior to the period of extended operation does not, by itself, provide a basis for concluding that aging management of a component is not required. These are indications that there have been no early failures or problems associated with the component up to that point and help to support or provide input into an analysis that reviews the potential aging effects associated with the component. Has a switchyard bus analysis been performed on the potential for torque relaxation of the bolted electrical connections due to thermal cycling? Does RG&E's Energy Delivery Department perform any periodic maintenance or screening tests (e.g. thermal scans) on the electrical connections of the switchyard bus?

With regard to existing programs under the Maintenance Rule, it is correct that these programs can be credited for license renewal. In order for a program to be credited for license renewal, however, it must be consistent with the ten attributes identified for license renewal AMPs. If the swithyard bus maintenance rule program provides aging management of the bus electrical connections or other aging effects of the switchyard bus, describe the ten attributes of the switchyard bus program, consistent with the guidance provided in Branch Technical Position RLSB-1 of the staff's license renewal Standard Review Plan (NUREG-1800). If it does not manage aging effects, then provide the details of your AMR that concludes there are no aging effects requiring management (torque relaxation of the bolted electrical connections due to thermal cycling should be among the aging effects addressed), or provide a description of the AMP which manages the effects.

Response

The Aging Management Review for switchyard bus did not analyze ohmic heating for switchyard bus. It was concluded that based on operating experience (both industry and plant specific), there was not enough evidence to consider torque relaxation of bolted switchyard connections as a credible aging effect. Such an analysis could consider the resistance of the bare conductors, and the heat transfer in free air. Since there is no electrical or thermal insulation to reduce heat transfer, the actual temperatures of the metal components were expected to be minimal. Operating Experience has been shown to be a strong indicator of the existence of potential aging effects, and may often be more representative than analytical information. Although a lack of discussion on switchyard components in NUREG-1801, Generic Aging

Lessons Learned, does not, by itself, provide a basis for concluding that aging management of a component is not required, the evaluation process described appears to be comprehensive, and yet did not identify aging effects requiring management of switchyard components. Ginna Station also performed a review of EPRI 1003057, License Renewal Electrical Handbook, and found the conclusions to be valid for switchyard bus.

While there is no evidence that torque relaxation is an aging effect requiring management, there are several routine maintenance and inspection activities performed at Ginna Station as part of existing programs to ensure safe, reliable operation of the plant. The Preventative Maintenance and Periodic Surveillance program has been previously submitted as part of the License Renewal Application, and subsequently modified by RAI responses. This program includes periodic assessments of performance and condition monitoring activities and associated goals and preventive maintenance activities performed consistent with 10CFR50.65 requirements. This program credits the Equipment Diagnostic Monitoring program which includes the Infrared Thermography Program. As part of this program Ginna Station performs periodic thermography scans of onsite transformer yard components including transformers in the scope of license renewal (12A, 12B), as well as the upstream circuit breakers (52/75112, 52/76702), disconnect switches, and associated 34.5 kV switchyard bus. A review of a typical thermography image shows that normal temperature rise is less than 10°F above ambient, which confirms the initial assumption that temperatures would be minimal and torque relaxation of bolted connections is not an aging effect requiring management within the period of extended operation.

Administrative controls will be implemented prior to the period of extended operation to ensure that thermographic inspections of 34.5 kV transformer yard components are performed at least once within each refueling cycle while components are energized. These controls will ensure that the inspections will not be cancelled or deferred without sufficient analysis and justification. This is consistent with other aspects of the Periodic Surveillance and Preventative Maintenance Program as described in License Renewal Program Basis Document LR-PSPM-PROGPLAN. This program will be revised to clarify that the program includes thermographic inspections of selected components, including transformer yard components.

<u>C-RAI 3.7 -7(a)</u>

The response to F-RAI 3.7-7 states that plant operating experience has not identified that the aging effects for high voltage insulator materials in non-marine atmospheric environments results in degradation requiring aging management. The response to F-RAI 3.7-7 also states that: "Because those high voltage insulators that are in-scope to the rule have not exhibited any aging effect requiring management and because any detrimental effect of aging on their functionality is monitored by the maintenance rule, no further License Renewal Programs need be applied."

Plant operating experience and lack of exhibited aging effects prior to the period of extended operation does not, by itself, provide a basis for concluding that aging management of a component is not required. These are indications that there have been no early failures or problems associated with the component up to that point and help to support or provide input into an analysis that reviews the potential aging effects associated with the component. Is there a potential for contamination buildup on the high voltage insulators at Ginna? Does RG&E's Energy Delivery Department perform any period maintenance or screening tests on the high voltage insulators?

With regard to existing programs under the Maintenance Rule, it is correct that these programs can be credited for license renewal. In order for a program to be credited for license renewal, however, it must be consistent with the ten attributes identified for license renewal AMPs. If the high voltage insulators maintenance rule program provides control of contamination buildup on the insulators or controls other aging effects of the insulators, describe the ten attributes of the high voltage insulators program, consistent with the guidance provided in Branch Technical Position RLSB-1 of the staff's license renewal Standard Review Plan (NUREG-1800). If it does not manage aging effects, then provide the details of your AMR that concludes there are no aging effects requiring management (control of contamination buildup on the insulators should be among the aging effects addressed), or provide a description of the AMP which manages the effects.

Response

An Aging Management Review has been performed for high voltage insulators within the scope of license renewal at Ginna Station. The following paragraph is based on this AMR:

> Various airborne materials such as dust, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and is normally washed away by rain; the glazed insulator surface aids this contamination removal. Surface contamination can be a problem in areas where there are greater concentrations of airborne particles such as near facilities that discharge soot or near the seacoast where salt spray is prevalent. Ginna is located next to a fresh water lake, in a rural, non-industrial area with moderate rainfall where airborne contaminants are comparatively low. There are no facilities in the area that discharge airborne particles that could buildup on the insulators and cause flashover or otherwise adversely impact the intended function. Consequently, the rate of contamination buildup on the insulators is not significant, and would be washed away by normal precipitation if present. A review of industry and plant operating experience identified IN 93-95, *Storm-Related Loss of Offsite Power Events Due to Salt Buildup on Switchyard Insulators.* A review of IN 93-95 concluded that salt buildup is not a valid stressor for high voltage insulators at Ginna Station. Therefore, surface contamination is not an aging effect requiring management for high voltage insulators at Ginna. Visual inspections of the insulators provide confirmatory evidence for this conclusion.

Operating Experience has been shown to be a strong indicator of the existence of potential aging effects, and may often be more representative than analytical information. Although a lack of discussion on switchyard components in NUREG-1801, Generic Aging Lessons Learned, does not, by itself, provide a basis for concluding that aging management of a component is not required, the evaluation process described appears to be comprehensive, and yet did not identify aging effects requiring management for switchyard components. Ginna Station also performed a review of EPRI 1003057, License Renewal Electrical Handbook, and found the conclusions to be valid for high voltage insulators. In this case, operating experience provides significant information about the aging mechanisms related to contamination of the high voltage insulators. This degradation mechanism is one that could manifest itself over a short period of time (possibly one year) if conditions for such degradation exist. With more than 30 years of operating experience, a lack of contamination indicates that high voltage insulators do not become contaminated at Ginna Station. At this time, there is no reason to believe that there will be a change in environment that could suddenly permit or contribute to insulator contamination. Therefore for this aging mechanism, operating experience and a lack of exhibited aging effects

provides a strong basis to conclude that aging management for high voltage insulators is not required.

The RG&E Energy Delivery department does not perform any periodic maintenance or screening tests on the high voltage insulators at Ginna Station.

C -RAI 4.1 -1

The RAI response indicates that metal corrosion allowance was used in supplier calculations but was not considered a TLAA per criterion 6. What is the basis for the corrosion allowance in the vendor calculations? Is it based on an assumed 40 year plant life?

Response

The vendor's metal corrosion allowance assessment was performed to determine the thickness of the Safety Injection pump cast iron bearing housing, over 40 years of operation. Although no TLAA to extend this thickness margin out to 60 years as performed, these bearing housings have been scheduled for a one-time inspection to assess loss of material due to corrosion. This inspection, scheduled to be complected prior to the period of extended operation, will determine if any age related degradation exists and if so appropriate corrective action will be taken in accordance with the Ginna Station Corrective Action Program.

C-RAI 4.7.7 -1

Provide the response to F-RAI 4.7.7 -1, item (b).

Response

As discussed in these topical reports, provided to the NRC for review by letter dated June 3, 2003, no deviations from NRC guidance was taken in the analyses.

In Section 7 of WCAP-15873, a point-by-point comparison is made of the Westinghouse analysis to the conditions of item (d) of ASME Code Case N-481, to show that all conditions are met.

In Section 1.3 of WCAP-15837, the criteria and resulting steps of the evaluation procedure are summarized, and show that the 60-year leak-before-break analysis for RCS piping is performed consistent with methodology approved previously by the NRC (see references in Section 1.4 of the WCAP).

C-RAI B2.1.1 -1

(a) Are all tanks in the scope of this program protectively coated at exterior surfaces?

(b) Provide the bases for not crediting the protective coatings applied on the carbon steel tanks as a preventive measure to mitigate .

(c) One of the key elements in GALL AMP XI.M29 is to implement preventive measures to mitigate the corrosion of the exterior surfaces of the carbon steel tanks. If you are not crediting the protective coatings for mitigating the effects of aging, what other mitigation measures do you plan to implement?

(d) The staff understands that the UT thickness measurements of tank bottom apply only to reactor make-up water storage tank (performed in 2001),and "A" and "B" condensate storage tanks (to be performed in 2003-2004), because the bottom of these tanks are not accessible for visual inspection. Will the bottom of these tanks be UT measured for thickness again prior to the beginning of the extended operation period.

(e) What is the guidance for additional measurements and inspections in the event that degradation is detected?

Response

a) The exterior surfaces of all of the tanks at Ginna Station are painted.

b) The protective coating (paint) is used to reduce the rate of loss of material due to corrosion when exposed to the ambient environment. During System Engineering walkdowns, if degradation of the coating is noted such that corrosion is evident, the situation is evaluated and corrected if considered necessary. Small imperfections in the coating are not considered as requiring corrective action. The carbon steel shell itself, not the protective coating, performs the license renewal intended function.

c) The fact that the tanks are painted does provide a mitigative feature to reduce the rate of corrosion of the tank exterior surface. Though credit is not explicitly taken for the protective coating, degradation of the coating is noted by System Engineers, and evaluated for its effect on the tank surface as appropriate.

d) The UT thickness measurement of the bottom of the reactor makeup water tank indicated no degradation of any significance after over 30 years of operation. If comparable results are achieved for the condensate storage tanks at the next inspection, RG&E will not plan to re-inspect these tank bottoms prior to the period of extended operation.

e) In the event degradation is detected, corrective action will be taken. This would include additional inspections to assess the rate of degradation, repair to the inside coating if needed, repair to the tank wall itself if minimum wall thickness requirements are not met, or other measures as determined by an Engineering evaluation.

**C-RAI B2.1.3 -3**

In response to (b), it is not clear if the applicant is restoring the liner plate to its nominal thickness before recoating. The applicant is requested to clarify this issue. In response to (c), the applicant is requested to include a sampling plan for removing the insulation for examining the liner surfaces.

Response

(b) The carbon steel liner plate was not restored to its nominal thickness. Only the zinc-rich coating was restored.

(c) One-third of the circumference of the moisture barrier at the interface between the Containment basement floor and the liner plate was inspected during the refueling outage in 2000. The remaining two-thirds of the moisture barrier will be inspected during the 2005 refueling outage. During the 2005 refueling outage, a minimum of three additional 20-foot lengths of insulation will be removed and inspections (including visual inspections and UT thickness measurements) of the exposed liner plate will be performed. Two of the areas selected for inspection will be on each side of the region inspected in 2002 on the southeast side of the Containment. The third area will be located on the northwest side. In addition, insulation will be removed at any locations requiring further investigation where the moisture barrier exhibits evidence of degradation due to cracking, separation or loss of seal. Visual inspections and UT thickness measurements of the liner plate will be performed in these areas.

**C-RAI B2.1.13**

The AMP Audit performed on June 24, 2003, identified a discrepancy between the LRA and the applicant's Fire Protection Program basis document, LR-FP-PROGPLAN. The LRA states the Fire Protection Program is consistent with GALL, whereas the basis document states that the AMP is consistent with GALL with discrepancies. Provide the basis for the discrepancies in GALL and LR-FP-PROGPLAN identified during the AMP Audit.

Response

The Fire Protection program is consistent with, but includes exceptions to, NUREG-1801, Section XI.M26, "Fire Protection". The exceptions are as follows:

- Halon system testing frequency is based upon a performance-based evaluation of system components documented in DA-ME-97-081 "Engineering Evaluation of Fire Protection System Inspection and Testing", February 10, 2000. This frequency is different from the six-month frequency stated in NUREG-1801.
- Visual inspections of fire doors and verification of clearances are performed on a quarterly basis, not bi-monthly as stated in NUREG-1801.
- Personnel performing inspections of fire barriers, doors, and penetration seals are qualified to perform those inspections in accordance with plant procedures QC-INS-2 "Qualification of Inspection Personnel" and A-1102 "Qualification and Certification of Test Personnel", but not necessarily in accordance with the requirements for VT-1 or VT-3 as defined in RG&E NDE Procedure NDE-102.

C-RAI B.2.1.22-1.

This RAI response was to focus on small heat exchangers that are cleaned and inspected (rather than having heat transfer testing) as part of the plant's PM Program which they stated is an exception to the Service Water System Program. The responses seem to miss this focus/exception and in some cases tend to discuss heat transfer testing.

1) what was the criteria used to scope small heat exchangers that would be cleaned and inspected per the PM program (the initial response indicates all heat exchangers are within the program).

2) when the heat exchangers are being cleaned/inspected, what method and acceptance criteria are used to identify aging - response discusses pressure, flow and temperature. How is this relative to cleaning and inspecting and the exception is that heat transfer testing is not performed on this group of heat exchangers? Are visual inspections performed, does the specific PM address what the aging mechanism is and how it can be identified?

4) is the cleaning and inspection data relative to the aging trended?

5) does the cleaning and inspection preventative maintenance action contain acceptance criteria relative to aging of small heat exchangers

There was a final part to this RAI that was not addressed: if enhancements to the PM program as stated in the LRA were necessary relative to the small heat exchangers?

Response

1) Small heat exchangers were placed in the PSPM program consistent with the guidance provided in Generic Letter 89-13. Action item II of 89-13 allows this as follows:

"An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger. This alternative might apply to small heat exchangers, such as lube oil coolers or pump bearing coolers or readily serviceable heat exchangers located in low radiation areas of the facility."

A listing of all heat exchangers within the Ginna Station Open-Cycle Cooling (Service) Water System Program is provided below:

| EIN | Description | OCCW Activity | PSPM Activity |
|---|---|---|---|
| ESW 08A/B | EDG Jacket Water Heat Exchangers | • monitor differential pressure to check for macro-fouling<br>• clean each refueling outage | • heat exchangers are cleaned and eddy current tested each refueling cycle (Reptask P301709 & P301710) |
| ESW09A/B | EDG Lubricating Oil Heat Exchangers | • monitor differential pressure to check for macro-fouling<br>• clean each refueling outage | • heat exchangers are cleaned and eddy current tested each refueling cycle (Reptask P301709 & P301710) |
| PSI01A/B/C | Safety Injection Pump Bearing Housing Cooling | • periodically monitor for adequate flow | • service water flow is measured at the discharge of the bearing coolers (PT-2.1S) |
| AAA01A/B | Charging Pump Room Coolers | • the heat transfer function of these heat exchangers is not in scope | • minwall inspection is periodically performed on the coolers (Reptasks P400001 and P401053) |
| AAA02A/B | RHR Pump Room Coolers | • the heat transfer function of these heat exchangers is not in scope | • none |
| AAA03A/B/C | SI/Containment Spray Pump Area Coolers | • these heat exchangers have been removed from service with blanking plates | • none |
| EAC13 | Spent Fuel Pool Heat Exchanger A | • thermal performance tested (PT-60.7) | • heat exchanger is cleaned and eddy current tested periodically (Reptask P301711) |
| EAC14 | Spent Fuel Pool Heat Exchanger B | • thermal performance tested (PT-60.8) | • heat exchanger is cleaned and eddy current tested periodically (Reptask P301712) |
| EAC01A/B | Component Cooling Water Heat Exchangers | • thermal performance test during each Mode 3 ->4 transition<br>• continue testing until fouling issue resolved | • heat exchangers are cleaned and eddy current tested periodically (Reptasks P301717 & P301718) |
| AFA01A/B | SAFW Pump Room Coolers | • inspect and clean every five years<br>• replace air filter yearly | • coolers are inspected/cleaned periodically (Reptasks P401084 & P401083) |
| ACA01A/B/C/D/ E/F/G/H/J/K/L/M | Containment Recirculating Fan Coolers (CRFCs) | • inspect and clean on rotating schedule<br>• monitor flow on operator rounds<br>• monitor SW flow / differential pressure each refueling outage (PT-60.9)<br>• air flow rates trended quarterly (PT-2.3.1Q)<br>• inspect air side during refueling and clean as required | • coolers are periodically opened and inspected for fouling (Reptasks P301572, P301573, P301574, P301575) |
| ACA07/08/09/10 | CRFC Motor Cooler B/C/D/A | • monitor SW differential pressure each outage, flow if problems indicated (PT-60.9)<br>• flush coolers every third outage | • coolers are periodically flushed (Reptasks P301707 & P301708)<br>• coolers are UT inspected periodically (Reptask P301595) |

| EIN | Description | OCCW Activity | PSPM Activity |
|---|---|---|---|
| EAF01 | Turbine-Driven AFW Pump Lube Oil Cooler | • monitor SW flow to floor drain<br>• clean inlet strainer quarterly during periodic pump test (PT-16Q-T) | • cooler is cleaned and eddy current tested periodically (Reptask P301618) |
| PAF03 | Turbine-Driven AFW Pump Bearing Housing Cooling | • monitor SW flow to floor drain<br>• clean inlet strainers quarterly during periodic pump test (PT-16Q-T) | • none |
| EAF02A/B | Motor-Driven AFW Pump Lube Oil Cooler | • monitor SW flow to floor drain<br>• clean inlet strainers quarterly during periodic pump test (PT-16Q-A & PT-16Q-B) | • coolers are cleaned and eddy current tested periodically (Reptask P301579 & P301619) |
| PAF01A/B | Motor-Driven AFW Pump Bearing Housing Cooling | • monitor SW flow to floor drain<br>• clean inlet strainers quarterly during periodic pump test (PT-16Q-A & PT-16Q-B) | • none |

2) There are two different types of monitoring activities which are performed on heat exchangers within the scope of the OCCW Program. Performance tests (PTs) are used to monitor parameters such as pressure, flow, and temperature. These tests are implemented by the PSPM Program (see table above). In addition, certain heat exchangers are cleaned and inspected as directed by the OCCW and PSPM Programs. These activities include visual and eddy current inspections. Enhancements will be incorporated in plant-specific procedures implementing the visual inspections and will include explicit guidance on detection of aging effects. Acceptance criteria for any degraded condition that is detected during visual inspections will be established by engineering evaluation of the degraded condition in accordance with Ginna Station corrective action program (see response RAI 2.1.23-7). Eddy current inspections are performed in accordance with existing NDE procedures which contain explicit acceptance criteria based on allowable wall loss. Tubes identified by eddy current inspections with wall loss exceeding the acceptance criteria are plugged. The number of plugged tubes is trended for each heat exchanger and compared with plugging limits which are specific for each heat exchanger. Note that the Containment Recirc Fan Motor Coolers are periodically flushed and the tubes are inspected by UT. Acceptance criteria for the UT inspections are also based on minimum allowable wall thickness.

4) Inspection data from visual and eddy current examinations is trended under the PSPM Program.

5) Yes. See response to questions 1) and 2).

Enhancements to plant-specific procedures which implement cleaning and inspection of small heat exchangers are addressed in paragraph 2 above and in the response to RAI 2.1.23-7 .

**C-RAI B2.1.29**

The licensee is requested to provide a listing of components that will be inspected for selective leaching, the components that will be assessed for hardness testing and how the hardness testing will be performed.

Response

The only copper-alloy components within the scope of license renewal identified by the aging management review process as susceptible to selective leaching are admiralty brass tubes in the "A" and "B" Component Cooling Water heat exchangers, and the "A" and "B" Emergency Diesel Generator (EDG) Jacket Water Coolers and Lube Oil Coolers. The tubing in these heat exchangers is inspected periodically by eddy current testing. These inspections are effective in detecting loss of material and changes in material permeability caused by the selective leaching process. Destructive metallurgical evaluation of admiralty brass tubes pulled from these units to characterize eddy current indications has verified evidence of the selective leaching mechanism in pits detected by these tests. Therefore eddy current testing presently performed on these heat exchangers is adequate for detection of tube wall degradation due to selective leaching and no other non-destructive examinations, including hardness tests, are required.

Gray cast iron components that will be examined for potential degradation due to selective leaching are the channel heads for the "A" and "B" EDG Jacket Water Coolers and Lube Oil Coolers. These coolers have been in service since plant startup and should therefore represent the most severe service condition for gray cast iron components exposed to raw water. The channel heads will be cleaned, examined visually and assessed for the feasibility of performing hardness tests prior to the end of the current license period. If it is determined that hardness tests can be performed, the tests will be made using an Equotip dynamic hardness tester.

**C-RAI B2.1.29 -1**

In accordance with 10 CFR 54.2(d), the applicant is required to provide a summary description of the programs and activities for managing the effects of aging and the evaluation of time limited aging analyses for the period of extended operation determined by paragraphs (a) and(c) of this section respectively in the UFSAR supplement for the facility. The applicant is requested to provide this information in the UFSAR supplement for the selective leaching of materials program.

Response

Appendix A of the LRA is supplemented by the following description of how Ginna Station implements "selective leaching of materials":

Selective Leaching of Materials

This program ensures the integrity of components made of cast iron, bronze, and brass exposed to service water, treated water, or ground water. The program utilizes visual inspections, as well as an assessment of the feasibility of using hardness tests (on a component-specific basis), to

determine if selective leaching is occurring in susceptible components, and whether the process will affect the ability of the components to perform their intended function.

C-RAI B2.1.31 -1

1. Section a) of this RAI asked a question regarding the "Steam Generator Shell Assembly". The RAI response repeatedly refers to SG shell, wrapper and upper internals. At Ginna, are all these components considered part of the "SG Shell Assembly"? If not, and only the "SG shell" relates to the SG Shell Assembly, the applicant should explain the purpose of referring to the wrapper and upper internals in the RAI response. (For example, are they crediting the SG Program for aging management of these two components? If so, these are added components beyond those originally identified in the LRA application.)

2. In the applicant's response to (3) "Detection of Aging Effects" - The applicant has stated that periodic visual inspections are performed of the secondary side (including inspections of accessible areas of the shell). This response does not provide sufficient detail for the staff to complete their review. The applicant should address how frequently the inspections are performed (e.g., every refueling outage, etc) and the basis for this frequency. In addition, the applicant should address the extent/sample size of the inspection of each of these components (i.e., mid-upper bundle, tube support structure and the shell) and the basis for this inspection. The applicant should ensure the response to the question above identifies in more detail what areas of the SG shell are "accessible". If operating experience is a major factor in dictating the response to this question, the licensee should provide additional details on site specific and generic industry operating experience related to these components.

3. In the applicant's response to (5) "Acceptance Criteria" - The applicant stated that evidence of secondary side degradation is dispositioned by engineering evaluation. This response does not provide sufficient detail for the staff to complete their review. The applicant should identify the acceptance criteria which dictate the conditions (based on the visual inspection) that should be brought to the applicant's attention such that an engineering evaluation would be required.

Response

1. The steam generator shell assembly refers to the shell of the steam generators, including the lower shell, transition cone, steam drum, feedwater nozzle, steam outlet nozzle, blowdown nozzles, and inspection port/manway penetrations and closures. The steam generator shell assembly is identified in Table 3.2-1, line number (2) and includes all components necessary to support the Class 2 pressure boundary and heat removal functions.

   The steam generator internals components include the feedring gooseneck, feedring and J-tubes, internal wrapper (or shroud), primary and secondary decks, lattice grid tube supports, U-bend restraints, and steam flow restrictor. Steam generator internals components are within the scope of license renewal and provide the necessary structural support for the tube bundle and direct secondary water flow such that the tube bundle can perform its primary pressure boundary and heat removal function. The steam generator internals components in Table 3.2-2, line numbers (24) and (25) were identified with a level of detail consistent with that described in the Standard Review Plan (NUREG-1800)

and GALL (NUREG-1801). The steam generator internals components include all secondary side structural components necessary to support the primary RCS pressure boundary and the heat removal function and are not added components beyond those identified in the LRA.

2. Secondary-side inspections of the steam generators at Ginna Station are presently performed whenever primary-side inspections are performed, i.e., every other refueling outage or every three years. This schedule is based on the latest approved revision of the EPRI PWR Steam Generator Examination Guidelines (Revision 6) effective in Fall 2003, along with US NRC Regulatory Guide 1.83 Revision 1, July 1975.

   The scope of the secondary-side inspections of the steam generators at Ginna Station is consistent with the guidelines of NEI 97-06. These inspections include Foreign Object Survey and Retrieval (FOSAR) and top-of-tubesheet inspections, upper and lower steam drum inspections, inspections of accessible J-tubes and wrapper (shroud) below the accessible J-tubes, upper-bundle U-bend area inspections including restraint assemblies, upper and lower lattice grid inspections, and remote visual inspections of accessible areas of the shell. The scope and extent of these inspections are the same each time they are performed. The shell inspections are performed by a camera mounted to a robotic car that runs on the shell. Most of the shell (≥ 75%) is accessible by this means.

3. Visual examinations of the secondary-side steam generator components are performed by personnel qualified in accordance with approved Ginna Station NDE procedures. Qualification is based on the requirements of Recommended Practice ASNT SNT-TC-1A, AWS QC1 "Qualification Standard for Visual Personnel", ANSI/ASNT CP-189 "Standard for Qualification and Certification of Non-Destructive Testing Personnel", and AWS D1.1 "Structural Welding Code". Acceptance criteria for visual examinations are explicitly detailed in approved Ginna Station NDE procedures. Any condition observed by the visual examiner which does not meet the acceptance criteria in the NDE procedures or any condition judged by the examiner to require further investigation is documented and evaluated in accordance with the Ginna Station Corrective Action Program.

**C-RAI B2.1.34**

Ginna's LRA did not provide the UFSAR supplement pertaining to AMP B2.1.34, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)." Please provide.

Response

Appendix A of the LRA is supplemented by the following description of how Ginna Station manages thermal aging embrittlement of cast austenitic stainless steel.

Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

This program included a determination that the RCS primary loop elbows and the reactor coolant pump casings are susceptible to thermal aging embrittlement. For these components, a plant-specific flaw tolerance evaluation was conducted, which concluded that adequate fracture toughness exists for the RCS loop, including the cast elbows, for the period of extended operation, and that the primary loop RCP casings are qualified to item (d) of ASME Code Case N-481 for the period of extended operation.

**C-RAI B2.1.34 -1**

(a) The applicant stated that 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. Was flaw tolerance evaluation performed for CASS RCP flanges? The staff understands that radiographic testing (RT) was performed on CASS valve bodies. Discuss the limitations of using RT in the detection and sizing of service induced cracks in the valve bodies and compare its capability in crack detection and sizing with respect to ultrasonic testing (UT).

(d) The referenced letter only discussed the industry-wide service experience pertaining to CASS valve bodies. Provide the industry-wide service experience pertaining to CASS piping components and CASS reactor coolant pump components.

Response

(a) The NRC Safety Evaluation Report (SER) for Reference 1 includes a discussion of thermal aging embrittlement and current inspection requirements. As noted in the SER, "Valve bodies and pump casings are adequately covered by existing inspection requirements in Section XI of the ASME Code, including the alternative requirements of ASME Code Case N-481 for pump casings. Screening for susceptibility to thermal aging is not required during the period of extended operation because the potential reduction in fracture toughness of these components should not have a significant impact on critical flaw sizes. Accordingly, the current ASME Code inspection requirements are sufficient." In addition, the SER states that aging management of RCP pump casings may be accomplished "through the demonstration of compliance with Code Case N-481. The one-time fracture mechanics evaluation ....must incorporate bounding material properties for the end of the period of extended operation."

Accordingly, flaw tolerance evaluations were not performed for CASS valve bodies at Ginna Station because, as stated in References 1 and 4, current ASME inservice inspection requirements are sufficient to manage the effects of thermal aging. However, in accordance with the SER, a one-time fracture mechanics evaluation was performed for the CASS RCP pump casings which incorporated the bounding material properties of the casings, including the flanges, for the end of the period of extended operation. This evaluation has been submitted to the staff for review by letter dated June 3, 2003.

(d) Industry operating experience for reactor coolant system piping, including cast austenitic stainless steel (CASS) piping and other components, has been summarized in Table 3-1 of Reference 1. Other industry experience is presented in References 2 and 3.

References:


1. WCAP-14575-A, "Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components", December 2000
2. EPRI TR-106092, "Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components in LWR Reactor Coolant Systems", September, 1997
3. EPRI TR-100034, "Cast Austenitic Stainless Steel Sourcebook", October 1991
4. NUREG-1801, Section XI.M12, "Thermal Aging of Cast Austenitic Stainless Steel"


**C-RAI Generic HVAC -2**

The response states that the component type "heat exchanger" is in scope for the intended function of pressure boundary, and not for heat transfer function, contradictory to Tables 2.3.3-9 and 2.3.3-10. Please clarify.

Response

The original response to the RAI did not make it clear to the Staff that subcomponents of heating and coiling coils that had a heat transfer intended function were evaluated as "heat exchangers". The LRA and the Individual Plant Assessment aging management reviews identify where each in-scope coiling coil, heating coil and heat exchanger is required to act as a pressure boundary and remove heat as appropriate. If a heating coil, cooling coil or heat exchanger is required to transfer heat it is so noted in Tables 2.3.3-9 and 2.3.3-10 as heat exchanger. As described above, the component types listed in Tables 2.3.3-9 and 2.3.3-10 represent all of the components of that type in the particular systems. Thus it is possible, depending on the actual device under review, to only use one of the functions listed as intended functions in the table. Since there are heat exchangers (or tubes) within the evaluated systems that do have a heat transfer function the table is correct.

Example:

The "A" standby auxiliary feed water pump room cooler - AFA01A shown on drawings 33013-1250,2-LR and 33013-1869-LR is identified on the drawings using the symbol for "cooling coil", and is included in the component type group "cooling coil". The tube side, OD and ID functions, are evaluated under "heat exchanger". Looking at the review tools for Essential Ventilation for AFA01A, in addition to AFA01A(cooling coil) there is also AFA01A-tubing-ODPB and AFA01A-tubing-ODHX (heat exchangers).