Lewis Sumner
Vice President
Hatch Project Support

Southern Nuclear
Operating Company, Inc.
40 Inverness Parkway
Post Office Box 1295
Birmingham, Alabama 35201

Tel 205.992.7279
Fax 205.992.0341

SOUTHERN COMPANY
Energy to Serve Your World℠

January 31, 2001

Docket Nos. 50-321
50-366

HL-6037

U. S. Nuclear Regulatory Commission
ATTN.: Document Control Desk
Washington, DC 20555

Edwin I. Hatch Nuclear Plant
Transmittal of Responses to
License Renewal Draft Open Items

Ladies and Gentlemen:

By letter dated January 5, 2001, the NRC transmitted approximately 61 draft open items related to the review of the Hatch license renewal application to Southern Nuclear Operating Company (SNC). SNC has reviewed these items and has developed additional information for many of them in an effort to aid the staff in closing as many open items as possible before issuance of the draft SER. This information is being transmitted by this letter. Enclosure 1 contains responses to selected draft open items. Enclosure 2 is a description of a non-EQ cable aging management program in response to open item 51. Enclosure 3 is revised evaluation boundary drawings provided in response to confirmatory item 2.3.4.2-2. Enclosure 4 is a torus visual aid provided in response to draft open items 41, 42, and 46.

If you have any questions concerning this information, please contact this office.

Respectfully submitted,

Lewis Sumner

H. L. Sumner, Jr.

HLS/JAM

Enclosures: 1. Responses to Selected Potential SER Open Items
2. Non-EQ Insulated Cables and Connections Aging Management Program
3. Revised Evaluation Boundary Drawings
4. Torus Cross-Section Visual Aid

A083

cc: Southern Nuclear Operating Company
Mr. P. H. Wells, Nuclear Plant General Manager
Mr. C. R. Pierce, License Renewal Services Manager

U. S. Nuclear Regulatory Commission, Washington, D.C.
Mr. C. I. Grimes, Branch Chief, License Renewal and Standardization Branch
Mr. L. N. Olshan, Project Manager-Hatch
Mr. W. F. Burton, Project Manager-Hatch License Renewal (w/ enclosures)

U. S. Nuclear Regulatory Commission, Region II
Mr. L. A. Reyes, Regional Administrator
Mr. J. T. Munday, Senior Resident Inspector-Hatch

ENCLOSURE 1

CONSOLIDATED SNC RESPONSES FROM ELECTRONIC COMMUNICATIONS

DATED JANUARY 9, 16, 22, 23, AND 24, 2001

TO POTENTIAL DRAFT SER OPEN ITEMS IN NRC'S

JANUARY 5, 2001 LETTER TO SNC

ADDITIONAL INFORMATION KEYED TO POTENTIAL DRAFT OPEN ITEM AND CONFIRMATORY ITEM NUMBERS IN NRC'S JANUARY 5, 2001 LETTER TO SNC

The following additional information addresses potential open items for the draft SER. This additional information is provided pursuant to various RAIs and follow-on discussions. The information is arranged numerically using the numbering scheme of the January 5, 2001 letter from NRC to SNC which transmitted some potential open items to SNC. In parentheses, for cross reference, are draft open item numbers from earlier versions. Note that these numbers do not necessarily correspond to the "final" open item numbering scheme to be used by NRC.

2. (2.1.3.1-1)

In Section 2.1.2.4 of the LRA, the applicant states that 10 CFR 54.4(a)(1)(i, ii, and iii) provide the scoping criteria for determining the functions of safety-related systems and structures that are within the scope of the rule. The applicant adds that each system and structure function in the plant listing of scoping results (Table 2.2-1) was determined with respect to these requirements by addressing the following questions:

- Is the system or structure function identified as safety-related because it is relied upon during and following design basis events to ensure the integrity of the reactor coolant pressure boundary?
- Is the system or structure function identified as safety-related because it is relied upon during and following design basis events to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition?
- Is the system or structure function identified as safety-related because it is relied upon during and following design basis events to ensure the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 100.11?

The staff notes, however, that the current language in 10 CFR 54.4 states, in part, that plant systems, structures, and components within the scope of license renewal are (1) safety-related systems, structures, and components which are those relied upon to remain functional during and following design basis events (as defined in 10 CFR 50.49(b)(1)) to maintain the following functions:

1. The integrity of the reactor coolant pressure boundary;
2. The capability to shut down the reactor and maintain it in a safe shutdown condition; or
3. The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guidelines in §50.34(a)(1), §50.67(b)(2), or §100.11 of this chapter, as applicable

Therefore, the applicant is requested to:

1. Provide a written evaluation that addresses the impact, if any, of not having explicitly considered in its scoping methodology for Plant Hatch, systems, structures, and components that are relied upon to ensure the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guidelines in §50.34(a)(1), §50.67(b)(2), or §100.11 10 CFR Part 50, as applicable, consistent with the facility's CLB; and

2. Submit a revision or supplement to the LRA that reflects the conclusions reached in such evaluation, and the current language in 10 CFR 54.4.

Response:

Plant Hatch has not applied the alternate source term provisions of 10 CFR 50.34(a)(1) and 50.67(b)(2) into its design or licensing basis; thus, there is no effect on Hatch license renewal scoping.

SNC amends its response provided via electronic communication on January 9, 2001 to further state that

> <u>Specifically, 10 CFR 50.34(a)(1) only applies to new applicants of construction permits and therefore does not impact the Hatch License Renewal Application.</u>

3. (2.2-1)

RAI 2.2-SR-2 requested the applicant to clarify the intended function for the primary containment chilled water system (Unit 2 only) listed in Table 2.2-1 of the LRA because it was different from the function described in Section 2.3.4.10 of the LRA. Table 2.2-1 cited drywell cooling as the intended function of this system that placed it in scope for license renewal. However, Section 2.3.4.10 stated that containment integrity was an additional intended function. The applicant stated in the August 29, 2000, RAI response that the correct function was containment integrity. However, another inconsistency was identified by the staff in its review of the RAI response. The system-to-function matrix submitted by the applicant (described above) listed two intended functions (drywell cooling and containment integrity). The applicant should resolve the discrepancies between the intended function identified in LRA 2.2-1 (drywell cooling only), the intended function identified in the response to RAI 2.2-SR-2 (containment integrity only), and the intended functions identified in LRA Section 2.3.4.10 and the matrices submitted by e-mails on May 24, 2000 and June 16, 2000 (drywell cooling and containment Integrity).

Response:

SNC has revised the text of the intended function description (LRA section 2.3.4.10) for P64-02 to more clearly indicate that the intended function is primary containment integrity that is afforded by the pressure boundary of the drywell cooling "subsystem" inside containment. In addition, a footnote has been provided for the intended function description which indicates the label (Drywell Cooling) is being retained for consistency with Plant Hatch Maintenance Rule function labels. In addition, a similar footnote has

been added to Table 2.2-1 to indicate that the label is being retained but the intended function is primary containment integrity.

The system-to-function matrix which was provided to NRC as an aid in the review of the Hatch LRA identifies those functions (both in scope and not in scope) whose boundaries include a part of a system. For example, the primary containment chilled water system (Unit 2 only) is designated as 2P64 in the Hatch nomenclature. The evaluation boundaries for functions 2C61-01 and 2P64-02 each include one or more 2P64 components. Thus, the system-to-function matrix includes both functions (identified by their labels) with respect to 2P64. LRA Table 2.2-1 can be consulted to determine which functions are in scope - that is, which functions are intended functions. The related section devoted to each intended function provides a textual description of the intended function.

The applicable pages from LRA Table 2.2-1 and Section 2.3.4.10 have been reproduced on the following pages with the above changes incorporated.

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
P51	Station Service Air	No	P51-01 Compressed Air Supply
		No	P51-02 RWCU, FPC & Condensate Demin Low Pressure Air Blowers
P52	Instrument Air	Yes	P52-01 Non-Interruptible Essential Instrument Air Supply
		No	P52-02 Interruptible Essential Instrument Air Supply
P61	Auxiliary Boiler	No	P61-01 Start-up Steam Supply
P62	Environmental Monitoring	No	P62-01 River Influent/Effluent Monitoring
P63	Turbine Building Chillers	No	P63-01 Turbine Building Cooling
P64	Primary Containment Chilled Water (Unit 2)	No	P64-01 Reactor Building/Radwaste Building Cooling
		Yes	P64-02 Drywell Cooling[1]
P65	Reactor Building Chilled Water	No	P65-01 Reactor Building Equipment/Area Cooling
P67	Control Building Chilled Water	No	P67-01 Chilled Water to Control Building HVAC
P70	Drywell Pneumatics	Yes	P70-01 Nitrogen Supply to Drywell Equipment
		No	P70-02 Containment Environment Control
P73	Hydrogen Water Chemistry	No	P73-01 IGSCC Mitigation
P85	Zinc Injection	No	P85-01 Inhibit Radiation Build-up
R13	Isophase Bus	No	R13-01 Bus Duct Cooling
		No	R13-02 Power Transmission
		No	R13-03 Metering & Relaying
R20	Plant A/C Electrical	Yes	R20-01 1E A/C Electrical Supply
		No	R20-02 Station Service A/C Electrical Supply
		No	R20-03 Grounding
R33	Conduits, Raceways & Trays	Yes	R33-01 Wire & Cable Integrity
		Yes	R33-02 Wire & Cable Integrity / Non-Safety Related

[1] The label is retained for consistency with Plant Hatch Maintenance Rule function labels. The intended function is primary containment integrity.

2.3.4.10 Primary Containment Chilled Water System [P64] (Unit 2 Only)

System Description

The primary containment chilled water system is designed to maintain the drywell area below a maximum volumetric average temperature of 150 °F dry bulb during normal operation by providing chilled water to the drywell fan coil units. The primary containment chilled water system consists of two chilled water recirculation pumps, two centrifugal chillers, a chemical addition tank, a chemical feed pump, and an expansion tank. Each chiller consists of a refrigerant compressor, condenser, cooler, accessories, and controls. Each chilled water recirculation pump circulates chilled water through the respective chiller to the fan coil units. Service water from the reactor building service water system is circulated through the chiller condensers for cooling. Demineralized water provides a source of makeup water for the chilled water system. The expansion tank, chemical addition tank, and associated makeup water supply are shared with the reactor and radwaste building chilled water system.

More information may be found in Unit 2 FSAR subsection 9.4.6.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P64-02 – Drywell Cooling.[2] The primary containment chilled water system provides cooling water to the Unit 2 drywell coolers. The drywell coolers provide temperature control for the drywell area during normal plant operation, but are not relied-upon to perform any cooling functions under the current licensing basis of the plant.

The primary containment chilled water system is only in the scope of License Renewal to the extent that it provides containment integrity. Specifically, the inscope components function to maintain primary containment via a closed loop inside containment.

[2] The label is retained for consistency with Plant Hatch Maintenance Rule function labels.

4. (2.2-2)

RAI 2.2-SR-4 requested the applicant to provide the basis for excluding the drywell cooling system (Unit 2 only) from the scope of license renewal. Section 9.4.6.2.1 of the Unit 2 FSAR states that the drywell cooling system is relied upon to maintain the drywell temperature below 165 ^{0}F during a loss of offsite power. In the August 29, 2000, RAI response, the applicant responded that the drywell cooling system is not a safety system and is not relied upon to mitigate a loss-of-coolant accident combined with a loss of offsite power. The applicant further stated that this system is not relied upon to control drywell temperature during a station blackout. The staff agrees with these statements; however, 10 CFR 54.4 requires that non-safety systems whose failure could prevent the satisfactory capability to shutdown the reactor or maintain it in a safe shutdown condition also be included in the scope of license renewal. The staff's concern relates to environmental qualification of equipment or sensors in the drywell. It appears from the FSAR that this system may be required to maintain temperature conditions in the drywell during a loss of offsite power so that the applicant can maintain the capability to safely shut down the reactor or maintain it in a safe shutdown condition. The FSAR does not provide any information as to the basis for the 165 ^{0}F requirement. Therefore, this is an open item, pending a determination of the basis for the 165 ^{0}F by the applicant.

Response:

The FSAR in Section 9.4.6.2.1 states that the drywell coolers are required to maintain a maximum drywell temperature of 165° F during a LOSP. It has been determined that the source of the 165° F temperature is a GE document entitled "BWR Plant Requirements" dated 1971. This document identifies design requirements which are the responsibility of the purchaser to insure that GE-supplied equipment are operated within their design parameters and to establish compatibility of GE equipment with the balance of plant. Page 16-2 of this document states that during a scram a large heat load is released into the drywell from the CRD scram discharge piping. It further states that part of this heat is released in the area under the vessel, and the temperature in this area must not rise above 165° F during this time or permanent damage to the neutron monitoring cables located in this area will result. Heat loads for the drywell are supplied in this section of the document. Bechtel performed a calculation in 1970 which determined that the drywell temperature under the vessel will remain below 165° F during a scram assuming one train of the drywell cooling system is operating.

The neutron monitoring cables are within the scope of license renewal and the aging characteristics are evaluated in an aging management review. These cables are constructed using either cross-linked polyethylene (XLPE), cross-linked polyolefin (XLPO), ethylene propylene rubber (EPR), or silicone rubber insulation. The most limiting of these insulation types is XLPE which is good for 60 years in a temperature environment of 151° F as described in the AMR. The other insulation types are good for 60 years at temperatures of 186° F or less.

The neutron monitoring cables provide the interface between the SRM, IRM, and LPRM in-vessel neutron detectors and the Reactor Protection System. The scram function of the Reactor Protection System is in the scope of license renewal. Under the scenario discussed in the FSAR and the GE document, a scram would have to occur simultaneously with a loss of one train of drywell cooling. The undervessel region would heat up due to the scram discharge piping heat load, and possibly adversely affect the

cable due to the high temperature. However, for this particular event, any adverse effects on the cable would be inconsequential because the cables would have already performed their function.

The GE document gives no basis for the statement that the cables could be damaged if the temperature rises above 165° F. In reality the cables could withstand temperatures much higher than 165° F for short periods of time and suffer no damage which would affect the cables' performance. This fact is borne out by the volume of test data for cables with similar insulation which have undergone LOCA and main steam line break testing since the mid-1980's at temperatures in excess of 340° F for several hours. The heat produced by a scram with a simultaneous loss of drywell cooling will not affect cable operability. Extended periods of high temperatures may accelerate aging of the insulation and ultimately have an effect on the cable's life. Events such as this are evaluated on a case-by-case basis.

The neutron monitoring cables are not covered by the environmental qualification program, and the 165° F temperature limit has no effect on any EQ equipment. Electrical equipment included in the EQ program located inside the drywell is qualified for the worst-case normal temperature to which it is exposed on a location-specific basis. These temperatures are monitored and recorded under the guidelines of the EQ program. Changes in normal service temperatures are factored into the qualified life calculations on a periodic basis. Neither the drywell cooling system nor its associated chilled water or plant service water cooling source are relied upon to maintain temperatures, and these systems are not relied upon for qualification of equipment under the EQ program.

The following additional clarifying information is provided for potential open item 4 concerning the status of the drywell cooling system.

The neutron monitoring cables in the drywell, which are the subject of this open item, are not included in the EQ program. Therefore, these cables do not have qualified lives. However, any event which could call into question the operability of the cables would be investigated under the corrective actions program. A temperature spike such as that postulated in the scenario in which a scram occurs simultaneously with a loss of drywell cooling would be an event which would result in a condition report being written, with a corrective action to investigate the condition and operability of the cables. These cables are included in the scope of the cable AMP described in response to potential draft SER open item 51. See the response to open item 51 for additional information about that program.

12. (2.4.3-2)

RAI 2.4-1 requested the applicant to provide clarifying information (either drawings or written description) to define the boundaries of drywell penetrations that are within the scope of license renewal. The drywell penetration components subject to an AMR are listed on Table 2.4.6-1 of the LRA. In its August 29, 2000, response to the staff's RAI, the applicant provided no additional information. Since the applicant did not provide drawings or a written description clarifying which drywell penetrations are considered to be within the scope of license renewal, the staff considers this to be an open item.

Response:

All drywell penetrations are in scope for license renewal at Plant Hatch.

13. (2.4.3-2)

RAI 2.4-1 requested the applicant to provide clarifying information (either drawings or written description) to define the boundaries of reactor building penetrations that are within the scope of license renewal. The reactor building penetration components subject to an AMR are listed on Table 2.4.7-1 of the LRA. In its August 29, 2000, response to the staff's RAI, the applicant provided no additional information. Since the applicant did not provide drawings or a written description clarifying which penetrations are considered to be within the scope of license renewal, the staff considers this to be an open item.

Response:

All external reactor building penetrations are in scope for license renewal at Plant Hatch.

14. (2.4.3-1)

In RAI-2.4-RB-3, the staff stated that airlock water stops appear to perform an intended function because they are part of the pressure boundary for the secondary containment. Accordingly, they should be included within the scope of license renewal. The applicant responded that the three-bulb rubber water stop in the joint between the railroad airlock and the reactor building was not identified in the LRA. The applicant agreed that the three-bulb water stop is part of the pressure boundary for the secondary containment, does contribute to the intended function, and should have been included in the LRA. The applicant stated that the water stop will be subject to an AMR and the results provided in a subsequent submittal.

Response:

A screening record was prepared for the three-bulb waterstop embedded in the separation joint between the Unit 1 Reactor building and the railroad airlock structure. Thus, the three-bulb waterstop has been added to the scope of license renewal. The stated intended function of this waterstop is to "Provide pressure boundary or fission product retention barrier to protect public health and safety in the event of any postulated DBEs." The waterstop has been addressed by AMR. It is subjected to an embedded environment and it has been determined that there are no detrimental aging effects, as described below.

The three-bulb waterstop embedded in the joint between the reinforced concrete railroad airlock structure and the reinforced concrete east wall of the Unit 1 reactor building is subjected to normal Reactor building temperatures of up to 90^0 F. Therefore, the rubber waterstop material will not be subject to degradation due to thermal exposure.

The three-bulb waterstop embedded in the joint between the reinforced concrete railroad airlock structure and the reinforced concrete east wall of the Unit 1 Reactor building is

not subjected to significant radiation exposure. There are no significant radiation sources near the joint and radiation contamination in this area is considered not to contribute to any aging effects.

16. (3.1.2-1)

In Sections A.1.2 and B.1.2 of the LRA, the applicant describes the CCW chemistry control program, which manages, in part, the aging effects of stainless steel, carbon steel and copper based alloy components exposed to the CCW environment. The applicant should provide more detail regarding the source of CCW and the applicable aging effects of components storing and/or delivering the water to this system.

Response:

Makeup water for CCW systems is exclusively provided by the demineralized water system which supplies clean, de-ionized water to CCW systems. The DWST and associated components which deliver makeup water are not within the scope of license renewal at Plant Hatch and are not subject to an aging management review.

The effects of aging in CCW system components in the scope of license renewal are mitigated by CCW chemistry controls as described in the LRA, section A.1.2 and the subsequent October 10, 2000 RAI response submittal, section B.1.2. As such, even though degradation of the DWST and associated delivery components could potentially contaminate the makeup water with some residual corrosion products or biological organisms, adequate chemistry controls are maintained by CCW chemistry control.

DWST chemistry controls are described in LRA section A.1.6 and the subsequent October 10, 2000 RAI response submittal, section B.1.6 and are credited to mitigate aging only in systems where the DWST provides makeup without further chemistry controls , such as the SLC storage tank.

SNC observes that this item may precipitate from a discussion regarding MIC in CCW systems. In a previous telecon, SNC discussed with the staff some probable sources of biological contamination including PSW Heat Exchanger leaks and maintenance activities. This discussion concludes that the actual sources of biological contamination in CCW systems is not known and is not really a current issue. From a license renewal and aging management perspective, the principal consideration is that through the credited activities, Hatch is actively taking steps to minimize any detrimental impact of biological activity on CCW system components.

17. (3.1.2-2)

The application states that the CCW chemistry control program does not directly monitor or trend age-related degradation and is not credited for such; however, the EPRI document provides the basis for trending, tracking, and evaluating CCW chemistry. The applicant makes note that engineering personnel assist in performing evaluations of the structural integrity of the in scope plant systems and, when necessary, chemistry modification is performed. The applicant should provide more detail of the structural

integrity evaluations performed and how these evaluations are used in conjunction with chemistry modification.

Response:

The phrase "structural integrity evaluations" refers to the necessary evaluations that may be performed to limit and prevent future chemistry excursions. In general, these evaluations would be triggered due to observed conditions such as an RBCCW / Plant Service Water heat exchanger leak. These evaluations include assisting chemistry department personnel in locating the sources of raw water in-leakage, the subsequent engineering actions necessary to eliminate the source of in-leakage, and evaluations necessary to minimize future leakage of raw water into closed cooling water systems.

18. (3.1.4-1)

In Sections A.1.4 and B.1.4 of the LRA, the applicant describes the PSW and RHRSW chemistry control program, which manages, in part, the aging effects of carbon steel, cast iron, copper alloy, galvanized steel and stainless steel components exposed to the PSW and residual heat removal service water system environment. The PSW and RHR service water are drawn from two raw water sources: river water supplied from the Altamaha River and well water supplied from deep draft wells located on site. The components exposed to a PSW and RHR service water environment are found in the PSW system and the residual heat removal system.

The staff requests the applicant to reconcile the discrepancy of crediting this program for the traveling water screen/trash racks system in Table 3.2.4-16 of the LRA, which is not listed in the scope section of B.1.4 of the LRA.

Response:

The W33 designator has been added to the scope section of B.1.4 to indicate that an isolation valve in the screen wash system credits PSW and RHRSW chemistry control. This notation was inadvertently omitted from the Appendix B document when it was transmitted to NRC.

LRA Table 3.2.4-16 correctly indicates that only the line item "valve bodies" credits this chemistry program to mitigate the effects of aging. The line item entry is for an isolation valve in the screen wash line credited by the FHA safe shutdown list. The LRA does not credit PSW and RHRSW chemistry control to manage aging of the traveling water screens and trash racks.

34. (3.1.29-1)

The applicant stated in Section B.3.7 of the LRA that the scope of this program included structures and components within the nuclear boiler system, residual heat removal system, core spray system, high pressure coolant injection system, reactor core isolation cooling system, and primary containment purge and inerting system. However, only a percentage of the components within the scope of the program will be examined during each inspection period. The inspection locations will be based on engineering

judgement and will include areas predicted to be most susceptible to corrosion, such as weld heat affected zones and crevices. The sample set may also include inspection points above the suppression pool water level because the "splash zone" can be a susceptible area. Regarding the inspection scope, SNC stated, in response to RAI 3.1.29-2 in its October 10, 2000 submittal, that a percentage of the components within the scope of the program would be examined during each inspection period. The staff requests that the applicant provide the specific percentage of components that will be examined during each inspection period, compared to the entire population under consideration. The staff requests this information so that it can determine whether the results of a limited sample size may be considered representative of, and therefore applied to, the entire population. The applicant also stated that this sample would be biased towards the areas most likely to exhibit corrosion related degradation. The staff requests that the applicant discuss the specific considerations for determining these areas (e.g, flow rates, temperatures, weld locations, etc.).

Response:

The torus submerged component inspection program will initially inspect a sample set of approximately 10 percent of the uncoated components located within the torus. The total percentage of components inspected may be revised up or down based on the results of the initial inspections. If corrosion were to occur, localized corrosion (crevice corrosion, pitting, or microbiologically influenced corrosion) is expected to be the most likely mode of degradation. For stainless steels and alloy steels, past experience indicates that environmental factors must exceed some minimum threshold for localized corrosion initiation and, that if initiation occurs in one component, it is likely to occur in similar areas of other components. The excellent past operating history of stainless steel and alloy steel components in the torus at Plant Hatch indicates that environmental thresholds have not been regularly exceeded in the past. As such, SNC concludes that extended intervals between inspections and limited sample sizes are justified until such time as significant localized corrosion is identified.

Inspections will focus on those locations more likely to exhibit localized corrosion. These locations include austenitic stainless steel welds and weld heat affected zones, creviced areas, areas potentially covered by debris or sludge, and dissimilar metal connections or mating surfaces.

35. (3.1.29-2)

The acceptance criteria for the program states that "Any unacceptable indication of corrosion will be evaluated by further engineering analysis..." This statement implies that some threshold has already been reached and a judgement (presumably based on an analysis) has been made. The staff requests that the applicant provide the specific acceptance criteria for the torus submerged components inspection program. The acceptance criteria should clearly state the threshold at which the site's corrective action program will be implemented. The staff requests this information so that it can determine whether the acceptance criteria support the detection and evaluation of aging effects such that the intended functions remain intact.

Response:

SNC wants to encourage a questioning attitude in the initial identification of potential conditions that might warrant further evaluation and or correction. Establishing an acceptance criterion, or threshold, for the initial identification of a condition requiring further evaluation works against that objective. Any indication of corrosion, if judged to be significant by the inspection personnel, will be evaluated by an engineering analysis and, if warranted, additional inspections will be performed. When appropriate, engineering analyses will include evaluations of component acceptability based upon the design code of record. Corrective actions, if required, will be addressed through the existing Plant Hatch corrective actions program.

38. (3.2.3.2.3-1)

The staff is concerned that unanticipated high cycle thermal fatigue resulting from thermal stratification or turbulent penetration could result in cracking of small bore piping. This type of cracking is not evaluated as part of the component cyclic or transient limit program. The ASME Code Class 1 inspection requirements for small bore piping include a surface examination, but not a volumetric examination. In order to detect cracking resulting from high cycle thermal fatigue, a volumetric examination is required. Since the proposed program does not include a volumetric examination, it may not be capable of detecting high cycle thermal fatigue cracks resulting from thermal stratification or turbulent penetration. Therefore, the applicant should supplement the existing programs with volumetric examination of the limiting locations in small bore piping systems, which could have thermal stratification or turbulent penetration.

Response:

In addressing the issue of thermal fatigue cracking of Class 1 piping components as a result of thermal stratification or turbulent penetration, SNC maintains that the current potential open item issue is limited to ASME Class 1 pipe welds which meet two specific criteria. First, ASME Section XI, Table IWB-2500-1, based on pipe sizes less than NPS 4, requires only surface examination. Second, the pipe size is sufficiently large that a failure could result in a rate of coolant loss in excess of the capacity of makeup systems (as described in IWB-1220(a)). An analysis performed by GE in 1997 determined the line sizes which could be excluded from ISI Class 1 surface and volumetric examination based on makeup capacity to be as follows:

- Hatch Unit 1 2.5" diameter for water and 5.0" diameter for steam
- Hatch Unit 2 2.1" diameter for water and 4.2" diameter for steam

Water lines are those which penetrate the RPV below normal water level and steam lines are those which penetrate the RPV above normal water level. Therefore, based on these values, water containing piping of NPS 2 and smaller and steam containing piping of NPS 4 and smaller are excluded from further consideration regarding the issue of thermal fatigue as presented in this open item.

Based on the above postulates, a review of Plant Hatch piping drawings reveals the following pipe segments that do not require volumetric examinations per IWB-2500, and

are large enough that a failure could result in a rate of coolant loss in excess of available makeup capacity:

- H16188 – RWCU piping between check valve 1G31-F203 and the branch connection to the HPCI injection line. This is a short segment of NPS 3 piping containing three welds.

- H16188 – 3" x 4" expander downstream of 1G31-F039 (check valve at RWCU discharge to the RCIC injection line. Only the weld at 1G31-F039 is less than NPS 4.

For these specific segments, a cursory evaluation of location, geometry, and normal operating conditions indicates that these piping segments are not in areas where thermal cycling due to turbulent eddy currents or thermal stratification would be expected. Additionally, these locations, with regard to turbulent penetration or thermal stratification, are likely bounded by volumetric examinations of other ASME Class 1 piping welds conducted under the requirements of other inspection activities such as ASME Section XI, Table IWB-2500-1 or NUREG 0619.

Therefore, SNC concludes that, based on volumetric examinations of bounding locations conducted by other programs, no additional aging management actions need be taken by Plant Hatch regarding this open item.

SNC notes that other NPS 3 piping does exist in the main steam drains. However, the diameter of this piping is less than the makeup capacity limit of 4.1" for steam side piping and is therefore excluded from further consideration.

40. (3.4.3.2-1)

In RAI 3.4-9, dated July 28, 2000, the staff noted that the applicant stated in the LRA that selective leaching was a corrosion mechanism that may result in loss of material for brass and gray cast iron components exposed to a raw water environment in the plant service water and fire protection systems. Given that selective leaching may not be detectable through standard visual inspections, the staff asked the applicant to discuss how the various inspection and testing programs are adequate to manage the aging effect (loss of material) resulting from this aging mechanism. In its October 10, 2000 response, the applicant stated that for susceptible components in the fire protection system, the components' functionality is closely linked to performance characteristics that are currently monitored though fire protection activities. The applicant also stated that no age-related failures were identified for these components in the plant's operating history. However, the applicant has committed to destructively examining one plant service water component from each commodity (brass and gray cast iron) in existence at Plant Hatch within the time frame of August 6, 2009 to August 6, 2014 for Unit 1 and June 13, 2013 and June 13, 2018 for Unit 2. The staff requests that the applicant provide additional information related to this one-time destructive examination, including what inspection methods and procedures will be used and the basis for the methods, what data will be collected during the inspection and the basis for the choice of data, what criteria will be used to evaluate the inspection findings, what actions will be taken based on the inspection findings, and how the findings will be documented.

Response:

As discussed previously, SNC has committed to take additional actions to detect detrimental selective leaching (i.e., de-alloying corrosion) of the currently installed brass or cast iron components. Selective leaching is a corrosion process in which one constituent of an alloy is preferentially removed, leaving behind a an altered residual structure. Metal in the affected components becomes porous and loses much of its strength, hardness, and ductility. Therefore, examination of component metallurgy, including hardness values, is an appropriate methodology to detect the existence of selective leaching that may not be detectable by nondestructive methods.

Component types susceptible to selective leaching whose failure, as determined by engineering evaluation, would not have an adverse effect on the system's intended functions will be excluded from the set of components considered under the scope of the examination. Component types whose failure would have an adverse impact on system intended function will be considered.

A Brinell hardness examination will be performed on one gray cast iron casting from a representative gray cast iron casting where sufficient information is available regarding the casting composition to obtain an estimate of Brinell hardness number (BHN). Current plans are to perform this examination in place in accordance with ASTM E10-00 and ASTM A833-84. However, laboratory testing by other methods may be utilized. The resulting BHN will be compared to expected values based on available textbook and vendor data. If the comparison of examination results with vendor data indicates that a significant loss of casting hardness may have occurred, then additional measures will include, as appropriate, additional analysis, sample expansion with additional inspections, and component replacement.

Evaluation of one brass component within the system will be performed utilizing an appropriate method. The examination method may include hardness testing similar to that described above for gray cast irons (either in place or in the laboratory) or component removal with a detailed visual or metallurgical analysis. If the examination results indicate that significant selective leaching may be occurring, then possible additional measures include additional analysis, sample expansion with additional inspections, and component replacement.

If the casting or component represents a portion of the system pressure boundary, "additional analysis", as mentioned above, may be performed to demonstrate that even with some loss of strength, sufficient component strength remains to meet the minimum requirements of the design code of record; thereby providing for continued operation. If the casting or component is not relied upon to maintain system pressure boundary, additional analysis may be performed to demonstrate that adequate component strength remains to retain structural integrity and perform its component intended function.

41. (3.6.3.1-1, Part 1)

In response to the RAI 3.6-36 related to the aging management review of penetrations in the torus, the applicant points out that they are covered under primary containment penetrations in Section C.2.6.2 of the LRA, together with the aging management review of drywell penetrations. Many penetrations in tori are submerged in torus water, an

environment distinctly different from that of the penetrations in drywell, and they require different ISI, coating and leak testing procedures. The staff requests SNC to provide justification why the torus penetrations should not be placed in a commodity group other than that for other components in the primary containment (i.e. drywell).

Response:

A visual aid, in the form of plant drawings (H-15002 for Unit 1 and H-25003 for Unit 2), will be provided separate from this e-mail to show a cross-section of the torus and the locations of the torus penetrations in the immersion (submerged) area. Penetrations are not specifically listed in Section C.2.2.3 of the LRA; however, penetrations, being made of the same materials, are considered to be among the items included in the aging management programs for components submerged in torus water. A list of the penetrations in the torus immersion area is shown below. No aging issues unique to submerged penetrations have been identified in the operating experience of the torus.

A review of torus inspection reports indicate that degradation of the torus coating, in the form of thinned coatings and some pitting corrosion in the torus immersion area is general in nature and occurs primarily on the shell. No specific corrosion has been noted around penetrations welded to the shell. Corrosion is generally more evident near the torus waterline and at or near the bottom of the torus where sludge or small debris collects.

<u>**Unit 1:**</u> Source, Drawing H-15002, Unit 1 TRM Table T7.0-1

Penetration No.	**Function**
X-203	RCIC pump suction
X-204A,B,C,D	RHR pump suction
X-206B,D	PASS sample return & Torus water level
X-207	HPCI pump suction
X-208A,B	Core Spray pump suction
X-209A,B,C,D	Torus water temperature
X-223A,B	Vacuum breaker air supply

<u>**Unit 2:**</u> Source, Drawing H-25003, Unit 2 TRM Table T7.0-1

Penetration No.	**Function**
X-203	RCIC pump suction
X-204A,B,C,D	RHR pump suction
X-206B,D,F,H	B&D spare, F&H Torus water level
X-207	HPCI pump suction
X-208A,B	Core Spray pump suction
X-209A,B,C,D	Torus water temperature
X-218A,B	Construction Drain
X-223A,B	Spare
X-227B	Spare
X-234A,B	Spare

SNC's electronic communication of January 9, 2001 provided additional information regarding issues raised by potential open items 41, 42, and 46. The response to item 41

specifically indicated that SNC would provide a visual aid in the form of two plant drawings to assist NRC staff in the review of the aging management programs for the torus. However, SNC proposes to amend that response by providing the attached artist's rendering of the torus section, along with associated aging management programs. This visual aid is consistent with the discussions held on December 18, 2000 regarding complexities associated with review of aging management activities for the torus. These issues are expressed in potential open items 42 and 46. Thus, SNC provides the visual aid as Enclosure 4 in support of all three potential open items.

42. (3.6.3.1-1)

In response to RAI 3.6-37 related to the specific environment around drywell and torus penetrations, the applicant referred to the programs enumerated in Section C.2 as noted in Tables 3.3.1-3 and 3.3.1-6. The staff specifically needs information for the environment (i.e. temperature, humidity, cumulative radiation, demineralized water) around groups of primary containment penetrations having similar operating histories in order to ascertain that appropriate aging management programs which are tailored to the specific operating history/environment are provided by the applicant for individual groups of containment penetrations. SNC is requested to provide this information. This is part of Open Item 3.6.3.1-1.

Response:

Two types of penetration are considered: electrical and mechanical (piping). Each drywell electrical penetration is composed of the electrical feed-through assembly and the structural piping to which it is attached. These penetrations are included in the EQ program and the electrical, non-metallic assemblies are evaluated and given a qualified life. The structural part of the penetration is managed by the ISI program. The environmental information below can be considered applicable to all drywell penetrations. The worst-case normal inside-containment environment for all drywell penetrations is as follows:

Temperature: 150° F
Radiation: 9.17 E7 Rads (gamma); 4.5 E16 NVT neutron fluence
Humidity: 50% - 90%
Moisture/wetting: None

The environment of torus penetrations varies between the submerged and non-submerged penetrations. The worst-case environment for torus penetrations is as follows:

Temperature: 105 F
Radiation: 1.4 E7 rads gamma
Humidity: 50% - 90%
Moisture/wetting: See visual aid for submerged penetrations

43. (3.6.3.1-2) aka Confirmatory Item 3.6.3.2-1

Table 3.3.1-7 indicates that the aging effects of reactor building (RB) penetrations are managed by the structural monitoring program (SMP) and the protective coating program. However, Section A.2.5 of the LRA does not specifically list reactor building penetrations as part of the SMP. SNC is requested to clarify if the RB penetrations are covered under the SMP, or provide information as to where the aging effects of reactor building penetrations are covered.

Response:

Reactor building penetrations are included in the SMP. Section C.2.6.3 of the LRA, which discusses steel as a commodity group, also explicitly identifies T54-Reactor Building Penetrations as included in the commodity. Listed among the aging management programs associated with this commodity is the SMP. Further, one can refer back to LRA Table 3.3.1-7 and see that the Reactor Building penetrations (T54), described as structural steel, are listed. The credited AMPs are shown as the Protective Coatings Program and the SMP. The FSAR supplement will be revised to show reactor building penetrations included in the structural monitoring program.

The applicable page from LRA Appendix A, Section A.2.5 has been reproduced on the following page with the above change incorporated.

A.2.5 STRUCTURAL MONITORING PROGRAM

A.2.5.1 Description

The Plant Hatch Structural Monitoring Program (SMP) provides condition monitoring and appraisal of certain important structures and structural components. The program is patterned after the Westinghouse Owners Group Life Cycle Management/License Renewal Program.

The covered structures within the scope of license renewal include the reactor buildings (including reactor building penetrations), turbine buildings, intake structure, main stack, diesel generator building, and control building. The condensate storage tank foundations and walls, plant service water valve pits, and nitrogen storage tank foundations are also examined. When practical, digital photography is used to document degradation found.

Structural inspections are primarily visual. Inspected structures include those normally accessible, as well as those below ground or embedded. When normally inaccessible structures are exposed because of excavation or modification, an examination of the exposed surfaces is performed.

A.2.5.2 Sample Size and Frequency

The inspection frequency for plant structures varies according to site conditions and susceptibility to aging degradation. Structures monitored under the provisions of 10 CFR 50.65 (a)(2) are inspected every five operating cycles, unless the conditions, environment, or noted degradation warrant increased frequency. The intake structure is currently inspected every outage because of the humid environmental conditions.

A.2.5.3 Industry Codes, Standards and Acceptance Criteria

The framework for the SMP is consistent with industry guideline NEI 96-03. The NEI 96-03 guidance was conditionally accepted in Regulatory Guide 1.160.

The SMP and supporting programs specify acceptance criteria for structural inspection and evaluation. The acceptance criteria are based upon ACI 349.3R-1996, but also include additional criteria for roof ponding, water leakage, coatings and penetration seals. The SMP acceptance criteria are consistent with NEI-96-03 and NRC Regulatory Guide 1.160, revision 2.

A.2.5.4 Aging Effects Requiring an Aging Management Program

Loss of material, cracking, flow blockage, and material property changes are the aging effects monitored by the Structural Monitoring Program.

A.2.5.5 Enhancements

The scope of the SMP will be expanded to include visual inspections of the following structures and components:

- Sealants in the joints between the reactor building exterior precast siding panels.

44. (3.6.3.1-3)

The response to RAI 3.6-39 indicates that to serve as a fission product barrier, the reactor building penetrations should have an AMP related to the reactor building penetrations' leak-tightness. A review of Hatch Technical Specifications (TS Section B 3.6.4.1) indicates that the limiting condition for operation, its applicability, and action and surveillance requirements for secondary containment provide adequate assurance that the leak-tightness characteristics of these penetrations will be monitored and maintained periodically during the extended period of operation. SNC is requested to provide justification as to why the TS requirements should not be included as part of the total aging management program for reactor building penetrations.

Response:

The following discussion presents SNC's basis for concluding that TS requirements should not be included as part of the overall aging management program for reactor building penetrations.

Numerous penetrations are considered to be secondary containment penetrations. The principal types of penetrations are mechanical (for piping), electrical (for conduits and cable trays) and HVAC (for HVAC ducts).

Mechanical penetrations are of all-welded construction, and have no seals or gaskets (see LRA, Table 3.3.1-7). Also, there are no seals and gaskets in HVAC ducts credited for maintaining secondary containment. Fire penetration seals located in fire barrier penetrations are managed by fire protection activities as shown in LRA Table 3.2.4-18. The penetrations for electrical conduits and cable trays consist of Nelson frames. There are no aging effects for the polymers and the steel of the Nelson Frames per LRA Table 3.4.1-1.

Any contribution of reactor building penetrations to secondary containment inleakage is thus, extremely small. In addition, even if a mechanism were postulated that would result in degradation of penetrations leading to secondary containment inleakage, the Plant Hatch Technical Specifications Surveillance Requirements for secondary containment do not provide a useful tool for license renewal due to the relative magnitude of postulated reactor building penetration inleakage as compared with other, dominant pathways.

Other secondary containment inleakage pathways include reactor building doors and caulked joints associated with the reactor building walls. Reactor building doors are not considered as penetrations. Rather, they are addressed in association with intended function L48-01. Aging management of doors (and door seals) is identified in LRA Table 3.2.4-4. Aging management for reactor building exterior walls (Panel Joint Seals and Sealants) is identified in LRA Table 3.3.1-5.

During a telecon on January 26, 2001 the overall drawdown characteristics of the Reactor Building were discussed. It was noted that, outside and apart from license renewal, as part of the numerous performance-based tests that are routinely performed by Plant Hatch as part of the Technical Specifications, a periodic test is performed which identifies the drawdown characteristics for secondary containment. However, for license renewal, SNC observes that aging degradation of each inleakage pathway contributor is

managed to maintain intended function by programs credited in the LRA. The various applicable sections of the LRA are noted in the above paragraphs.

45. (3.6.3.1-4)

The applicant stated that the turbine building has components that are fabricated from carbon steel and galvanized steel (e.g., anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel) that are exposed to the inside, outside, wetting-other-than-humidity, buried, and embedded environments. The applicant identified loss of material as the aging effect in Table 3.3.1-8 of the LRA. The applicant evaluated the aging effects for these materials and environment in Sections C.2.6.1 and C.2.6.3 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting and MIC.). The applicant identified cracking as an aging effect for concrete and masonry block walls in Section C.2.6.1, but did not identify cracking as an aging effect in Table 3.3.1-8. SNC is requested to clarify this discrepancy.

Response:

In a December meeting, SNC indicated that this question was addressed in the response to RAI 3.6-52. During the meeting, NRC further requested that SNC address whether any block walls within the scope of A46 evaluations are in the turbine buildings. Based on a review of design documentation, SNC responds that there are no A46 block walls in the turbine buildings.

46. (3.6.3.2-1)

In response to RAI 3.6-41 related to tori corrosion, the applicant provided a description of torus degradations found in both Plant Hatch units. However, the applicant emphasized that, in spite of the degradations, the actual shell thicknesses are well above the required minimum shell thicknesses. For both the units, the applicant stated that it plans to continue desludging, visual examination, and spot coating repairs periodically, based on the history of past inspection. The staff believes that operating experience at Plant Hatch and other industry operating experience related to tori corrosion indicate a need for a program to manage tori corrosion during the period of extended operation. SNC is requested to provide justification as to why this program should not be a separate program in the LRA.

Response:

The protective coatings program specifically addresses corrosion of torus surfaces and structures required to maintain primary containment and any other coated surfaces within the torus. The torus submerged components inspection program specifically addresses corrosion of uncoated stainless steel and alloy steel components within the torus. SNC's commitment is to maintain the torus by applying these programs to manage aging. SNC intends to implement these two programs individually at Plant Hatch instead of identifying all activities under the torus submerged inspection program. In addition, the coatings in the torus are inspected by plant personnel who routinely deal with coating issues whereas the torus submerged components inspection program will be used by other plant personnel. Identifying these two programs individually in the license renewal application as they are intended to be implemented eliminates future potential confusion of the scope and provides distinction of the skill and training requirements of these programs. These programs are described in detail in previous SNC submittals regarding Plant Hatch license renewal.

The following information sources are available:

- Hatch LRA, section A.2.3 and A.3.7.
- 10/10/2000 Appendix B Program Descriptions, Sections B.2.3 and B.3.7.
- 10/10/2000 RAI Responses; RAIs 3.1.29-1 through 3.1.29-13 and 3.6-41.

47. (3.6.3.2-2)

Section C.2.6.2 of the LRA stated that the ISI program provides for visual inspection of the internal and external surfaces and fasteners, thereby providing assurance that the containment shell and internal structures have not degraded due to corrosion and/or cracking. 10 CFR 50.55a endorsed the ASME Section XI, Subsection IWE Code with the condition that 10 CFR 50.55a(b)(2)(ix) provisions be complied with. The LRA is not clear regarding this requirement. RAI 3.6-11 asked SNC to confirm that both the scope and the detail of the inspection implemented in accordance with ASME Section XI Table IWE-2500-1 also comply with the requirements for 10 CFR 50.55a(b)(2)(ix). The RAI also asked SNC to discuss how it is implementing a staff position that applicants for license renewal need to evaluate, on a case-by-case basis, the acceptability of inaccessible areas even though conditions in accessible areas may not indicate the presence of degradation in inaccessible areas. SNC stated that it complies with the

inspection requirements of 10CFR50.55a(b)(2)(ix) with one exception. Details of this exception, which is identified as Plant Hatch's relief request MC-9, are contained in SNC's submittal to the NRC dated July 19, 2000. SNC further stated that Section C.2.6.2 of the LRA identifies any applicable aging effects for steel commodities for primary containment and internal structures. Aging effects determined to require management are based on the environment present for the commodity. Each commodity was evaluated for the maximum expected conditions, such as maximum neutron exposure, elevated temperature and high humidity. SNC maintained that neutron exposure and elevated temperature do not exceed the threshold limits where degradation could occur. Other environmental conditions do not result in different aging effects for inaccessible areas than are applicable to accessible areas. Therefore, for inaccessible areas, no aging effect has been identified that is different from those resulting from the environmental conditions in the accessible areas. On the basis of the review of the above information, the staff concludes that SNC complies with the requirements for 10 CFR 50.55a(b)(2)(ix). However, SNC did not fully answer the second part of the question related to implementation of the above noted staff position. SNC is requested to provide additional information regarding the staff position.

Response:

SNC's programmatic activities related to this item are consistent with the draft GALL. In particular, the Plant Hatch inservice inspection program included requirements of the NRC Final Rule 10CFR50.55a [including 10 CFR 50.55a(b)(2)(ix)] along with the ASME Section XI Subsection IWE for examination of the Class MC components.

At Plant Hatch, the designation "inaccessible areas" is limited to two specific areas:

- Embedded containment shell
- Containment basemat and buried external walls

Aging is an issue for the containment basemat and buried external walls if groundwater or soil aggressive chemical limits per NUREG-1611 are exceeded.

The groundwater and soil parameters at Plant Hatch are within the acceptable limits (pH >5.5, chloride <550 ppm, & sulfate <1500 ppm) specified in NUREG-1611. The soil chemistry at Plant Hatch should be essentially the same as it was before and after the plant was constructed. The soil in the vicinity of the seismic category I structures is compacted backfill with non-aggressive chemical characteristics. The soil in the remainder of the plant site area is generally undisturbed soil. Soil chemistry generally reflects the same chemical composition as the ground water and surface water to which it is exposed. The water chemistry in the Altamaha River is very nearly the same as it was when the plant was constructed. The chemistry of the soil in the vicinity of the plant buildings should also be very nearly the same as it was when the plant was constructed.

Thus, SNC concludes that ground water is not aggressive, and no special program is required. However, the Structural Monitoring Program document will be revised to include the following directive: "Additional emphasis will be placed on the importance of inspecting and documenting the condition of normally inaccessible (underground or embedded) structures, whenever the inaccessible structural components are exposed or uncovered."

Aging is not a concern for the embedded containment shell, if the following conditions are verified:

1. Concrete meeting the requirements of ACI 318 or 349 and 201.2R was used for the containment concrete in contact with the embedded containment shell or liner.
2. The concrete is free of penetrating cracks
3. The moisture barrier is subject to aging management activities.
4. Boric acid (or other chemical) spills or water ponding are not common in the containment.

Concrete quality in contact with the embedded containment liner at Plant Hatch meets or exceeds the requirements of ACI 318 and ACI 201.2R. The concrete is subjected to periodic inspection to assure that it is free of penetrating cracks. The moisture barrier is subject to IWE Category E-D Examination. Repair or replacement is performed based on inspection results. Boric acid is not used, and other chemical spills or water ponding are not common in the containment.

51. (3.7.2.2-2)

Sections 3.4, C.1.3 and C.2.5 of the LRA conclude that no aging effects associated with high temperature and radiation require aging management for cables, connectors, splices, and terminal blocks. On July 14, 2000, the staff issued RAI 2.5 requesting SNC to provide, a description of the following:

- An aging management program for accessible and inaccessible electrical cables and connections that may be exposed to an adverse localized environment caused by heat or radiation and,

- An aging management program for accessible and inaccessible electrical cables used in instrumentation circuits that are sensitive to a reduction in conductor insulation resistance exposed to an adverse localized environment caused by heat or radiation.

SNC did not provide a cable aging management program, and maintains that the evaluation of non-EQ cables determined that each cable type was capable of performing its function for the entire plant life, including the renewal term.

The staff believes that the SNC basis for not proposing an AMP for cables, connectors, splices, and terminal blocks is not consistent with previous license renewal reviews, SAND96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants," and EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments." Therefore, the staff request that the applicant provide an AMP for cables, connectors, splices, and terminal blocks that is consistent with the guidelines identified above.

Response:

Although SNC does not believe a non-EQ cable aging management program is required to adequately manage aging effects during the renewal term based on plant-specific environmental surveys at Plant Hatch, the scope of such a program is relatively small. Thus, SNC agrees to establish an additional AMP to address the issues raised by this potential open item. The Insulated Cables and Connections Aging Management Program description is provided as Enclosure 2 to this letter.

59. (4.6.2-2)

In response to RAI 4.6.1, the applicant indicates that procedures and training used to limit cold over-pressure events during the license renewal period will be the same as those approved by the NRC when Plant Hatch requested the BWRVIP-05 technical alternative be used for the current term. In addition, the applicant compared the mean RT_{NDT} for Combustion Engineering fabricated welds from the NRC staff's July 28, 1998 SER to the mean RT_{NDT} of the circumferential welds in Plant Hatch at 54 EFPY. The mean RT_{NDT} values in the staff SER were values determined for the limiting BWR RPVs fabricated by Combustion Engineering, Babcock and Wilcox, and Chicago Bridge and Iron. Since the Plant Hatch RPVs were fabricated by Combustion Engineering, the results from the staff SER are applicable to Plant Hatch. The mean RT_{NDT} values projected for the circumferential welds were calculated using the neutron fluence at the 1/4T location and included a margin term. The mean RT_{NDT} in the staff analysis was determined using the neutron fluence at the clad/weld metal interface and did not include a margin term. Therefore, the applicant should revise its analysis based on the projected neutron fluence at the clad/weld interface and need not include a margin term when calculating the mean RT_{NDT}.

Response:

SNC concurs with the staff recommendation. The following text represents a revised response to RAI 4.6-1:

> RESPONSE TO RAI 4.6-1 (Revised 1/16/01):
>
> The information requested for Hatch 1 and 2 is in Appendix E of the Hatch LRA. The Hatch limiting circumferential weld properties from Tables 3-1 and 3-2 of LRA Appendix E are compared to the information in Table 2.6-4 and Table 2.6-5 from the staff SER on BWRVIP-05.
>
> The NRC staff used materials and fluence data in Tables 2.6-4 and 2.6-5 to evaluate failure probability of BWR circumferential welds at 32 and 64 EFPY. The NRC used Mean RT_{NDT} for the comparison. Mean RT_{NDT} is defined as: Mean $RT_{NDT} = RT_{NDT} + \Delta RT_{NDT}$. The Mean RT_{NDT} used by the NRC have been compared to the Hatch values derived using the data from Appendix E of the LRA. The Hatch 1 and Hatch 2 values at 54 EFPY are bounded by the 32 EFPY analysis by the NRC by at least 40 °F, and almost 75 °F at 64 EFPY. Although a conditional failure probability has not been calculated, the fact that the Hatch 54 EFPY value is bounded by the 32 and the 64 EFPY value the staff used leads to

the conclusion that Hatch RPV conditional failure probability is bounded by the NRC analysis.

The procedures and training used to limit cold over-pressure events will be the same the NRC approved when Plant Hatch requested the BWRVIP-05 technical alternative be used for current term. There is nothing unique about the renewal term in this regard.

Circumferential Weld

Group	CE (VIP) 32 EFPY	CE (CEOG) 32 EFPY	CE (VIP) 64 EFPY	CE (CEOG) 64 EFPY	Hatch 1 54 EFPY	Hatch 2 54 EFPY
Cu%	0.13	0.183	0.13	0.183	0.197	0.047
Ni%	0.71	0.704	0.71	0.704	0.060	0.049
CF	151.7	172.2	151.7	172.2	91.0	31.0
Fluence ($10^{19}n/cm^{2}$)	0.20	0.20	0.40	0.40	0.236	0.244
ΔRT_{NDT} (°F)	86.4	98.1	113.2	128.5	55.5	19.2
$RT_{NDT(U)}$ (°F)	0	0	0	0	-10	-50
Mean RT_{NDT} (°F)	86.4	98.1	113.2	128.5	45.5	-30.8
P(F/E) NRC	2.81 E-5	6.34 E-5	1.99 E-4	4.38 E-4	---	---
P(F/E) BWRVIP	No failure	---	---	---	---	---

References:

1. LRA Appendix E, Tables 3-1 and 3-2.
2. Final SER of the BWR Vessel and Internals Project BWRVIP-05 Report (TAC No. M93925), dated July 28, 1998
3. GE-NE-A00-05389-08, July 1995, Power Uprate Evaluation Task Report for Edwin I. Hatch Plant Units 1 and 2, 110% Power Uprate Revised Impact on Vessel Fracture Toughness.
4. GE-NE-A13-00402-9, March 1998, Extended Power Uprate Evaluation Task Report for Edwin I. Hatch Plant Units 1 and 2 Revised Impact on Vessel Fracture Toughness.
5. BWRVIP-74 – BWR Vessel and Internals Project BWR Reactor Vessel Inspection and Flaw Evaluation Guidelines, TR-113596
6. Structural Integrity Associates Letter, SIR-00-160, Rev. O, December 18, 2000.

60. (4.6.2-3)

The applicant provided plant-specific information in response to RAI 4.6-2 to demonstrate that the Plant Hatch beltline materials meet the criteria specified in the report. The mean RT_{NDT} for the Plant Hatch axial welds were not compared to the mean

RT_{NDT} in Table 1. The mean RT_{NDT} was compared to the mean RT_{NDT} for axial welds in the NRC staff's July 28, 1998 SER. The SER in the May 7, 2000 letter supercedes the analysis in the July 28, 1998 letter. Therefore, the applicant should revise its analysis to compare the mean RT_{NDT} for the Plant Hatch axial welds to the mean RT_{NDT} for Pilgrim Mod 2.

Response:

The following revised response to RAI 4.6-2 includes the requested comparison to the mean RT_{NDT} for Pilgrim Mod 2. The axial welds table represents the revised table as provided to NRC via email January 23, 2001.

RESPONSE TO RAI 4.6-2 (Revised 1/16/01)

The information requested for Hatch 1 and 2 is in Appendix E of the Hatch LRA. The Hatch limiting axial weld properties from Tables 3-1 and 3-2 of Appendix E are compared to the information in Table 2.6-4 and Table 2.6-5 from the staff SER on BWRVIP-05. The NRC noted that it issued a revised SER on BWRVIP-05 on March 7, 2000 and that the limiting axial weld should be compared with data in Table 3 of that document (Mod 2 in Table below). The NRC used Mean RT_{NDT} for the comparison. Mean RT_{NDT} is defined as: Mean $RT_{NDT} = RT_{NDT} + \Delta RT_{NDT}$. The Mean RT_{NDT} used by the NRC have been compared to the Hatch values derived using the data from Appendix E of the LRA. A comparison of the Mean RT_{NDT} values from the NRC report with the Hatch data shows that the NRC analysis bounds the Hatch welds. Although a conditional failure probability has not been calculated, the fact that the Hatch 54 EFPY value is less than the 64 EFPY value the staff used leads to the conclusion that Hatch is bounded by the NRC analysis.

Axial Weld

Group	Mod 2	Hatch 1 54 EFPY	Hatch 2 54 EFPY
Cu%		0.316	0.216
Ni%		0.724	0.043
CF		219.0	98.0
Fluence ($10^{19}n/cm^{2)}$		0.347	0.244
ΔRT_{NDT} (°F)		155.1	60.6
$RT_{NDT(U)}$ (°F)	-2	-50	-50
Mean RT_{NDT} (°F)	114	105.1	10.6
P(F/E) NRC	5.02 E-6	---	---
P(F/E) BWRVIP		---	---

References:

1. LRA Appendix E, Tables 3-1 and 3-2.
2. Final SER of the BWR Vessel and Internals Project BWRVIP-05 Report (TAC No. M93925), dated July 28, 1998
3. GE-NE-A00-05389-08, July 1995, Power Uprate Evaluation Task Report for Edwin I. Hatch Plant Units 1 and 2, 110% Power Uprate Revised Impact on Vessel Fracture Toughness.
4. GE-NE-A13-00402-9, March 1998, Extended Power Uprate Evaluation Task Report for Edwin I. Hatch Plant Units 1 and 2 Revised Impact on Vessel Fracture Toughness.
5. BWRVIP-74 – BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines, TR-113596.
6. Structural Integrity Associates Letter, SIR-00-160, Rev. O, December 18, 2000.

61. (4.7-1)

In a telephone conversation on October 24, 2000, the staff noted that the TLAAs consider both active and passive time-dependent functions. Since the FSAR stated that the operating cycles of the MSIV are assumed to be 2050 cycles for 40 years, MSIV cycles should be considered as a TLAA. To disposition this issue, the applicant should either provide a revised RAI response which discusses the basis of the vendor specification for the MSIV cycles (2050) in the FSAR, including current procedures that ensure this limit is not exceeded and why this would not be a concern for the extended period of operation, or provide sufficient information as described in the staff's RAI to demonstrate that the testing, inspection, and maintenance/repair program will effectively manage the aging effects associated with the MSIVs during the renewal period. To meet the requirements of 10 CFR 54.21 (c)(1)(iii), the applicant is also requested to

revise Sections A.4.1.1 and A.4.1.1 of the LRA to include a summary discussion of the MSIV operating cycles TLAA.

Response:

As noted in the response to RAI 4.7-1, at the time of LRA submittal, GE had been unable to fully determine the basis for the FSAR discussion regarding MSIV cycles. Consequently, as a conservative measure, SNC identified the FSAR reference to MSIV cycles as a TLAA in the LRA. Since that time, GE has determined that the number is not a TLAA since it is derived from a specification, not from a calculation or analysis. On the basis of this confirmation from GE, SNC has now confirmed that the MSIV cycles discussion referenced in the FSAR is not a TLAA.

SNC also notes that, outside the scope of license renewal, the MSIVs are tested extensively as a part of existing Technical Specifications requirements, and because the valves fall within the purview of the Maintenance Rule and are being maintained consistent with the requirements of that rule. Because these valves are periodically tested and refurbished, as necessary, GE has indicated it is appropriate to restore the valve service life when valve internals are refurbished. Based on this supporting information, even if the assumption were made that the FSAR text constituted a *de facto* TLAA, not directly supported by a calculation or analysis, the periodic restoration of the valve service life results in the supposed TLAA failing the criterion that the calculation or analysis be relevant to making a safety related determination. Please note that although the MSIV cycles do not constitute a TLAA, as presented in the LRA, the MSIV valve bodies are in scope for license renewal and are subject to AMR.

Confirmatory Item 2.3.4.2-1:

Section 2.3.4.11 of the LRA states that the system includes an air receiver, particulate filters, and regulators, among other components. In RAI 2.3.4-DPS-2, the staff requested the applicant to justify the exclusion of these components from being subject to an AMR. The applicant responded that the air receiver was inadvertently omitted from Table 2.3.4-11. Subsequently, in a telephone conference, dated September 13, 2000, the applicant, in response to the staff's request, agreed to add the air receiver to Tables 2.3.4-11 and 3.2.4-11 as a part of the revision to the RAI response.

Response:

Table 2.3.4-11 of the Plant Hatch LRA has been revised as shown below to include the air received inadvertently omitted. Per the usual convention in the LRA, the air receiver is characterized as a tank.

Table 2.3.4-11 Components Supporting Drywell Pneumatics System [P70] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Filter Housings	Pressure Boundary	Carbon Steel
Filter Housings	Pressure Boundary	Stainless Steel
Flanges	Pressure Boundary	Carbon Steel
Flexible Hoses	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Tanks	Pressure Boundary	Carbon Steel
Tubing	Pressure Boundary	Copper
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Copper

Table 3.2.4-11 has been revised as shown on the following page to include the air receiver.

Table 3.2.4-11 Aging Effects Requiring Management for Components Supporting Drywell Pneumatics System [P70] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Filter Housings / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Filter Housings / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Flexible Hoses / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Flanges / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Piping / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Piping / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Tanks / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Tubing / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper	Cracking	None Required
Valve Bodies / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Valve Bodies / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Valve Bodies / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper Alloy	Cracking	None Required

Confirmatory Item 2.3.4.2-2:

In a letter dated July 14, 2000 to the applicant, the staff issued RAI 2.3.4-PSW-1 regarding the functional boundary of turbine building isolation piping that ends in the middle of the piping run, and does not appear to be within the scope of license renewal. The staff also raised a similar question in RAI 2.3.4-PSW-5 regarding the loop seals to the diesel generator coolers. By letter dated August 29, 2000, the applicant stated that drawing HL-11600 shows that turbine building service water flow is monitored by safety related differential pressure (dP) switches downstream of isolation valves, which isolate the nonsafety loads from the rest of the system during a break in the service water system. The isolation valves and instrumentation for these dP switches are within the scope of license renewal and subject to an AMR. The dP switches located downstream of these valves detect flow and are required for proper isolation of the line. Because the location of the dP switches and the associated instrumentation extend beyond the point that would normally serve as the evaluation boundary, the applicant conservatively extends the AMR boundary up to the first anchor point at the valve box located beyond the dP switches location, and will revise the drawing to include reference notes that depict this condition.

Response:

Reference notes describing the boundary locations have been added to drawing HL-11600. A copy of this drawing is provided in Enclosure 3.

Confirmatory Item 2.3.5.2-1

In RAI 2.3.5-EHC-1, the staff noted that four EHC regulators, that are identified in Section 2.3.5.1 of the LRA as being within scope, could not be located on the boundary drawings. The RAI requested that the applicant identify the EHC regulators (1N11-N042A/B and 2N32-N301A/B) in the boundary drawings. In response, the applicant clarified the locations on the boundary drawings for the two Unit 1 regulators on drawing No. HL-11601 and the two Unit 2 regulators on drawing No. HL-21012. However, the applicant indicated that there is an error on drawing HL-11601, in that it identifies two separate components with the same identifying number as N11-N042B. Based on the additional information, the staff was able to find these four regulators in the drawings as stated. Correction of the component identification error in the boundary drawings is a Confirmatory Item.

Response:

Boundary drawing HL-11601 has been corrected and a copy is provided in Enclosure 3.

ENCLOSURE 2

INSULATED CABLES AND CONNECTIONS AGING MANAGEMENT PROGRAM

INSULATED CABLES AND CONNECTIONS AGING MANAGEMENT PROGRAM

The Insulated Cables and Connectors Aging Management Program is a condition monitoring program designed to confirm that age-related degradation is not inhibiting component function of insulated cables and connectors within the scope of license renewal during the period of extended operation.

Program Scope

The Insulated Cables and Connections Aging Management Program includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in adverse, localized environments in the Primary Containment Structure, Reactor Building, Radwaste Building, Diesel Generator Building, Turbine Building, Control Building, Intake Structure, and Main Stack, which could be subject to applicable aging effects from heat or radiation. This program does not include cables and connections that are in the Environmental Qualification program. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the equipment. An applicable aging effect is an aging effect that, if left unmanaged, could result in the loss of a component's license renewal intended function in the period of extended operation.

Preventive or Mitigative Actions

The methods used are different for accessible insulated cables and connections and for inaccessible insulated cables and connections, which cannot be visually inspected.

Accessible insulated cables and connections installed in adverse, localized environments will be visually inspected for jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. Surface anomalies are indications that can be visually monitored to preclude the conductor insulation applicable aging effect.

Inaccessible insulated cables and connections will be tested. The specific type of test performed will be determined prior to each test.

Parameters Inspected or Monitored

Change in material properties of the conductor insulation is the applicable aging effect. The changes in material properties managed by this program are those caused by severe heat or radiation – conditions that establish an adverse, localized environment.

Detection of Aging Effects

Accessible insulated cables and connections installed in adverse, localized environments will be inspected at least once every 10 years.

Inaccessible cables and connections will be tested at least once every 10 years.

Samples may be used for this program. If used, an appropriate sample size will be determined prior to the inspection or test.

Following issuance of a renewed operating license for Plant Hatch, the initial inspections and tests will be completed by the end of the initial license term for each unit (August 6, 2014 for unit 1 and June 13, 2018 for unit 2).

Monitoring and Trending

For accessible and inaccessible insulated cables and connections, the monitoring and trending activities will be defined by the specific type of inspection or test to be performed.

Plant procedures require that deficiencies discovered during the performance of the program activities be documented in accordance with the condition reporting process. Corrective action, as described in Chapter 17 of the Unit 2 FSAR is part of the Plant Hatch Quality Assurance (QA) Program.

Acceptance Criteria

The acceptance criteria is different for accessible insulated cables and connections and for inaccessible insulated cables and connections.

For accessible insulated cables and connections installed in adverse, localized environments, the acceptance criterion is no unacceptable, visual indications of jacket surface anomalies, which suggest that conductor insulation applicable aging effects may exist, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the license renewal intended function.

For inaccessible insulated cables and connections, the acceptance criteria for the test will be defined by the specific type of test to be performed and the specific type cable to be tested.

Corrective Actions

Further investigation by engineering will be performed on accessible and inaccessible insulated cables and connections when the acceptance criteria are not met, in order to ensure that the license renewal intended functions will be maintained consistent with the current licensing basis. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, relocation or replacement. Specific corrective actions will be implemented in accordance with the Corrective Actions Program. The Corrective Actions Program applies to all structures and components within the scope of the Insulated Cables and Connections Aging Management Program. When an unacceptable condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible insulated cables and connections.

Confirmation Process

The confirmation will ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective. For accessible and inaccessible insulated cables and connections, the confirmation process will be defined by the specific type of inspection or test to be performed.

Administrative Controls

Administrative controls will provide a formal review and approval process. For accessible and inaccessible insulated cables and connections, the administrative controls process will be defined by the specific type of inspection or test to be performed.

Operating Experience

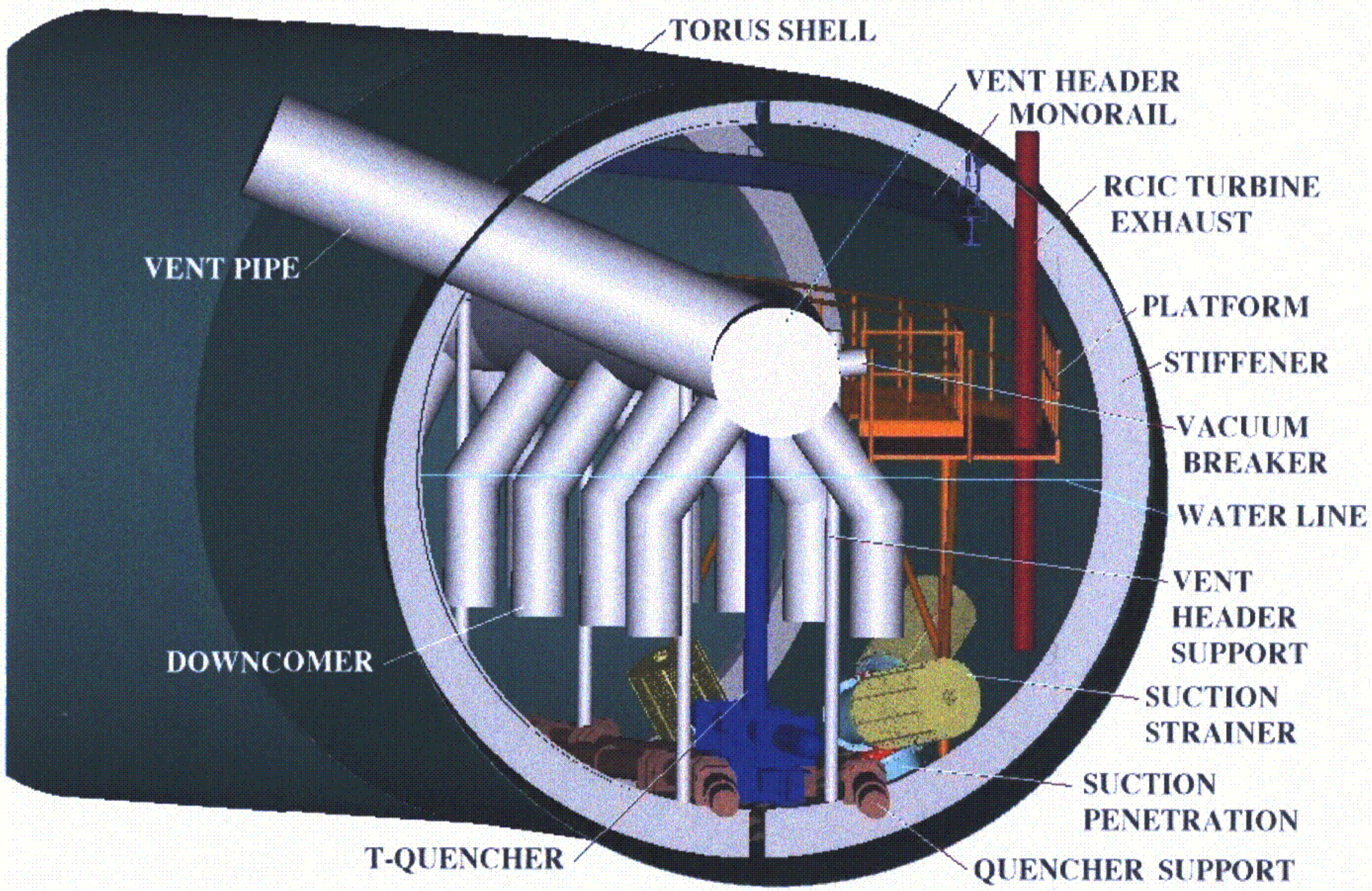
The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

ENCLOSURE 3

REVISED EVALUATION BOUNDARY DRAWINGS PROVIDED IN RESPONSE TO CONFIRMATORY ITEM 2.3.4.2-2

ENCLOSURE 4

TORUS SECTION VISUAL AID PROVIDED TO SUPPORT RESPONSES TO POTENTIAL DRAFT SER OPEN ITEMS 41, 42, AND 46



SECTION THROUGH TORUS
E.I. HATCH NUCLEAR PLANT

Aging Management Programs

<u>Above Torus Waterline</u>
Inservice Inspection Program
Primary Containment Leakage Rate Testing Program
Protective Coatings Program
Component Cyclic or Transient Limit Program
* Suppression Pool Chemistry Control
* Torus Submerged Components Inspection Program

<u>Below Torus Waterline</u>
Inservice Inspection Program
Primary Containment Leakage Rate Testing Program
Protective Coatings Program
Component Cyclic or Transient Limit Program
Suppression Pool Chemistry Control
Torus Submerged Components Inspection Program

• = SPLASH ZONE ONLY

C01

Torus Section 1/17/01
LGT