March 28, 2003

Mr. Stephen A. Byrne
Senior Vice President, Nuclear Operations
South Carolina Electric & Gas Company
Virgil C. Summer Nuclear Station
Post Office Box 88
Jenkinsville, South Carolina 29065

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE V.C. SUMMER NUCLEAR STATION (VCSNS), LICENSE RENEWAL APPLICATION - SECTIONS 3.1, AND APPENDIX B.

Dear Mr. Byrne:

By letter dated August 6, 2002, South Carolina Electric & Gas Company (SCE&G) submitted, for the Nuclear Regulatory Commission's (NRC's) review, an application pursuant to 10 CFR Part 54 to renew the operating license for VCSNS. The NRC staff is reviewing the information in the license renewal application and has identified areas where additional information is needed to complete the review.

The enclosed requests for additional information (RAIs) are numbered to coincide with the numbering of the license renewal application. These RAIs concern Section 3.1 and related Appendix B sections.

The staff is willing to meet with SCE&G and to clarify the RAIs before SCE&G submits its responses. If you have any further questions, please contact me at 301-415-1025 or rca@nrc.gov.

Sincerely,

/***RA***/

Rajender Auluck, Senior Project Manager
License Renewal Section
License Renewal and Environmental Impacts Program
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Docket No.: 50-395

Enclosure: As stated

cc w/enclosure: See next page

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Request for Additional Information

3.1.2.2 Aging Management Evaluations in The Gall Report That Are Relied on License Renewal, For Which Gall Recommends Further Evaluation

3.1.2.2.2 Loss of Material Due to Pitting And Crevice Corrosion

Aging Management Evaluations in the GALL Report that Are Relied on for License Renewal, For Which GALL Recommends Further Evaluation

3.1.2.2.2 Loss of Material due to Pitting and Crevice Corrosion

RAI 3.1.2.2.2-1 In LRA Table 3.1-1, AMR Item 2, the applicant states that cracking in the steam generator shell caused by flaw growth is managed by the in-service inspection plan (LRA Appendix B.1.7). The plan is stated to be consistent with NUREG-1801, Section XI.M1, which, in turn, is based upon ASME. Loss of material caused by general, pitting, and crevice corrosion is managed by the chemistry program (LRA Appendix B.1.4). The staff notes that the applicant's in-service inspection program cites Section XI, Subsections IWB, IWC, and IWD. However, Section XI.M1 of NUREG-1801 states, "In certain cases, the ASME inservice inspection program is to be augmented to manage effects of aging for license renewal...." For the case of pitting corrosion at the surfaces of the steam generator shell assembly, NRC Information Notice (IN) 90-04 recommends the use of such augmented procedures, including the use of enhanced ultrasonic techniques and additional visual and magnetic particle examinations as required.

a. Provide an enhanced condition-monitoring program that can reliably detect loss of material due to pitting and crevice corrosion, and detect cracks at the inside surface of the VCSNS steam generator girth welds and shell plates so that loss of material and cracking are effectively managed.

b. The applicant states that its AMR results are consistent with NUREG-1801, which references to NRC IN 90-04 as the basis for enhanced detection of aging effects in the shell. Confirm whether the 100% secondary-side inspection during refueling outage 12 included an examination of the steam generator shell assembly for the presence of degradation (e.g., pitting). If such examinations were performed, identify the inspection methods used, list the exact shell components inspected, confirm whether these methods were adequate to detect pitting, and describe the inspection results.

3.1.2.2.4 Loss of Fracture Toughness due to Neutron Irradiation Embrittlement

RAI 3.1.2.2.4-1 The reactor vessel internals program assumes sufficient redundancy in bolt function that the plant can continue to function safely with fewer than 100% of the bolts intact. The staff finds that this approach is consistent with the one described in NUREG-1801, GALL Section XI.M16 ("PWR Vessel Internals"). However, the staff needs additional information for evaluating the program. With respect to the application of this program to the detection of irradiation embrittlement of the baffle former bolts, identify the neutron fluence threshold for which the baffle former bolts become susceptible to loss of fracture toughness due to neutron irradiation embrittlement and void swelling, submit the technical justification for the threshold, identify the percentage of the bolts to be selected for inspection, and submit the technical basis for this selection process. A similar question is asked in RAI 3.1.2.2.12; however, it addresses irradiation-assisted stress corrosion cracking.

3.1.2.2.6 Crack Initiation and Growth due to Stress Corrosion Cracking, Intergranular Stress Corrosion Cracking, and Thermal and Mechanical Loading

RAI 3.1.2.2.6-1 In LRA Appendix B.2.7, the applicant has identified the information sources that will be used to identify the susceptible locations in small-bore RCS piping and to select the sample locations for inspections. Confirm whether all on-going industry activities related to failure mechanisms for small-bore piping including the recommendations of the EPRI sponsored Materials Reliability Program (MRP) Industry Task Group (ITG) on Thermal Fatigue will be followed and whether changes to inspection activities based on industry recommendations will be evaluated. Confirm also whether the samples locations selected for inspection will be the bounding locations for Class 1 small-bore piping within the scope of the license renewal.

3.1.2.2.7 Crack Growth due to Cyclic Loading

RAI 3.1.2.2.7-1 In LRA Table 3.1-1, AMR Item 7, the applicant states that the VCSNS vessel is constructed of ASME SA 533 Grade B, Cl 1 plate material and not ASME SA 508 Cl 2 forgings. Therefore, the aging effect of growth of underclad cracking is not applicable to the VCSNS vessel. However, Table 5.2-8 of the VCSNS FSAR identifies SA 508 Cl 2 as one of the materials for reactor vessel shell, flange and nozzle forgings and nozzle safe ends. Clarify this discrepancy and if growth of underclad cracking is an aging effect, indicate what program will manage the applicable aging effect.

3.1.2.2.9 Crack Initiation and Growth due to Stress Corrosion Cracking or Primary Water Stress Corrosion Cracking

RAI 3.1.2.2.9-1 With respect to Ni alloy components please provide the following information:

a. In LRA Table 3.1-1, AMR Item 9, the applicant credits the Alloy 600 aging management program (LRA Appendix B.1.1) as one of the three programs for managing crack initiation and growth due to PWSCC of two Ni alloy components, core support pads and bottom head penetrations. In LRA Appendix B.1.1, the applicant also states that the Alloy 600 aging management program is consistent with GALL AMP XI.M11. However, according to Table 3.1-1 of NUREG-1800, the GALL AMP XI.M11 is credited for managing cracking only in CRD nozzles (i.e., vessel head penetrations) and no other Ni alloy components. Clarify this discrepancy.

b. In LRA Table 3.1-1, AMR Item 11, the applicant credits LRA Appendix B.1.1, Alloy 600 aging management program, which is a condition monitoring program, for managing cracking of Alloy 82/182 welds for the pressurizer instrumentation penetrations and heater sleeves due to PWSCC. However, in LRA Appendix B.1.1, the applicant states that this program is consistent with NUREG/CR-1801 AMP XI.M11, which includes only reactor pressure vessel head penetrations in its scope and no other Alloy 600 components. Therefore, the applicant needs to modify the scope of its Alloy 600 aging management program (LRA Appendix B.1.1) to include all other Alloy 600 components in addition to reactor vessel head penetrations.

RAI 3.1.2.2.9-2 The inservice inspection plan (LRA Appendix B.1.7) specifies ASME Section XI VT-3 examination to detect cracking of the core support pads. However, VT-3 examinations may not be sufficient to detect cracking of the core support pads. Submit an aging management program for managing cracking in core support pads and bottom head penetrations during the extended period of operation. Specifically, submit the following information: (1) inspection method used in detecting cracking in these components, (2) technical basis showing the adequacy of this method to detect cracking, (3) inspection frequency and its justification, and (4) acceptance criteria.

RAI 3.1.2.2.9-3 The applicant has not presented the aging management review results for the pressurizer heater sheaths. Confirm whether the heater sheaths at VCSNS are made of Alloy 600. If so, then provide a program for managing cracking of the heater sheaths due to PWSCC.

3.1.2.2.10 Crack Initiation and Growth due to SCC

RAI 3.1.2.2.10-1 In AMR Item 10, Table 3.1-1 of the LRA, the applicant identified crack initiation and growth due to SCC as an aging effect for the reactor coolant system (RCS) cast austenitic stainless steel (CASS) piping components. The applicant credits the chemistry program and the inservice inspection (ISI) plan to manage these aging effects. Explain whether the inspection techniques included in the ISI plan are qualified for detecting and sizing cracks in the CASS components. Also, confirm whether the ISI plan includes inspection of heat-affected zones associated with any weld repairs performed on these CASS components.

3.1.2.2.12 Crack Initiation and Growth due to SCC and Irradiation-Assisted Stress Corrosion Cracking (IASCC)

RAI 3.1.2.2.12-1 Under the reactor vessel internals inspection program, the applicant has selected volumetric inspection as the plant-specific basis for addressing the issue of crack initiation and growth due to SCC and irradiation-assisted stress corrosion cracking in the baffle former bolts. However, the staff needs additional information for evaluating the program. With respect to the application of this program to the detection of IASCC cracking of the baffle former bolts, identify the neutron fluence threshold for which the baffle former bolts become susceptible to IASCC cracking, submit technical justification for the threshold, identify the percentage of the bolts to be selected for inspection, and submit the technical basis for this selection process.

3.1.2.2.14 Loss of Section Thickness due to Erosion at the Feedwater Impingement Plate and Support

RAI 3.1.2.2.14-1 In LRA Table 3.1-1, AMR Item 14, the applicant addresses loss of section thickness due to erosion at the steam generator feedwater impingement plate and support. In its discussion, the applicant states that these components do not have a license renewal intended function for VCSNS and aging management is therefore not required. However, the applicant provides no justification for this conclusion. The staff is not clear whether the feedwater impingement plate and support are installed in the VCSNS steam generators. If these components are installed in the VCSNS steam generators, the applicant needs to provide the technical basis for excluding the steam generator feedwater impingement plate and support from the scope of license renewal.

3.1.2.2.15 Crack Initiation and Growth due to PWSCC, ODSCC, and/or IGA

RAI 3.1.2.2.15-1 In LRA Appendix B.1.10, “Steam Generator Management Program,” the applicant states that the steam generator management program is consistent with GALL AMP XI.M19. GALL AMP XI.M19 states that all PWR licensees have voluntarily committed to a steam generator degradation management program described in NEI 97-06, whose guidelines were under NRC staff review at the time of NUREG-1801 publication. GALL AMP XI.M19 states that the plant technical specifications, staff-approved NEI 97-06 guidelines, and any other alternate regulatory basis for steam generator degradation management that have been previously approved by the staff for that plant, are adequate to manage the effects of aging on the steam generator tubes.

a. The GALL report (NUREG 1801) was published approximately two years ago. The staff is not clear as to the applicant’s commitment with respect to NEI 97-06. Confirm whether VCSNS has committed to the steam generator management program described in NEI 97-06 for the period of extended operation.

b. Identify the alternate regulatory basis for steam generator degradation mechanisms that have been approved by the staff for VCSNS and confirm whether these alternate bases are incorporated in the steam generator management program as presented in LRA Appendix B.1.10.

RAI 3.1.2.2.15-2 The staff notes that after more than ten years of experience with thermally treated Alloy 690 tubes in the U.S. steam generator service, EPRI TE-106365-R14 reports virtually no incidents of wastage and pitting corrosion for these tubes. However, a small number of tubes have been plugged due to wear.

a. Describe the design features incorporated into the Westinghouse Delta-75 steam generators in VCSNS to minimize wear.

b. Describe the features of the steam generator management program to ensure that loss of material due to wear, loose parts, and other causes is effectively prevented or mitigated.

Aging Management of Plant-Specific Components

3.1.2.4.2 Reactor Coolant Piping, Valves and Pumps

RAI 3.1.2.4.2-1 With respect to bolting provide the following information:

a. LRA Table 3.1-1, AMR Item 22, identifies loss of closure integrity rather than loss of preload and cracking as an aging effect for stainless steel and low-alloy steel bolting requiring management. Explain how the management of loss of closure integrity instead of loss of preload and cracking would ensure that the intended function of the bolted joint (pressure boundary integrity) would be maintained during the extended period of operation.

b. In LRA Table 3.1-1, AMR Item 22, the applicant presents the AMR results for the reactor coolant pressure boundary bolting. The applicant states that the AMR results are consistent with NUREG-1801 in materials and environments, but not in aging effects. The applicant further states that loss of closure integrity, rather than loss of preload or cracking, is the aging effect requiring management. The applicant credits the inservice inspection plan for managing these effects. Explain the difference between loss of closure integrity and loss of preload or cracking.

RAI 3.1.2.4.2-2 LRA Table 3.1-1, AMR Item 20, states that the CASS elbows and nozzles of the RCS Class 1 piping are not susceptible to loss of fracture toughness because these components have low molybdenum content and have delta ferrite levels of less than 20%. This is acceptable because the material chemistry for these components meets the screening criteria set forth in the letter dated March 19, 2000, from Christopher Grimes, NRC, to Douglas Walters, NEI. This AMR Item is, however, not identified in LRA Table 2.3-2. Clarify this discrepancy.

RAI 3.1.2.4.2-3 The austenitic stainless steel and CASS RCS piping is susceptible to stress corrosion cracking at their external surface if it comes in contact with halogens that may be present in the thermal insulation. Cracking has not been identified as an aging effect at the external surface of these components. Discuss the controls that are in place to ensure that all insulation used on austenitic stainless steel and CASS RCS piping is free from halogens. Note that this is identified as License Renewal Action Item 4 by the industry report WCAP-14575-A, "Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components, December 2000."

RAI 3.1.2.4.2-4 The NRC Information Notice 2000-17, "Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer," reports a crack in Alloy 182 butter and 182/82 weld on RCS 'A' hot leg nozzle to pipe weld. Submit the following information related to this event:

a. Explain how this cracking event has been taken into account in the ISI Plan (LRA Appendix B.1.7).

b. The operating experience is described in LRA Appendix B.1.1, Alloy 600 Aging Management Program, but it is not clear whether this program is credited for managing PWSCC cracking in Alloy 82/182 welds in RCS Class 1 piping. Clarify this discrepancy.

c. Identify any mitigative actions (e.g., mechanical stress improvement) taken since the submittal of the LRA to minimize the growth of existing PWSCC cracks and describe any plan for ensuring the effectiveness of these actions during the extended period of operation.

RAI 3.1.2.4.2-5 The chemistry program (LRA Appendix B.1.4) references water quality that is compatible with the materials of construction used in the Class 1 piping and associated components in order to minimize loss of material and cracking. This program incorporates EPRI and Institute of Nuclear Power Operations (INPO) guidelines, which reflect industry experience, and the “lessons learned” from VCSNS and external industry operating experience. Confirm whether the chemistry program incorporates the guidelines in EPRI TR-105714 (Rev. 3 or later revisions or update). Identify any differences between the chemistry program and these guidelines and submit technical justification for these differences.

RAI 3.1.2.4.2-6 According to LRA Table 2.3-2, the results for austenitic stainless steel piping and fittings (less than NPS 4”), and orifices exposed to chemically treated borated coolant are presented in LRA Table 3.1-1, AMR Item 6, and LRA Table 3.1-2, AMR Item 6. Both AMR items identify the same aging effect (i.e., cracking) but different aging management programs. AMR Item 6 of LRA Table 3.1-1 credits three programs, the chemistry program (LRA Appendix B.1.4), the ISI plan (LRA Appendix B.1.7), and the small-bore Class 1 piping inspections (LRA Appendix B.2.7) for managing cracking. However, AMR Item 6 of LRA Table 3.1-2 credits only one program, the chemistry program (LRA Appendix B.1.4), for managing cracking. Explain this apparent discrepancy.

RAI 3.1.2.4.2-7 In AMR Item 20, Table 3.1-1 of the LRA, the applicant states that the CASS components in the reactor coolant piping (elbows and accumulator nozzles) are statically cast. These components have low molybdenum content and have ferrite levels of less than 20%. Therefore, based on the screening criteria set forth in the NRC letter dated May 19, 2000, from C. Grimes (NRC) to D. Walter (NEI), these CASS components are not subject to loss of fracture toughness due to thermal aging. Explain how the ferrite content was determined.

RAI 3.1.2.4.2-8 LRA Table 3.3-1 AMR Item 6 states that the ambient environment at VCSNS does not contain contaminants of sufficient concentration to cause any applicable aging effects requiring aging management for reactor coolant system non-Class 1 stainless steel components exposed to a moist air environment. The staff is requesting that the applicant provide additional information so that the staff can evaluate the applicant's determination that there are no aging effects for these stainless steel components. Submit information about the concentration of contaminants in the VCSNS ambient environment and present technical basis for determining an absence of aging effects requiring aging management.

3.1.2.4.3 Reactor Vessel

RAI 3.1.2.4.3-1 LRA Table 2.3-3 refers to LRA Table 3.1-1, AMR Item 24, for AMR results for stainless steel cladding on reactor vessel closure head dome, closure head and vessel flanges, and bottom head. The AMR item identifies cracking as an aging effect requiring management. However, the GALL report, NUREG 1801, does not identify cracking as an aging effect for cladding on these components, which are made of SA 533B, Cl 1. Submit a technical basis for identifying cracking as an applicable aging effect for the cladding.

RAI 3.1.2.4.3-2 In LRA Table 3.1-1, AMR Item 22, the applicant states that loss of material due to wear is not considered a valid aging effect for control rod drive flange bolting requiring management. This statement implies that VCSNS has installed control rod drive flange bolting. However, Section 5.4.2 of the VCSNS FSAR states that the upper ends of the CRD nozzles have a welded flexible canopy seal and not bolting. Explain this discrepancy.

RAI 3.1.2.4.3-3 LRA Table 2.3-3 refers to LRA Table 3.1-1, AMR Item 28, for the AMR results for the reactor vessel closure studs assembly. However, LRA Table 3.1-1, AMR Item 28, presents the AMR results for vessel and vessel closure head flanges and not for closure studs assembly. Explain this discrepancy. (Note that according to the GALL report, the component group addressed by the AMR Item 28 should have included reactor vessel and reactor vessel closure head flanges instead of reactor vessel closure studs).

RAI 3.1.2.4.3-4 The austenitic stainless steel and Ni-alloy based reactor vessel appurtenances (i.e., CRD housings, vessel head penetrations, and Alloy 82/182 welds) are susceptible to stress corrosion cracking at the external surface if they come in contact with halogens that may be present in the thermal insulation. The applicant has not identified cracking as an aging effect at the external surface of these components. Discuss the controls that are in place to ensure that all insulation used on austenitic stainless steel and Ni-alloy based reactor vessel components are free from halogens.

RAI 3.1.2.4.3-5 LRA Table 2.3-3 refers to LRA Table 3.1-1, AMR Item 23, and LRA Table 3.1-2, AMR Item 11, for the AMR results for the Alloy 600 reactor vessel closure head penetration tubes. Both AMR items address cracking as an aging effect for these tubes but identify different programs for managing this effect. Item 23 recommends the Alloy 600 AMP, whereas, Item 11 recommends the chemistry program. Explain why two different programs have been identified to manage the same aging effect of cracking for the Alloy 600 reactor vessel closure head penetration tubes.

RAI 3.1.2.4.3.6 The AMR results for the PWR reactor vessel flange leak detection line (GALL Item No. IV.A2.1-f) are presented in Table 1 of GALL Volume 1 (NUREG-1801). Therefore, AMR Item 9 in LRA Table 3.1-1 should also include this AMR result. Confirm whether AMR Item 9 of LRA Table 3.1-1, includes the AMR results for PWR reactor vessel flange leak detection line. If so, identify the aging management programs for this component. If not, provide an explanation or basis for not including these AMR results.

3.1.2.4.4 Reactor Vessel Internals

RAI 3.1.2.4.4-1 In LRA Table 3.1-1, AMR Items 5 and 31, the applicant identifies loss of fracture toughness due to irradiation as one of the applicable aging effects for the stainless steel reactor vessel internals in the fuel zone region. The applicant's identification of all of the reactor vessel internals in the fuel zone region as being susceptible to loss of fracture toughness due to irradiation represents an acceptable position to the staff. However, the staff needs additional information. Submit a criterion used to identify the vessel internals that are susceptible to loss of fracture toughness due to neutron irradiation along with its technical basis, and explain why the reactor vessel internals outside the fuel zone region are not considered susceptible to loss of fracture toughness due to irradiation.

RAI 3.1.2.4.4-2 The applicant credits the Reactor Vessels Internals Inspection Program (LRA Appendix B.2.4) with managing loss of preload due to stress relaxation in VCSNS hold-down spring, clevis insert bolts, and upper and lower support column bolts (LRA Table 3.1-1, AMR Items 30 and 35). In contrast, NUREG-1801 specifies that both inservice inspection and loose parts monitoring should be applied to manage loss of preload due to stress relaxation in the lower and upper support column bolts (GALL Items IV, B2.1-k and B2.5-h). For the hold-down spring (GALL Item B2.1-d) and clevis insert bolts (GALL Item IV, B2.5-i), NUREG-1801 states that either loose parts monitoring or neutron noise monitoring is to be used in addition to inservice inspection to manage loss of preload. Explain how the Reactor Vessels Internals

Inspection Program alone in the absence of either loose parts monitoring or neutron noise monitoring will adequately manage loss of preload in these components.

3.1.2.4.5 In-Core Instrumentation System

RAI 3.1.2.4.5-1 With respect to in-core instrumentation bolting provide the following information:

a. In LRA Table 3.1-2, AMR Item 4 identifies stainless steel as material for in-core thermocouple seal bolting. However, in the "Discussion" column for this AMR item, the applicant refers to high strength material for this bolting. Clarify this discrepancy. If high-strength, low-alloy steel is the bolting material, then explain why loss of material due to boric acid corrosion caused by leaking borated coolant is not an aging effect for this bolting material.

b. The applicant has identified loss of closure integrity rather than loss of preload and cracking as an applicable aging effect requiring management for closure bolting for in-core thermocouple seals. Explain how managing of loss of closure integrity would ensure that the pressure boundary of the bolted joint would be maintained during the extended period of operation.

c. In Westinghouse-designed PWRs, mechanical high-pressure seals, located at the seal table, are used to seal the area between the thimble tubes and the long-radius guides. Describe how the sealing of the area between the thimble tube and the guide is achieved at VCSNS and confirm whether bolted connection is employed for this mechanical seal. If a bolted connection is employed, then identify applicable aging effects and present an AMP for managing these effects.

d. The inservice inspection plan program (LRA Section B.1.7) is credited for managing loss of mechanical closure integrity, which includes loss of preload, loss of material and cracking of the bolted closures for the in-core thermocouple seal assemblies. The inservice inspection plan, which is based on ASME Section XI, Subsection IWB, requires VT-1 visual examination of bolts. Explain how the VT-1 examination can manage the effect of loss of preload so that the intended function of the bolted closure, i.e., pressure boundary, is maintained during the extended period of operation.

3.1.2.4.6 Pressurizer

RAI 3.1.2.4.6-1 The applicant states that the identification of the applicable aging effects for the pressurizer in LRA Table 3.1-1 is consistent with the GALL report. However, The GALL report presents an AMR for five additional pressurizer components [pressurizer seismic lugs, heater elements (heater sheaths), manway pad gasket seating surface, safety valves, and relief valves] that are not addressed in the LRA. According to Table 2-1 in the Westinghouse report WCAP 14574-A "License Renewal Evaluation: Aging Management Evaluation for Pressurizers," the first three components are within the scope of license renewal and require AMRs. Provide technical justification for not presenting an AMR for these three components, i.e., pressurizer seismic lugs, heater elements, and manway pad gasket seating surface. Also explain why the AMR results for safety and relief valves are not presented in LRA Table 3.1-1.

RAI 3.1.2.4.6-2 According to LRA Table 2.3-6, the applicant presented an AMR for pressurizer nozzles and safe ends. However, it is not clear to the staff about which specific nozzles are addressed by the LRA. Confirm whether the following five pressurizer nozzles and safe ends are included: surge nozzle, spray nozzle, safety nozzle, relief nozzle, and their safe ends, and instrument nozzle.

RAI 3.1.2.4.6-3 In LRA Table 2.3-6, the applicant presented AMR of manway cover (Row 4) and manway forgings (Row 7) exposed to chemically treated borated coolant. Why are the AMR results for these two components different? Does the AMR of manway forgings include that of manway flanges?

RAI 3.1.2.4.6-4 According to Section 3.2.5 of the Westinghouse report, WCAP-14574-A, "License Renewal Evaluation: Aging Management Evaluation for Pressurizers," four components of the pressurizer for which an AMR is performed, are exposed to fluid flows that have the potential to result in erosion of the components: surge nozzle thermal sleeve and safe end, and spray nozzle thermal sleeve and safe end. The applicant has not identified loss of material due to erosion as an applicable aging effect for these components. Explain why loss of material due to erosion is not an applicable aging effect for these components. If loss of material due to erosion is an applicable aging effect, then provide an AMP for managing it.

RAI 3.1.2.4.6-5 The attachment welds at the inside surface of the pressurizer are susceptible to cracking due to stress corrosion cracking if they are sensitized during fabrication. The applicant has not presented an AMR for these welds. Identify the components that are welded to the inside surface of the pressurizer and provide technical justification for determining whether cracking due to SCC is an applicable aging effect. If cracking is an applicable aging effect for the attachment welds, then provide an AMP for managing this effect.

RAI 3.1.2.4.6-6 LRA Table 3.1-1, AMR Item 24, credits the chemistry program (LRA Appendix B.1.4) and in-service inspection plan program (LRA Appendix B.1.7) for managing cracking of the pressurizer shell, lower head and upper head cladding with austenitic stainless steel and internally exposed to chemically treated borated coolant. The in-service inspection plan is mainly directed at structural welds in the pressurizer shell and heads and not at stainless steel cladding. However, in 1990, crack-like indications were discovered in the Haddam Neck pressurizer cladding. Thermal fatigue can initiate and propagate such cracking through the cladding and into the ferritic base metal or weld metal beneath the clad. Therefore, submit an AMP to verify whether thermal fatigue-induced cracking has initiated in the clad and propagated through it into the ferritic base metal or weld metal beneath the clad.

RAI 3.1.2.4.6-7 LRA Table 3.1-1, AMR Item 22, credits the in-service inspection plan program (LRA Appendix B.1.7) for managing loss of mechanical closure integrity, which includes loss of preload, loss of material and cracking, of the bolted closures for the pressurizer manway cover bolts. The inservice inspection plan, which is based on ASME Section XI, Subsection IWB, requires volumetric, and VT-1 and VT-2 visual examinations of bolts. Explain how these examinations manage the effects of loss of preload so that the intended function of the bolted closure, i.e., pressure boundary, is maintained during the extended operation.

3.1.2.4.7 Steam Generators

RAI 3.1.2.4.7-1 In LRA Table 3.1-1, AMR Item 9, the applicant addresses possible crack initiation and growth due to SCC and PWSCC in various nickel-based alloy components, including nozzles for the steam generator instrument and drain lines. In the discussion section of AMR Item 9, the applicant did not include the steam generator instrument and drain lines in the component group for aging management. The applicant implies that the SCC and PWSCC aging effects are not applicable to the steam generator instrument and drain lines in VCSNS. As detailed in NUREG-1801, Table IV.D1 Item D1.1-j, a plant-specific aging management program is to be applied to pressure boundary and structural instrument nozzles that are fabricated with Alloy 600.

a. The staff is not clear whether the instrument and drain lines in VCSNS steam generators are made of Alloy 600. If the lines are not made of Alloy 600, SCC and PWSCC in GALL Table IV.D1.1-j may not be applicable; however, the applicant needs to identify appropriate aging effect(s) and AMP(s) to manage the material that was used in the fabrication of the instrument and drain lines. Clarify why steam generator instrument and drain nozzles are not included in the aging management in AMR Item 9 in Table 3.1-1 of the LRA.

b. If Inconel 82/182 weld metal is used in the nozzle welds, then these welds are susceptible to crack initiation and growth due to PWSCC. Confirm whether these welds at VCSNS are made of Alloy 82/182, and if so, provide a program for managing cracking in these welds due to PWSCC.

RAI 3.1.2.4.7-2 In LRA Table 3.1-1, AMR Item 15, the applicant addresses the potential aging effects associated with steam generator tubes, sleeves, and plugs. In GALL Item IV.D.1.2-a, -b, -c, -d, -e, -f, -g, -h, -i, -j, and -k, the staff identified the following aging effects associated with tubes, plugs and sleeves: (1) crack initiation and growth due to PWSCC, outside diameter stress corrosion cracking, and intergranular attack; (2) loss of material due to wastage and pitting corrosion; (3) deformation due to corrosion at tube support plate intersections; (4) loss of section thickness due to fretting and wear; (5) denting due to corrosion of carbon steel tube support plate; (6) loss of section thickness due to flow-accelerated corrosion; and (7) ligament cracking due to corrosion. Clarify which aging effects in the above GALL IV.D.1.2 component group is applicable to the VCSNS steam generator tubes, sleeves and plugs. For those aging effects that are not applicable to the VCSNS steam generators, provide technical justification.

RAI 3.1.2.4.7-3 In LRA Table 3.1-1, AMR Item 17, the applicant addresses possible ligament cracking due to corrosion in the steam generator carbon steel tube support plate. The GALL report addresses ligament cracking due to corrosion of carbon steel steam generator tube supports. The applicant states that the tube supports at VCSNS are made of 405 stainless steel and the alloy 690 anti-vibration bars are included in this component group. The applicant states that the chemistry program alone is sufficient to manage cracking in the tube supports and anti-vibration bars. In GALL IV D.1.1-i, the staff specifies the inservice inspection program and water chemistry program to manage cracking of stainless steel components. Also, in GALL IV D.1.2-i and j, the staff specifies the inservice inspection program and water chemistry program to manage cracking of Alloy 690 components.

a. Provide the technical basis for the conclusion that the water chemistry program by itself is sufficient to manage cracking in tube supports and anti-vibration bars in light of the recommended inservice inspection program in the GALL report.

b. Discuss whether tube support plates and anti-vibration bars were inspected during refueling outage 12. If inspected, what were the inspection results. (See RAI 3.1.2.3.7-2).

RAI 3.1.2.4.7-4 In LRA Table 3.1-1, AMR Item 21, the applicant addresses potential wall thinning due to flow-assisted corrosion for the steam generator steam and feedwater nozzles and safe ends. The applicant concludes that this aging effect is not applicable to these components at VCSNS; therefore, aging management for this effect is not required, but provides no justification for this conclusion. As detailed in NUREG-1801, Table IV. D1, Item D1.1-d, steam and feedwater nozzles and safe ends are managed under the flow accelerated corrosion program. Provide the technical basis for concluding that wall thinning due to flow-accelerated corrosion is not an applicable aging effect and that no aging management program is needed for these nozzles and safe ends.

RAI 3.1.2.4.7-5 In LRA Table 3.1-1, AMR Item 22, the applicant states that for steam generator class 2 bolting, loss of closure integrity rather than loss of preload or cracking is the aging effect requiring management and that the additional aging mechanism of stress relaxation is being managed. In GALL IV.D1.1-f, the staff identifies the aging effect of loss of preload due to stress relaxation for secondary manway and handhole bolting, for which the staff identifies the bolting integrity program as the AMP.

a. Explain the difference between loss of closure integrity and loss of preload. Explain how the management of stress relaxation differ from the management of loss of preload for bolting.

b. Confirm whether bolt retorquing is performed at VCSNS as a part of its maintenance activities and, if so, why it is not credited for managing loss of preload in bolting.

RAI 3.1.2.4.7-6 In LRA Table 3.1-1, AMR Item 27, the applicant addresses loss of material due to erosion as a potential aging effect for steam generator secondary manways and handholds [handholes] that are made of carbon steel. The applicant states that "...VCSNS has Westinghouse recirculating steam generators..." without further elaboration.

a. Clarify whether there are any secondary manways and handholes in the VCSNS recirculating steam generators and if there are, specify whether loss of material due to erosion or any potential degradation may be applicable.

b. If the VCSNS replacement steam generators have no secondary side manways and handholes, discuss how the inservice inspection of the secondary side of the steam generators is performed (e.g., how is the inspection equipment accessed to the secondary side?)

RAI 3.1.2.4.7-7 In LRA Table 3.1-1, AMR Item 32, the applicant identifies the aging effect of crack initiation and growth due to SCC and PWSCC for the channel head divider plate in the VCSNS steam generators. In LRA Table 3.1-2, AMR Item 7, the applicant identifies the aging effect of loss of material due to crevice and pitting corrosion for the same component. The applicant states that the cracking aging effect is managed by the in-service inspection plan (LRA Appendix B.1.7) and the chemistry program (LRA Appendix B.1.4), and the loss-of-material aging effect is managed by the chemistry program.

a. Confirm whether the weld on the divider plate is an Alloy 82/182 weld. Discuss industry and VCSNS operating experience for the channel head divider plate with respect to possible SCC and PWSCC of the welds joining the divider plate to the tubesheet and lower head.

b. If the weld metal used on the divider plate is Alloy 82/182, discuss whether the Alloy 600 aging management program (LRA Appendix B.1.1) includes managing of cracking of these welds due to PWSCC and SCC.

c. Clarify whether the in-service inspection plan includes the examination of the weld on the divider plate which includes the weld between the plate and tubesheet, and the plate and the steam generator lower head.

<u>RAI 3.1.2.4.7-8</u> In LRA Table 3.1-2, the applicant identifies a number of combinations of components and aging effects that are not included in NUREG-1801 (See Table 3.1-2, AMR Items 3, 7, 8, 9, 11, and 13). To ensure that all of the applicable aging effects are identified, the applicant needs to provide industry operating experience for these components exposed to their respective environments.

<u>RAI 3.1.2.4.7-9</u> In LRA Table 3.1-2, AMR Item 3, the applicant discusses possible loss of material due to crevice, general, pitting, and galvanic corrosion in carbon steel steam generator components (components were not identified).

a. The applicant notes that these components are not specifically addressed in Chapter IV of NUREG-1801 and states that the chemistry program (LRA appendix B.1.4) alone provides adequate management for these aging effects. Discuss why inservice inspection program or other relevant AMPs are not considered to monitor the aging effects for these components. Provide a condition monitoring program to verify the effectiveness of the chemistry program in mitigating loss of material in these components due to various corrosion mechanisms.

b. Discuss industry operating experience with the components that are covered in this AMR Item, and confirm whether these components were included in the 100% inspection of the steam generator secondary side during refueling outage 12 as discussed in LRA Appendix B.1.10.

<u>RAI 3.1.2.4.7-10</u> In LRA Table 3.1-2, AMR Item 8, the applicant discusses possible loss of material due to crevice and pitting corrosion in steam generator secondary-side thermal sleeves and the steam flow limiter that are fabricated with nickel based alloy, including thermally treated Alloy 690. The applicant notes that these components are not specifically addressed in Chapter IV of NUREG-1801 and states that the chemistry program (LRA Appendix B.1.4) will manage the aging effects of these components. However, the staff notes that the applicant did not consider the inservice inspection program to manage the potential aging effect for the components. The chemistry program can only mitigate or prevent the loss of material, but

cannot monitor the component integrity should degradation occur. Discuss how the loss of material due to crevice and pitting corrosion of the components can be monitored without an inservice inspection program.

RAI 3.1.2.4.7-11 In LRA Table 3.1-2, AMR Item 9, the applicant discusses possible crack initiation and growth due to SCC and flaw growth in steam generator secondary-side thermal sleeves and the steam flow limiter fabricated with nickel based alloy, including thermally treated Alloy 690. The applicant notes that these components are not specifically addressed in Chapter IV of NUREG-1801 and states that the chemistry program (LRA Appendix B.1.4) and in-service inspection plan (LRA Appendix B.1.7) will manage the aging effects of these components. However, the staff notes that ASME Section XI, Subsections IWB or IWC do not explicitly include inspection of some of the secondary side components and the attachment welds for these components. Confirm whether the in-service inspection plan include inspection of all the components in this AMR Item and the attachment welds for these components. If not, provide a condition-monitoring program for managing cracking in these components and associated attachment welds.

RAI 3.1.2.4.7-12 In LRA Table 3.1-2, AMR Item 10, the applicant discusses possible loss of material due to crevice and pitting corrosion and possible crack initiation and growth due to SCC in the feedwater distribution components (pipe and fittings) that are fabricated with alloy steel (chrome molybdenum). The applicant states that the chemistry program (LRA Appendix B.1.4) and inservice inspection plan (Appendix B.1.7) provide adequate management for these aging effects. Discuss industry and VCSNS experience with these components and state whether these components were included in the 100% inspection of the steam generator secondary side during refueling outage 12.

RAI 3.1.2.4.7-13 In Table 3.1-2, AMR Item 13, the applicant discusses loss of material due to crevice and pitting corrosion and crack initiation and growth due to SCC in the components that are fabricated with stainless steel and nickel-based alloys, including tube support plates, anti-vibration bars, and flow-distribution baffle. The applicant states that the chemistry program alone (LRA Appendix B.1.4) provides adequate management for these aging effects.

a. Discuss why an inservice inspection plan is not considered to monitor the potential aging effects of cracking and loss of material on these components.

b. Discuss industry and VCSNS experience with these components.

c. Discuss whether these components were included in the inspection of the steam generator secondary side during refueling outage 12. If not, discuss a condition-monitoring program to confirm that no loss of material or cracking is occurring in these components.

Time-Limited Aging Analyses

4.2 Reactor Vessel Neutron Embrittlement

4.2.2.1 Upper Shelf Energy

RAI 4.2.2.1-1 Submit a table of the V.C. Summer 60 year EOL USE values for each of the beltline materials. Tabulate the heat numbers, material ID, copper values, Initial USE, the EOL 1/4 T fluence, and the EOL 1/4 T USE. Discuss how surveillance capsule results were evaluated in your determination of the USE values.

4.2.2.2 Pressurized Thermal Shock

RAI 4.2.2.2-1 Submit a table of the V.C. Summer 60 year EOL RT_{PTS} values for each of the beltline materials. Tabulate the heat numbers, material ID, copper and nickel values, chemistry factor, Initial RT_{NDT} , margin, EOL peak fluence, fluence factor, delta RT_{PTS}, and EOL RT_{PTS}. Discuss how surveillance capsule results were applied in your determination of the RT_{PTS}. values.

4.2.2.3 Pressure-Temperature Limits

4.2.2.3-1 The staff requests that the applicant identify LTOP as part of the reactor vessel neutron embrittlement time-limited aging analysis, and commit to develop LTOP values for the period of extended operation, as was done for the P-T limits.

Other TLAAs

4.7.1 Reactor Coolant Pump Flywheel

RAI 4.7.1-1 Discuss how WCAP-14535 is applicable to the VCSNS reactor coolant pump flywheel. Indicate what material was used to fabricate the flywheel. Does the VCSNS flywheel belong to a specific flywheel group as defined by WCAP-14535? Has VCSNS submitted, for staff review, its assessment of the plant-specific applicability of WCAP-14535 for V.C. Summer? If so, please provide the applicable references. What is the inspection frequency for the flywheels?

4.7.2 Leak-Before-Break

RAI 4.7.2-1 As a result of the V.C. Summer event in which primary water stress corrosion cracking (PWSCC) was identified in an Inconel 82/182 main coolant loop-to-reactor pressure vessel weld, the NRC staff has become concerned about the impact of PWSCC on licensee leak-before-break (LBB) evaluations. NUREG-1061, Volume 3, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks," which addresses the general methodology accepted by the NRC staff for demonstrating LBB behavior, stipulates that no active degradation mechanism may be present in a line which is under consideration for LBB. Draft Standard Review Plan 3.6.3, "Leak-Before-Break Evaluation Procedures," suggests that lines with potentially active degradation mechanisms may be considered for LBB approval provided that two mitigating action/programs are in place to address the potential active degradation mechanism.

The NRC considers the resolution of the impact of PWSCC on existing LBB evaluations to be a 10 CFR Part 50, operating reactor issue. The NRC staff has previously addressed this issue with the industry's PWR Materials Reliability Program (MRP) and received an interim report from the MRP, "PWR Materials Reliability Program, Interim Alloy 600 Safety Assessment for U.S. PWR Plants (MRP-44), Part 1: Alloy 82/182 Pipe Butt Welds," dated April 2001, which attempted to provide a technical basis for addressing this issue. The NRC expects to receive a final version of the MRP-44, Part 1, report from the MRP. Based on the information in the final MRP report and any additional, relevant information available to the NRC staff, the NRC will evaluate what actions or analyses, if any, may be required to confirm the continued applicability of existing licensee LBB evaluations.

a. Regarding the V.C. Summer LRA, the NRC staff requests that the applicant provide a licensee commitment which states that for the period of extended operation of V.C. Summer, the applicant will implement actions or perform analyses, as deemed to be necessary by the NRC, to confirm continued applicability of existing V.C. Summer LBB evaluations. These actions or analyses will be consistent with those required to address the impact of PWSCC on existing LBB evaluations under 10 CFR Part 50 considerations.

b. Present information about any mitigative actions (e.g., mechanical stress improvement) that may have taken place at VCSNS since submittal of the LRA to manage PWSCC cracks in Alloy 82/182 piping welds? If so, confirm whether the future VCSNS LBB analysis will account for these mitigative actions.

Aging Management Programs (System Specific)

B.1.1 Alloy 600 Aging Management Program

<u>RAI B.1.1-1</u> With respect to inspections of vessel head and vessel head penetration provide the following information:

a. The Alloy 600 management program (LRA Section B.1.1) relies on detecting PWSCC cracks in head penetrations by means of inspection for signs of boric acid leakage during outages. Submit the following additional information regarding the boric acid leakage inspection: (1) Confirm that the boric acid leakage inspection includes inspection of bare vessel head (insulation being removed from the vessel head prior to inspection), (2) confirm that after the inspection vessel head is cleaned of any boric acid deposits prior to installing the insulation, (3) confirm whether ASME VT-2 examination method is used to detect leakage through a crack in the vessel head penetration, and (4) since the leakage through a PWSCC crack is generally very small, provide technical basis ensuring that the boric acid leakage inspection will be able to detect such a small leakage.

b. In response to NRC Bulletin 2001-01, the applicant states that, in 1999, VCSNS performed VT-3 inspections of the vessel head interior surface and did not find any recordable indications. Identify the objective of that inspection and confirm whether it can reliably detect any cracking or loss of material at the vessel head interior surface.

c. NRC Bulletin 2002-2 was issued after the submittal of the LRA. Describe how the discussion in this bulletin on adequacy of the current inspection requirements and programs for vessel head penetrations would impact the VCSNS Alloy 600 aging management program.

d. IN 2000-17, Supplement 2, "Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer," it was mentioned that the licensee intended to make several enhancements to their leak detection capability including: 1) performing noble gas sampling, 2) performing a reactor coolant system water inventory balance once per day, 3) addition of a main control board annunciator for a 0.75 gallon per minute leak, and 4) revising the procedures for boric acid inspections to list specific components and locations to be inspected and to provide specific guidance on evaluation methodologies. Explain why VCSNS is not crediting this enhanced leak detection capability for managing cracking due to PWSCC in Alloy 82/182 welds and Alloy 600 base metal.

<u>RAI B.1.1-2</u> In LRA Section B.1.1, the applicant states that PWSCC cracks can also be detected by monitoring primary coolant leakage per Technical Specifications during plant operation. It is unlikely that monitoring of primary coolant leakage would be sensitive enough to detect a very small leakage through a PWSCC crack. Submit operating experience supporting the use of primary coolant leakage monitoring during operation for detecting a PWSCC crack.

<u>RAI B.1.1-3</u> As suggested in the NRC closure letter from K. R. Cotton to G. J. Taylor, dated December 17, 1999, for SCE&G response to Generic Letter 97-01; the LRA needs to include a summary of the results of any inspections that have been completed on VCSNS vessel head penetrations prior to the license renewal application. Therefore, submit the following information for these inspections: (1) number of vessel head penetrations inspected and their locations on the vessel head, (2) inspection methods used, (3) number of Alloy 82/182 attachment welds inspected, and (4) inspection results.

<u>RAI B.1.1-4</u> The applicant states that the program will be enhanced according to the changes indicated by emerging regulatory requirements and identified by industry programs. However, the Alloy 600 aging management program, described in LRA Section B.1.0, does not specify whether the applicant would participate in the industry program for managing PWSCC type aging on vessel head penetrations. Confirm VCSNS participation in the industry program.

<u>RAI B.1.1-5</u> The FSAR supplement for the Alloy 600 management program (LRA Section B.1.1) is presented in LRA Appendix A, Section 18.2.4. The supplement states that the pressurizer and steam generator subcomponents in addition to the vessel subcomponents are within the scope of the program. However, because the applicant states that the program is consistent with the GALL AMP XI.M11, the scope of the program is limited to only vessel head penetrations and does not include other Alloy 600 components. Clarify this discrepancy and modify the supplement accordingly.

B.1.3 Bottom-Mounted Instrumentation Inspection

<u>RAI B.1.3-1</u> The applicant states that the bottom-mounted instrumentation inspection program monitors tube wall degradation in 100% of the BMI thimble tubes using eddy current testing (ECT). Submit information about whether the entire length of each thimble tube is inspected or only a selected portion of the length and present corresponding technical basis.

RAI B.1.3-2 The applicant states that the frequency of ECT examination is based on an analysis of data obtained using wear rate relationships that are predicted based on Westinghouse research. Submit an explanation for the wear rate relationship and describe the Westinghouse research mentioned here.

RAI B.1.3-3

(a) The applicant states that the ECT results are trended, wear rates are calculated, and inspections are planned prior to the refueling outage in which the thimble tube wear is predicted to exceed the acceptance criteria. Regarding the predicted wear rate, NRC I&E Bulletin 88-09 states that, based on the available data, it is not possible to accurately predict thimble tube wear rates. Explain how this difficulty in accurately predicting thimble tube wear rates is taken into account in developing the applicant's plan for the next thimble tube inspection.

(b) In describing its operating experience, the applicant states that the analysis of the wear rate data derived from the inspections performed at RF-4 and RF-5 determined that the next inspection of the thimble tubes is not required until RF-14. Explain and justify the use of this extrapolation of the limited inspection results for scheduling the next inspection of the thimble tubes. Has this extrapolation of wear data been approved by the NRC? If so, identify a reference.

RAI B.1.3-4 The bottom-mounted instrumentation inspection program uses 75% loss of initial wall thickness as an acceptance criterion. Provide the technical justification for this criterion and explain how the allowances for such items as inspection methodology and wear scar geometry uncertainties, which were mentioned in NRC I&E Bulletin 88-09, are included in the criterion.

RAI B.1.3-5 The bottom-mounted instrumentation inspection program also requires that the thimble tubes must be capped or replaced if the projected through-wall wear exceeds 80% prior to the next scheduled ECT. However, the VCSNS response to Bulletin 88-09 suggests that the thimble tube must be replaced when wall wear exceeds 60%. Explain this discrepancy.

RAI B.1.3-6 Since the issuance of IE Bulletin 88-09, the applicant has performed two inspections (RF-4 and RF-5) on thimble tubes at VCSNS. The applicant reports that several thimble tubes were repositioned in RF-5, but no thimble tubes were capped or required replacement. Confirm whether all the thimble tubes were inspected during these two inspections. If not, provide a discussion of and the technical basis for the scope of inspection that has been performed and how the scope of inspection is determined for future inspections. Also, discuss inspection expansion plans, if applicable to this program.

B.1.8 Reactor Head Closure Studs Program

RAI B.1.8-1 In LRA Table 3.1-1, AMR Item 18, the applicant states that the aging effect requiring management is loss of closure integrity. The applicant states that the AMR results are consistent with NUREG-1801 in materials and environments, but not in aging effects. The applicant further states that loss of closure integrity, rather than loss of preload or cracking, is the aging effect requiring management. Explain the difference between loss of closure integrity and loss of preload or cracking.

B.1.10 Steam Generator Management Program

RAI B.1.10-1 In LRA Appendix B.1.10, the applicant states that the steam generator management program is consistent with GALL AMP XI.M19, and no deviations are noted. The applicant also describes its operating experience with the steam generator management program and states that no significant degradation was found during routine inspections. The staff notes that operating experience with the VCSNS replacement steam generators (Westinghouse Delta-75) is quite limited, but additional experience is available with other replacement steam generators of similar design with thermally treated Alloy 690 tubes and Type 405 stainless steel tube support plates. Summarize the industry operating experience with Alloy 690 tubes and Type 405 stainless steel tube support plates.

RAI B.1.10-2 In LRA Appendix B.1.10, the applicant states that a partial eddy current inspection was performed during refueling outages 9, 10, and 11. A 100% eddy current inspection and full secondary side inspection of steam generators A, B, and C were performed during refueling outage 12.

a. Submit more information about the secondary side inspection during refueling outage 12, i.e., identify the secondary side components inspected, type of inspection performed, guidance used, and the frequency of such inspection to be performed during the extended period of operation.

b. Provide detailed information about the primary side inspection of the steam generators (i.e., tubes and plugs) during refueling outages 9, 10, 11, and 12. Discuss the components inspected, inspection scope, inspection technique used, and guidelines used.

c. The applicant states that no significant degradation was detected by the inspection performed during the refueling outages 9, 10, 11, and 12. The staff would like to have more information about these inspections so that it can assess the susceptibility of Alloy 690 tubes and plugs to different aging effects. Discuss all primary and secondary side degradations that have been detected since the operation of the VCSNS replacement steam generators.

RAI B.1.10-3 The FSAR supplement for the steam generator management program in LRA Appendix A, Section 18.2.35, states that the program implements the requirements of VCSNS Technical Specification 4.4.5 and follows the recommendations provided by NEI and EPRI guidelines, specifically their commitment to NEI 97-06.

a. Include, in the FSAR supplement, the specific references to the NEI and EPRI guidelines, specifically, their commitment to NEI 97-06.

b. If the applicant's steam generator management program is consistent with the GALL report, the applicant needs to state in LRA Appendix A, Section 18.2.35, that its steam generator management program is consistent with GALL XI.M19.

c. In LRA Appendix A, Section 18.2.35, the applicant states that "...The purpose of the Steam Generator Management Program is to perform examinations of nickel-based alloy steam generator tubes and tube plugs to ensure that cracking and loss of material are identified and corrected prior to exceeding allowable limits..." The staff believes that the applicant's steam generator management program should inspect components other than tubes and tube plugs, if the program were to be consistent with GALL XI.M19. List all the components that will be inspected in the steam generator management program.

B.1.24 Reactor Vessel Surveillance Program

RAI B.1.24-1 The VCSNS reactor vessel surveillance program consists of capsules with a projected fluence exceeding the 60-year fluence at the end of 40 years. The applicant plans to remove the two remaining surveillance capsules during RF-14. As a result, no surveillance capsules will be left in the vessel during the extended period of operation. Confirm whether the operating restrictions will be established at the end of RF-14 to ensure that the plant is operated under conditions to which the surveillance capsules were exposed and the exposure conditions of the reactor vessel will be monitored to ensure that they continue to be consistent with those used to project the effects of embrittlement to the end of license. In addition, confirm whether an alternative dosimetry will be used at VCSNS to monitor neutron fluence during the period of extended operation.

RAI B.1.24-2 Provide information regarding the fluence calculation methodology, i.e., how is it consistent with the recommendations of DG-1053 and RG 1.190? In addition, confirm whether an alternative dosimetry will be used at VCSNS to monitor neutron fluence during the period of extended operation. Provide applicable references.

RAI B.1.24-3 In LRA Appendix B.1.24, "Reactor Vessel Surveillance Program," the applicant states that VCSNS will perform a one-time analysis to demonstrate that the material in the inlet and outlet nozzles and upper shell courses will not become controlling during the period of extended operation. Describe the one-time analysis to be performed and explain why such a demonstration is needed. If the demonstration is not successful, confirm that the reactor vessel surveillance program will be reestablished. Submit the results of the analysis, for staff's review, prior to the extended period of operation.

B.2.1 Small-Bore Class 1 Piping Inspection

RAI B.2.1-1 The applicant has committed to perform destructive examinations of small bore piping. This is of significance to the staff in order to make a reasonable assurance determination of this AMP; therefore, the applicant should include this commitment of performing destructive examinations of small bore piping in the FSAR supplement for the AMP described in LRA Appendix B.2.7.

B.2.4 Reactor Vessel Internals Inspection

RAI B.2.4-1 In LRA Appendix B, Section B.2.4, the applicant describes its AMP to manage aging processes in reactor vessel internals. The LRA states that this AMP is consistent with GALL AMP XI.M16, with the clarification that the resolution criterion for the enhanced VT-1 examination at the Summer Plant is expected to be less than 0.0005-in. resolution, which is specified in the GALL program. Submit technical justification for using less than 0.0005-in resolution, and explain how the anticipated reduction in the resolution criterion will be determined.

RAI B.2.4-2 LRA Section B.2.4 describes the VCSNS Reactor Vessel Internals Inspection Program, a new program to assess the condition of reactor vessel internals in order to assure that the applicable aging effects will not result in loss of the intended functions during the period of extended operation. With respect to the irradiation embrittlement of the RV internal components, the staff notes that NUREG/CR-6048, Oak Ridge National Laboratory, has used $5x10^{20}$ neutrons/cm^2 (E > 0.1 MeV) as the threshold for loss of fracture toughness due to radiation embrittlement in Type 304 austenitic stainless steel materials. Confirm whether this threshold value will be used at VCSNS for austenitic stainless steel vessel internals. If an alternate value is proposed, then submit a technical basis for that alternate value. Also provide the technical basis for the selection of the RV internal components for inspection.

RAI B.2.4-3 LRA Section B.2.4 describes the VCSNS Reactor Vessel Internals Inspection Program, a new program to assess the condition of reactor vessel internals in order to assure that the applicable aging effects will not result in loss of the intended functions during the period of extended operation. With respect to the application of this program to the detection of irradiation-assisted stress corrosion cracking of RV internals components, the staff requests additional information on how the applicant determines which RV internal components are susceptible to irradiation-assisted stress corrosion cracking, what components will be selected for inspection, and what the technical basis is for this selection process.

RAI B.2.4-4 LRA Section B.2.4 describes the VCSNS Reactor Vessel Internals Inspection Program, a new program to assess the condition of reactor vessel internals in order to assure that the applicable aging effects will not result in loss of the intended functions during the period of extended operation. The staff reviewed the applicant's FSAR supplement (LRA Section 18.2.18) to verify that it provides an adequate description of the programs credited with managing this aging effect, as required by 10 CFR 54.21(d). The staff notes that the description of the Reactor Vessel Internals Inspection in LRA Section B.2.4 states that "specific acceptance criteria for changes in dimension due to void swelling, loss of preload due to stress relaxation, and loss of material due to wear will be determined by analysis as part of the inspection plan." The staff requests that the applicant commit to supplement the reactor vessel internals inspection program and to submit an integrated report to the NRC prior to the end of the initial operating term for V.C. Summer. The report should summarize the understanding of the aging effects applicable to the reactor vessel internals and should contain a description of the V.C. Summer inspection plan, including methods for detection and sizing of cracks and acceptance criteria. This should also be discussed in the FSAR supplement.

B.1.2 Boric Acid Corrosion Surveillances (BACS) Program

RAI B.1.2-1 The definition section of Appendix B.1.2, "Boric Acid Corrosion Surveillances" (BACS), states that this program is consistent with GALL XI.M10, except for enhancements related to dissimilar metal weld inspections. The staff requests the applicant to discuss the enhancements to this program by addressing the following:

- operating experience since publication of GALL report and since submittal of the application in addition to the impacts of this experience on the program, if any.
- how the systems outside containment, currently inspected under other existing programs, will continue to be inspected under the enhanced Boric Acid Corrosion Surveillances Program.

<u>RAI B.1.2-2</u> The operating experience section of Appendix B.1.2, “Boric Acid Corrosion Surveillances,” discusses the hot leg axial cracking at VCSNS on October 7, 2000 and further states that the BACS were subsequently enhanced to ensure that all dissimilar metal welds are included in the population of components that are visually inspected at refueling outages or when appropriate plant conditions permit access. The staff requests the applicant to list the locations of all dissimilar metal welds exposed to borated coolant to be included within the scope of this program.

<u>RAI B.1.2-3</u> In Table 3.1-1, “Summary of Aging Management Programs for the Reactor Coolant System Evaluated in NUREG-1801 that are Relied on for License Renewal,” AMR Item 26 credits the BACS for managing loss of material due to boric acid corrosion of the pressurizer carbon steel and low alloy steel components; i.e., shell, upper and lower heads, nozzles, integral support, manway cover and bolts. The staff requests the applicant to discuss how this program will be sufficient to manage the corrosive effects of boric acid leakage on the base metal of these insulated components during the extended period of operation; i.e, postulated leakage from the pressurizer nozzle-to-vessel welds, pressurizer nozzle-to-safe end welds, and pressurizer manway bolting materials.

<u>RAI B.1.2-4</u> In Table 3.1-1, "Summary of Aging Management Programs for the Reactor Coolant System Evaluated in NUREG-1801 that are Relied on for License Renewal," AMR Item 26 credits the BACS for managing the loss of material due to boric acid corrosion for the external surfaces of carbon steel components in reactor coolant system pressure boundary. In Table 2.3-7, "Steam Generators Component Types Subject to Aging Management Review and Their Intended Functions," the applicant identified the steam generator elliptical head and channel head as being within the pressure boundary and therefore, managed by the BACS. The staff requests the applicant to discuss how the BACS will manage the external surfaces of the VCSNS steam generators in light of BL 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” and GL 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR Plants”.

B.1.4 Chemistry Program

<u>RAI B.1.4-1.</u> The program description section of Appendix B.1.4, “Chemistry Program”, states that this program does not commit to performing one-time inspections to verify its effectiveness as suggested by NUREG-1801, XI.M2. The following are examples of components exposed to chemically treated water that will be managed by this program alone:

- From Table 3.1-2, “Summary of Aging Management Evaluations for the Reactor Coolant System that are Different From or Not Addressed in NUREG-1801 but are Relied on for License Renewal”:
    - AMR Item 3, loss of material due to crevice, general, pitting, and galvanic corrosion in CS SG components (other than the shell - upper and lower barrel, transition cone, elliptical head)
    - AMR Item 5, crevice and pitting corrosion of SS piping and piping system components
    - AMR Item 6, crevice and pitting corrosion of piping and piping system components

- AMR Item 7, crevice and pitting corrosion of reactor internals, reactor vessel, RCP, incore thermocouple seal

- AMR Item 14, loss of material in the RCP thermal barrier flange and loss of material due to crevice and pitting corrosion of non-Class 1 piping and valve bodies for the pressurizer relief tank spray

- loss of material in SS and Ni-alloy reactor vessel components (i.e., CRD housings, cladding, vent plug, bottom head and closure head penetration tubes, reactor vessel core support pads, and nozzle safe ends)

- loss of material and cracking on the outside surface of the BMI thimble tubes and the inside surface of the guide tubes supporting the thimble tubes between the seal table and vessel lower head

- From Table 3.3-1, "Summary of Aging Management Program for the Auxiliary Systems Evaluated in NUREG-1801 that are Relied on for License Renewal":

  - loss of material in carbon steel components in the air handling and local ventilation and cooling, chilled water, spent fuel pool cooling, and gaseous waste processing systems due to crevice, galvanic, general, and pitting corrosion

The staff requests the applicant to discuss the operating history and the results of the most recent surveillances or inspections for these and similar components in the various water environments assure that the above-listed types of corrosion (crevice, general, pitting, and galvanic) are adequately managed.

The staff also requests the applicant to discuss if there a one-time inspection for the most susceptible locations; i.e., low flow and/or stagnant areas, in the components that credit this program for aging management. If so, the staff requests the applicant to describe the one-time inspection; e.g., scope, determination of sample size, identification of inspection locations, determination of examination technique, and the evaluation of the need for follow-up examinations.

<u>RAI B.1.4-2</u> The applicant appears to have combined aspects of several GALL programs into its chemistry program. Therefore, the staff requests the applicant to discuss to what extent this program relies on the GALL AMPs described in Chapters XI.M20, "Open-Cycle Cooling Water System," and XI.M21, "Closed-Cycle Cooling Water System. In addition, the applicant is requested to discuss how the features of these GALL programs are incorporated into the VCSNS chemistry and cooling water corrosion programs. References to the various EPRI documents for the chemistry guidelines credited in this program should also be stated in the FSAR supplement.

<u>RAI B.1.4-3</u>   By letter dated October 1, 2002, the applicant provided a table entitled "Virgil C. Summer Nuclear Station Database AMR Query," which states in several entries that CS components; e.g., CS cooling coil headers or pump casings, evaporator tubesheets and water boxes, valve bodies, pipe and fittings, and tanks, in a treated water environment are subject to cracking due to stress corrosion cracking (SCC). Additional information is also provided in the

accompanying applicant-supplied VCSNS Mechanical Database AMR Query Notes A-CC-c and A-CC-h on pages 23 and 25, respectively. However, no aging management program has been credited to manage this aging effect. According to the ASM Handbook, Vol. 11, "Failure Analysis Prevention," and EPRI TR-107396, "Closed Cooling Water Chemistry Guidelines," October 1997, SCC occurs in carbon steels usually in the presence of hydroxides, carbonates or nitrates. Therefore, the staff requests the applicant to discuss how this aging effect is managed; i.e., name of the program(s) which manage this aging effect and how this program can prevent, detect or mitigate the effects of SCC in these carbon steel components.

<u>RAI B.1.4-4</u> The program description section of Appendix B.1.4, "Chemistry Program", states that this program is consistent with GALL XI.M30, "Fuel Oil Chemistry"; however, the application does not discuss the verification of the program's effectiveness at locations where contaminants may accumulate as recommended in GALL. Therefore, the staff requests the applicant to discuss the basis for not including the verification of this program to manage loss of material.

<u>RAI B.1.4-5</u> In Table 3.1-2, "Summary of Aging Management Evaluations for the Reactor Coolant System that are Different From or Not Addressed in NUREG-1801 but are Relied on for License Renewal", AMR Item 7 credits the chemistry program for managing loss of material due to crevice and pitting corrosion in the pressurizer shell and heads clad with austenitic stainless steel, and stainless steel components internally exposed to chemically treated borated coolant. These components are susceptible to crevice and pitting corrosion due to high levels of oxygen which may be present in the reactor coolant. However, if hydrogen overpressurization is maintained in the reactor coolant at sufficiently high levels, protection is provided in the creviced geometries of pressurizer's internal surfaces. The staff requests the applicant to discuss how the chemistry program will ensure a sufficient level of hydrogen overpressurization to manage crevice corrosion in the pressurizer's internal surfaces.

B.1.15 Containment Coating Monitoring and Maintenance Program

<u>RAI B1.15-1</u> The Containment Coating Monitoring and Maintenance Program, as described in LRA FSAR Section 18.2.11, states that, for inaccessible areas, sampling approaches based on plant-specific characteristics, industry-wide experience, and testing history are evaluated in lieu of actual visual inspections. The staff requests the applicant to discuss these sampling procedures used to verify that aging-related degradation of the containment coating will be effectively managed in accordance with the current licensing basis during the period of extended operation. In addition, the staff requests additional information on the element 4, "Detection of Aging Effects," of the Containment Coating Monitoring and Maintenance Program consistent with the SRP-LR and in sufficient detail to allow adequate assessment of this element. If this element was determined to not be applicable, the staff requests a justification for this determination.

B.1.6 Flow-Accelerated Corrosion Monitoring Program

<u>RAI B.1.6-1</u> The program description section of Appendix B.1.6, "Flow-Accelerated Corrosion (FAC) Monitoring Program," states that this program is consistent with GALL XI.M17, "Flow-Accelerated Corrosion". The applicant also states that the need for inspections is determined by a calculation performed in accordance with engineering procedures and that if components exhibit high wear during a cycle these are replaced with more FAC-resistant material. The

EPRI document, NSAC-202L-R2, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” recommends the use of a predictive method for determining the rate at which component degradation is occurring by FAC. The NRC staff notes that CHECWORKS or a similar predictive code should be used to predict component degradation in the systems conducive to FAC, as indicated by specific plant data, including material, hydrodynamic, and operating conditions. The staff requests the applicant to discuss the “calculation performed in accordance with engineering procedures” to determine inspection need. Specifically, the staff requests a discussion of the methods used at VCSNS for predicting component degradation by FAC and how these predictive methods are used to determine the need and frequency of inspections.

<u>RAI B.1.6-2</u> The staff requests a list of components within the scope of this program which are most susceptible to FAC in addition to the initial wall thickness (nominal), current (measured) wall thickness and the future predicted wall thickness to demonstrated the effectiveness of the FAC monitoring program.

<u>RAI B.1.6-3</u> The FAC monitoring program includes the use of a predictive method to calculate the wall thinning of components susceptible to FAC. In order for the staff to evaluate the accuracy of these predictions, the staff requests a sample list of components for which wall thinning is predicted and measured by UT or other method.

B.2.1 Above Ground Tank Inspection

<u>RAI B.2.1-1</u> The description section of Appendix B.2.1, “Above Ground Tank Inspection,” states in element 5, “Monitoring and Trending,” that no actions are taken to trend inspection results. This one-time inspection program determines if further actions are required. The staff notes that the evaluation of the techniques and the timing of the one-time inspection improve with the accumulation of plant-specific and industry-wide experience. As a result of the insights gained from the recent discovery of boric acid-induced corrosion of the Davis-Besse vessel, the staff requests that the applicant to address any changes which are made in monitoring and trending for those components exposed to borated water.

<u>RAI B.2.1-2</u> The staff notes that GALL XI.M29 “Above Ground Carbon Steel Tanks,” is not credited for aging management in the VCSNS LRA. This GALL program defines preventive measures to mitigate corrosion of the external surface of carbon steel tanks with paint or coatings in accordance with standard industry practice. The staff also notes that Appendix B.1.15,”Containment Coating Monitoring and Maintenance Program,” is an existing aging management program that manages the loss of material due to coating degradation but is not credited with managing the external degradation of the tanks. The staff requests the applicant to discuss how the Above Ground Tank Inspection Program adequately manages the external surface of the above ground tanks if this program only inspects the internal surfaces of the tanks.

<u>RAI B.2.1-3</u> The description section of Appendix B.2.1, “Above Ground Tank Inspection,” states that this program will be consistent with the GALL XI.M32, “One-Time Inspection.” However, in comparing this program with the one-time inspection program defined in GALL, the staff requests the applicant to address the following:

a) Element 4, “Detection of Aging Effects” - This program does not discuss the qualification of the personnel conducting the inspection.

b) Element 6, "Acceptance Criteria" - This program does not discuss or refer to the design minimum wall thickness nor to the criteria for verifying the absence of cracking.

B.2.10 Buried Piping and Tanks Inspection

RAI B.2.10-1 In Appendix B.2.10, "Buried Piping and Tanks Inspection," under element 2, "Preventive Actions," the applicant states that underground components are coated and wrapped during installation to prevent direct contact with the soil environment. The staff requests the applicant to briefly describe the coating techniques used and to discuss the verification of the adequacy of these techniques in light of the inadequate cathodic protection discussed in the operating history section.

RAI B.2.10-2 In Appendix B.2.10, "Buried Piping and Tanks Inspection," under element 3, "Parameters Monitored or Inspected," the applicant states that the condition of coatings and wrappings will be determined by visual inspection whenever buried components are excavated for maintenance or for other reasons. The applicant later cited operating experience with buried piping and tanks which used UT. The staff requests the applicant to discuss if UT will be used in addition to or in place of the visual inspection and the criteria used to determine the applicability of the technique used.

RAI B.2.10-3 In Appendix B.2.10, "Buried Piping and Tanks Inspection," under element 4, "Detection of Aging Effects," the applicant stated that a specific inspection frequency for buried components is not warranted. The staff requests the applicant to discuss why periodic inspection of the most susceptible locations is not needed especially in areas with the highest likelihood of corrosion and in areas with a history of corrosion problems.

RAI B.2.10-4 In Appendix B.2.10, "Buried Piping and Tanks Inspection," under element 6, "Acceptance Criteria," the applicant states that the acceptance criteria are "no unacceptable degradation of coatings and wrappings that could result in loss of material and therefore a loss of component intended function, as determined by engineering evaluation." The staff requests the applicant to discuss how the coating and wrapping degradation will be reported and evaluated; e.g., by site corrective actions or other procedure.

RAI B.2.10-5 The operating history section of Appendix B.2.10, "Buried Piping and Tanks Inspection," discusses the inspection of the fuel oil storage tanks and associated piping performed as a result of the inadequacy of the cathodic protection system for these components. The staff requests the applicant to discuss the operating experience/inspection of the other storage tanks and piping within the scope of this system.

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