November 14, 2001

LICENSEES: Virginia Electric Power Company

FACILITIES: North Anna, Units 1 and 2
Surry, Units 1 and 2

SUBJECT: SUMMARY OF OCTOBER 9, 11, and 15, 2001, TELECOMMUNICATION WITH VIRGINIA ELECTRIC AND POWER COMPANY

On October 9, 11, and 15, 2001, the U.S. Nuclear Regulatory Commission (NRC) staff had conference calls with representatives of Virginia Electric and Power Company (VEPCO) to discuss information relating the staff's review of the North Anna, Units 1 and 2 (NAS 1 and 2), and Surry, Units 1 and 2 (SPS 1 and 2) license renewal applications (LRAs) review. The information discussed, the applicant's responses, and the follow-up actions are in Attachment 1. A list of participants is included in Attachment 2.

A draft of this telephone conversation summary was provided to VEPCO to allow them the opportunity to comment on the contents of its input prior to the summary being issued.

/***RA***/

Robert J. Prato, Project Manager
License Renewal and Standardization Branch
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Docket Nos. 50-338, 50-339, 50-280, and 50-281

Attachment: As stated

cc w/att: See next page

LICENSEES: Virginia Electric Power Company

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Surry, Units 1 and 2

SUBJECT: SUMMARY OF OCTOBER 9, 11, and 15, 2001, TELECOMMUNICATION WITH VIRGINIA ELECTRIC AND POWER COMPANY

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Section 2.3.1, "Reactor Cooland System"

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Michael Henig	VEPCO
Julius Wroniewicz	VEPCO
Marc Hotchkiss	VEPCO
Tom Snow	VEPCO
Muhammad Razzaque	NRC
Robert Prato	NRC

Subsections 2.3.2, "Engineered Safety Features Systems"

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Muhammad Razzaque	NRC
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Subsections 2.3.3, "Auxiliary Systems"

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Tom Snow	VEPCO
Muhammad Razzaque	NRC
David Cullison	NRC
Robert Prato	NRC

Section 3.1.5, "Steam Generator"

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Michael Henig	VEPCO
Julius Wroniewicz	VEPCO
Marc Hotchkiss	VEPCO
Tom Snow	VEPCO
Jim Williams	VEPCO

George Georgiev	NRC
Z. Fu	NRC
Robert Prato	NRC

Section 4.2.1, "Upper Shelf Energy"

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Section 4.2.1, "Pressurized Thermal Shock"

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Section B2.2.8, "Fuel Oil Chemistry"

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Section B2.2.18, "Steam Generator Inspections"

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Tom Snow	VEPCO
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SUMMARY OF TELECOMMUNICATION WITH
VIRGINIA ELECTRIC AND POWER COMPANY
OCTOBER 9, 10, and 15, 2001

Section 2.3.1.1, “Reactor Coolant”

Item 2.3.1-1 In both LRAs, Section 2.3.1, the applicant states that two concentric, hollow, metallic O-rings between the closure head flange and the reactor vessel flange form an inner and outer seal. Furthermore, it was stated in the UFSAR that leakage through the reactor vessel head flange will leak off between the double O-ring seal to the leakoff provided. Leakage into this leakoff path will cause high temperature in this line, which will actuate an alarm in the control room. Based on the staff’s experience with license renewal, the staff has determined that these leakoff lines should, in general, be within scope requiring aging management. However, the applicant may submit a plant-specific justification, if any, to exclude the subject components from an AMR.

The reactor vessel flange leakoff lines are not subject to an AMR. Therefore, the applicant will respond to an RAI justifying its position.

The staff does not agree that the leakoff lines are outside the scope of the reactor coolant pressure boundary. The staff has generally concluded that the inner O-ring, the leakoff lines, and the outer O-ring all support he reactor cooland pressure boundary. Although in select cases, the staff has excluded the leakoff lines because of flow restriction, in general, the leakoff lines require an AMR. Please provide a site-specific technical justification for both NAS and SPS as to why aging management is not required, or manage any applicable aging for these components.

Section 2.3.1.3, “Reactor Vessel Internals”

Item 2.3.1.3-1 In both LRAs, Section 2.3.3, the applicant states that the core support ledge supports the entire weight of the reactor vessel internals and the fuel, and the lower internals assembly hangs from the ledge. The upper internals assembly sits on the circumferential spring, which is compressed when the vessel head is lowered and tightened down in order to minimize flow-induced vibrations and to prevent upward motion of the lower internals assembly. The core support ledge and the circumferential spring, however, do not appear to be included within the scope of license renewal and are not subject to an AMR. Please justify the exclusion of these components, that are within the scope of license renewal, from an AMR.

The core support ledge and circumferential spring are within the scope of license renewal and are subjected to aging management review. The core support ledge can be found in Table 2.3.1-2, “Reactor Vessels,” (page 2-134 of the Surry LRA). It is listed as “Vessel Flange and Core Support Ledge (and cladding).” The circumferential spring can be found in Table 2.3.1-3 Reactor Vessel Internals (page 2-135 of the Surry LRA). It is listed as “Core Barrel Holddown Spring.”

The staff found the applicant’s response acceptable and will not need any additional information regarding this matter.

Item 2.3.1.3-2 The following reactor vessel internal components were identified to be within scope, and require an AMR, in Table 2-1 of the Westinghouse generic topical report WCAP-14577 because they perform intended functions which are within the scope of the rule. However, these components do not appear to be included within the scope of license renewal and are not subject to an AMR. Please justify the exclusion of these components, that are within the scope of license renewal, from an AMR: lower support forging or casting, core barrel outlet nozzle, guide tube and flow downcomers, drive rod, irradiation specimen guide, bottom mounted instrumentation (BMI) columns and flux thimbles, mixing device, and specimen plugs.

The following components are within the scope of license renewal and subjected to aging management review:

a. The lower support forging or casting can be found in Table 2.3.1-3 Reactor Vessel Internals (page 2-136 of the Surry LRA). It is listed as "Lower Support Plate and Columns."

b. The core barrel outlet nozzle has been grouped with the core barrel since it is an integral part of the core barrel. The core barrel can be found in Table 2.3.1-3 Reactor Vessel Internals (page 2-135 of the Surry LRA). It is listed as "Core Barrel."

c. The guide tube and flow downcomers can be found in Table 2.3.1-3 Reactor Vessel Internals (page 2-135 of the Surry LRA). It is listed as "Control Rod Guide Tubes."

d. The bottom mounted instrumentation (BMI) columns can be found in Table 2.3.1-3 Reactor Vessel Internals (page 2-135 of the Surry LRA). It is listed as "Instrument Guide Tubes."

e. The flux thimbles can be found in Table 2.3.1-2 Reactor Vessels (page 2-132 of the Surry LRA). It is listed as "Bottom Mounted Instrumentation Flux Thimble Tubes". The inclusion of the flux thimbles in the Reactor Vessel section in lieu of the Reactor Vessel Internals section is detailed at the top of page 3-15 (Surry LRA) in the section titled "Confirmation of Topical Report Applicability."

Table 2-1 and Table 2-2 of the Westinghouse generic topical report WCAP-14577, Rev. 1-A, March 2001, as accepted by the NRC in the final SER, does not define any intended functions for and excludes the drive rod, irradiation specimen guide, mixing device, and specimen plug from an AMR.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 2.3.1.4, "Pressurizer"

Item 2.3.1.4-1 The manway pad gasket seating surface was identified to be within scope, and require an AMR, in Table 2-1 of the Westinghouse generic topical report WCAP-14574 for pressurizers. This component, however, does not appear to be included within the scope of license renewal and is not subject to an AMR. Please provide a basis for the exclusion.

The pressurizer manway pad gasket seating surface is within the scope of license renewal and has been subjected to aging management review. As identified in Table 2.3.1-4 of the License Renewal Application, the manway pad gasket seating surface is included in the line item, "Manway (includes Pad and Cladding)."

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 2.3.1.4-2 The NAS UFSAR, Section 5.5.5.2.1, describes the presence of a screen at the surge line nozzle and baffles in the lower section of the pressurizer to assist mixing and prevent an insurge of cold water from flowing directly to the steam/water interface. These components, however, do not appear to have been included within the scope of license renewal and are not subject to an AMR. The staff requests the applicant to explain why these components which provide functional support for in-scope equipment in the pressurizer are not in scope requiring an AMR.

The surge line nozzle basket and baffles in the lower portion of the pressurizer do not perform an intended function. This position is consistent with Table 2-1 of WCAP-14574A, December 2000, and the associated safety evaluation report.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 2.3.1.4-3 Section 2.1 of the Westinghouse generic topical report WCAP-14574 states that in addition to the pressure boundary function, pressurizers have a function to limit pressure changes, to an allowable range, that are caused by reactor coolant thermal expansion and contraction during plant load changes. The staff requests the applicant to clarify whether the pressure control function of pressurizers is relied upon to mitigate design-basis events/accidents, or whether it can be classified as one of those functions delineated in 10 CFR Part 54.4(a). If it is, then the applicant should identify pressure control as a relevant license renewal function for pressurizers, and also should include the structures and components, which support this function to be within the scope of license renewal requiring aging management.

The pressurizer pressure control function is not relied upon to mitigate design basis events or accidents. Therefore, pressure control is not identified as a license renewal intended function. This position is consistent with Section 2.2 of WCAP-14574A, December 2000, and the associated safety evaluation report.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 2.3.1.5, "Steam Generator"

Item 2.3.1.5-1 From the system description presented in the LRA, the staff's view is that the following steam generator components provide structural and/or functional support for in-scope equipment. The staff, therefore, requests the applicant to justify why the steam generator stay rod spacer pipes, internal feedwater distribution ring (feedring), and J-nozzles did not require aging management.

The stay rod spacer pipes were subjected to aging management review and are included under the line item, "Stay Rods" in License Renewal Application Tables 2.3.5-1 and 3.1.5-1. The stay rod spacer pipes and stay rods are both constructed of carbon steel and exposed to a treated water/steam environment. Therefore, the stay rod spacer pipes are not identified as a separate line item.

The feedwater inlet ring and associated J-nozzles are not included in the scope of license renewal since they do not perform a license renewal intended function.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Subsections 2.3.2, "Engineered Safety Features (ESF) Systems"

Item 2.3.2.4-1 It was stated in the UFSAR that a modified design incorporating vortex suppressing devices was developed so that the containment sump will be free of any harmful vortices for any postulated operating conditions. The modifications made to the sump involved the installation of two layers of floor grating in the sump and the installation of perforated vortex breakers inside the cylindrical screens (Secs. 3A.79, 6.2.2.4.3; North Anna UFSAR). These components do not appear to have been described in the LRA, and are not included within the scope of license renewal requiring an AMR. The staff requests the applicant to provide a basis for their exclusion; or to submit an AMR for these components. In addition, if similar components (screens/vortex suppressors) are employed inside tanks at pump suction lines, then the applicant should also identify those components, and submit an AMR for those components.

Vortex breakers are considered an integral part of sump screen. They are made of the same material and exposed to the same environment as the sump screens and are managed by the Infrequently Accessed Area Inspections Activity AMA.

The NAS UFSAR, Sections 3A.79 and 6.2.2.4.3, indicate that the two layers of floor gratings installed in the sump do perform a LR intended function. Based on the staff's inquiry the applicant recognized the need to include them in the scope of license renewal and to subject them to an AMR. The applicant is expecting an RAI to document this change in the LRA.

The North Anna UFSAR, DBDs, and the tank fabrication specification indicate that vortex breakers are not used in the ESF tanks.

The staff will provide an RAI requesting that the applicant include the floor gratings installed in the sump as being within the scope of license renewal and subject them to an AMR.

Subsections 2.3.3, “Auxiliary(aux) Systems”

Item 2.3.3.1-1 In the SPS UFSAR (Chemical and Volume Control System, page 9.1-6) the applicant states that, “.....pressurizer auxiliary spray valves are equipped with quick-disconnect instrument air fittings to provide a method to locally operate the valves with a portable air source. The operation of these valves provides an alternate letdown path and pressurizer control during plant cooldown following a postulated fire in accordance with the requirements of Appendix R to 10 CFR 50.” If these statements imply that the auxiliary spray is relied upon to demonstrate compliance with regulated events, such as, fire protection, then the staff requests the applicant to explain why the structures and components which support this function should not be in scope of license renewal requiring aging management. This may include the spray head (the component which actually sprays the water) to provide assurance that clogging of the spray holes due to aging effects over the extended period of operation will not degrade the spray function.

The valves and piping associated with auxiliary spray to the pressurizer perform a reactor coolant pressure boundary function. Therefore, they are within the scope of license renewal and were subjected to aging management review.

Auxiliary spray to the pressurizer is isolated during an Appendix R event. Therefore, auxiliary spray has no license renewal intended function during an Appendix R event. The above referenced UFSAR statement is misleading. A UFSAR change request has been submitted (prior to this concern being identified by the staff) to clarify this statement. The proposed wording for this change is: “[t]he letdown orifice isolation valves and the pressurizer auxiliary spray valves are equipped with quick-disconnect instrument air fittings to provide connections to locally operate the valves with a portable air source. The operation of the letdown orifice isolation valves provides an alternate letdown path during plant cooldown following a postulated fire in accordance with the requirements of Appendix R to 10 CFR 50. The analysis for Appendix R requires that the auxiliary spray valve be disabled closed to ensure pressurizer pressure control, and therefore, are within the scope of license renewal and subject to an AMR. The auxiliary spray valve quick disconnect is not credited in the Appendix R analysis.”

The pressurizer spray head is not within the scope of license renewal since it does not perform an intended function. This position is consistent with WCAP - 14574A, December 2000, and the associated safety evaluation report.

The staff found the applicant’s response acceptable and will not need any additional information regarding this matter.

Item 2.3.3.3-1 In both LRAs, Table 2.3.3-2, the applicant states that valve bodies are in scope and require an AMR. However, the aging management review results for the incore instrumentation (IC) components, presented in Table 3.3.1-2 of the LRA, states that valve bodies do not require aging management because the environment (internal and external) is air. The staff requests the applicant to respond to the following questions/concerns:

a. Are the isolation valve bodies, which do act as a pressure boundary in the event of a leak in the IC system pressure boundary components, included in the table? If not, why not?

The isolation valve bodies are included in License Renewal Application Tables 2.3.3-2 and 3.3.1-2.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. The inside environment of an isolation valve in the event of a leak will be borated water, not air, which may induce aging related degradation.

The incore instrument isolation valves are normally exposed to air internally and externally. The valves would only be exposed to borated water in the event of a leaking thimble tube. Therefore, borated water is not evaluated as an environment for the valves. The Corrective Action System, which incorporates the requirements of 10 CFR 50 Appendix B, would be used to initiate corrective actions associated with a leaking thimble tube.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Sections 2.3.3.4(SPS) and 2.3.3.5 (NAS), "Sampling System(SS)"

Item 2.3.3.4-1 Sampling System(SS) - Verify if sample coolers are within the license renewal scope. The some of the sampling system drawings listed on page 2-55 of the NAS application and page 2-53 of the Surry application show that the sample coolers are not within the license renewal scope while others show that these coolers are in scope. The list of component groups for the Sampling System that require an aging management review in Table 2.3.3-5 of the NAS LRA, and Table 2.3.3-4 of the SPS LRA includes the sample coolers.

The sample coolers perform a pressure boundary function for the component cooling system and are shown as being in scope on the component cooling system LRA drawings referenced in Section 2.3.3.5 of the NAS LRA and Section 2.3.3.4 of the SPS LRA. The sample coolers have sampling system designators in the mark numbers. Therefore, they have been included in the screening results for the sampling system. The sample coolers have not been highlighted a second time on the sample system drawings.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 2.3.3.9, "Neutron Shield Tank Cooling"

Item 2.3.3.9-1 In the NAS LRA, Section 2.3.3.9, " Neutron Shield Tank Cooling," the vent and chemical addition connections on the Neutron Shield Surge Tank as shown on drawings 11715-LRM-079B, Sheet 5 and 12050-LRM-079A, Sheet 5 are not included in the license renewal boundary. The Neutron Shield Surge Tank and the other piping connected to the surge tank are within the license renewal boundary. Justify why these connections are not within the license renewal boundary.

The vent and chemical addition lines are physically located on the top of the Neutron Shield Surge tank and do not perform an intended function for license renewal since the tank is not pressurized.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 2.3.3.9-2 The NAS LRA, Section 2.3.3.24, "Building Drains," system description on page 2-77 states that the portion of the building drain system that is subject to aging management review consists of the main control room and emergency switchgear room (MCR/ESGR) chiller rooms sump discharge path components that prevent flooding of the chiller rooms.

The corresponding drawings are 11715-LRB-201A, Sheets 1 and 2. The drawings show that a significant portion of the discharge path outside the service building is not within the license renewal scope. The point at which the discharge piping is no longer within the license renewal scope appears to be arbitrarily set in the middle of the discharge path pipe run. Justify why the entire MCR/ESGR chiller rooms sump discharge path is not within the license renewal scope.

The sump pump discharge piping inside the Service Building performs a pressure boundary function since the piping is required to ensure water is removed from the Service Building for flood protection of the chiller rooms. The piping outside the Service Building does not perform an intended function.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 2.3.3.9-3 In the SPS LRA, Section 2.3.3.9, "Neutron Shield Tank Cooling," the vent and chemical addition connections on the Neutron Shield Surge Tank as shown on drawings 11448-LRM-072E, Sheet 2 and 11548-LRM-072B, Sheet 3 are not included in the license renewal boundary. The Neutron Shield Surge Tank and the other piping connected to the surge tank are within the license renewal boundary. Justify why these connections are not within the license renewal boundary.

The vent connection off the top of the Neutron Shield Surge Tank does not perform an intended function for license renewal since the tank is not pressurized.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 2.3.3.30, "Plumbing (PL)"

Item 2.3.3.30-1 In the SPS LRA, page 2-78, the applicant states that "[t]he portion of the PL system that is subject to aging management review consists of the Turbine Building sump pumps and discharge." The corresponding drawings are 11448-LRB-15B, Sheet 1 for Unit 1 and 11548-LRB- 15B, Sheet 1 for Unit 2. On both drawings, the entire run of the discharge piping is not shown, but there is a note "See LR Note B" where the pipe drawing is truncated. LR Note B states that the pipe continues to the outside of the Turbine Building. Verify that the portion of discharge piping not shown on the drawings is within the license renewal scope.

The portion of piping not shown on the drawing and located within the Turbine Building is within the scope of license renewal.

The staff found the applicant's verification acceptable and will not need any additional information regarding this matter.

Item 2.3.3.30-2 Drawing 11448-LRB-15B, Sheet 1, shows that the piping with valve 1-PL-13 coming off the sump discharge piping and returning to the turbine building sump is not within the license renewal scope. Provide justification for this line not being within the license renewal scope.

Failure of this piping would not affect the flooding analysis assumptions for the removal of water from the Turbine Building. Therefore, the piping does not perform an intended function and is not in scope for license renewal.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 2.3.3.30-3 The SPS UFSAR, Page 9C-5, states that operation of the turbine building sump pumps can delay or prevent floodwaters from entering the Emergency Switchgear Room. It also states that the turbine building sump pumps remove floodwaters that result from ruptures in the turbine building which flow via the floor drain system into the sump. This implies the floor drain system is necessary for the PL system to perform its intended function of delaying or preventing floodwaters from entering the Emergency Switchgear Room. Provide justification for not including the floor drain system within the license renewal scope.

In the event of flooding in the Turbine Building (TB), the TB drains may overflow. As stated on page 9C-5 of the UFSAR, the checked plate manhole covers over the sumps were replaced with open grating. The open grating provides an unobstructed flow path directly into the sump. Therefore, the Turbine Building drains are not relied upon for the PL system to perform its intended function to remove water from the Turbine Building. The wording in the UFSAR will be evaluated for clarity and revised if required.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 3.1.5, "Steam Generator"

Item 3.1.5.2.1-1a The applicant states in Section 3.1.5 of the LRA that cracking of steam generator components due to fatigue is evaluated as a TLAA. Also, in

Section 4.3 of the LRA, the applicant states that steam generators components have been analyzed using the methodology of the ASME B&PV Code, Section III, Class 1. The steam generator components within the scope of the license renewal for NAS and SPS are classified as ASME Class 1 and 2 components.

a. Identify Class 1 components that have been evaluated for fatigue and provide the bounding cumulative usage factors when considered the extended period of operation.

   The steam generator fatigue analysis did not differentiate between Class 1 and Class 2 subcomponents. Therefore, the Class 1 and Class 2 steam generator subcomponents that were identified as having TLAAs were evaluated for fatigue using the methodology for Class 1 components. The 40-year cumulative usage factors bound the period of extended operation since the number of design cycles assumed for 40 years is bounding for 60 years of operation.

   The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Describe how cracking due to fatigue is evaluated for Class 2 components.

   The Class 2 steam generator subcomponents having TLAAs were evaluated for fatigue using the same methodology as the Class 1 steam generator subcomponents.

   The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.5.2.1-1b The rate of heat transfer in the steam generator shell surface immediately above the water line is higher than that in the shell surface just below the water line. This is because the formation and collapse of steam bubbles in this region enhances heat transfer. As the water level oscillates up and down during service, this will result in a cyclic temperature change which will impose a cyclic stress at the shell surface. Indicate whether this effect has been considered as a potential fatigue degradation effect and, is so, what are the consequences with respect to fatigue-induced cracking of the steam generator shell surface at the water/steam interface. In addition, clarify whether such surface cracking of the shell surface at the water/steam interface is detectable using the AMPs applicable to steam generators.

The applicant has not considered this form of cyclic fatigue in the steam generator aging management review. There is no operating experience that indicates that cracking due to this form of cyclic fatigue is an aging effect requiring aging management. Additionally, there are no current licensing commitments or requirements to evaluate or manage fatigue at locations, other than those required by ASME, Section XI.

The staff found the applicant’s response acceptable and will not need any additional information regarding this matter.

Item 3.1.5.2.1-2a In both LRAs, Table 3.1.5-1, steam generator components are subject to loss of material requiring aging management. This loss of material occurs when steam generator carbon steel/low alloy steel components are exposed to borated water leakage, and when steam generator carbon/low alloy steel, stainless steel, and Ni-based alloy components are exposed to treated water/steam. Borated water leakage on carbon steel surfaces causes corrosion as stated in Generic Letter 88-05. Explain the age-related degradations associated with the loss of material in the second group of steam generator components when exposed to treated water/steam.

Loss of material due to crevice corrosion and pitting corrosion is an aging effect requiring management for the stainless steel and nickel-based alloy steam generator subcomponents exposed to a treated water/steam environment. In addition, loss of material due to fretting is also an aging effect requiring management for nickel-based alloy steam generator tubes exposed to a treated water/steam environment.

Loss of material due to crevice corrosion, pitting corrosion, and general corrosion is an aging effect requiring aging management for the carbon steel and low-alloy components exposed to a treated water/steam environment.

The staff found the applicant’s response acceptable and will not need any additional information regarding this matter.

Item 3.1.5.2.1-2b Information Notice 96-09, Supplement 1, identifies erosion-corrosion of steam generator support plates as an active damage mechanism. Clarify whether this aging effect is likely to affect the NAS and SPS steam generators. Since erosion-corrosion is not usually dependent on water chemistry, indicate whether this potential effect may be managed by the steam generator inspections AMP, if it is found to be applicable. Also, identify the most likely locations for the occurrence of erosion-corrosion, and the technique(s) for monitoring the aging effect due to erosion-corrosion.

The Surry and North Anna steam generator tube support plates are fabricated of stainless steel and utilize the quatrefoil tube hole design. Stainless steel is not susceptible to erosion-corrosion in the steam generator secondary treated water/steam environment.

There are no steam generator subcomponents within the scope of license renewal that are subject to flow accelerated corrosion.

The staff found the applicant’s response acceptable and will not need any additional information regarding this matter.

Item 3.1.5.2.1-2c Industry operating experience, as sited in NUREG-1801, identifies loss of material caused by flow-accelerated corrosion as an applicable aging effect for feedwater inlet ring and supports on a non-Westinghouse steam generator. These items are not included in either LRA, Table 3.1.5-1, which lists subcomponents requiring aging management. Provide a justification as to why the feedwater inlet ring and support are not part of an AMP.

The feedwater inlet ring and associated supports are not included in the scope of license renewal because they do not meet an any of the scoping criteria under 10 CFR 54.4(a) and, therefore, do not serve a license renewal intended function.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.5.2.1-3 The applicant identified "Loss of Pre-Load" as the aging effect requiring aging management of the primary manway cover bolting. No such aging effect has been identified for the secondary manway cover bolting. Also, industry experience (NRC IE Bulletin 82-02) indicates that a loss of pre-load in bolted connections could result from stress corrosion cracking, specifically for some alloy steels with lower yield strengths. (a) Identify the range of yield strengths used at NAS and SPS, and susceptibility of those material strengths. (b) Clarify why the secondary manway cover bolting is not subject to loss of pre-load during the extended period of operation.

a. As described in both LRAs, Appendix C, Item C3.2.1, the applicant performs random testing of bolting materials for hardness, tensile strength, and chemical composition. A sample review of approximately 160 test results, over a five-year period, did not identify any yield strengths greater than 150 ksi. Therefore, the low-alloy steel bolting used at NAS and SPS is not susceptible to stress corrosion cracking.

   The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Loss of pre-load can result from stress relaxation. This aging mechanism typically results in component leakage, which is readily identified by visual inspection or observation.

   As described in both LRAs, Appendix C, item C3.4, plant Technical Specifications require strict control of the reactor coolant pressure boundary (i.e. Class 1 components) so that leakage can be quickly identified and accounted for during plant operation. Bolted connections in the Class 1 pressure boundary warrant additional assurances beyond those required for ASME Class 2, 3, and Non-Class fasteners. Therefore, loss of pre-load is conservatively applied to ASME Class 1 bolted connections only.

   The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.5.2.2-1 Both LRAs, Table 3.1.5-1, do not include tube sleeves as one of the steam generator components that require aging management. Clarify whether any steam generator tubes have sleeves and describe any ISI activities that are, or will be, used to verify their integrity during the extended period of operation.

Tube sleeves are not used at Surry or North Anna.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.5.2.2-2 In both LRAs, Section 2.3.1.5, the applicant states that internal surfaces of the steam generator in contact with borated water reactor coolant are clad with stainless steel weld overlay. In Table 3.1.5-1, however, the tubesheet surface in contact with primary coolant is stated to be clad with nickel-based alloy.

a. Clarify the discrepancy identified above.

Table 3.1.5-1 is correct. Section 2.3.1.5 should also have included a reference to nickel-based alloy cladding.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Both LRAs, Table 3.1.5-1, appears to show that the tubesheet, on the secondary side, consists of a carbon steel surface that is exposed to secondary water. Clarify whether this secondary side surface is indeed carbon steel, or a corrosion resistant cladding. If the secondary side of the tube sheet is not cladded, discuss the possibility of bi-metallic corrosion between the Inconel tubes and the carbon steel tubesheet surface.

The secondary side of the tube sheet is not cladded. Loss of material at the tube-to-tube sheet interface is an aging effect requiring aging management. The secondary chemistry program manages this aging effect. While nickel-based alloys that are in contact with carbon steel establish the required potential difference for galvanic corrosion, the secondary chemistry program ensures that the required electrolytic solution is not present. Additionally, there is no operating experience supporting galvanic corrosion in this region of the steam generators.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.5.2.2-3 Tube support plates provide structural support to steam generator tubes, which provide the reactor coolant pressure boundary. At NAS and SPS, the tube support plates are made of stainless steel and are subject to degradation that could cause cracking and loss of material. In both LRAs, Table 3.1.5-1, the applicant identifies chemistry control of secondary systems as the AMA for managing cracking and loss of material in tube support plates. Based on the industry survey conducted by the Westinghouse owners group (WCAP- 15031), in response to Generic Letter 97- 06, the tube support plate ligaments have low susceptibility to cracking. In addition, the applicant states in its responses to this GL that eddy current testing is performed for tube support plate locations for degradation during each steam generator scheduled inspection. Clarify why steam generator inspections are not considered as an AMP for tube support plates.

Cracking due to stress corrosion cracking (SCC) is an aging effect requiring aging management for the steam generator tube support plates. This aging mechanism is managed with the secondary chemistry control program. A corrosive environment is a required condition for SCC. Secondary chemistry control is sufficient to manage the secondary system environment to eliminate the potential for corrosion. Therefore, the Steam Generator Inspections activities need not be credited as an aging management activity for this form of degradation in the tube support plates.

With respect to loss of material, operating experience has shown that the tube support plates for all four units have not experienced this form of degradation. Therefore, demonstrating the secondary chemistry program is adequate manage the loss of material in this application.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.5.2.2-4 In both LRAs, Appendix B, Section B2.2.1, the applicant states that there are two augmented inspection activities for North Anna and one augmented inspection activity for Surry applicable to steam generators. The feedwater nozzles at both plants are inspected by performing UT or supplemental RT every refueling outage at North Anna and every refueling outage on a rotating basis at Surry. The steam generator supports at North Anna were visually VT-1 inspected every 40 months. (a) Explain why these augmented inspections are performed. (b) Clarify why this AMP (augmented inspection activities) is not included as one of the applicable AMPs for feedwater nozzles in Table 3.1.5-1 of the LRA. (c) Discuss why the feedwater nozzles are inspected on a rotating basis at Surry units only (not North Anna). (d) Explain why only the North Anna (not Surry) steam generator supports are visually examined every 40 months. Indicate which steam generator supports are visually inspected.

a. The feedwater nozzles are inspected because of concerns raised in response to NRC IE Bulletin 79-13, *Cracking of Feedwater System Piping*, and are the result of an evaluation of potential thermal fatigue cracking of feedwater piping.

   The steam generator supports at North Anna are inspected due to the requirements of Technical Specification 4.4.10.1.2 regarding the A572 material of the supports. There is no similar technical specification requirement for Surry. The supports for the steam generators at Surry are made of materials A-352 and A-106.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Although the inspection of feedwater nozzles does not directly refer to the AMA for Augmented Inspections, it does refer to the AMA for Steam Generator Inspections, which states that the feedwater nozzles are inspected in accordance with the AMA for Augmented Inspections. This reference is provided in the introduction portion of Section B2.2.18.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

c. The statement that the feedwater nozzles at Surry are inspected on a rotating basis is incorrect due to an administrative error. The feedwater nozzles for both Surry and North Anna are inspected during each refueling outage in accordance with the requirements of the applicant's Augmented Inspection Program.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

d. Inspections involve the main, external attachments that support the vertical load of the steam generators. Only the North Anna supports are visually inspected due to Technical Specifications requirements regarding the A-572 material. There are no similar Technical Specifications requirements for the A-352 and A-106 materials utilized at Surry. This visual examination is in addition to the requirements of ASME Section XI, Category C-C to perform PT or MT inspections of the supports during each inspection interval. The ASME Section XI requirement is applicable to both Surry (LRA Table 3.5.9-1, NSSS Equipment Supports) and North Anna (LRA Table 3.5.9-1, NSSS Equipment Supports).

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.5.2.2-5 In accordance with its response to Generic Letter 97-06, the applicant indicates that it would follow the Westinghouse Owners Group (WOG) recommendations as part of its continuing secondary-side inspection program. At that time the applicant adopted appropriate inspection and maintenance activities to address all known degradation effects in steam generator internals. No near-term changes in the steam generator inspection program were necessary. The WOG suggested additional inspections in wrapper welds, wrapper drop, transition cone girth welds and tube support plate ligaments to be included in the existing inspection activities for a long-term solution to those age-related degradation identified in GL 97-06. In accordance with NEI 97-06, "Steam Generator Program Guidelines," the licensee intends to implement the recommended inspection activities as given in WCAP- 15031 and WCAP-15104. Discuss the applicant's plan n implementing the WOG recommendations in the existing AMP, "Steam Generator Inspections."

The applicant's response to Generic Letter 97-06 has been reviewed and accepted by the NRC staff. The Steam Generator Inspections aging management activity identified in Appendix B of the license renewal application is consistent with the applicant's response to Generic Letter 97-06. No further enhancements of the Steam Generator Inspections aging management activity are planned.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 4.2.1, "Upper Shelf Energy"

Item 4.2.1-1 In the NAS LRA, Section 4.2.1, the applicant states that calculations performed in accordance with Regulatory Guide 1.99 demonstrate that the upper shelf energy (USE) values for the limiting reactor vessel beltline materials (welds) at the end of the period of extended operation are greater than the 10 CFR 50 Appendix G requirement of 50 ft-lb. In addition, the applicant states that the analysis associated with USE has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). Provide a) the methodology used to project the USE analysis to the end of the period of extended operation, and b) the USE value (in ft-lbs) at the end of the period of extended operation.

The North Anna license renewal USE evaluation involved (a) performance of RG 1.99 Revision 2 Position 1.2 USE calculations and (b) comparison of measured and predicted reductions in USE for North Anna Units 1 and 2 surveillance materials to confirm that Position 1.2 calculations are conservative.

The beltline fluence values were calculated using the NRC-approved Virginia Power reactor vessel fluence analysis methodology.

Best-estimate copper content values were determined by averaging the values obtained from original vessel fabrication, and surveillance capsule analysis reports.

Measured values of the initial USE for each beltline material were obtained from Westinghouse material certification test reports.

Charpy data were derived from North Anna Units 1 and 2 capsules V, U, and W. The data were subjected to a hyperbolic tangent curve-fit.

The observed reductions in USE for surveillance materials compare favorably with the USE reductions predicted by RG 1.99 Revision 2.

Therefore, it is concluded that the North Anna Units 1 and 2 reactor vessel beltline materials will have USE greater than 50 ft-lb at the end of a 20-year license renewal period. The lowest USE values are 54 ft-lb for Unit 1 and 52 ft-lb for Unit 2.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 4.2.1-2 In the SPS LRA, Section 4.2.1, the applicant states that the limiting reactor vessel beltline materials (welds) have been demonstrated by an equivalent margins analysis (EMA) to meet the USE requirements of 10 CFR 50 Appendix G throughout the period of extended operation. The applicant also states that this includes extending the cumulative core burnup applicability limit of the analysis to 48 effective full power years using the methodology of BAW-2192-P-A and BAW-2178-P-A (Low Upper-Shelf Toughness Fracture Analysis of Reactor Vessels of B&W Owners Group Reactor Vessel Working Group for Load Levels A & B and C&D, respectively). Provide a summary explanation of the analysis used to project the EMA to the end of the period of extended operation.

The Surry USE EMA analysis was performed for ASME Levels A, B, C, and D service loadings based on the evaluation acceptance criteria of Section XI, Appendix K.

For Levels A and B service loadings, the low upper-shelf fracture mechanics evaluation was performed according to the evaluation procedures contained in Section XI, Appendix K.

Levels C and D service loadings were evaluated using the one-dimensional, finite element, thermal and stress models and linear elastic fracture mechanics methodology of Framatome Technologies' PCRIT computer code to determine stress intensity factors for a worst case pressurized thermal shock transient.

The material properties (J-integral resistance) model was developed from a large database of fracture specimens, as described in the report for a low upper-shelf analysis performed for reactor vessels at Florida Power and Light's Turkey Point Units 3 and 4.

The analysis demonstrates that the reactor vessel beltline welds at Surry Units 1 and 2 satisfy the ASME Code requirements of Appendix K for ductile flaw extensions and tensile stability using projected low upper-shelf Charpy impact energy levels for the weld material at reactor fluence values to the end of extended period of operation.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 4.2.2, "Pressurized Thermal Shock"

Item 4.2.2-1 In both LRAs, Section 4.2.2, the applicant states that the RTPTS values for the beltline materials at the end of the period of extended operation are lower than the applicable screening criteria values established in 10 CFR 50.61. In addition the applicant states that the analysis associated with PTS has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). Provide a) the 48 EFPY fluence, b) the chemistry, and c) the analysis in accordance with 10 CFR 50.61 (c) (1) and (2) that resulted in the RT_{PTS} value for the limiting beltline materials for North Anna and Surry.

The beltline fluence values were calculated using the NRC-approved Virginia Power reactor vessel fluence analysis methodology.

By letter dated April 27, 2001, the applicant submitted an update to NRC's Reactor Vessel Integrity Database (RVID). This submittal included the most recently acquired and analyzed reactor vessel integrity data for North Anna Units 1 and 2. Similarly, the applicant submitted an update to RVID for Surry Units 1 and 2 in November 19, 1999.

Ranges for reactor vessel beltline material fluence applicable to a 20-year license renewal period are as follows:

Surry Unit 1

RPV Weld Wire Heat or Material ID	Location	EOLR ID Fluence (x1E19)
122V109VA1	Nozzle Shell Forging	0.496
C4326-1	Intermediate Shell	5.400
C4326-2	Intermediate Shell	5.400
4415-1	Lower Shell	5.400
4415-2	Lower Shell	5.400
J726/25017	Nozzle to Int Shell Circ Weld	0.496
SA-1585/72445	Int. to Low Sh. Circ (ID 40%)	4.700
SA-1650/72445	Int. to Low Sh. Circ (OD 60%)	4.700
SA-1494/8T1554	Int Shell Long. Welds L3 & L4	0.914
SA-1494/8T1554	Lower Shell Long. Weld L1	0.790
SA-1526/299L44	Lower Shell Long. Weld L2	0.790

Surry Unit 2

RPV Weld Wire Heat or Material ID	Location	EOLR ID Fluence (x1E19)
123V303VA1	Nozzle Shell Forging	0.471
C4331-2	Intermediate Shell	5.340
C4339-2	Intermediate Shell	5.340
C4208-2	Lower Shell	5.340
C4339-1	Lower Shell	5.340
L737/4275	Nozzle to Int Shell Circ Weld	0.471
R3008/0227	Int. to Lower Shell Circ Weld	5.340
WF-4/8T1762	Int. Shell Long. L4 (ID 50%)	1.080
SA-1585/72445	Int. Sh. L3 (100%), L4 (OD 50)	1.080
WF-4/8T1762	LS L2 (ID 63%), L1 (100)	1.080
WF-8/8T1762	LS Long. Weld L2 (OD 37%)	1.080

North Anna Unit 1

RPV Weld Wire Heat or Material ID	Location	EOLR ID Fluence (x1E19)
990286/295213	Nozzle Shell Forging	0.211
990311/298244	Intermediate Shell Forging	5.900
990400/292332	Lower Shell Forging	5.900
25295	Nozzle to Int. Shell Circ Weld (0D 94%)	0.211
4278	Nozzle to Int. Shell Circ Weld (ID 6%)	0.211
25531	Int. to Lower Shell Circ Weld	5.900

North Anna Unit 2

RPV Weld Wire Heat or Material ID	Location	EOLR ID Fluence (x1E19)
990598/291396	Nozzle Shell Forging	0.225
990496/292424	Intermediate Shell Forging	5.910
990533/297355	Lower Shell Forging	5.910
4278	Nozzle to Int. Shell Circ Weld (0D 94%)	0.225
801	Nozzle to Int. Shell Circ Weld (ID 6%)	0.225
716126	Int. to Lower Shell Circ Weld	5.910

10 CFR 50.61 Pressurized Thermal Shock (PTS) screening calculations applicable to a 20-year license renewal period were performed using the fluence values presented above, and the data previously submitted to update the NRC's RVID. All PTS screening calculation results are below the screening criteria specified in 10 CFR 50.61.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section B2.2.8, "Fuel Oil Chemistry"

Item B2.2.8-1 In the applicant's license renewal application (LRA) the fuel oil chemistry program manages only aging effects due to loss of material from the components exposed to the fuel oil environment. However, fuel oil with improper chemistry, in addition to corrosion effects, can also produce accumulation of particulate or biological growth which could be a source of the aging effects caused by fouling of heat transfer surfaces in the exchangers. Since the diesel fuel oil coolers in the Alternate AC (AAC) Diesel Generator Systems (Table 3.3.4-1) are exposed to the fuel oil environment, possibility of such aging effect exists. Explain why this aging effect was not considered and only the aging effect due to loss of material was included in the LRA.

The applicant recognizes heat transfer degradation due to fouling as an aging effect requiring management for heat exchangers only exposed to a raw water environment as defined in Appendix C3.3.

However, the Fuel Oil Chemistry activity does sample the fuel oil for bacteria, particulates, water and sediment which will identify conditions that could lead to fouling, so that corrective actions can be initiated in a timely manner. The applicant has not identified any operating experience related to heat transfer degradation of the AAC diesel fuel coolers.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.8-2 Monitoring and trending in the in the fuel oil chemistry program specifies sampling and testing for viscosity and water/sediment content of the freshly delivered fuel oil before its transfer to the supply tanks for safety-related equipment. However, section 9.5.4.4 of the UFSAR for the North Anna plant, referenced in the LRA, the applicant states that no testing of fuel oil is performed on newly delivered fuel oil before its transfer into the aboveground storage tanks. Please, explain this apparent discrepancy.

The above-ground storage tank is the first on-site storage location for fuel that is off-loaded from a tanker, and the oil is not sampled prior to being placed in the above-ground tank. However, this tank does not provide a supply of oil directly to any safety-related equipment. As indicated in Section B2.2.8 of the LRA, fuel is sampled in the above-ground tank prior to being transferred to a supply tank for any safety-related equipment. Thus both the UFSAR statement and the statement in Section B2.2.8 of the LRA are correct.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section B2.2.18, "Steam Generator Inspections"

Item B2.2.18-1 In Section B2.2.18 of Appendix B of the LRA, the applicant lists the component types that are to be inspected in compliance with ASME Section XI, Subsections IWB, IWC, and IWF. However, this list does not include the primary manway cover and insert, and the tube support plate that are given in Table 3.1.5-1 of the LRA as being part of the steam generator inspections AMP. Clarify why these additional subcomponents are not included in the above- mentioned ASME Section XI ISI program.

The steam generator inspection AMA is not credited for managing aging for the primary manway cover and insert, or for the tube support plates, as indicated in Table 3.1.5-1. The ASME Section XI inservice inspections were not selected for managing the aging of these components since they do not include welds. Instead aging management is accomplished with a combination of chemistry controls for the stainless steel components and boric acid corrosion surveillance for the external surfaces of carbon steel components.

The staff found the applicant's clarification acceptable and will not need any additional information regarding this matter.

Item B2.2.18-2 In the list of ASME Section XI inspection categories, given in Section B2.2.18 of Appendix B of the LRA, the applicant does not include the Examination Category B- H, which pertains to the inspection of integral attachments to the steam generator. (a) Clarify why B-H inspections are not performed as part of the ASME Section XI ISI program. (b) Identify if Examination Category B-P is applicable to steam generators. Discuss the types of inspection activities associated with Examination Categories

B-P and B-Q that are applicable to steam generator tubes, plugs, and sleeves (if installed in the future).

a. The integral attachments considered for the steam generators are the external supports that support the vertical load. These attachments are part of the secondary side of the steam generator and are inspected in accordance with ASME Section XI, Category C-C. As required by Category C-C, the surface examinations are either PT or MT.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Category B-P is applicable to steam generators in the form of system pressure tests which involve external VT-2 pressure boundary inspections. Primary-to-secondary tube leakage (including leakage of tube plugs) would be quantified using calculations required by the Technical Specifications. Sleeves are not utilized in the Surry and North Anna steam generators. The Category B-Q examinations involve eddy-current tests of the steam generator tubes.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.18-3 In Section B2.2-18 of Appendix B of the LRA, the applicant describes the steam generator inspections program. In the section on activities in the "Monitoring and Trending" of aging effects, a brief description is given of the types of non-destructive tests that are used for the various steam generator monitoring activities. The staff finds these monitoring techniques to be acceptable. The applicant also states that "Engineering evaluations are performed for inspection results that do not meet established acceptance standards." This indicates that trending of the results is not actually carried out, and that the applicant carries out engineering safety evaluations only when the inspection results are found to be outside the limits of acceptance criteria. Clarify whether trending is indeed performed on a continuing basis so that preventive actions may be planned well in advance of the time that the inspection results fall outside the limits of acceptance criteria.

The results of non-destructive examinations and videotaped inspections are retained and utilized to provide a basis for trending and development of plans for subsequent inspections and anticipatory repairs.

The staff found the applicant's clarification acceptable and will not need any additional information regarding this matter.

Item B2.2.18-4 The applicant states in Section B2.2.18 of Appendix B of the LRA, which describes the AMP on steam generator inspections, that acceptance criteria for steam generator subcomponent inspections are provided in ASME Section XI, Subsections IWB 3500 and IWC 3500. Results for steam generator inspections that are outside the scope of ASME Section XI are stated to be dispositioned by the applicant's Engineering Department. However, the applicant does not specify the nature of the acceptance criteria that are used by Engineering in such situations. Describe the acceptance criteria that are used in steam generator inspection activities that are not covered by ASME Section XI ISIs.

Engineering evaluations are performed on a case-by-case basis. As such, no single set of acceptance criteria exists to encompass all evaluations. The nature of the defects that are found through inspections determine the direction and extent of the engineering evaluation that is required. Engineering evaluations are performed considering the original design basis of the system, structure, or component. Any corrective actions resulting from the engineering evaluation are implemented through the Corrective Action System.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.18-5 In both LRAs, Section B2.2-18 of Appendix B, the applicant states that the confirmation process for steam generator inspection AMAs include; (a) primary-to- secondary leak detection using several procedures, (b) evaluation of post-maintenance conditions, and (c) walkdowns to check for system leakage. These procedures will indicate that steam generator integrity has been maintained or restored after any required maintenance or repair activities. The applicant should also state whether its use of routine examination for crud formation and deposition is also used as a confirmation of steam generator integrity since excessive crud is an indication of accelerated loss of material.

As indicated in Section B2.2.18, under "Scope" description, inspections in the secondary side of the steam generators involve video inspections of the tubesheet area and the annulus area to detect the presence of deposits, sludge, foreign material, or other general degradation. If excessive deposits were found, the corrective action system would require evaluation of the source of the material and development of plans for mitigating the effects of the finding.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.18-6 Information Notice 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," states that volumetric examination (UT) of these welds, required by ASME Section XI, may not be sufficient to differentiate isolated cracks from inherent geometric conditions. Following this notice, the applicant performed a 100% MT inspection for the NAS 2 and SPS 1 steam generators, and found no degradation. However, in response GL 97-06, the Westinghouse owners group survey indicated in WCAP-15031 that cracking in transition cone girth weld has been observed in some steam generators. (a) Clarify if the 100% MT inspections performed at NAS 2 and SPS 1 were one-time inspections. (b) Discuss how the cracking in the transition cone girth welds will be managed for the extended period of operation.

c. The MT examinations for the inside diameter of the upper shell-to-transition cone girth weld were performed as a one-time inspection.

d. In accordance with ASME Section XI, girth weld inspections are performed using the ultrasonic testing technique. These inspections will continue during the period of extended operation.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.18-7 The NRC Bulletin 88-02, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes", required each licensee to perform an analysis that includes the following: (a)The analysis would include an assessment of stability ratios for the most limiting tube locations to assess the potential for rapidly propagating fatigue cracks. This assessment would be conducted such that the stability ratios are directly comparable to that for the tube which ruptured at North Anna. (b)The analysis would include an assessment of the depth of penetration of each AVB. The purpose of this assessment is twofold: (1) to establish which tubes are not effectively supported by AVBs and (2) to permit an assessment of flow perking factors.

Please clarify if the analysis performed was based on a 40 or 60 year of operating. If it was based on a 40-year operation, please provide an analysis per NRCB 88-02 for the extended operation, or, please provide justifications that no further analysis is necessary.

NRC Bulletin 88-02 states that its applicability is for Westinghouse-designed steam generators having carbon steel support plates. Since the replacement steam generators that were installed at Surry prior to 1988 have stainless steel support plates, the bulletin was determined to not be applicable.

The North Anna steam generators that were in use in 1988 did contain carbon steel tube support plates. The response to Bulletin 88-02 described an analysis that addressed the issues of flow peaking factors and AVB penetration into the tube bundle. However, since the steam generators for North Anna Units 1 and 2 were replaced in the early 1990's , they contain tube support plates that are made of stainless steel. At the time of steam generator replacement, Bulletin 88-02 was determined to no longer be applicable as indicated in the Virginia Power Design Change Package for steam generator replacement.

The staff found the applicant's clarification acceptable and will not need any additional information regarding this matter.