STP Nuclear Operating Company
South Texas Project Electric Generating Station P.O. Box 289 Wadsworth, Texas 77483

January 28, 2002
NOC-AE-02001245
10CFR50.90

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

South Texas Project
Units 1 and 2
Docket No. STN 50-498 and STN 50-499
License Amendment Request -
Proposed Amendment to Technical Specification 4.4.5.3a

Pursuant to 10CFR50.90, STP Nuclear Operating Company (STPNOC) hereby requests an amendment to Technical Specification (TS) 4.4.5.3a, "Steam Generator Surveillance Requirements." The proposed one-time (per unit) change revises the steam generator inservice inspection frequency requirements in TS 4.4.5.3a for South Texas Project Electric Generating Station (STPEGS) Unit 1 immediately after refueling outage 1RE10 and for Unit 2 immediately after refueling outage 2RE10. The change would allow a 40-month inspection interval after one inspection resulting in C-1 classification, rather than after two consecutive inspections resulting in C-1 classification. This change is proposed to eliminate unnecessary steam generator inspections, which will result in significant dose, schedule, and cost savings.

The Unit 1 steam generators (SGs) were replaced during 1RE09 in May 2000. The replacement steam generators (RSGs) are the Westinghouse Delta 94 design, which incorporates significant improvements, including thermally treated Alloy 690 tubing. The Delta 94 is a scaled-up version of the V. C. Summer Delta 75 RSGs, which have been in service since 1994. The latest 100% bobbin inspection of all three V. C. Summer SGs found no indications of stress corrosion cracking.

During Unit 1 refueling outage 1RE10 following the first cycle of operation after replacement, 100% of the steam generator tubes were inspected full-length (i.e., from hot leg tube end to cold leg tube end, including the U-bends) with eddy current. Approximately 75 +Point examinations were also performed. No defective or degraded tubes were indicated.

Additionally, fifteen thermally treated Alloy 600 tubes have been in service in Unit 2 SG "D" for the past ten years. They have undergone approximately 90 separate inspections with no indication of crack-like defects.

These inspection results, along with the improved RSG design and industry experience with thermally treated Alloy 690 tubing, provide the basis for proposing a one-time (per unit) extension of the inspection interval from a maximum of 24 calendar months to a maximum of 40 months after one category C-1 inspection result.

A001

STI: 31393408

The Unit 2 steam generators will be replaced with Delta 94 RSGs during 2RE09, which is scheduled for completion in December 2002. Implementation of the increased inspection interval for Unit 2 would be contingent upon the 2RE10 SG tube inspection results falling in the C-1 classification.

STPNOC is aware of ongoing industry and NRC work on resolution of questions about foreign and domestic thermally treated Alloy 600 inspection indications. We believe that our site-specific thermally treated Alloy 600 experience, the stress corrosion-free performance of Delta 75 thermally treated Alloy 690 SGs, and overall industry experience with thermally treated Alloy 690 tubes provide an acceptable approval basis for our one-time request.

Attachment 1 to this letter provides the No Significant Hazards Determination and Attachment 2 provides the TS page marked up with the proposed change. Attachment 3 provides the retyped TS page. There are no changes proposed to the Bases for TS 3/4.4.5, but the Bases are provided in Attachment 4 for information.

The STP Plant Operations Review Committee and the Nuclear Safety Review Board have reviewed and approved the proposed change. STPNOC has notified the State of Texas in accordance with 10CFR50.91(b).

STPNOC requests approval of the proposed change prior to July 15, 2002, to support the scope freeze for refueling outage 1RE11, which is scheduled to begin in March 2003.

If there are any questions regarding this proposed amendment to TS 4.4.5.3a, please contact Mr. Mark Kanavos, Manager, Modifications and Design Basis Engineering at (361) 972-7181 or me at (361) 972-8757.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on January 28, 2002

J. J. Sheppard
Vice President,
Engineering & Technical Services

jtc

Attachments:
1. Licensee's Evaluation
2. Proposed Technical Specification Changes (Mark-up)
3. Proposed Technical Specification Page (Retyped)
4. Bases Page (For Information Only)

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Attachment 1

Licensee's Evaluation

LICENSEE'S EVALUATION

1.0 DESCRIPTION

This letter is a request to amend Operating Licenses NPF-76 and NPF-80 for South Texas Project (STP) Units 1 and 2. The proposed one-time (per unit) change revises the steam generator inservice inspection frequency requirements in Technical Specification (TS) 4.4.5.3a after refueling outages 1RE10 and 2RE10 to allow a 40-month inspection interval after one inspection resulting in C-1 classification, rather than after two consecutive inspections resulting in C-1.

The reason for this one-time change is to eliminate unnecessary SG inspections, resulting in significant dose, schedule, and cost savings.

STP Nuclear Operating Company (STPNOC) requests approval of the proposed change prior to July 15, 2002, to support postponing SG tube inspections currently planned for refueling outage 1RE11, which begins on March 26, 2003. Once approved, the amendment shall be implemented within 30 days.

2.0 PROPOSED CHANGE

Currently, TS 4.4.5.3a states, in part:

> If two consecutive inspections, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months;

The proposed change is to add a note following the paragraph cited above:

> Note: A one-time (per unit) inspection interval of a maximum of once per 40 months is allowed for the inspection performed immediately following 1RE10 and 2RE10. This is an exception to 4.4.5.3a in that the interval extension is based on all of the results of one inspection falling into the C-1 category.

3.0 BACKGROUND

Technical Specification 4.4.5.3a requires that subsequent inservice inspections of SG tubes after the first inservice inspection be performed at intervals of not less than 12 calendar months nor more than 24 calendar months after the previous inspection. Further, if two consecutive inspections, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

The inspection of the SG tubes ensures that the structural integrity of this portion of the reactor coolant system (RCS) will be maintained. Inservice inspection of SG tubes is essential in order to maintain surveillance of the condition of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of SG tubes also provides a means of characterizing the nature and cause of any tube degradation so that timely corrective measures can be taken.

4.0 TECHNICAL ANALYSIS

4.1 Steam Generator Design Improvements

Industry experience with recirculating SGs using mill annealed Alloy 600 tubes has led to significant design improvements in replacement steam generator (RSG) design and fabrication. Problems associated with tube degradation, such as stress corrosion cracking (SCC), intergranular attack (IGA), pitting, and wastage, have been addressed through changes in tube materials and stress relief. Problems associated with secondary system fouling, and flow-induced vibration and wear have been addressed with changes to the tube bundle support system, and through design of the main and auxiliary feedwater headers for loose parts control. These design improvements, along with others, have been incorporated into the Westinghouse Delta 94 SG design.

The Delta 94 SG design embodies the key characteristics of the proven Westinghouse Model F RSG design. The most reliable features carried over from Model F include the use of thermally treated Alloy 690 tube material, Type 405 stainless steel tube support plate (TSP) material, broached flat contact tube support holes, hydraulically expanded tubesheet joints, "minimum gap" U-bend construction, and foreign material exclusion in the design of the feedwater distribution headers. These features are described in more detail below.

Thermally Treated Alloy 690 Tubing

The use of thermally treated Alloy 690 provides additional corrosion resistance for the tubes that has been proven not only by years of laboratory testing, but also in actual plant operation. As of November 2000, the Westinghouse Delta model RSGs have been stress corrosion-free for six calendar years of operation at a hot leg temperature of 619°F, which is comparable to the current STP Unit 2 hot leg temperature of 620°F. This includes the latest V. C. Summer examination consisting of 100% bobbin coil examination of all SGs,

10% top-of-tube-sheet +Point examination in one SG, and a fourteen-tube sample of +Point examination of low row U-bends.
Each of the four STP RSGs (per unit) contains 7,585 U-tubes fabricated from thermally treated Alloy 690 U-tubes with a nominal outside diameter of 0.688 inch and a nominal wall thickness of 0.040 inch. The development of thermally treated Alloy 690 tubing was prompted by the significant number of mill annealed Alloy 600 tubes being removed from service due to degradation. Thermally treated Alloy 690 tubing is similar to Alloy 600 tubing, but contains a 13% higher chromium content and a correspondingly reduced nickel content. The higher chromium content and controlled heat treatment reduces the possibility of sensitization (i.e., the amount of chromium depleted in areas adjacent to the metal grain boundaries), thus increasing resistance to corrosion attack at the metal grain boundaries. Heat treatment of Alloy 690 for optimum resistance to SCC involves mill annealing at temperatures sufficient to put all the carbon into solution, followed by a thermal treatment to precipitate carbides on the metal grain boundaries. Resistance to SCC is greatest when the metal grain boundaries are fully populated with carbides with no sensitization.

Extensive testing has been performed which demonstrates that thermally treated Alloy 690 tubing is superior to mill annealed Alloy 600 tubing in its resistance to both primary and secondary system SCC, pitting, and general corrosion. Examples of this data are given in proceedings from the 1986 EPRI Workshop on Thermally Treated Alloy 690 Tubes for Nuclear Steam Generators (Reference 1). Primary side corrosion at 680°F testing was performed with statically loaded reverse U-bend specimens, where cracking was observed within approximately 300 hours for mill annealed Alloy 600 tubing and 800 hours for thermally treated Alloy 600 tubing. Cracking was not observed for the thermally treated Alloy 690 tubing, even after 12,000 hours. Testing was also performed on statically loaded tensile specimens tested in 680°F primary water. While mill annealed Alloy 600 tubing exhibited cracking within 2,900 hours, thermally treated Alloy 690 did not exhibit cracking after 7,000 hours of testing. Thermally treated Alloy 690 was also compared to mill annealed Alloy 600 tubing in 760°F steam tests to produce accelerated primary water SCC (PWSCC). These test results showed mill annealed Alloy 600 tubing exhibited cracking within 1,000 hours, while thermally treated Alloy 690 did not exhibit any signs of cracking after 6,000 hours (References 2 and 3).

The environments considered were pure water, primary water, and uncontaminated all volatile treatment (AVT) secondary system water. The thermally treated Alloy 690 improvement factor for SCC in primary water and in uncontaminated AVT environments is over 10.

The improvement factors for other possible secondary side environments were

- > 10 for near neutral uncontaminated AVT water
- > 6 to about 20 for chlorides
- ~ 5 for caustics (i.e., $pH > 10$)

- ~ 5 for "other" environments (e.g., resin liquor polluted or complex alumina silica)
- ~ 2 for sulfur-contaminated environments
- ~ 2 for lead-contaminated caustic environments.

Service experience indicates that the more aggressive test environments that result in low improvement factors for thermally treated Alloy 690 rarely occur in actual plant service. Considering this service experience, as well as the improvement factors for the various environments, an overall improvement factor of approximately 4 is considered reasonable but conservative for the secondary side.

The tubing procurement specification used in construction of the Unit 1 RSGs was designed to assure mill production of tubing that achieves the corrosion resistance properties as indicated by industry standards and research. The specification also outlines the physical, mechanical, and extensive inspection and qualification requirements necessary to limit fabrication defects. Cracks, laminations, scratches, draw-marks, pores, seams, laps, or stains are considered defects and are subject to rejection or conditioning in accordance with tested, approved, and controlled methods.

The STP RSGs are the Westinghouse Delta 94 design, which incorporates significant improvements, including thermally treated Alloy 690 tubing. The Delta 94 model is a scaled up version of the V.C. Summer Delta 75 replacement steam generators, which have been in service since 1994 for a total of 5.2 effective full power years (EFPY) up to their last inspections. The V. C. Summer SG inspection in October 2000 included 100% bobbin inspection of all three steam generators, 332 hot leg top of tube sheet +Point inspections and ~65 special interest +Point inspections. No indications of stress corrosion cracking were present. Three antivibration bar wear signals at 5 and 9% depth were found, which were identifiable at base line and previous inspections, and are projected not to reach plugging conditions for 18 additional cycles.

During STP Unit 1 refueling outage 1RE10 following the first cycle of operation after replacement, 100% of the steam generator tubes were inspected full-length (i.e., from hot leg tube end to cold leg tube end, including the U-bends) with eddy current. Additionally approximately 75 +Point examinations were also performed. No defective or degraded tubes were indicated.

Fifteen thermally treated Alloy 600 tubes have been in service in the STP Unit 2 Model E SG "D" for the past 10 years for a total of 8.9 EFPY. During this time they have undergone approximately 90 separate inspections with no indication of crack-like defects. One volumetric indication deep within the tube sheet, most likely from original manufacturing anomalies was detected, but did not require plugging.

Industry data supports the laboratory test results demonstrating the superior performance of thermally treated Alloy 690 as compared to mill annealed Alloy 600 tubing. These inspection results, along with the improved replacement steam generator design and industry experience of thermally treated Alloy 690 tubing, provide the basis for proposing a one-time extension of the inspection interval from a maximum of 24 calendar months to a maximum of 40 months after one category C-1 inspection result.

Tube Bundle Support System

Experience with first generation mill annealed Alloy 600-tubed recirculating SGs has identified the following issues relating to tube bundle support design.

- Dry-out and deposition in crevices of drilled-hole type support plates leading to under deposit IGA.
- SCC resulting from denting of the tubes due to magnetite development on the carbon steel tube support plates (TSPs) or crevices at the tubesheet joint.
- IGA and/or SCC associated with the high residual stress of rolled tube-to-tubesheet joint expansion particularly in combination with the unexpanded crevice design, which encouraged crevice corrosion as sludge concentrated in this critical area.
- Mechanical wear to the tube from fretting caused by flow-induced vibration.

As described below, the Westinghouse RSG design incorporates features to greatly reduce or eliminate these potential damage mechanisms.

The thermally treated Alloy 690 tubes are supported on the secondary side by nine TSPs fabricated from Type 405 stainless steel. All TSPs have trifoil-shaped holes produced by broaching to reduce tube dryout and chemical concentration in the regions where the tubes pass through the TSPs. The TSP broached holes result in line contact of the tube at only three points or "lands." The broached-hole, flat land TSP is designed to reduce the tube-to-TSP crevice area, while providing for maximum steam/water flow in the open areas adjacent to the tube. This flat land contact geometry provides increased dryout resistance over the drilled-hole configuration. The broached lobes prevent sludge from widening the tube hole dryout zone, and the broached design directs flow adjacent to the tube and adds margin against dryout. The stainless steel TSP material oxide volume ratio is 1.0 as compared with the carbon steel oxide volume, which grows by four times, leading to blocked crevices and chemical concentration.

A flow distribution baffle located between the lowest TSP and the tubesheet is designed to minimize the number of tubes exposed to low velocity flow in the vicinity of the tubesheet. The flow distribution baffle is fabricated from Type 405 stainless steel and has nonafoil broached holes that are different than the TSPs. The flow distribution baffle plate makes line contact with each tube at nine locations around the tube periphery. The baffle is designed and located to produce a sweeping flow across the tubesheet. This is expected to minimize the sludge deposition area on the tubesheet. Also, the center portion of the flow distribution baffle is cut out. This design controls the cross-flow velocity so that the low velocity region (and sludge deposition zone) is located at the center of the tube bundle near the blowdown intake.

The STP RSGs have the advanced minimum gap U-bend support structure, wider bars, and better material for anti-vibration bars (AVBs) over the Model F design. These factors increase the tube wear margin by more than a factor of 50 in wear depth and 80 in wear volume over the earlier RSGs. Thus, repairs for wear degradation are unlikely. Four sets of staggered AVBs are installed to provide support for the U-bends of the tubes. Increasing the number of sets of AVBs reduces the number of tubes that are potentially affected by the vibration mechanism to which tube degradation has been attributed in some conventional SGs. The AVB assemblies within each set are installed at staggered depths to minimize pressure drop in the U-bend region to increase the circulation ratio and to reduce the potential for steam blanketing. This arrangement provides at least single sided support above the top TSP for every tube in the tube bundle. The AVBs are inserted deeper at several peripheral locations of the U-bend in order to provide additional support.

The square tube pitch arrangement in Model F SGs has been changed to a triangular pitch in the Delta 94 RSGs to enhance heat transfer area and tube stability, and to provide additional vibration margin. Laboratory tests indicate tube stability to be as much as 50% higher with the triangular pitch.

The tube-to-tubesheet joint accomplishes axial load resistance and the physical fastening of the tubing to the vessel. Original SG designs encountered severe corrosion problems at the tube-to-tubesheet joint region associated with open (i.e., unexpanded) crevices, and/or SCC at the high residual stress cold worked locations on the surface of the transition zone between the roller expanded and unexpanded tube. The Delta 94 RSG design incorporates the use of full-depth hydraulic expansion of the tubes in the tubesheet to close the crevice with minimal residual stresses. The principal technical requirements for the tube expansion process that are satisfied by hydraulic expansion are that the:

- residual stresses in the expanded tube be as low as possible
- tube expansion transition be as close as possible to the secondary side of the tubesheet so as to minimize secondary side crevice depth
- expanded tube be tight against the tubesheet so as to minimize the potential ingress of secondary side fluid in the tube-to-tubesheet joint interface

Industry experience indicates that hydraulic expansion results in one of the lowest residual stresses of any tubesheet joint process. As of early 1998, the 84 Westinghouse SGs manufactured between 1980 and late 1997, with more than 800,000 hydraulically expanded tubesheet joints, showed no indication of degradation.

Introduction of Feedwater

Feedwater is introduced to the secondary side of the SG through the feedwater nozzle. The feedwater flows through a welded thermal sleeve of thermally treated Alloy 690 and into the elevated feedwater distribution ring pipe and pipe fittings, and out through 34 spray nozzle assemblies located on the top side of the ring. The thermally treated Alloy 690 spray nozzle assemblies are arranged to uniformly distribute the feedwater into the upper downcomer plenum. The feedwater is joined in the upper downcomer plenum by water removed from the wet steam in the first and second stage moisture separators. The water mixture enters the downcomer annulus, travels down to the bottom of the annulus, and enters the tube bundle at the tubesheet.

All components of the feedwater distribution equipment are of all-welded construction and are made of materials that are resistant to erosion/corrosion, thermal fatigue, and corrosion cracking. Configuration of the system avoids trapping of steam, particularly at non-vented high points, which could result in water hammer. Feedwater is discharged into the SG at the top of the feedring, which is entirely submerged during normal operation.

Even though the RSG secondary mass is somewhat greater than that of the Model E SGs, the steam nozzle flow limiter and feedring design both limit the rate of energy release in the event of a large pipe break. The original Model E SG feed line break event had the potential to produce high loads on the tubes in the preheater. This loading has been eliminated in the RSGs, which introduce the feedwater in the upper shell region away from the tube bundle.

The feedwater temperature had to be limited in the Model E SG to minimize the potential for bubble collapse water hammer or smaller scale bubble collapse within the tube bundle preheater. Bubble collapse and hydrodynamic instability were resolved in the RSG design by mixing the feedwater with the recirculating water in the upper shell region and downcomer prior to discharging it into the tube bundle near the top of the tubesheet.

Increased Circulation Ratio

Circulation ratio is defined as the ratio of riser mass flow rate to steam outlet flow rate. Maximizing circulation ratio of the SG secondary side fluid minimizes concerns regarding heat transfer performance, sludge management, corrosion product transfer, tube dry-out, etc. The RSGs have a circulation ratio approximately 30% greater than the Model E SGs. The benefits of higher circulation ratio are that the:

- void fraction in the upper bundle is slightly less
- margin to dryout in the U-bend is slightly larger
- fluid damping in the U-bend is slightly larger
- sweeping forces at the top of the tubesheet are slightly higher

Sludge Collection and Steam Generator Cleaning

Sludge inventory can accumulate although the Delta 94 SG tube bundle is designed to minimize the impact of sludge. Therefore, the SG is equipped with a sludge collector, fabricated as an integral part of the primary moisture separator assembly, and designed to minimize the amount of suspended particles in the secondary side recirculation flow. This reduces the accumulation of sludge at the top of the tubesheet. The sludge collector consists of a cylindrical drum divided into two levels by an internal horizontal plate. During normal operation, a controlled amount of recirculation flow mixture enters the sludge collector through central entrance holes in the top, flows slowly and radially outward, and exits at the outlet holes near the periphery. This path provides a laminar flow settling zone for the suspended solids. The sludge collector is based on the principle that suspended particles will settle if the flow velocity is less than the threshold settling velocity. Because the cross-flow velocity in the collector is less than the settling velocity, the suspended particles will be "captured" in the sludge collector. It has built-in cleaning jets and a suction line used during periodic maintenance to remove the sludge from the collector.

Calculations show that the sludge collector reduces the solids concentration in the bulk water at a rate equivalent to nearly 4% continuous blowdown. In developmental testing, the sludge collector has been found to reduce both the suspended solids and the amount of sludge deposited on the tubesheet by a factor of three.

The Delta 94 RSG has a 2.5-inch Schedule 40 Alloy 690 blowdown pipe located on top of the tubesheet in the tubelane. The pipe extends essentially the full length of the tubelane and has two end connections 180° apart on the tubesheet. It is designed to accommodate a 1.0% feedwater flow continuous blowdown rate from a single pipe connection (two connections are provided) at full power conditions. The primary function of the blowdown line is to remove bulk fluid from the flow entering the tube bundle.

The RSG is designed with a wide tubelane to enhance maintenance access to the tube bundle, and the TSPs have large flow slots that permit upper bundle cleaning and inspection tools to enter through the lower handholes.

There is no preheater, preheat baffle plates, tubelane partition plate, or T-blowdown to reduce or inhibit inspection and cleaning access.

Loose Parts Potential

The RSG design incorporates features to minimize the development of loose parts during operation and maintenance. Specific design efforts have been taken to minimize corrosion potential on small thickness metal parts. Overall, the improved design features incorporated in the RSGs provide reasonable assurance that tube integrity will be maintained over the proposed operating period.

Tube wear due to foreign objects introduced during RSG manufacture should be less because of strict access control procedures used during fabrication. A clean room was employed for assembling the tube bundle. Personnel access to the clean room was under strict administrative control. A tracking system was implemented such that all personnel, tools, and consumables were accounted for upon each entry and exit or use within the clean room. Operations such as machining, grinding, welding, and burning were shielded to isolate or confine any foreign material produced to prevent loss of cleanliness of hardware in the area. Machine exhaust containing oil vapor, lead, lead compounds, or other detrimental materials was vented outside the clean room. When welding or brazing was performed in the clean room, precautions were taken to control spatter and arc strikes, and to exhaust welding or brazing smoke from the clean room. During machining operations when it was impossible to use internal plugs or seals to close an opening, forced dry, clean inert gas or air was used as a means of ensuring that foreign materials were precluded from entering the opening.

The feedwater ring spray nozzle assemblies have a series of 0.29-inch outlet holes, which function to trap potential foreign objects that might otherwise be introduced from the feedwater systems. If parts are small enough to pass through the spray nozzle perforations, they will also pass between the tubes. Such objects will be transported by the flow into the low velocity region where they have the least potential to produce tube wear. Field maintenance practices also minimize the potential for introduction of loose parts during routine maintenance activities.

4.2 First Outage Inspection Sampling

Technical Specification 4.4.5.3a requires that the first inservice inspection of SG tubes be performed after six effective full power months (EFPM) but within 24 calendar months of initial criticality after SG replacement. This inspection requirement was satisfied during refueling outage 1RE10. As required by TS 4.4.5.2, "Steam Generator Tube Sample Selection and Inspection," TS Table 4.4-1, "Minimum Number of Steam Generators to be Inspected During Inservice Inspection," and TS Table 4.4-2, "Steam Generator Tube Inspection," the inspection requirements for the first inservice inspection were exceeded by inspecting 100% of the tubes in all four SGs. The inspection results showed no degraded or defective tubes, thus falling into the C-1 category.

For the second inservice inspection of SG tubes, TS require that a minimum of 12% of the entire unit's SG tube population be inspected in at least one SG. By performing 100% full-length (i.e., from hot leg tube end to cold leg tube end, including the U-bends) inspection of all SG tubes during the first outage after replacement, STPNOC inspected significantly more tubes than would be required by the TS for both the first and second inservice inspections after replacement. Therefore, even though STPNOC is proposing a one-time extension of the interval between inspections, the scope of the inspections already performed during refueling outage 1RE10 was significantly expanded from that required by the TS over the first two refueling outages after SG replacement.

First outage inspection sampling results, along with industry experience and the operational assessment discussed below, indicate that tube integrity will be maintained over the proposed operating period.

The first outage inspection sampling for 2RE10 in Unit 2 will be the same as described above for 1RE10 in Unit 1.

4.3 Condition Monitoring Assessment

A Condition Monitoring Assessment was performed after 1RE10. This proprietary document provides guidelines for evaluating the condition of SG tubes based on inspection results. The results showed that all performance criteria had been met based on full-length (i.e., from hot leg tube end to cold leg tube end, including the U-bends) bobbin inspection of all of the tubes of all four SGs. Accordingly, all performance criteria were met based on the 1RE10 inspection results of the "as found" condition of the SGs. A similar Conditioning Monitoring Assessment will be performed after 2RE10.

4.4 Operational Assessment

An Operational Assessment was performed after 1RE10 in accordance with EPRI SG Integrity Assessment Guidelines to evaluate the predicted condition of the SGs after two cycles of operation. A similar Operational Assessment will be performed after 2RE10.

One possible damage mechanism that could affect RSG tube integrity is wear from secondary side foreign objects. Sludge lancing was performed on the secondary side tubesheet region of all four SGs during refueling outage 1RE10. Pre-lancing inspections identified several small (less than 1.5 inch-long) pieces of spiral-wound metal gasket banding in SG "A". No tube wear had occurred and the lancing process removed the material. A bounding loose part analysis was prompted by indications of a possible loose part below the sixth hot leg support plate, deep in the bundle that could not be visually investigated. The bounding analysis assumed a loose part actually existed, and was located at the worst SG tube location with respect to tube wear and at the most advantageous orientation to cause tube wear. The hypothetical wear analysis of a metal gasket banding piece demonstrated safe operation for the proposed inspection interval. The results of the 1RE10 inspection, the bounding analysis, improved SG design, and our Foreign Material Exclusion (FME) Program provide confidence that foreign object wear will not occur over the proposed operating period.

During the Unit 1 refueling outage 1RE10 inspection, no forms of degradation were identified. Therefore, the structural and accident leakage performance criteria in Reference 4 are predicted to be met until the SGs are inspected during 1RE12, which is currently scheduled for October 2004. This represents an operation interval of approximately 36 calendar months between SG inspections.

South Texas Project meets or exceeds current industry guidelines with respect to primary and secondary water chemistry.

4.6 Industry Data

The STP Delta 94 RSGs are scaled-up versions of the V. C. Summer Delta 75 RSGs, which have been in service since 1994 (5.2 EFPY as of the last inspection). The October 2000 inspection of the V. C. Summer SGs included 100% bobbin inspection of all three SGs, 332 hot leg top-of-tube-sheet +Point inspections, and approximately 65 special interest +Point inspections. No indications of stress corrosion cracking were present. Three possible AVB wear signals were found which were identifiable at the baseline (pre-service inspection) and a previous inservice inspection. Two were sized at a depth of 9% and one was at 5%. These are projected not to reach plugging conditions for eighteen additional cycles. Lack of wear scar standards in the baseline precludes sizing of these indications as they appear in the baseline. The indications are likely to be fabrication artifacts, but they were conservatively treated as wear by V. C. Summer. A growth rate of 1.7% through-wall per EFPY is calculated in the assumption that these indications are assumed to be active wear. This information provides reasonable assurance that wear indications will not become structurally significant over the proposed length of STP operation prior to the inspections at 1RE12 and 2RE12.

Inspections of the fifteen thermally treated Alloy 600 tubes in service in STP Unit 2 and inspections of the thermally treated Alloy 690 tubes of the lead Delta model SGs at V.C. Summer show that the Delta SGs have not experienced any indications of stress corrosion degradation. Corrosion-related degradation is not expected, particularly not early in the life of these RSGs due to the superior corrosion resistant properties of thermally treated Alloy 690 tubes.

The SG chemistry control programs at V. C. Summer and STP are comparable. Both plants have a deaerator and maintain SG chemistry well within the EPRI guidelines.

4.7 Dose, Schedule, and Cost Impact

If the proposed change is not approved for refueling outage 1RE11, our current plan is to perform 20% full-length bobbin inspection, 20% top of tube sheet +Point, and 20% row 1 and row 2 U-bend +Point inspections in all four SGs. The following dose, schedule, and cost impacts are predicted assuming this scope:

- Accumulated personnel dose including SG platform setup, manway removal, eddy current inspection, and tube plugging is estimated to be approximately 30.5 person-REM.
- The approximate cost associated with inspecting all four SGs, including contractor craft support, is $ 3,000,000.

- The approximate time to perform 20% full-length bobbin inspection of four SGs is seven days from removal of the first manway to reinstallation of the last manway after completion of the inspection.

Steam generator inspections during 1RE10 had to be terminated on several occasions due to eddy current probe and guide tube contamination with cobalt coming from the RSG tube inside surfaces. The SG inspection equipment was very highly contaminated and inspection was terminated to protect inspection personnel from high radiation exposures until the equipment could be replaced. The SG inspections accounted for approximately 37% of the total refueling outage exposure.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

STPNOC has evaluated whether a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of Amendment," as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No

There is no direct increase in SG leakage because the proposed change does not alter the plant design. The scope of inspections performed during 1RE10, the first refueling outage following SG replacement, exceeded the TS requirements for the first two refueling outages after replacement combined. That is, more tubes were inspected than were required by TS. Currently, South Texas Project Unit 1 does not have an active SG damage mechanism and will meet the current industry examination guidelines without performing inspections during the next refueling outage. The results of the Condition Monitoring Assessment after 1RE10 demonstrated that all performance criteria were met during 1RE10. The results of the 1RE10 Operational Assessment show that all performance criteria will be met over the proposed operating period. The results from 2RE10 inspections are expected to be the same.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No

The proposed change will not alter any plant design basis or postulated accident resulting from potential SG tube degradation. The scope of inspections performed during 1RE10 and planned for 2RE10, the first refueling outage for each unit following SG replacement, significantly exceed the TS requirements for the scope of the first two refueling outages after SG replacement combined.

The proposed change does not affect the design of the SG s, the method of operation, or reactor coolant chemistry controls. No new equipment is being introduced and installed equipment is not being operated in a new or different manner. The proposed change involves a one-time extension to the SG tube inservice inspection frequency, and therefore will not give rise to new failure modes. In addition, the proposed change does not impact any other plant system or components.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No

Steam generator tube integrity is a function of design, environment, and current physical condition. Extending the SG tube inservice inspection frequency by one operating cycle will not alter the function or design of the SGs. Inspections conducted prior to placing the SGs into service (pre-service inspections) and inspection during the first refueling outage following SG replacement demonstrate that the SGs do not have fabrication damage or an active damage mechanism. The scope of those inspections significantly exceeded those required by the TS. These inspection results were comparable to similar inspection results for the same model of RSGs installed at other plants, and subsequent inspections at those plants yielded results that support this extension request. The improved design of the replacement SGs also provides reasonable assurance that significant tube degradation is not likely to occur over the proposed operating period.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10CFR20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10CFR51.22(c)(9). Therefore, pursuant to 10CFR51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 PRECEDENT AND REFERENCES

7.1 Precedent

In Reference 6, Exelon Corporation proposed a one-time change to the TS to revise the SG inspection frequency requirements in TS 5.5.9.d.2 for the Braidwood Unit 1 Fall 2001 refueling outage to allow a 40-month inspection interval after one SG inspection, rather than after two consecutive inspections resulting in C-1 classification. Exelon supplemented the application in References 7 and 8 in response to NRC requests for additional information (RAIs). The NRC approved the Exelon request in Reference 9 on August 9, 2001.

The STP RSGs are manufactured by Westinghouse rather than by Babcock and Wilcox International (BWI), the manufacturers of the Braidwood Unit 1 RSGs. However, the Westinghouse Delta 94 RSGs and the BWI RSGs both utilize thermally treated Alloy 690 for the tube material and stainless steel for the tube support structures, and have other similar improvements designed to significantly reduce corrosion in the SGs.

STPNOC has used the Braidwood application, including the Braidwood responses to the NRC RAIs, as guidance for the type and detail of information necessary. The NRC found that the safety performance had been significantly improved in the RSGs after the incorporation of material changes and design changes. With the addition of Braidwood Unit 1 operating experience based on the first inservice inspection after SG replacement and operating experience with similar SGs, Braidwood Unit 1 SG operation was justified for another cycle without another consecutive inspection.

7.2 References

1. T. Yonezawa, "Evaluation of the Corrosion Resistance of Alloy 690," EPRI NP-4665S- SR Proceedings: Workshop on Thermally Treated Alloy 690 Tubes for Nuclear Steam Generators, Pittsburgh, PA, June 26 - 28, 1986, paper No. 12

2. R. G. Aspeden, T. F. Grand and D. L. Harrod, "Corrosion Performance of Alloy 690," EPRI NP-6750-M Proceedings: 1989 EPRI Alloy 690 Workshop, New Orleans, LA, April 12 - 14, 1989

3. G. Santarini, "Alloy 690: Recent Corrosion Results," EPRI NP-6750-M Proceedings: 1989 EPRI Alloy 690 Workshop, New Orleans, LA, April 12 - 14, 1989

4. Letter from D. Modeen (NEI) to S. Collins (NRC), "Revised Industry Steam Generator Program Generic License Change Package," Enclosure 9, NEI 97-06, "Steam Generator Program Guidelines," draft Revision 1, December 11, 2000

5. Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes (for comment)," August 1976

6. Letter from R. M. Krich (Exelon) to NRC, "Request for Technical Specifications Change Braidwood Station, Unit 1, Steam Generator Inspection Frequency Revision for the Fall 2001 Refueling Outage," February 9, 2001

7. Letter from R. M. Krich (Exelon) to NRC, "Response to Request for Additional Information for Technical Specifications Change to Revise Steam Generator Inspection Frequency for the Fall 2001 Refueling Outage for Braidwood Station, Unit 1," May 18, 2001

8. Letter from R. M. Krich (Exelon) to NRC, "Response to Request for Additional Information for Technical Specifications Change to Revise Steam Generator Inspection Frequency for the Fall 2001 Refueling Outage for Braidwood Station, Unit 1," June 26, 2001

9. Letter from M. Chawla (NRC) to O. D. Kingsley (Exelon), "Issuance of Amendments - Technical Specifications Changes to Revised Steam Generator Inspection Frequency, Braidwood Station, Units 1 and 2 (TAC Nos. MB1226 and MB1227)," August 9, 2001

Attachment 2

Proposed Technical Specification Changes

(Mark-up)

4.4.5.3 Inspection Frequencies - The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection following steam generator replacement shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality after the steam generator replacement. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months;

   Note: Inservice Inspection is not required during the steam generator replacement outage.

   Note: A one-time (per unit) inspection interval of a maximum of once per 40 months is allowed for the inspection performed immediately following 1RE10 and 2RE10. This is an exception to 4.4.5.3a in that the interval extension is based on all of the results of one inspection falling into the C-1 category.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 4.4-2 at 40-month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 4.4.5.3a.; the interval may then be extended to a maximum of once per 40 months; and

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.4-2 during the shutdown subsequent to any of the following conditions:

   1) Primary-to-secondary tube leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.6.2, or

   2) A seismic occurrence greater than the Operating Basis Earthquake, or

   3) A loss-of-coolant accident requiring actuation of the Engineered Safety Features, or

   4) A main steam line or feedwater line break.

Attachment 3

Proposed Technical Specification Page
(Retyped)

4.4.5.3 Inspection Frequencies - The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection following steam generator replacement shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality after the steam generator replacement. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months;

   Note: Inservice Inspection is not required during the steam generator replacement outage.

   Note: A one-time (per unit) inspection interval of a maximum of once per 40 months is allowed for the inspection performed immediately following 1RE10 and 2RE10. This is an exception to 4.4.5.3a in that the interval extension is based on all of the results of one inspection falling into the C-1 category.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 4.4-2 at 40-month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 4.4.5.3a.; the interval may then be extended to a maximum of once per 40 months; and

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.4-2 during the shutdown subsequent to any of the following conditions:

   1) Primary-to-secondary tube leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.6.2, or

   2) A seismic occurrence greater than the Operating Basis Earthquake, or

   3) A loss-of-coolant accident requiring actuation of the Engineered Safety Features, or

   4) A main steam line or feedwater line break.

Attachment 4

Bases Pages

(For Information Only)

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STEAM GENERATOR BASES

The Surveillance Requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83, Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those chemistry limits found to minimize corrosion of the steam generator tubes. If the secondary coolant chemistry is not maintained within these limits, localized corrosion may likely result in stress corrosion cracking. The extent of cracking during plant operation would be limited by the 3.4.6.2.c limitation of steam generator tube leakage between the Reactor Coolant System and the Secondary Coolant System. Cracks having a primary-to-secondary leakage less than this limit during operation will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that primary-to-secondary leakage as low as 150 gallons per day per steam generator can readily be detected. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged or (for Model E steam generators only) repaired. Defective tubes in Model E steam generators may be repaired by a Westinghouse laser welded sleeve. The technical bases for sleeving repair are described in Westinghouse Reports WCAP-13698, Revision 2, "Laser Welded Sleeves for 3/4 Inch Diameter Tube Feedring-Type and Westinghouse Preheater Steam Generators," April 1995 and WCAP-14653, "Specific Application of Laser Welded Sleeves for South Texas Project Power Plant Steam Generators," June 1996.

Wastage-type defects are unlikely with proper chemistry treatment of the secondary coolant. However, even if a defect should develop in service, it will be found during scheduled inservice steam generator tube examinations. Except as discussed below, plugging or (for Model E steam generators only) repair will be required for all tubes with imperfections exceeding the plugging or repair limit of 40% of the original tube nominal wall thickness. If a tube contains a Westinghouse laser welded sleeve with imperfection exceeding 40% of nominal wall thickness, it must be plugged. The basis for the sleeve plugging limit for Model E steam generators is based on Regulatory Guide 1.121 analysis, and is described in the Westinghouse sleeving technical reports listed above. Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect degradation that has penetrated 20% of the original tube wall thickness. Repaired tubes are also included in the inservice tube inspection program.

For Model E steam generators only, the voltage-based repair limits of SR 4.4.5 implement the guidance in GL 95-05 and are applicable only to Westinghouse-designed steam generators (SGs) with outside diameter stress corrosion cracking (ODSCC) located at the tube-to-tube support plate intersections. The criteria of GL 95-05 are also applicable to the Unit 2 flow distribution plate intersections. The voltage-based repair limits are not applicable to other forms of SG tube degradation nor are they applicable to ODSCC that occurs at other locations within the SG. Additionally, the repair criteria apply only to indications where the degradation mechanism is dominantly axial ODSCC with no significant cracks extending outside the thickness of the support plate. Refer to GL 95-05 for additional description of the degradation morphology.

Implementation of SR 4.4.5 for Model E steam generators requires a derivation of the voltage structural limit from the burst versus voltage empirical correlation and then the subsequent derivation of the voltage repair limit from the structural limit (which is then implemented by this surveillance).

The voltage structural limit is the voltage from the burst pressure/bobbin voltage correlation, at the 95-percent prediction interval curve reduced to account for the lower 95/95-percent tolerance bound for tubing material properties at 650°F (i.e., the 95-percent LTL curve). The voltage structural limit of the tube at flow distribution baffle intersections, (which have large tube to plate clearances) is based on a $3\Delta P_{NO}$ structural margin. For tubes at the cold leg tube support plate intersections and the hot leg intersections at plates L through R for which the small clearances provide constraint against tube burst during normal operation, the structural limit is based on a $1.43\Delta P_{SLB}$ structural margin. For the hot leg intersections at plates C, F, and J with the limited displacement of the lower tube support plates demonstrated by analyses in WCAP-15163, Rev. 1, Addendum 1, the constraint of the tube support plate reduces the burst probability of those tubes having axially oriented ODSCC indications that are confined within the tube support plate to negligible levels and the tube repair limit is not required to prevent tube burst. The need for tube repair is dictated by the need to satisfy allowable steam line break leakage limits.

For those intersections where the possibility of tube burst must be considered (i.e., at the flow distribution baffle, at cold leg intersections, and at the hot leg intersections at plates L through R), the voltage structural limit must be adjusted downward to obtain the upper voltage repair limit to account for potential flaw growth during an operating interval and to account for NDE uncertainty. The upper voltage repair limit; V_{URL}, is determined from the structural voltage limit by applying the following equation:

$$V_{URL} = V_{SL} - V_{GR} - V_{NDE}$$

where V_{GR} represent the allowance for flaw growth between inspections and V_{NDE} represents the allowance for potential sources of error in the measurement of the bobbin coil voltage. Further discussion of the assumptions necessary to determine the voltage repair limit are discussed in GL 95-05.

The mid-cycle equation in SR 4.4.5.4.a.11.e should only be used during unplanned inspections of Model E steam generators in which eddy current data is acquired for indications at the tube support plates.

SR 4.4.5.5 implements several reporting requirements for Model E steam generators recommended by GL 95-05 for situations which the NRC wants to be notified prior to returning the SGs to service. For the purpose of this reporting requirement, leakage and conditional burst probability can be calculated based on the as-found voltage distribution rather than the projected end-of-cycle voltage distribution (refer to GL 95-05 for more information) when it is not practical to complete these calculations using the projected EOC voltage distributions prior to returning the SGs to service. Note that if leakage and conditional burst probability were calculated using the EOC voltage distribution for the purposes of addressing the GL section

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6.a.1 and 6.a.3 reporting criteria, then the results of the projected EOC voltage distribution should be provided per the GL section 6.b.(c) criteria.

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be promptly reported to the Commission in a Special Report pursuant to Specification 6.9.2 within 30 days and prior to resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.