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SOUTHERN COMPANY
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February 13, 2008

Docket Nos.: 50-424
50-425

NL-08-0148

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

Vogtle Electric Generating Plant Units 1 and 2
License Amendment Request to Revise Technical Specification (TS)
Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10,
"Steam Generator Tube Inspection Report" for Interim Alternate Repair Criterion

Ladies and Gentlemen:

On November 30, 2007, Southern Nuclear Operating Company (SNC) submitted to the NRC a license amendment request to propose a permanent alternate repair criterion (ARC) to TS 5.5.9 to limit the inspection depth in the SG tubesheet expansion zone, known as H*/B*. The SNC submittal was similar to the February 21, 2006 Wolf Creek Nuclear Operating Corporation (WCNOC) proposed amendment request to allow a permanent ARC.

On December 21, 2007, NRC Division of Operating Reactor Licensing personnel contacted WCNOC executive management to communicate that the NRC would not be able to approve the proposed permanent revision to TS 5.5.9 to support the Spring 2008 refueling outage. As a result of the December 21, 2007 communication, a subsequent teleconference was held on January 3, 2008, between the NRC, industry representatives, and involved utility representatives, in which the NRC stated that they would consider a proposed interim submittal to support the tube sheet ARC for plants with hydraulically expanded Alloy 600 thermally treated tubing in the tubesheet.

Pursuant to 10 CFR 50.90, SNC hereby requests an amendment to Facility Operating License Nos. NPF-68 and NPF-81 for Vogtle Electric Generating Plant (VEGP), Units 1 and 2, respectively.

The attached amendment request is subdivided as shown below:

Enclosure 1 provides a basis for the proposed change.

Enclosure 2 includes the marked-up TS pages with the proposed changes.

A001
NRR

Enclosure 3 includes the associated typed TS pages with the proposed changes incorporated for VEGP.

Enclosure 4 provides an application for withholding, affidavit, proprietary information notice, and copyright notice for information proprietary to Westinghouse Electric Company, LLC.

Enclosure 5 provides a non-proprietary version of Westinghouse Electric Company LLC, LTR-CDME 08-11-NP, "Interim Alternate Repair Criterion (ARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone," Non-Proprietary Version.

Enclosure 6 provides a proprietary version of Westinghouse Electric Company LLC, LTR-CDME 08-11-P, "Interim Alternate Repair Criterion (ARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone," Proprietary Version.

The NRC regulatory commitments contained in this letter are provided as a table in Enclosure 7.

Enclosure 8 provides correction of references written into Section 5 text, GP-18283, "Transmittal of Document – LTR-CDME-08-25, "Errata for LTR-CDME-08-11; Interim Alternate Repair Criterion (ARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone.""

Enclosure 6 contains information proprietary to Westinghouse Electric Company LLC; it is supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the NRC and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR 2.390, "Public inspections, exemptions, requests for withholding." Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390.

Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse affidavit should reference CAW-08-2383 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC; P. O. Box 355; Pittsburgh, Pennsylvania, 15230-0355.

SNC requests approval of the proposed license amendments by March 15, 2008 in order to support the VEGP-1 refueling outage that is currently scheduled to begin March 16, 2008. Excessive plugging increases Reactor Coolant System (RCS) flow resistance through the SG and reduces heat transfer area, thereby reducing margins in RCS flow and in SG tubing secondary side Departure from Nucleate Boiling (DNB), respectively. In addition, personnel responsible for the tube plugging activities will not be subject to additional radiation dose by having to unnecessarily plug SG tubes.

The proposed changes shall be implemented in the VEGP units as follows:

- The Unit 1 TS change shall be implemented in the interval between the conclusion of Unit 1 Cycle 14 and the first Mode 4 entry in the mode ascension during the 1R14 Refueling Outage; and
- The Unit 2 TS change shall be implemented in the interval between the conclusion of Unit 2 Cycle 13 and the first Mode 4 entry in the mode ascension during the 2R13 Refueling Outage.

Mr. Tom E. Tynan states he is a Vice President of Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company and to the best of his knowledge and belief, the facts set forth in this letter are true.

If you have any questions, please advise.

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

Tom E. Tynan
Vice President -Vogtle

Sworn to and subscribed before me this 13th *day of* February, *2008.*

Notary Public

My commission expires: 10/14/2009

TET/DRG/<>

Enclosures: 1. Basis for Proposed Change

2. Markup of Proposed Technical Specifications Page Changes for VEGP

3. Typed Pages for Technical Specification Changes for VEGP

4. Westinghouse Letter, CAW-08-2383, Application for Withholding and Affidavit, Proprietary Information Notice, and Copyright Notice

5. Westinghouse Electric Company LLC, LTR-CDME 08-11-NP, "Interim Alternate Repair Criterion (ARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone," Dated January 31, 2008 (Non-Proprietary).

6. Westinghouse Electric Company LLC, LTR-CDME 08-11-P, "Interim Alternate Repair Criterion (ARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone," dated January 31, 2008 (Proprietary).

7. List of Regulatory Commitments

8. GP-18283, "Transmittal of Document – LTR-CDME-08-25, "Errata for LTR-CDME-08-11; Interim Alternate Repair Criterion (ARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone."" dated February 12, 2008.

cc: Southern Nuclear Operating Company
Mr. J. T. Gasser, Executive Vice President
Mr. L. M. Stinson, Vice President – Fleet Operations Support
Mr. D. H. Jones, Vice President – Engineering
RType: CVC7000

U. S. Nuclear Regulatory Commission
Mr. V. M. McCree, Acting Regional Administrator
Mr. S. P. Lingam, NRR Project Manager – Vogtle
Mr. G. J. McCoy, Senior Resident Inspector – Vogtle

State of Georgia
Mr. N. Holcomb, Commissioner – Department of Natural Resources

Vogtle Electric Generating Plant Units 1 and 2
License Amendment Request to Revise Technical Specification (TS) Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report" for Interim Alternate Repair Criterion

Enclosure 1

Basis for Proposed Change

Vogtle Electric Generating Plant Units 1 and 2
License Amendment Request to Revise Technical Specification (TS)
Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10,
"Steam Generator Tube Inspection Report" for Interim Alternate Repair Criterion

Enclosure 1

Basis for the Proposed Change

Table of Contents

1.0 Summary Description

This amendment application proposes a one time steam generator (SG) tubing eddy current inspection interval revision to the Vogtle Electric Generating Plant (VEGP) Technical Specifications (TS) 5.5.9, "Steam Generator (SG) Program," to incorporate an interim alternate repair criterion in the provisions for SG tube repair criteria during the Unit 1 inspection performed in Refueling Outage 14 and subsequent operating cycle, and during the Unit 2 inspection performed in Refueling Outage 13 and subsequent 18-month SG tubing eddy current inspection interval and subsequent 36-month SG tubing eddy current inspection interval. This amendment application requests approval of an interim alternate repair criterion (IARC) that requires full-length inspection of the tubes within the tubesheet but does not require plugging tubes if any axial or circumferential cracking observed in the region greater than 17 inches below the top of the tubesheet (TTS) is less than a value sufficient to permit the remaining circumferential ligament to transmit the limiting axial loads. This amendment application is required to preclude unnecessary plugging while still maintaining structural and leakage integrity.

Approval of this amendment application is requested to support VEGP 1 Refueling Outage 14 (Spring 2008) and the subsequent operating cycle, since the existing one cycle amendment expires at the end of the current operating cycle.

2.0 Detailed Description

Proposed Changes to Current TS

TS 5.5.9 c. currently states:

"c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube repair criteria may be applied as an alternative to the 40% depth-based criteria:

1. For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation found in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

   For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be plugged upon detection.

2. For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the hot leg tubesheet shall be plugged upon detection."

This criterion would be revised as follows, as noted in italic type:

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube repair criteria *shall* be applied as an alternative to the 40% depth-based criteria:

1. *For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.*

   For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the hot leg tubesheet shall be plugged upon detection.

2. *For Unit 1 during Refueling Outage 14 and the subsequent operating cycle, tubes with less than or equal to a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service. Tubes with service-induced crack-like flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.*

3. *For Unit 2 Refueling Outage 13 and subsequent 18-month eddy current inspection interval, tubes with less than or equal to a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service.*

   For Unit 2 Refueling Outage 13 and subsequent 36-month eddy current inspection interval, tubes with less than or equal to a 183 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 183 degree circumferential service-induced crack-like flaw

found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service.

For Unit 2 Refueling Outage 13 and subsequent 18-month and 36-month eddy current inspection intervals, tubes with service-induced crack-like flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

TS 5.5.9 d. currently states:

d. "Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded. For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 120, 90, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic nondestructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack."

This criterion would be revised as follows to delete provisions which are no longer applicable, and to add provisions with respect to the Unit 2 36-month inspection interval as noted in strikethrough text and italic type:

d. "Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. ~~*For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded*~~For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded. *For Unit 2 during Refueling Outage 13 and the 36-month eddy current inspection interval, SGs in which the portion of the tube below 17 inches from the top of the tubesheet has no greater than 183 degree circumferential service-induced crack-like flaws are excluded from the requirements of Paragraph 3 below.* The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations."

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 120, 90, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic nondestructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

TS 5.6.10 currently states:

"A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, "Steam Generator (SG) Program." The report shall include:

a. The scope of inspections performed on each SG;

b. Active degradation mechanisms found;

c. Nondestructive examination techniques utilized for each degradation mechanism;

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications;

e. Number of tubes plugged during the inspection outage for each active degradation mechanism;

f. Total number and percentage of tubes plugged to date; and

g. The results of condition monitoring, including results of tube pulls and in-situ testing."

TS 5.6.10 would be revised to add the following 3 additional reporting criteria:

h. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the number of indications and location, size, orientation, and whether initiated on primary or secondary side for each service-induced crack-like flaw within the thickness of the tubesheet;

i. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign leakage to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report; and

j. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the calculated accident leakage rate from the portion of the tube 17 inches below the top of the tubesheet for the most limiting accident in the most limiting SG.

3.0 Background

TS 5.5.9 requires that an SG tube program be established and implemented to ensure that SG tube integrity is maintained. SG tube integrity is maintained by meeting specified performance criteria (in TS 5.5.9.b) for structural and leakage integrity, consistent with the plant design and licensing bases. TS 5.5.9 requires a condition monitoring assessment be performed during each outage during which the SG tubes are inspected to confirm that the performance criteria

are being met. TS 5.5.9 also includes provisions regarding the scope, frequency, and methods of SG tube inspections. Of relevance to the amendment application, these provisions require that the number and portions of tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type that may be present along the length of a tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The applicable tube repair criteria, specified in TS 5.5.9.c, are that tubes found by an inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

On November 30, 2007, Southern Nuclear Operating Company (SNC) submitted to the NRC a license amendment request (Reference 2) to propose a permanent alternate repair criterion (ARC) to TS 5.5.9 to limit the inspection depth in the SG tube expansion zone, known as H*/B*. The SNC submittal was similar to the February 21, 2006 Wolf Creek Nuclear Operating Corporation (WCNOC) proposed amendment request to allow a permanent ARC. The H*/B* ARC seeks to minimize the depth of rotating coil inspection of the SG tubes within the tubesheet. The premise of H*/B* is that the expansion joint provides sufficient structural restraint to prevent the tube from pulling out of the tubesheet under normal operating and accident conditions, and that the accident induced leakage during accident conditions is bounded by a factor of two on the observed normal operating leakage. The H*/B* approach remains a valid approach for addressing degradation in the lower portion of the tube.

On December 21, 2007, NRC Division of Operating Reactor Licensing personnel contacted WCNOC executive management to communicate that the NRC would not be able to approve the proposed permanent revision to TS 5.5.9 to support the Spring 2008 refueling outage (March 2008). As a result of the December 21, 2007 communication, a subsequent teleconference was held on January 3, 2008, between the NRC, industry representatives, and involved utility representatives, in which the NRC stated that they would consider a proposed interim submittal to support the tube sheet ARC for plants with hydraulically expanded Alloy 600 thermally treated tubing in the tubesheet. The teleconference is documented by a January 22, 2008, memorandum (Reference 9).

Westinghouse Electric Company LLC, LTR-CDME 08-11-P, "Interim Alternate Repair Criterion (ARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone," (Reference 3) provides the technical justification for an interim alternate repair criterion (IARC) that requires full-length inspection of the tubes within the tubesheet but does not require plugging tubes if the extent of any circumferential cracking observed in the region greater than 17 inches below the top of the tubesheet (TTS) is less than a value sufficient to permit the remaining circumferential ligament to transmit the limiting axial loads [the greater of 3 times the normal operating (NOP) or 1.4 times the steam line break (SLB) end cap loads]. Axial cracks below 17 inches from the TTS are not relevant to the tube pullout arguments, because axial cracks do not degrade the axial load carrying capability of the tube. Axial cracks do not require plugging if they are below 17 inches from the top of the tubesheet.

The calculation of the limiting circumferential ligament has been defined. The calculation assumes that friction loads between the tube and tubesheet from any source are zero. This assumption avoids potential effects of uncertainties in tube and tubesheet material properties.

Also, based on the same assumption that the contact pressure between the tube and the tubesheet from any source is zero, this evaluation provides a basis for demonstrating that the accident induced leakage will always meet the value assumed in the plant's safety analysis if the observed leakage during normal operating conditions is within its allowable limits. The need

to calculate leakage from individual cracks is avoided by the calculation of the ratio of accident induced leakage to normal operating leakage.

Although the tube-end weld is specifically excluded from the tube by TSTF-449, Rev. 4 (Reference 4) it is, nevertheless, also necessary to consider the capability of a degraded weld to prevent tube pullout for this IARC. Because of the underlying assumption of zero friction load between the tubes and the tubesheet, the weld must provide the IARC's ultimate structural restraint of the tube within the tubesheet. Therefore, a limiting ligament size has also been determined for the tube-to-tubesheet weld and is discussed below.

4.0 Technical Evaluation

An evaluation has been performed in Enclosure I to assess the need for removing tubes from service due to the occurrence of circumferentially or axially oriented cracks in a tubesheet. The conclusions of the evaluation are primarily threefold:

1. Axial cracks in tubes below a distance of 17 inches below the top of the tubesheet can remain in service in the VEGP SGs as they are not a concern relative to tube pullout and leakage capability.

2. Circumferentially oriented cracks in tubes with an azimuthal extent of less than or equal to 214 degrees can remain in service for one cycle of operation (18-month SG tubing eddy current inspection interval). Circumferentially oriented cracks in tubes with an azimuthal extent of less than or equal to 183 degrees can remain in service for one 36-month SG tubing eddy current inspection interval.

3. Circumferentially oriented cracks in the tube-to-tubesheet welds with an azimuthal extent of less than or equal to 294 degrees can remain in service for one cycle of operation (18-month SG tubing eddy current inspection interval). Circumferentially oriented cracks in the tube-to-tubesheet welds with an azimuthal extent of less than or equal to 263 degrees can remain in service for one 36-month SG tubing eddy current inspection interval.

A bounding analysis approach is utilized for both the minimum ligament calculation and leakage ratio calculation. "Bounding" means that the most challenging conditions from the plants with hydraulically expanded Alloy 600TT tubing are used. Three different tube diameters are represented by the affected plants (11/16" dia., Model F; 3/4" dia., Model D5; 7/8" dia., Model 44F). The most limiting conditions for structural evaluation depend on tube geometry and applied normal operating loads; thus, the conditions from the plant that result in the highest stress in the tube are used to define the minimum required circumferential ligament. The limiting leak rate ratio depends on the leak rate values assumed in the safety analysis and allowable normal operating leakage that results in the longest length of undegraded tube.

The requirements proposed in this License Amendment Request are structured in consideration of unit specific factors. Stress corrosion crack (SCC) indications have been detected in all 4 VEGP Unit 1 SGs; therefore, SG tubing eddy current inspection in all 4 SGs is required each refueling outage (18-month cycle). No SCC has been detected in the VEGP Unit 2 SGs; therefore, the current SG tubing eddy current inspection strategy in the VEGP Unit 2 SGs can be continued, in which 2 SGs are inspected in a given outage and the other 2 SGs are inspected in the subsequent outage.

Discussion of Performance Criteria

The performance criteria of NEI 97-06, Rev. 2 (Reference 5) are the basis for these analyses. The performance criteria in the VEGP TS, which are based on NEI 97-06, Rev. 2, are:

The structural integrity performance criterion is:

> *All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.*

The structural performance criterion is based on ensuring that there is reasonable assurance that a steam generator tube will not burst during normal operation or postulated accident conditions.

The accident-induced leakage performance criterion is:

> *The primary to secondary accident induced leakage rate for any design basis accident, other than a steam generator tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all steam generators and leakage rate for an individual steam generator. Leakage is not to exceed 1 gpm per steam generator.*

Primary-to-secondary leakage is a factor in the dose releases outside containment resulting from a limiting design basis accident. The potential primary-to-secondary leak rate during postulated design basis accidents shall not exceed the offsite radiological dose consequences required by 10 CFR Part 100 guidelines or the radiological consequences to control room personnel required by GDC-19, or other NRC-approved licensing basis.

The IARC for the tubesheet region are designed to meet these criteria. The structural criterion regarding tube burst is inherently satisfied because the constraint provided by the tubesheet to the tube prohibits burst.

Limiting Structural Ligament Discussion

As defined in Enclosure I, the bounding remaining structural ligament which meets the NEI 97-06, Rev. 2, Performance Criterion described above and required for the tube to transmit the operational loads is 115 degrees arc. This assumes that the residual ligament is 100% of the tube wall in depth. A small circumferential initiating crack is predicted to grow to a throughwall

condition before it is predicted to reach a limiting residual ligament. A residual ligament in a part-throughwall condition is not a significant concern, because of the assumption that all circumferential cracks detected are 100% throughwall.

Consideration of NDE Uncertainty

The NDE uncertainty must be addressed to assure that the as-indicated circumferential arc of the reported crack is a reliable estimate of the actual crack. ETSS (Examination Technique Specification Sheet) 20510.1 (Reference 6) describes the qualified technique used to detect circumferential PWSCC in the expansion transitions and in the tubesheet expansion zone (TEZ). The qualification data is provided in the ETSS.

The fundamental assumption for the IARC is that all circumferential cracks detected are 100% throughwall. Thus, even a shallow crack of small length will be considered to be throughwall. Further, tube burst is not an issue for the IARC because of the constraint provided by the tubesheet; rather, it is axial separation of the tube that is the principal concern. Assuming that all circumferential cracks are throughwall reduces the inspection uncertainty to length of the cracks only. Further, the accuracy of the length determination is an issue only when the indicated crack approaches the allowable crack length (the complement of the required residual ligament) and if the indicated crack length is a reasonable estimate of the structural condition of the tube.

Prior investigations have correlated the axial strength of the tube to the Percent Degraded Area (PDA) of the flaw (Reference 10). PDA takes into account the profile of the existing crack, including non-throughwall portions and shallow tails of the crack. Using the data from ETSS 20510.1 for cracks with a 90%, or greater, throughwall condition from both NDE and destructive examination, a comparison of the actual crack lengths and corresponding PDA for the cracks to a theoretical PDA, which assumes that cracks are 100% throughwall, has been made. All of the points with a PDA of 60% or greater fall below the theoretical PDA line. As the crack lengths increase, the separation of the actual PDA from the theoretical PDA tends to increase. The conclusion that the as-indicated crack angle is conservative is further supported by considering the characteristics of the eddy current (EC) probes. Each probe has a "field of view," that is, a window of finite dimension in which it detects flaws. The field of view for the + Point probe typically varies between 0.1 inch to 0.2 inch depending on the specific characteristics of the probe. Therefore, as the probe traverses its path, a flaw will be detected as the leading edge of the field of view first crosses the location of the flaw, continuing until the trailing edge of the field of view passes the opposite end of the flaw. This is known as "lead-in" and "lead-out" of the probe, and the effect of these are to render the indicated flaw length greater than the actual flaw length. Therefore, it is concluded that the indicated flaw length will be conservative relative to the actual flaw length, especially when it is assumed that the entire length of the indicated flaw is 100% throughwall.

Based on the above, it is concluded that if the detected circumferential cracks are assumed to be 100% throughwall, the as-indicated crack lengths will be inherently conservative with respect to the structural adequacy of the remaining ligament. Therefore, no additional uncertainty factor is necessary to be applied to the as-measured circumferential extent of the cracks.

Consideration of Crack Growth

The growth of cracks due to PWSCC in this submittal request is dictated by four default growth rates from Reference 3. The distribution of growth rates is assumed to be lognormal. Typical

values and conservative values are given, although it is recommended in EPRI 1012987; "Steam Generator Integrity Assessment Guidelines," dated July 2006 (Reference 8), to use the default values only when the historical information is not available and not to use the typical values unless the degradation is mild. (No significant crack growth data exists for the circumferential cracking in the tubesheet expansion region.) Both data sets provided in Reference 3 have mean values and 95% upper bound values. For this analysis, the typical 95% upper bound growth rate is used.

The circumferential growth rates are expressed as inches per effective full power year (EFPY).

Table 1.0 Calculation of Required Minimum Ligament for 18 and 36 Months Operating Periods

	Bounding Structural Ligament	EFPY	Growth (In./EFPY) (1)	Growth (Deg./EFPY) (2)	Growth for Operating Period (degrees)	Minimum Structural Ligament (degrees)	Critical Ligament (degrees)
Tube	18 Calendar Month (CM) Operation	1.5	.12	20.65	31	115	146
	36 CM Operation	3.0	.12	20.65	62	115	177

1) 95% upper value of typical growth rates from Reference 3
2) Based on smallest (Model F) mean tubesheet bore dimension

The residual structural ligament must be adjusted for growth during the anticipated operating period between the current and the next planned inspection. Typically, the operating periods for the affected plants are 18 calendar months (1.5 EFPY); however, some plants have planned outages in which no primary side inspections will be performed. Thus, cycle length adjustments are made to the minimum structural ligament required. For the VEGP SGs, referring to Table 1.0 above, the maximum allowable throughwall circumferential crack size in a SG tube is 214° (= 360° – 146°) for one cycle of operation (18 month SG tubing eddy current inspection interval). For the 36 month SG tubing eddy current inspection interval, the maximum allowable through wall circumferential crack size in a SG tube is 183 degrees (= 360° - 177°). No additional uncertainty factor is necessary to be applied to the as-measured circumferential extent of the cracks.

Primary-to-Secondary Leakage Discussion

A basis, using the D'Arcy formula for flow through a porous medium, is provided to assure that the accident induced leakage for the limiting accident will not exceed the value assumed in the safety analysis for the plant if the observed leakage during normal operation is within its limits for the bounding plant is discussed in Reference 3. The bounding plant envelopes all plants who are candidates for applying H*/B*. The D'Arcy formulation was previously compared to other potential models such as the Bernoulli equation or orifice flow formulation and was found to provide the most conservative results.

Assuming zero contact pressure in the tube joint, the length of undegraded crevice required to limit the accident induced leakage to less than the value assumed in the safety analysis for the limiting plant is calculated to be 3.78 inches. By definition of the IARC, a tube that can remain in service has an undegraded crevice of 17 inches. Therefore, a factor of safety of 4.5 is available (17 inches / 3.78 inches). Expressed in length terms, the length margin in the crevice is 13.22 inches. Significant margin on crevice length is available even if only the distance below the neutral axis of the tubesheet is considered. This distance is approximately 6.5 inches. A factor of safety of 1.72 is available. Expressed in length terms, the length margin in the crevice is 2.72 inches below the neutral axis of the tubesheet. During normal operating conditions, the tubesheet flexes due to differential pressure loads, causing the tubesheet holes above the neutral axis to dilate, and below the neutral axis, to constrict. No mechanical benefit is assumed in the analysis due to tubesheet bore constriction below the neutral axis of the tubesheet; however, first principles dictate that the tubesheet bore and crevice must decrease. Therefore, the leakage analysis provided is conservative.

Based on the above, with a length of undegraded crevice of 17 inches, it is concluded that if the normal operating leakage is within its allowable value, the accident induced leakage will also be within the value assumed in the VEGP safety analysis. The total increase in leakage during a postulated accident condition would be less than a factor of 3.5 (0.35 gpm allowable leakage during a SLB event / 0.1 gpm allowable leakage during normal operating conditions).

Reporting Requirements

In the January 3, 2008 and January 16, 2008 NRC/industry teleconferences, the NRC indicated that TS 5.6.10 should include reporting requirements applicable to the implementation of the IARC. SNC is proposing reporting requirements based on the SNC November 30, 2007 license amendment request (Reference 2) with some modifications.

- The proposed reporting requirements are only required for the applicable period of the IARC.

- Enclosure 6 calculated a value of the calculated accident leakage rate from the most limiting accident in the most limiting SG to be greater than 2 times the maximum operational primary to secondary leakage rate. Therefore, the reporting requirements do not include a requirement to describe how the calculated accident leakage rate from the most limiting accident was determined if the leakage rate is less than 2 times the maximum operational primary to secondary leakage rate.

Inspection and Repair of Tube

The tube below the IARC depth will be examined with a qualified technique, e.g., +Point probe. Axial flaws have no impact on the structural integrity of the tube in this region and may be left in service. For Unit 1, circumferential indications which exceed the maximum acceptable tube flaw size of 214 degrees will be plugged. For Unit 2, circumferential indications which exceed the maximum acceptable tube flaw size of 214 degrees will be plugged for the 18-month SG tubing eddy current inspection interval, and circumferential indications which exceed the maximum acceptable tube flaw size of 183 degrees will be plugged for the 36-month SG tubing eddy current inspection interval. Flaws that require plugging will result in expansion per EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines." Stress concentration areas may be used to define the extent of the expansion, e.g., if a repairable indication is

located in a bulge/overexpansion (BLG/OXP) eddy current signal, the expansion may be limited to the non-inspected BLG/OXPs.

Inspection and Repair of Tube End Welds

For the tube end weld eddy current examination, the weld will be evaluated on a best effort basis for crack-like indications. As discussed in Reference 3, for Unit 1, crack-like indications in the tube end weld that exceed the maximum acceptable weld flaw size of 294 degrees will be visually examined on a "best effort" basis with inspection systems capable of achieving a resolution similar to the Maximum Procedure Demonstration Lower Case Character Height as discussed in ASME Section XI. For Unit 2, crack-like indications in the tube end weld that exceed the maximum acceptable weld flaw size of 294 degrees for the 18-month SG tubing eddy current inspection interval and that exceed the maximum acceptable weld flaw size of 263 degrees for the 36-month SG tubing eddy current inspection interval will likewise be visually examined. Dose rates in steam generator channel heads will typically necessitate performance of the inspection using remote inspection systems.

If the visual examination confirms that a flaw is present in the weld-to-tube interface and exceeds the applicable maximum acceptable weld flaw size described in the preceding paragraph, the tube will be plugged. This approach is conservative based on the assumption that the full visible length of indications are through wall. Defense in depth during operation is provided by application of a conservative ratio of steam line break leakage to normal operating leakage, and the associated special technical specification reporting requirement proposed in this request.

Tubes containing visual indications in the tube end weld that exceed the acceptance criteria will be removed from service by tube plugging. The installed plug joint becomes the pressure boundary. Plug installation results in significant contact pressure between the tube and the plug, as well as the tube and the tubesheet. This pressure, as demonstrated by the plug qualifications, meets all applicable loading and design conditions. The high contact pressures in the expanded plug load path will limit leakage, such that it would be indistinguishable from indications left inservice in the length of the tube below 17 inches from the top of the tubesheet and is, therefore, bounded by the leakage analysis for the IARC.

If the visual examination confirms that the weld-to-tube joint is sound and a flaw exists in the weld-to-clad joint, the tube is also acceptable to leave in service. Leaving the tube in service is acceptable because the attached weld prevents the tube from being ejected in an accident scenario.

An evaluation for tube end welds that require plugging will be completed under the Corrective Action Program to provide reasonable assurance that unacceptable welds are removed from service.

5.0 Regulatory Evaluation

5.1 No Significant Hazards Consideration

SNC has evaluated whether or not 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

Of the various accidents previously evaluated, the proposed changes only affect the steam generator tube rupture (SGTR) event evaluation and the postulated steam line break (SLB), locked rotor and control rod ejection accident evaluations. Loss-of-coolant accident (LOCA) conditions cause a compressive axial load to act on the tube. Therefore, since the LOCA tends to force the tube into the tubesheet rather than pull it out, it is not a factor in this licensing amendment request. Another faulted load consideration is a safe shutdown earthquake (SSE); however, the seismic analysis of Model F steam generators has shown that axial loading of the tubes is negligible during an SSE.

At normal operating pressures, leakage from primary water stress corrosion cracking (PWSCC) below 17 inches from the top of the tubesheet is limited by both the tube-to-tubesheet crevice and the limited crack opening permitted by the tubesheet constraint. Consequently, negligible normal operating leakage is expected from cracks within the tubesheet region.

For the Unit 1 SGTR event, the required structural margins of the steam generator tubes is maintained by limiting the allowable ligament size for a circumferential crack to remain in service to 214 degrees below 17 inches from the top of the tubesheet. For the Unit 2 SGTR event, the required structural margins of the steam generator tubes is maintained by limiting the allowable ligament size for a circumferential crack to remain in service to 214 degrees below 17 inches from the top of the tubesheet for the 18-month SG tubing eddy current inspection interval and to remain in service 183 degrees below 17 inches from the top of the tubesheet for the 36-month SG tubing eddy current inspection interval. Tube rupture is precluded for cracks in the hydraulic expansion region due to the constraint provided by the tubesheet. The potential for tube pullout is mitigated by limiting the Unit 1 allowable crack size to 214 degrees and limiting the Unit 2 allowable crack size to 214 degrees for the 18-month SG tubing eddy current inspection interval and to 183 degrees for the 36-month SG tubing eddy current inspection interval. These allowable crack sizes take into account eddy current uncertainty and crack growth rate. It has been shown that a Unit 1 circumferential crack with an azimuthal extent of 214 degrees and a Unit 2 circumferential crack with an azimuthal extent of 214 degrees for the 18-month SG tubing eddy current inspection interval and an azimuthal extent of 183 degrees for the 36-month SG tubing eddy current inspection interval meet the performance criteria of NEI 97-06, Rev. 2, "Steam Generator Program Guidelines" and the Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes." Likewise, a best effort visual inspection will be conducted to confirm that a Unit 1 circumferential crack of greater than 294 degrees and that a Unit 2 circumferential crack of greater than 294 degrees for the 18-month SG tubing eddy current inspection interval and a circumferential crack of greater than 263 degrees for the 36-month SG tubing eddy current inspection interval do not remain in service in the tube end weld metal in any tube mitigating the potential for tube pullout. Therefore, the margin against tube burst/pullout is maintained during normal and postulated accident conditions and the proposed change does not result in a significant increase in the probability or consequence of a SGTR.

The probability of a SLB is unaffected by the potential failure of a SG tube as the failure of a tube is not an initiator for a SLB event. SLB leakage is limited by leakage flow restrictions resulting from the leakage path above potential cracks through the tube-to-tubesheet crevice. The leak rate during postulated accident conditions (including locked rotor and control rod ejection) has been shown to remain within the accident analysis assumptions for all axial or

circumferentially oriented cracks occurring 17 inches below the top of the tubesheet. Since normal operating leakage is limited to 150 gpd (approximately 0.10 gpm), the attendant accident condition leak rate, assuming all leakage to be from indications below 17 inches from the top of the tubesheet, would be bounded by 0.35 gpm. This value is within the accident analysis assumptions for the limiting design basis accident for VEGP, which is the postulated SLB event.

Based on the above, the performance criteria of NEI-97-06, Rev. 2 and draft Regulatory Guide (RG) 1.121 continue to be met and 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 accident from any accident previously evaluated?

Response: No

The proposed change does not introduce any changes or mechanisms that create the possibility of a new or different kind of accident. Tube bundle integrity is expected to be maintained for all plant conditions upon implementation of the interim alternate repair criterion. The proposed change does not introduce any new equipment or any change to existing equipment. No new effects on existing equipment are created nor are any new malfunctions introduced.

Therefore, based on the above evaluation, the proposed changes do 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

The proposed change maintains the required structural margins of the steam generator tubes for both normal and accident conditions. NEI 97-06, Rev. 2 and RG 1.121 are used as the basis in the development of the limited tubesheet inspection depth methodology for determining that steam generator tube integrity considerations are maintained within acceptable limits. RG 1.121 describes a method acceptable to the NRC staff for meeting General Design Criteria 14, 15, 31, and 32 by reducing the probability and consequences of an SGTR. RG 1.121 concludes that by determining the limiting safe conditions of tube wall degradation beyond which tubes with unacceptable cracking, as established by inservice inspection, should be removed from service or repaired, the probability and consequences of a SGTR are reduced. This RG uses safety factors on loads for tube burst that are consistent with the requirements of Section III of the ASME Code.

For axially oriented cracking located within the tubesheet, tube burst is precluded due to the presence of the tubesheet. For circumferentially oriented cracking in a tube or the tube-to-tubesheet weld, Reference 3 defines a length of remaining tube ligament that provides the necessary resistance to tube pullout due to the pressure induced forces (with applicable safety factors applied). Additionally, it is shown that application of the limited tubesheet inspection depth criteria will not result in unacceptable primary-to-secondary leakage during all plant conditions.

Based on the above, it is concluded that the proposed changes do not result in any reduction of margin with respect to plant safety as defined in the Updated Safety Analysis Report or bases of the plant Technical Specifications.

Based on the above, SNC concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements

Steam Generator (SG) tube inspection and repair limits are specified in Section 5.5.9, "Steam Generator (SG) Program" of the VEGP Technical Specifications (TS). The current TS require that flawed tubes be repaired if the depths of the flaws are greater than or equal to 40% through wall. The TS repair limits ensure that tubes accepted for continued service will retain adequate structural and leakage integrity during normal operating, transient, and postulated accident conditions, consistent with General Design Criteria (GDC) 14, 15, 30, 31, and 32 of 10 CFR 50, Appendix A. Specifically, the GDC state that the Reactor Coolant Pressure Boundary (RCPB) shall have "an extremely low probability of abnormal leakage . . . and gross rupture" (GDC 14), "shall be designed with sufficient margin" (GDCs 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing...to assess...structural and leaktight integrity" (GDC 32). Structural integrity refers to maintaining adequate margins against gross failure, rupture, and collapse of the steam generator tubing. Leakage integrity refers to limiting primary to secondary leakage during all plant conditions to within acceptable limits.

5.3 Precedent

SNC was previously granted similar TS changes. One was granted on September 12, 2006 (Reference 1) that involved a one-time change to TS 5.5.9, "Steam Generator (SG) Tube Surveillance Program," regarding the required SG inspection scope for Vogtle, Unit 1, during Refueling Outage 13 and the subsequent operating cycle and Vogtle, Unit 2, during Refueling Outage 12, and the subsequent operating cycle. The other change was granted on September 21, 2005 (Reference 10) that involved a one-time change to TS 5.5.9, "Steam Generator (SG) Tube Surveillance Program," regarding the required SG inspection scope for Vogtle, Unit 2, during Refueling Outage 11, and the subsequent operating cycle. These changes modified the inspection requirements for portions of the SG tubes within the hot leg tubesheet region of the SGs.

5.4 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 with the implementation of the interim alternate repair criterion discussed above.

6.0 Environmental Considerations

SNC has evaluated the proposed amendment for environmental considerations. The 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 10 CFR 20, and 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 amendments meet the eligibility criterion for categorical exclusion set for in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 References

1. Vogtle Electric Generating Plant Units 1 and 2, "Issuance of Amendments Regarding the Steam Generator Tube Surveillance Program," September 12, 2006, (TAC Nos. MD2642 and MD2643).

2. Vogtle Electric Generating Plant Units 1 and 2, "License Amendment Request to Technical Specification (TS) Sections TS 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report," November 30, 2007, (ADAMS Accession No. ML073380100).

3. Westinghouse Electric Company LLC, LTR-CDME 08-11-P, "Interim Alternate Repair Criterion (ARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone," January 31, 2008.

4. TSTF-449, Rev. 4, "Steam Generator Tube Integrity," Technical Specifications Task Force Standard Technical Specification Change Traveler, April 14, 2005.

5. NEI 97-06, Rev. 2, "Steam Generator Program Guidelines," May 2005.

6. ETSS 20510.1; Technique for Detection of Circumferential PWSCC at Expansion Transitions.

7. EPRI TR-107197; Depth Based Structural Analysis Methods for Steam Generator Circumferential Indications; November 1997.

8. EPRI 1012987; "Steam Generator Integrity Assessment Guidelines," July 2006.

9. NRC Memorandum, "Wolf Creek Generating Station – Summary of Conference Call Held with PWR Licensees on the New Temporary License Amendment Needed for Steam Generator Tube Inspections in Spring 2008 Refueling Outages," January 22, 2008 (TAC No. MD7762).

10. Vogtle Electric Generating Plant Units 1 and 2, "Issuance of Amendments Regarding the Steam Generator Tube Surveillance Program," September 21, 2005, (TAC Nos. MC8078 and MC8079).

Vogtle Electric Generating Plant Units 1 and 2
License Amendment Request to Revise Technical Specification (TS)
Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10,
"Steam Generator Tube Inspection Report" for Interim Alternate Repair Criterion

Enclosure 2

Markup of Proposed Technical Specifications

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm per SG.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

Insert for TS page 5.5-8

shall

The following alternate tube repair criteria ~~may~~ be applied as an alternative to the 40% depth based criteria:

~~1. For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation found in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.~~

~~For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be plugged upon detection.~~

~~2. For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.~~

~~For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the hot leg tubesheet shall be plugged upon detection.~~

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. ~~For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded.~~ For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

Insert for TS page 5.5-9

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 120, 90, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic nondestructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

(continued)

Insert for TS page 5.5-8:

1. For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

   For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the hot leg tubesheet shall be plugged upon detection.

2. For Unit 1 during Refueling Outage 14 and the subsequent operating cycle, tubes with less than or equal to a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service. Tubes with service-induced crack-like flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

3. For Unit 2 Refueling Outage 13 and the subsequent 18-month eddy current inspection interval, tubes with less than or equal to a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service.

   For Unit 2 Refueling Outage 13 and subsequent 36-month eddy current inspection interval, tubes with less than or equal to a 183 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 183 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service.

   For Unit 2 Refueling Outage 13 and subsequent 18-month and 36-month eddy current inspection intervals, tubes with service-induced crack-like flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet

shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

Insert for TS page 5.5-9:

For Unit 2 during Refueling Outage 13 and the 36-month eddy current inspection interval, SGs in which the portion of the tube below 17 inches from the top of the tubesheet has no greater than 183 degree circumferential service-induced crack-like flaws are excluded from the requirements of Paragraph 3 below.

5.6 Reporting Requirements

5.6.9 Deleted.

5.6.10 Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing;

Insert for TS page 5.6-6

Insert for TS page 5.6-6:

h. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the number of indications and location, size, orientation, and whether initiated on primary or secondary side for each service-induced crack-like flaw within the thickness of the tubesheet,

i. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign leakage to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,

j. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the calculated accident leakage rate from the portion of the tube 17 inches below the top of the tubesheet for the most limiting accident in the most limiting SG.

Vogtle Electric Generating Plant Units 1 and 2
License Amendment Request to Revise Technical Specification (TS)
Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10,
"Steam Generator Tube Inspection Report" for Interim Alternate Repair Criterion

Enclosure 3

Typed Pages for Technical Specifications

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm per SG.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube repair criteria shall be applied as an alternative to the 40% depth based criteria:

1. For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

   For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the hot leg tubesheet shall be plugged upon detection.

2. For Unit 1 during Refueling Outage 14 and the subsequent operating cycle, tubes with less than or equal to a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service. Tubes with service-induced crack-like flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

3. For Unit 2 Refueling Outage 13 and the subsequent 18-month eddy current inspection interval, tubes with less than or equal to a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service.

   For Unit 2 Refueling Outage 13 and subsequent 36-month eddy current inspection interval, tubes with less than or equal to a 183 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 183 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service.

   For Unit 2 Refueling Outage 13 and subsequent 18-month and 36-month eddy current inspection intervals, tubes with service-induced crack-like flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded. For Unit 2 during Refueling Outage 13 and the 36-month eddy current inspection interval, SGs in which the portion of the tube below 17 inches from the top of the tubesheet has no greater than 183 degree circumferential service-induced crack-like flaws are excluded from the requirements of Paragraph 3 below. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 120, 90, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic nondestructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

(continued)

5.5 Programs and Manuals

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1980:

a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass ≤ 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1980 at the system flow rate specified below ± 10%.

ESF Ventilation System	Flow Rate
Control Room Emergency Filtration System (CREFS)	19,000 CFM
Piping Penetration Area Filtration and Exhaust (PPAFES)	15,500 CFM

(continued)

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass ≤ 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1980 at the system flow rate specified below ± 10%.

ESF Ventilation System	Flow Rate
CREFS	19,000 CFM
PPAFES	15,500 CFM

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, shows the methyl iodide penetration less than or equal to the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and greater than or equal to the relative humidity specified below.

ESF Ventilation System	Penetration	RH
CREFS	.2%	70%
PPAFES	10%	95%

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters, the charcoal adsorbers, and CREFS cooling coils is less than the value specified below when tested in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1989 at the system flow rate specified below ± 10%.

ESF Ventilation System	Delta P	Flow Rate
CREFS	7.1 in. water gauge	19,000 CFM
PPAFES	6 in. water gauge	15,500 CFM

e. Demonstrate that the heaters for the CREFS dissipate ≥ 95 kW when corrected to 460 V when tested in accordance with ASME N510-1989.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

(continued)

5.5 Programs and Manuals (continued)

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Gaseous Waste Processing System, the quantity of radioactivity contained in each Gas Decay Tank, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The gaseous radioactivity quantities shall be determined following the methodology in Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure." The liquid radwaste quantities shall be limited to 10 curies per outdoor tank in accordance with Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures."

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Gaseous Waste Processing System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

b. A surveillance program to ensure that the quantity of radioactivity contained in each gas decay tank is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents; and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is limited to ≤ 10 curies per tank, excluding tritium and dissolved or entrained noble gases. This surveillance program provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting concentrations would be less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.13 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable

(continued)

5.5 Programs and Manuals

5.5.13 Diesel Fuel Oil Testing Program (continued)

ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

1. an API gravity or an absolute specific gravity within limits, or an API gravity or specific gravity within limits when compared to the supplier's certificate;

2. a flash point within limits for ASTM 2D fuel oil, and, if gravity was not determined by comparison with supplier's certification, a kinematic viscosity within limits for ASTM 2D fuel oil; and

3. a clear and bright appearance with proper color.

b. Other properties for ASTM 2D fuel oil are within limits within 30 days following sampling and addition to storage tanks; and

c. Total particulate concentration of the fuel oil is $\leq$ 10 mg/l when tested every 31 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program surveillance frequencies.

5.5.14 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. a change in the TS incorporated in the license; or

2. a change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

(continued)

5.5 Programs and Manuals

5.5.14 Technical Specifications (TS) Bases Control Program (continued)

d. Proposed changes that meet the criteria of (b) above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.15 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

(continued)

5.5 Programs and Manuals

5.5.15 Safety Function Determination Program (SFDP) (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.16 MS and FW Piping Inspection Program

This program shall provide for the inspection of the four Main Steam and Feedwater lines from the containment penetration flued head outboard welds, up to the first five-way restraint. The extent of the inservice examinations completed during each inspection interval (ASME Code Section XI) shall provide 100% volumetric examination of circumferential and longitudinal welds to the extent practical. This augmented inservice inspection is consistent with the requirements of NRC Branch Technical Position MEB 3-1, "Postulated Break and Leakage Locations in Fluid System Piping Outside Containment," November 1975 and Section 6.6 of the FSAR.

5.5.17 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Testing Program," dated September 1995, as modified by the following exceptions:

1. Leakage rate testing for containment purge valves with resilient seals is performed once per 18 months in accordance with LCO 3.6.3, SR 3.6.3.6 and SR 3.0.2.

2. Containment personnel air lock door seals will be tested prior to reestablishing containment integrity when the air lock has been used for containment entry. When containment integrity is required and the air lock has been used for containment entry, door seals will be tested at least once per 30 days during the period that containment entry(ies) is (are) being made.

3. The visual examination of containment concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified

(continued)

5.5 Programs and Manuals

5.5.17 Containment Leakage Rate Testing Program (continued)

by ASME Section XI Code, Subsection IWL, except where relief or alternative has been authorized by the NRC. At the discretion of the licensee, the containment concrete visual examinations may be performed during either power operation, e.g., performed concurrently with other containment inspection-related activities such as tendon testing, or during a maintenance/refueling outage.

4. A one time exception to NEI 94-01, Rev. 0, "Industry Guidelines for Implementing Performance-Based Option of 10 CFR 50, Appendix J":

Section 9.2.3:	The next Type A test, after the March 2002 test for Unit 1 and the March 1995 test for Unit 2, shall be performed within 15 years.

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 37 psig.

The maximum allowable containment leakage rate, L_a, at P_a, is 0.2% of primary containment air weight per day.

Leakage rate acceptance criteria are:

a. Containment overall leakage rate acceptance criteria are $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the combined Type B and Type C tests, and $\leq 0.75\ L_a$ for Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$,

2) For each door, the leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

(continued)

5.5 Programs and Manuals (continued)

5.5.18 Configuration Risk Management Program

The Configuration Risk Management Program (CRMP) provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for which a risk-informed allowed outage time has been granted. The program shall include the following elements:

a. Provisions for the control and implementation of a Level 1 at power internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Condition for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Condition for unplanned entry into the LCO Condition.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Condition.

e. Provisions for considering other applicable risk significant contributors such as Level 2 issues and external events, qualitatively or quantitatively.

5.5.19 Battery Monitoring and Maintenance Program

This program provides for restoration and maintenance, based on the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications," of the following:

a. Actions to restore battery cells with float voltage < 2.13 V, and

b Actions to equalize and test battery cells that had been discovered with electrolyte level below the top of the plates.

5.6 Reporting Requirements

5.6.9 Deleted.

5.6.10 Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing,

h. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the number of indications and location, size, orientation, and whether initiated on primary or secondary side for each service-induced crack-like flaw within the thickness of the tubesheet,

i. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign leakage to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,

(continued)

5.6 Reporting Requirements

5.6.10 Steam Generator Tube Inspection Report (continued)

j. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the calculated accident leakage rate from the portion of the tube 17 inches below the top of the tubesheet for the most limiting accident in the most limiting SG.

Vogtle Electric Generating Plant Units 1 and 2
License Amendment Request to Revise Technical Specification (TS)
Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10,
"Steam Generator Tube Inspection Report" for Interim Alternate Repair Criterion

Enclosure 4

Westinghouse Letter, CAW-08-2383, Application for Withholding and Affidavit, Proprietary Information Notice, and Copyright Notice

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Our ref: CAW-08-2383

February 6, 2008

APPLICATION FOR WITHHOLDING PROPRIETARY INFORMATION FROM PUBLIC DISCLOSURE

Subject: LTR-CDME-08-11 P-Attachment, "Interim Alternate Repair Criterion (ARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone," dated January 31, 2008 (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-08-2383 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by Southern Nuclear Operating Company.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-08-2383, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J.A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: Jon Thompson (NRC O-7E1A)

bcc: J. A. Gresham (ECE 4-7A) 1L
R. Bastien, 1L (Nivelles, Belgium)
C. Brinkman, 1L (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L (letter and affidavit only)
G. W. Whiteman, Waltz Mill
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E.C. Arnold, EC 557A

CAW-08-2383

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Sworn to and subscribed before me
this 6th day of February, 2008

Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Sharon L. Markle, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Jan. 29, 2011
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse "Application for Withholding" accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitute Westinghouse policy and provide the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in LTR-CDME-08-11 P-Attachment, "Interim Alternate Repair Criterion (ARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone," dated January 31, 2008 (Proprietary), for submittal to the Commission, being transmitted by Southern Nuclear Operating Company Application for Withholding Proprietary Information from Public Disclosure to the Document Control Desk. The proprietary information as submitted for use by Westinghouse for Vogtle Units 1 and 2 is expected to be applicable to other licensee submittals in support of implementing an interim alternate repair criterion (IARC) that requires a full-length inspection of the tubes within the tubesheet but does not require plugging tubes with a certain arc length of circumferential cracking below 17 inches from the top of the tubesheet.

This information is part of that which will enable Westinghouse to:

(a) Provide documentation of the analyses, methods, and testing for the implementation of an interim alternate repair criterion for the portion if the tubes within the tubesheet of the Vogtle Units 1 and 2 steam generators.

(b) Assist the customer in obtaining NRC approval of the Technical Specification changes associated with the interim alternate repair criterion.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for the purposes of meeting NRC requirements for licensing documentation.

(b) Westinghouse can sell support and defense of the technology to its customers in the licensing process.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar calculation, evaluation and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

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