July 11, 2006

NRC 2006-0061
10 CFR 50.90

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

Point Beach Nuclear Plant, Unit 1
Docket 50-266
License No. DPR-24

License Amendment Request 248;
Technical Specification 5.5.8, Steam Generator Program

Pursuant to 10 CFR 50.90, Nuclear Management Company, LLC (NMC), hereby submits a proposed amendment to the Technical Specifications (TS) for Point Beach Nuclear Plant (PBNP), Unit 1. The proposed amendment would revise TS 5.5.8, "Steam Generator (SG) Program". The revision would exclude the portion of the tube below 17 inches from the top of the tubesheet from the SG tube inspection requirements for Unit 1 on a one-time basis for a single operating cycle.

This proposed license amendment request, in effect, redefines the PBNP Unit 1 primary pressure boundary from the tube end weld to 17 inches below the top of the tubesheet. This change is supported by Westinghouse Electric Company, LLC, LTR-CDME-05-201-P, "Limited Inspection of the Steam Generator Tube Portion Within the Tubesheet at Point Beach Unit 1", Revision 1, dated May 2006. The NRC has previously granted similar amendments, on a one-time basis, for Braidwood Station, Unit 2, and Byron Station, Unit 2, in letters dated April 25, 2005, and September 19, 2005, respectively.

Enclosure 1 provides a description and analysis of the proposed change. Enclosure 2 provides the TS pages marked up to show the proposed change. Enclosure 3 provides revised (clean) TS pages. By letter dated February 16, 2006, NMC submitted a proposed amendment to incorporate Technical Specification Task Force (TSTF) Standard Technical Specification Traveler, TSTF 449, "Steam Generator Tube Integrity." NRC approval of this amendment request is anticipated shortly; therefore, TS page 5.5.8-7 from the proposed amendment forms the basis for the markups in Enclosures 2 and 3.

Enclosure 4 submits Westinghouse document, LTR-CDME-05-201-NP, "Limited Inspection of the Steam Generator Tube Portion Within the Tubesheet at Point Beach Unit 1", Revision 1, dated May 2006 (Non-Proprietary). Enclosure 5 submits Westinghouse document, LTR-CDME-05-201-P, "Limited Inspection of the Steam

Generator Tube Portion Within the Tubesheet at Point Beach Unit 1", Revision 1, dated May 2006 (Proprietary). Also provided in Enclosure 5 are a Westinghouse authorization letter, accompanying affidavit, Proprietary Information Notice and Copyright Notice for the analysis provided in Enclosure 5.

Since the document pages listed above as Proprietary contain information proprietary to Westinghouse Electric Company, they are 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 Commission and addresses with specificity, for each, the considerations listed in paragraph (b)(4) of Section 2.390 of the Commission's regulations.

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 above documents, or the supporting Westinghouse affidavit, should reference the appropriate authorization letter (CAW-06-2139) and be addressed to B. F. Maurer, Acting Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

To support the Unit 1 spring 2007 refueling outage, NMC requests approval of the proposed license amendment by March 2007, with the amendment being implemented within 45 days.

This letter contains no new commitments or revisions to existing commitments.

In accordance with 10 CFR 50.91, a copy of this application, with attachments, is being provided to the designated Wisconsin Official.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on July 11, 2006.

Dennis L. Koehl
Site Vice-President, Point Beach Nuclear Plant
Nuclear Management Company, LLC

Enclosures

cc: Regional Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

ENCLOSURE 1

DESCRIPTION AND ANALYSIS OF CHANGE

LICENSE AMENDMENT REQUEST 248
TECHNICAL SPECIFICATION 5.5.8
STEAM GENERATOR PROGRAM

POINT BEACH NUCLEAR PLANT, UNIT 1

1.0 INTRODUCTION

This License Amendment Request (LAR) is made pursuant to 10 CFR 50.90 to revise Technical Specification (TS) 5.5.8, "Steam Generator (SG) Program". The revision would exclude the portion of the tube below 17 inches from the top of the tubesheet from the SG tube inspection requirements for Unit 1 on a one-time basis for Unit 1 Refueling Outage 30 and the subsequent operating cycle. This proposed license amendment request, in effect, redefines the PBNP Unit 1 primary pressure boundary from the tube end weld to 17 inches below the top of the tubesheet at the inlet and outlet of the tube.

2.0 DESCRIPTION OF PROPOSED CHANGE

The proposed amendment would revise TS 5.5.8.

The revision would exclude the portion of the tube below 17 inches from the top of the tubesheet from the SG tube inspection requirements on a one-time basis for Unit 1 Refueling Outage 30 and the subsequent operating cycle.

TS 5.5.8 is proposed for modification as follows (additions are double-underlined).

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. 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.

For Unit 1 Refueling Outage 30, a sample of the SG A and/or B inservice tubes from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be inspected by rotating probe (SG tubing below 17 inches is excluded from inspection). This inspection shall include a 20% minimum sample of the total population of bulges and overexpansions within the SG from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet with the exception of the tube at row 38 column 69 in the A steam generator, which is not expanded the full length of the tubesheet.

Additionally, administrative editorial changes are made to correct a page number in the TS table of contents and delete two blank pages in TS Section 5.

3.0 BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system.

Specification 5.5.8, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.8, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The Point Beach Unit 1 SGs are Westinghouse Model 44F with nominal 7/8 inch diameter thermally treated Inconel alloy 600 tubes. Model 44F SGs were fabricated in the 1979 through 1988 timeframe using similar manufacturing processes with a few exceptions.

PBNP Technical Specifications require inspecting the entire length of the SG tubes within the nominal 22 inch thick tubesheet. Due to the limited sensitivity of bobbin coil inspections in the tubesheet region, rotating pancake coil inspections are performed. These inspections are considerably slower, which results in additional time and dose to perform them in this region of the SG. The inspection requirement of tube-end to tube-end is unnecessary based on the results of document LTR-CDME-05-201-P, "Limited Inspection of the Steam Generator Tube Portion Within the Tubesheet at Point Beach Unit 1", Revision 1, dated May 2006. Tube indications found deep in the tubesheet, that is, indications more than 17 inches below the top of tubesheet, do not have safety significance.

However, existing requirements necessitate that all tubes with crack-like indications be plugged. Unnecessary tube plugging could result in the site incurring additional dose, costs and loss of SG thermal performance with no commensurate improvement in safety or reliability.

Prior to 2005, NMC had not inspected the deep portions of the PBNP SG tubesheets (> 3 inches below the top of the tubesheet) using techniques capable of detecting circumferential cracking within the tubesheet in areas significantly below the top of tubesheet expansion transition region. Following issuance of NRC Information Notice (IN) 2005-09, "Indications In Thermally Treated Alloy 600 Steam Generator Tubes And Tube-To-Tubesheet Welds," NMC inspected 20% of the hot leg tubing the full length of the tubesheet in the Unit 1 A steam generator during the fall 2005 inspection, which has been the site's only steam generator inspection since the issuance of the Information Notice. No crack-like indications were found, as referenced in our letter, "Fall 2005 Unit 1 (U1R29) Steam Generator Tube Inspection Report," Docket Number 50-266, dated February 21, 2006.

As discussed in Technical Specification 5.5.8, each SG tube is welded to the tubesheet. The heat effect zone of this seal weld can alter tube material properties. Indications have been found in similar welds at other utilities. This weld was originally considered the primary boundary in the replacement steam generator design. The PBNP replacement steam generators are fabricated with the tubes expanded into the tubesheet along the entire length of the tubesheet with the exception of the tube at row 38 column 69 in the A steam generator. This tube is not expanded the full length of the tubesheet as discussed in Fall 2005 Unit 1 (U1R29) Steam Generator Tube Inspection Report," Docket Number 50-266, dated February 21, 2006 and previous submittals. Although the new steam generators still have the seal welds, the enclosed analysis demonstrates that the tube-to-tubesheet mechanical interface will adequately serve as the primary boundary.

This issue is only applicable to the Unit 1 steam generators with thermally treated alloy 600 tubing as stated in NRC Information Notice 2005-09. The Unit 2 steam generators have thermally treated Inconel alloy 690 tubing and are not affected by this condition.

4.0 TECHNICAL ANALYSIS

The technical justification to limit the examination of Point Beach Unit 1 SG tubes to a depth of only 17 inches below the top of the tubesheet on a one time basis for Unit 1 Refueling Outage 30 and the subsequent operating cycle is provided in the enclosed Westinghouse technical evaluation. This justification is based on the use of a bounding leak rate evaluation and the application of a structural analysis of the tube-to-tubesheet joint for the Point Beach Unit 1 Model 44F

steam generators. The justification includes a redefinition of the steam generator tube primary-to-secondary pressure boundary.

During Unit 1 Refueling Outage 30, a 20% minimum sample of the total population of bulges and overexpansions within the steam generators from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet will be inspected with a rotating pancake probe.

Where:

Bulge refers to a tube diameter deviation within the tubesheet of 18 volts or greater as measured by bobbin probe; and,

Overexpansion refers to a tube diameter deviation within the tubesheet of 1.5 mils or greater as measured by bobbin probe.

The conclusion of the technical justification is that the structural and leak rate integrity of the steam generator tube primary-to-secondary pressure boundary is unaffected by degradation at any level below a depth of 17 inches from the top of the tubesheet or the tube end welds. The tube-to-tubesheet hydraulically expanded joints make it extremely unlikely that any operating or faulted condition loads are applied to the tube tack expanded region or the tube welds.

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding a SGTR is the basis for the SG tube integrity Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to or greater than the operational LEAKAGE rate limits in LCO 3.4.13, “RCS Operational LEAKAGE,” plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is released to the atmosphere via safety valves.

The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture.) In these analyses, the steam discharge to the atmosphere is based on primary to secondary LEAKAGE from each SG of 500 gallons per day or is assumed to increase to 500 gallons per day as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, “RCS Specific Activity,” limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19, 10 CFR 100 or the NRC approved licensing basis (e.g., a small fraction of these limits).

Results and Conclusion

Based on the above justification, implementation of the proposed Technical Specification change is consistent with the analysis and demonstrates that the operational readiness of the steam generators, the ability to detect component degradation that might affect component OPERABILITY, and safety margins, will be maintained.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Determination

In accordance with the requirements of 10 CFR 50.90, Nuclear Management Company (licensee) hereby requests amendments to facility operating license DPR-24, for Point Beach Nuclear Plant, Unit 1. The purpose of the proposed amendments is to revise Technical Specification (TS) 5.5.8, "Steam Generator (SG) Program". The revision would exclude the portion of the tube below 17 inches from the top of the tubesheet from the SG tube inspection requirements on a one-time basis for Unit 1 Refueling Outage 30 and the subsequent operating cycle. This proposed license amendment request, in effect, redefines the PBNP Unit 1 primary pressure boundary from the tube end weld to 17 inches below the top of the tubesheet for one operating cycle. Additionally, administrative editorial changes are made to correct a page number in the TS table of contents and delete two blank pages in TS Section 5.

Nuclear Management Company (NMC) has evaluated the proposed amendment in accordance with 10 CFR 50.91 against the standards in 10 CFR 50.92 and has determined that the operation of the Point Beach Nuclear Plant in accordance with the proposed amendment presents no significant hazards. The NMC evaluation against each of the criteria in 10 CFR 50.92 follows.

1. **Operation of the Point Beach Nuclear Plant in accordance with the proposed amendments does not result in a significant increase in the probability or consequences of any accident previously evaluated.**

   The proposed change revises Technical Specification (TS) 5.5.8, "Steam Generator (SG) Program" to redefine the PBNP Unit 1 primary pressure boundary for purposes of the SG tube inspection requirements on a one-time basis for Unit 1 Refueling Outage 30 and the subsequent operating cycle. The redefined primary pressure boundary is relocated from the seal weld at the bottom of the SG tube to the tube-to-tubesheet mechanical interface.

   The required structural integrity margins of the SG tubes in this area are unaffected by this change and will be maintained by the SG tubesheet. SG tubes are hydraulically expanded into the tubesheet. Steam generator tube rupture is constrained by the tubesheet for tubes with cracks in the tubesheet.

This constraint results from the hydraulic expansion process which restricts further expansion of the tube, thermal expansion mismatch between the tube and tubesheet and from the differential pressure between the primary and secondary side. Thermal expansion and differential pressure also restrain the tube axially. For conservatism, hydraulic preload was not factored into the analysis.

The proposed change continues to require that the SG Program include performance criteria that will provide reasonable assurance that the SG tubing will retain integrity over the full range of operating conditions (including startup, operation in the power range, hot standby, cooldown and all anticipated transients included in the design specification).

The SG performance criteria are based on tube structural integrity, accident induced leakage, and operational LEAKAGE. The analysis shows that structural integrity retains acceptable safety factors against burst under normal steady state full power operation primary-to-secondary pressure differential and against burst applied to the design basis accident primary-to-secondary pressure differentials. The analysis also shows that accident induced leakage is bound by twice the normal operating leakage and well below the accident analysis assumption for each stream generator. The primary to secondary operational LEAKAGE limit is not changed.

The planned inspection and supporting analysis provide reasonable assurance that the SG tubing will remain capable of fulfilling its specific safety function of maintaining reactor coolant pressure boundary integrity throughout the operating cycle and in the unlikely event of a design basis accident. The proposed change does not, therefore, significantly increase the probability of an accident previously evaluated.

The consequences of design basis accidents are, in part, functions of the DOSE EQUIVALENT I-131 in the primary coolant and the primary to secondary LEAKAGE rates resulting from an accident. The plant technical specification limits for operational LEAKAGE and for DOSE EQUIVALENT I-131 in primary coolant, which ensure the plant is operated within its analyzed condition, are unaffected by the proposed change. Therefore, the proposed change does not significantly increase the consequences of any accident previously evaluated.

The proposed change does not significantly affect the probability of any event initiators. There will be no change to normal plant operating parameters, engineered safety feature actuation setpoints, accident mitigation capabilities, or accident analysis assumptions or inputs.

Therefore, the probability or consequences of any accident previously evaluated will not be significantly increased as a result of the proposed change.

2. **Operation of the Point Beach Nuclear Plant in accordance with the proposed amendments does not result in a new or different kind of accident from any accident previously evaluated.**

   Implementation of the proposed change will not introduce any adverse changes to the plant design basis or postulated accidents resulting from potential tube degradation. Primary to secondary leakage that may be experienced during all plant conditions will continue to be monitored to ensure it remains within current accident analysis assumptions. The proposed change does not affect the method of operation of the SGs, or primary or secondary coolant chemistry controls. In addition, the proposed change does not impact any other plant system or component.

   No new accident scenarios, transient precursors, failure mechanisms, or limiting single failures are introduced as a result of the proposed change. Equipment important to safety will continue to operate as designed. The changes do not result in any event previously deemed incredible being made credible. The changes do not result in adverse conditions or result in any increase in the challenges to safety systems. Therefore, the proposed change does not create the possibility of a new or different type of accident from any accident previously evaluated.

3. **Operation of the Point Beach Nuclear Plant in accordance with the proposed amendments does not result in a significant reduction in a margin of safety.**

   The steam generators (SGs) are an integral part of the reactor coolant pressure boundary and, as such, are relied upon to maintain the primary system's pressure and inventory. They are also relied upon to remove residual heat from the primary system. The safety function of an SG is maintained by ensuring the integrity of its tubes. Steam generator tube integrity is a function of the design, environment, and the physical condition of the tube. The proposed change redefines the PBNP Unit 1 primary pressure boundary from the tube end weld to 17 inches below the top of the tubesheet and incorporates revisions to the inspection criteria for SG tube inspection in the tubesheet. The SG operating environment is not affected by the change. The proposed change maintains the required structural margins of the SG tubes for both normal and accident conditions.

   For cracking located within the tubesheet, steam generator tube rupture is constrained by the tubesheet. For circumferentially oriented cracking, the associated analysis for the proposed change validates that 17 inches of

degradation free expanded tubing provides the necessary resistance to tube pullout with applicable safety factors applied.

The revised inspection criteria continue to verify SG tube integrity. The safety function of the affected components will be maintained with the redefined primary pressure boundary.

There are no new or significant changes to the initial conditions contributing to accident severity or consequences. The proposed amendment will not otherwise affect the plant protective boundaries, will not cause a release of fission products to the public, nor will it degrade the performance of any other structures, systems or components (SSCs) important to safety. Therefore, the requested change will not result in a significant reduction in the margin of safety.

Conclusion

Operation of the Point Beach Nuclear Plant in accordance with the proposed amendment will not result in a significant increase in the probability or consequences of any accident previously analyzed; will not result in a new or different kind of accident from any accident previously analyzed; and, does not result in a significant reduction in any margin of safety. Therefore, operation of the Point Beach Nuclear Plant in accordance with the proposed amendment does not result in a significant hazards determination.

5.2 Applicable Regulatory Requirements

Point Beach was licensed prior to the 1971 publication of Appendix A, “General Design Criteria for Nuclear Power Plants”, (GDC) to 10 CFR Part 50. As such, Point Beach is not licensed to the Appendix A GDC. The Point Beach Final Safety Analysis Report (FSAR), Section 1.3, lists the plant-specific GDC to which the plant was licensed. The Point Beach GDC are similar in content to the draft GDC proposed for public comment in 1967. The Point Beach GDC addressing the reactor coolant pressure boundary are Point Beach GDC- 9, “Reactor Coolant Pressure Boundary”; GDC-33, “Reactor Coolant Pressure Boundary Capability”; GDC-34, “Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention”; and GDC-36, “Reactor Coolant Pressure Boundary Surveillance”. The applicable criteria for this system are discussed in FSAR Section 4.1, “Reactor Coolant System – Design Basis”.

Point Beach GDC-9, 33, 34 and 36 require, in part, that the reactor coolant pressure boundary be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime; be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component; be designed and operated to reduce to an acceptable level the probability of rapidly propagating

type failures; and have provisions for inspection, testing, and surveillance of critical areas by appropriate means to assess the structural and leak tight integrity of the boundary components during their service lifetime.

10 CFR 50.36(c)(5) states that, “Administrative controls are the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner.” The technical analysis performed by NMC concludes that the proposed changes to TS 5.5.8.d will continue to provide the appropriate procedural and program controls for inservice testing and steam generator tube surveillance.

10 CFR 50.55a specifies that components which are part of the reactor coolant pressure boundary must meet the requirements for Class 1 components in Section III of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Code). Section 50.55a further requires, in part, that throughout the service life of a pressurized water reactor facility, ASME Code Class 1 components meet the requirements, except design and access provisions and pre-service examination requirements, in Section XI, ‘‘Rules for Inservice Inspection [ISI] of Nuclear Power Plant Components,’’ of the ASME Code, to the extent practical. This requirement includes the inspection and repair criteria of Section XI of the ASME Code.

The tube repair limits in the TSs were developed with the intent of ensuring that degraded tubes (1) maintain factors of safety against gross rupture consistent with the plant design basis (*i.e.*, consistent with the stress limits of the ASME Code, Section III) and (2) maintain leakage integrity consistent with the plant licensing basis while, at the same time, allowing for potential flaw size measurement error and flaw growth between SG inspections.

NMC concludes that the proposed changes are in accordance with 10 CFR 50.36(c)(5) with regards to maintaining the necessary procedural and program controls to assure operation of the facility in a safe manner. These changes also continue to meet the applicable requirements of 10 CFR 50.55a. The proposed changes thus continue to be compliant with the above regulatory requirements.

The technical analysis in Section 4.0 above concludes that the proposed changes to TS 5.5.8 will continue to assure that the design requirements of the reactor coolant pressure boundary are met. The proposed changes will not adversely affect the other requirements of these criteria.

5.3 Commitments

There are no actions committed to by NMC in this document. The statements in this submittal are provided for information purposes and are not considered to be commitments.

6.0 ENVIRONMENTAL EVALUATION

NMC has determined that the information for the proposed amendment does not involve a significant hazards consideration, authorize a significant change in the types or total amounts of effluent release, or result in any significant increase in individual or cumulative occupational radiation exposure. Therefore, NMC concludes that the proposed amendment meets the categorical exclusion requirements of 10 CFR 51.22(c)(9) and that an environmental impact appraisal need not be prepared.

7.0 PRECEDENT

The NRC has previously granted similar amendments, on a one-time basis, for Braidwood Station, Unit 2, and Byron Station, Unit 2, in letters dated April 25, 2005, and September 19, 2005, respectively.

ENCLOSURE 2

PROPOSED (MARKED-UP) TECHNICAL SPECIFICATION CHANGES

LICENSE AMENDMENT REQUEST 248
TECHNICAL SPECIFICATION 5.5.8
STEAM GENERATOR PROGRAM

POINT BEACH NUCLEAR PLANT, UNIT 1

(6 pages follow)

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5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

1. Structural integrity performance criterion: 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.

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

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

for all SGs and leakage rate for an individual SG.
Leakage is not to exceed 500 gallons per day 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.

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. 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.

For Unit 1 Refueling Outage 30, a sample of the SG A and/or B inservice tubes from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be inspected by rotating probe (SG tubing below 17 inches is excluded from inspection). This inspection shall include a 20% minimum sample of the total population of bulges and overexpansions within the SG from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet with the exception of the tube at row 38 column 69 in the A steam generator, which is not expanded the full length of the tubesheet.

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

2. i. Unit 1 (alloy 600 Thermally Treated tubes): 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

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

than 48 effective full power months or two refueling outages (whichever is less) without being inspected.

ii. Unit 2 (alloy 690 Thermally Treated tubes): Inspect 100% of the tubes at sequential periods of 144, 108, 72, 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 72 effective full power months or three 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 non-destructive 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.

5.5 Programs and Manuals

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5.5 Programs and Manuals

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ENCLOSURE 3

REVISED (CLEAN) TECHNICAL SPECIFICATION PAGES

LICENSE AMENDMENT REQUEST 248
TECHNICAL SPECIFICATION 5.5.8
STEAM GENERATOR PROGRAM

POINT BEACH NUCLEAR PLANT, UNIT 1

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5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

1. Structural integrity performance criterion: 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.

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

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

for all SGs and leakage rate for an individual SG.
Leakage is not to exceed 500 gallons per day 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.

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. 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.

For Unit 1 Refueling Outage 30, a sample of the SG A and/or B inservice tubes from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be inspected by rotating probe (SG tubing below 17 inches is excluded from inspection). This inspection shall include a 20% minimum sample of the total population of bulges and overexpansions within the SG from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet with the exception of the tube at row 38 column 69 in the A steam generator, which is not expanded the full length of the tubesheet.

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

2. i. Unit 1 (alloy 600 Thermally Treated tubes): 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

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

than 48 effective full power months or two refueling outages (whichever is less) without being inspected.

ii. Unit 2 (alloy 690 Thermally Treated tubes): Inspect 100% of the tubes at sequential periods of 144, 108, 72, 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 72 effective full power months or three 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 non-destructive 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.

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5.5.9 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, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

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.

5.5.10 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of the Control Room Emergency Filtration System (F-16) at the frequencies specified in Regulatory Guide 1.52, Revision 2, and in accordance with ASTM D3803-1989 and the methodology of ANSI N510-1980, as prescribed below.

a. Demonstrate for the Control Room Emergency Filtration System (F-16) that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass ≤ 1.0% when tested in accordance with the methodology of ANSI N510-1980, Section 10, excluding subsection 10.3, at a system flowrate of 4950 cfm ± 10%.

b. Demonstrate for the Control Room Emergency Filtration System (F-16) that an inplace test of the charcoal adsorber shows a penetration and system bypass ≤ 1.0% when tested in accordance with the methodology of ANSI N510-1980, Section 12, excluding subsection 12.3, at a system flowrate of 4950 cfm ± 10%.

5.5 Programs and Manuals

5.5.10 Ventilation Filter Testing Program (VFTP) (continued)

c. Demonstrate for the Control Room Emergency Filtration System (F-16) that a laboratory test of a sample of the charcoal adsorber, when obtained in accordance with the methodology of ANSI N510-1980, Section 13, excluding subsection 12.3, shows the methyl iodide penetration ≤ 1.0%, when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity of 95%, applying the tolerances of ASTM D3803-1989.

d. Demonstrate for the Control Room Emergency Filtration System (F-16) that the pressure drop across the combined HEPA filters and the charcoal adsorbers is less than 6 inches of water when tested in accordance with the methodology of ANSI N510-1980, Sections 10 and 12, excluding subsections 10.3 and 12.3, at a system flowrate of 4950 cfm ± 10%.

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

5.5.11 Explosive Gas Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the on-service Gas Decay Tank.

The program shall include a limit for oxygen concentration in the on-service Gas Decay Tank and a surveillance program to ensure the limit is maintained. This limit shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion).

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

5.5 Programs and Manuals

5.5.12 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 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,

   2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

   3. a clear and bright appearance with proper color;

b. Within 31 days of addition of the new fuel oil to storage tanks verify that the properties of the new fuel oil, other than those addressed in a. above, are within limits for ASTM 2D fuel oil; and

c. Total particulate concentration of the fuel oil is $\leq$ 10 mg/l when tested every 92 days in accordance with the applicable ASTM standard.

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

5.5.13 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 involve 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.

5.5 Programs and Manuals

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

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

d. Proposed changes that meet the criteria of Specification 5.5.13b 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).

5.5.14 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.

5.5 Programs and Manuals

5.5.14 Safety Function Determination Program (SFDP) (continued)

A loss of safety function exists when, assuming no concurrent single failure, and assuming no concurrent loss of offsite power or loss of onsite diesel generator(s), 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.

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.

When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.15 Containment Leakage Rate Testing Program

a. 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-Test Program,” dated September, 1995.

b. The peak design containment internal accident pressure, P_a, is 60 psig.

c. The maximum allowable containment leakage rate, L_a at P_a, shall be 0.4% of containment air weight per day.

5.5 Programs and Manuals

5.5.15 Containment Leakage Rate Testing Program (continued)

d. Leakage rate acceptance criteria are:

1. Containment leakage rate acceptance criterion is $\leq$ 1.0 L_a.

2. During the first unit startup following testing in accordance with this program, the leakage rate acceptance are $\leq$ 0.6 L_a for the combined Type B and Type C tests and $\leq$ 0.75 L_a for the Type A tests.

3. Air lock testing acceptance criteria are:

i. Overall air lock leakage rate is $\leq$ 0.05 L_a when tested at $\geq P_a$.

ii. For each door seal, leakage rate is equivalent to $\leq$ 0.02 L_a at $\geq P_a$ when tested at a differential pressure of $\geq$ to 10 inches of Hg.

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

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

5.5 Programs and Manuals

5.5.16 Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) Leakage Program

A program shall be established to verify the leakage from each RCS PIV is within the limits specified below, in accordance with the Event V Order, issued April 20, 1981.

a. Minimum differential test pressure shall not be less than 150 psid.

b. Leakage rate acceptance criteria are:

1. Leakage rates less than or equal to 1.0 gpm are considered acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are considered unacceptable.

5.5.17 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containments, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. The program shall include baseline measurements prior to initial operations. The Tendon Surveillance Program, inspection frequencies, and acceptance criteria shall be in accordance with Regulatory Guide 1.35, Revision 3, 1990.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Tendon Surveillance Program inspection frequencies.

ENCLOSURE 4

WESTINGHOUSE DOCUMENT,
LTR-CDME-05-201-NP, "LIMITED INSPECTION OF THE STEAM GENERATOR TUBE PORTION WITHIN THE TUBESHEET AT POINT BEACH UNIT 1",
REVISION 1,
DATED MAY 2006
(NON-PROPRIETARY)

(52 pages follow)

LTR-CDME-05-201-NP, Revision 1

Limited Inspection of the Steam Generator Tube Portion Within the Tubesheet at Point Beach Unit 1

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ABSTRACT

Nondestructive examination indications of primary water stress corrosion cracking were found in the Alloy 600 thermally treated Westinghouse Model D5 steam generator tubes at the Catawba 2 nuclear power plant in the fall of 2004. Most of the indications were located in the tube-to-tubesheet welds with a few of the indications being reported as extending into the parent tube. In addition, a small number of tubes were reported with indications about 3/4 inch above the bottom of the tube, and multiple indications were reported in one tube at internal bulge locations in the upper third of the tubesheet. The tube end weld indications were dominantly axial in orientation and almost all of the indications were concentrated in one steam generator. Circumferential cracks were also reported at internal bulge locations in two of the Alloy 600 thermally treated steam generator tubes at the Vogtle 1 plant site in the spring of 2005.

Based on recent requirements interpretations published by the NRC staff in Generic Letter 2004-01 and Information Notice 2005-09, the Nuclear Management Company requested that a recommendation be developed for examination of the Westinghouse Model 44F steam generator tubesheet regions at Point Beach Unit 1. An evaluation was performed that considered the requirements of the ASME Code, Regulatory Guides, NRC Generic Letters, NRC Information Notices, the Code of Federal Regulations, NEI 97-06, and additional industry requirements (Reference 6). The conclusion of the technical evaluation is that the structural and leak rate integrity of the primary-to-secondary pressure boundary is unaffected by degradation of any level below a depth of 17 inches from the top of the 22 inch thick tubesheet or the tube end welds because the tube-to-tubesheet hydraulically expanded joints make it extremely unlikely that any operating or faulted condition loads are applied to the tube tack expanded region or the tube welds. Internal tube bulges, i.e., within the tubesheet, were created in a number of tubes as an artifact of the manufacturing process. The possibility of degradation at these locations exists based on the reported degradation at Catawba 2 and at Vogtle 1. A justification is provided herein for the examination of Point Beach Unit 1 tubes to a depth of 17 inches below the top of the tubesheet for one cycle of operation. This justification is based on the use of a bounding leak rate evaluation and the application of a structural analysis of the tube-to-tubesheet joint that is provided in the Appendix of this report for the Point Beach Unit 1 Model 44F steam generators. Application of the bounding leak rate and structural analysis approaches supporting this conclusion requires the approval of the NRC staff through a license amendment for one cycle of operation because it is based on a redefinition of the primary-to-secondary pressure boundary relative to the original design of the plant.

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1.0 INTRODUCTION

Indications of cracking were reported based on the results from the nondestructive, eddy current examination of the steam generator (SG) tubes during the fall 2004 outage at the Catawba 2 nuclear power plant operated by the Duke Power Company (References 1, 2 and 3). The SGs at the Catawba 2 plant are type Westinghouse Model D5 with 3/4 inch nominal outside diameter (OD) thermally treated Alloy 600 tubes (A600TT). The tube indications at Catawba were reported about 7.6 inches from the top of the tubesheet in one tube, and just above the tube-to-tubesheet welds in a region of the tube known as the tack expansion (TE) in several other tubes. Finally, indications were also reported in the tube-end welds (TEWs), also known as tube-to-tubesheet welds, joining the tube to the tubesheet with a small number of those indications extending into the tubes. The spatial distribution by row and column number is shown on Figure 1 for SG A, Figure 2 for SG B, and Figure 3 for SG D at Catawba; there were no indications in SG C.

Circumferential indications were reported in the spring of 2005 in two SG tubes (one tube had two indications) at the Vogtle Unit 1 plant operated by the Southern Nuclear Operating Company, Reference 4. The SGs at the Vogtle Unit 1 plant are type Westinghouse Model F with 11/16 inch nominal outside diameter (OD) thermally treated Alloy 600 tubes (A600TT). To date, similar indications have not been reported in the Alloy 600TT tubes at the other plant sites with Model D5 or Model F SGs

The Point Beach Unit 1 SGs are of the Westinghouse Model 44F with nominal 7/8 inch diameter A600TT tubes. To date, no indications have been reported at the other plant sites with Model 44F SGs. However, it is believed that no RPC (rotating probe coil) inspection of the tube region in the vicinity of the tack expansions or the tube-to-tubesheet welds has been performed. It is likely that only bobbin coil eddy current test (ECT) and visual examination using SG bowl cameras have been performed in the vicinity of the tube-to-tubesheet weld. In other words, ECT inspections using techniques capable of detecting circumferential cracking within the tubesheet have not been used in areas significantly below the top-of-tubesheet expansion transition region, typically limited to a depth of 3 inches from the top of tubesheet or the tube transition region.

The Model 44F SGs were fabricated in the 1979 through 1988 timeframe using similar manufacturing processes with a few exceptions. For example, the fabrication technique used for the installation of the SG tubes at Point Beach 1 would be expected to lead to a much lower likelihood for crack-like indications to be present in the region known as the tack expansion relative to Catawba 2 because a different process for effecting the tack expansions was adopted prior to the time of the fabrication of the Point Beach 1 SGs.

A recommended examination plan for the tubes and welds is delineated in Section 9.0 of this report. With regard to the tack expansion region of the tube and the tube end welds, the recommendation is to not perform any specific inspection of the SG tubes at Point Beach Unit 1. This recommendation is not part of an attempt to license the H* methodology for application to the tubes in the Point Beach Unit 1, however, the structural analysis of the tube and the tubesheet documented in that reference is valid for use in supporting the application of a an independent leakage evaluation methodology based on the change in contact pressure between the tube and the

tubesheet between normal operation and postulated accident conditions. Moreover, in order to address potential uncertainties associated with the determination of specific leak rates, the Nuclear Management Company decided to increase the effective depth for RPC inspection of the tubes to 17 inches from the top of tubesheet (TTS). This allows the use of the newly developed leak rate methodology with regard to the potential for indications in the tack expansion transition or tube weld since excluded potential degradation regions would be limited to the lower 5 inches of the tube in the nominally 22 inch thick tubesheet, which is well below the mid-plane of the tubesheet. As described in Section 6.0 of this report, the potential leakage in tubes due to degradation below 17 inches from the TTS would clearly be below the limiting accident analysis assumption.

The findings in the Catawba 2 and Vogtle 1 SG tubes present three distinct issues with regard to the SG tubes at the Point Beach Unit 1 plant:

1) indications in internal bulges or expansion anomalies within the tubesheet,
2) indications at the elevation of the tack expansion transition, and
3) indications in the tube-to-tubesheet welds, including some extending into the tube.

The scope of this document is to: a) address the applicable requirements, including the original design basis, Reference 7, and regulatory issues, Reference 8, and b) provide analysis support for technical arguments to limit inspection of the tubesheet region to an area above which degradation could result in potentially not meeting the SG performance criteria, i.e., the depths specified in Appendix A, or 17 inches, as recommended herein. This report was prepared to facilitate the approval of a modification of the H* criteria to justify the RPC exclusion zone to the portion of the tube below 17 inches from the top of the tubesheet and provide the necessary information for a NRC staff review of the technical basis for that request. Degradation below the top 17 inches of tube within the tubesheet can remain in service since it is demonstrated herein to not be safety significant.

The development of the H* criteria involved consideration of the performance criteria for the operation of the SG tubes as delineated in NEI 97-06, Revision 2, Reference 9, and draft RG 1.121, Reference 10. The bases for the performance criteria are the demonstration of both structural and leakage integrity during normal operation and postulated accident conditions. Appendix A of this report includes documentation of structural analyses regarding the efficacy of the tube-to-tubesheet joint, and leak rate analyses based on empirical data and computer code modeling of the leakage from tubes postulated to be cracked 100% throughwall within the tubesheet. The structural model was based on standard analysis techniques and finite element models as used for the original design of the SGs and documented in numerous submittals for the application of criteria to deal with tube indications within the tubesheet of other models of Westinghouse designed SGs with tube-to-tubesheet joints fabricated by other techniques, e.g., explosive expansion. The corresponding structural analysis of the Point Beach Unit 1 Model 44F SG tube-to-tubesheet joints is provided in the Appendix to this report.

All full depth expanded tube-to-tubesheet joints in Westinghouse designed SGs have a residual radial preload between the tube and the tubesheet. Early vintage SGs involved hard rolling which

resulted in the largest magnitude of the residual interface pressure. Hard rolling was replaced by explosive expansion, which resulted in a reduced magnitude of the residual interface pressure. Finally, hydraulic expansion replaced explosive expansion for the installation of SG tubes, resulting in a further reduction in the residual interface pressure. In general, it was found that the leak rate through the joints in hard rolled tubes, if any, is insignificant. Testing demonstrated that the leak rate resistance of explosively expanded tubes was not as great and prediction methods based on empirical data to support theoretical models were developed to deal with the potential for leakage. The same approach was followed to develop a prediction methodology for hydraulically expanded tubes. However, the model has been under review since its inception, with the intent of verifying its accuracy because it involved analytically combining the results from independent tests of leak rate through cracks with the leak rate through the tube-to-tubesheet crevice. The H* model for leak rate is such a model and its review could be time consuming since it has not been previously reviewed by the NRC staff. An alternative approach was developed for application at Point Beach Unit 1 based on engineering expectations of potential differences in the leak rate between normal operation and postulated accident conditions based on a first principles approach to the engineering.

A summary of the evaluation is provided in Section 2.0 of this report. The historical background and design requirements for the tube-to-tubesheet joint are discussed in Sections 3.0 and 4.0 respectively, a summary of the conclusions from the structural analysis of the joint is provided in Section 5.0, the leak rate analysis in Section 6.0, dispositioning of cracked tubes inadvertently found below the inspection distance is discussed in Section 7.0, conclusions from the structural and leak rate evaluations are provided in Section 8.0, and recommended tube inspection plans are contained in Section 9.0.

2.0 SUMMARY DISCUSSION

Evaluations were performed to assess the need for special purpose NDE probe examinations, e.g., RPC, of the SG tube region within the tubesheet at Point Beach Unit 1. The conclusions from the evaluation are that a 20% sample[1] of the tube bulges and over expansions, designated as BLG and OXP respectively for ECT purposes, in the two inspected SGs to at least 17 inches could be performed to ensure structural integrity. The sample size is based on the population of such signals to a depth of at least 17 inches into the tubesheet for each SG. If indications are confirmed during the inspection of the sample, the inspection scope will be expanded to include the entire population of BLG and OXP signals to a depth of 17 inches for the affected SG and a 20% sample of each of the unaffected SGs. The leakage performance requirement, in addition to the structural requirements, is met because it has been demonstrated that a bounding value of the leak rate during a postulated SLB event can be estimated from the leak rate during normal operation.

[1] A 20% inspection of all inservice tubes is required. When inspections are only planned for one of the two SGs, an inspection sample equivalent to 20% of all tube bulges and over expansions (the total number in all SGs) is needed to meet the requirements.

It is noted that the above inspection recommendation excludes the region of the tube referred to as the tack expansion or the tack expansion transition. In addition, consideration was given to the need to perform inspections of the tube-to-tubesheet weld in spite of the fact that the weld is specifically not part of the tube in the sense of the plant technical specification, see Reference 2. With regard to the latter two regions of the primary-to-secondary pressure boundary in accord with the original design of the SGs, it is concluded that there is no need to inspect either the tack expansion, its transition, or the tube-to tubesheet welds for degradation because the tube in these regions has been shown to meet structural and leak rate criteria regardless of the level of degradation. Furthermore, it could also be concluded that for some of the tubes, depending on radial location in the tubesheet, there is not a need to inspect the region of the tube below the neutral plane of the tubesheet, roughly 11 inches below the top. The results from the evaluations performed as described herein demonstrate that the inspection of the tube within a nominal 5 inches of the tube-to-tubesheet weld and of the weld is not necessary for structural adequacy of the SG during normal operation or during postulated faulted conditions, nor for the demonstration of compliance with leak rate limits during postulated faulted events.

In summary:

- The analyses of Appendix A demonstrates that the structural integrity requirements of NEI 97-06, Reference 9, and draft RG 1.121, Reference 10, are met by sound tube engagement lengths ranging from [ ]^{a,c,e} from the top of the tubesheet, thus the region of the tube below those elevations, including the tube-to-tubesheet weld is not needed for structural integrity during normal operation or accident conditions.
- NEI 97-06, Reference 9, defines the tube as extending from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, but specifically excludes the tube-to-tubesheet weld from the definition of the tube. The acceptance of the definition by the NRC staff was recorded in the Federal Register on March 2, 2005, Reference 11.
- The welds were originally designed and analyzed as primary pressure boundary in accordance with the requirements of Section III of the 1965 Edition of the ASME Boiler & Pressure Vessel Code through the 1966 Summer Addenda, Reference 7. The analysis of the weld is documented in Reference 12 for the Point Beach Unit 1 SGs. The typical as-fabricated and the as-analyzed weld configurations are illustrated on Figure 4.
- Section XI of the ASME Code, Reference 14 (1971) through 15 (2002), deals with the in-service inspection of nuclear power plant components. The ASME Code specifically recognizes that the SG tubes are under the purview of the NRC through the implementation of the requirements of the Technical Specifications as part of the plant operating license.

The hydraulically expanded tube-to-tubesheet joints in Model 44F SGs are not leak-tight and considerations were made with regard to the potential for primary-to-secondary leakage during postulated faulted conditions.

The leak rate during postulated accident conditions would be expected to be less than that during normal operation for indications near the bottom of the tubesheet (including indications in the tube end welds) based on the observation that while the driving pressure increases by about a factor of two, the flow resistance increase associated with an increase in the tube-to-tubesheet contact pressure can be up to a factor of 3, Appendix A. While such a decrease in leak rate is rationally expected, the postulated accident leak rate could conservatively be taken to be bounded by twice the normal operating leak rate if the increase in contact pressure is ignored. Since normal operating leakage is administratively limited (by NEI 97-06) to less than 0.10 gpm (150 gpd) in the Point Beach Unit 1 steam generators, the attendant accident condition leak rate, assuming all leakage to be from lower tubesheet indications, would be bounded by 0.20 gpm[2], which is less than the accident analysis assumption of 0.35 gpm (500 gpd) included in the Point Beach Unit 1 UFSAR (Section 14.2.5). Therefore, the leak rate under normal operating conditions could exceed its allowed value before the accident condition leak rate would be expected to exceed its allowed value. This approach is termed an application of the "bellwether principle." This assessment also envelopes postulated circumferential cracking of the tube or the tube-to-tubesheet weld that is 100% deep by 360° in extent because it is based on the premise that no weld is present.

Based on the information summarized above, no inspection of the tube-to-tubesheet welds, tack roll region or bulges below the distance determined to have the potential for safety significance as specified in Appendix A, i.e., the H* depths, would be considered to be necessary to assure compliance with the structural requirements for the SGs. In addition, based on the results from consideration of application of the bellwether principle regarding potential leakage during postulated accident conditions, the planned inspection to a depth of 17 inches below the top of the tubesheet is conservative and justified.

The selection of a depth of 17 inches obviates the need to consider the location of the tube expansion transition below the TTS, usually bounded by a length of about 0.3 inches. For structural purposes, the value of 17 inches greatly exceeds the engagement lengths determined from the analysis documented in the Appendix. The application of the bellwether approach to the leak rate analysis as described in Section 6.0 negates the need to consider specific distances from the TTS and relies only on the magnitude of the contact pressure in the vicinity of the tube above 17 inches below the TTS. The bellwether approach does not apply to the tube in Row 38 Column 69 of SG A, which is the only unexpanded tube at Point Beach Unit 1.

3.0 HISTORICAL BACKGROUND REGARDING TUBE INDICATIONS IN THE TUBESHEET

There has been extensive experience associated with the operation of SGs wherein it was believed, based on NDE, that throughwall tube indications were present within the tubesheet. The installation of the SG tubes usually involves the development of a short interference fit, referred to as the tack expansion, at the bottom of the tubesheet. The tack expansion was usually completed

[2] The expected leak rate would decrease significantly if the attendant increase in contact pressure and resistance to leak were included.

by hard rolling through October of 1979 and thereafter, in most instances, by the Poisson expansion of a urethane plug inserted into the tube end and compressed in the axial direction. The tube-to-tubesheet weld was then performed to create the ASME Code pressure boundary between the tube and the tubesheet.[3] The Point Beach Unit 1 replacement SGs used the urethane plug tack expansion in all their tubes.

The development of the F* alternate repair criterion (ARC) in 1985-1986 for tubes hard rolled into the tubesheet was prompted by the desire to account for the inherent strength of the tube-to-tubesheet joint away from the weld and to allow tubes with degradation within the tubesheet to remain in service, Reference 14. The result of the development activity was the demonstration that the tube-to-tubesheet weld was superfluous with regard to the structural and leakage integrity of the rolled joint between the tube and the tubesheet. Once the plants were in operation, the structural and leakage resistance requirements for the joints were based on the plant Technical Specifications, and a means of demonstrating joint integrity that was acceptable to the NRC staff was delineated in Reference 10. License amendments were sought and granted for several plants with hard rolled tube-to-tubesheet joints to omit the inspection of the tube below a depth of about 1.5 inches from the top of the tubesheet. Similar criteria, designated as W*, were developed for explosively expanded tube-to-tubesheet joints in Westinghouse designed SGs in the 1991-1992 timeframe, Reference 16. The W* criteria were first applied to operating SGs in 1999 based on a generic evaluation for Model 51 SGs, Reference 17, and the subsequent safety evaluation by the NRC staff, Reference 18. However, the required engagement length to meet structural and leakage requirements was on the order of 4 to 6 inches because the explosively expanded joint does not have the same level of residual interference fit as that of a rolled joint. It is noted that the length of joint necessary to meet the structural requirements is not the same as, and is usually shorter than, that needed to meet the leakage integrity requirements.

The post-weld expansion of the tube into the tubesheet in the Point Beach Unit 1 Model 44F SGs was completed by a hydraulic expansion of the tube instead of rolling or explosive expansion, similar to Model D5 and Model F SGs. The hydraulically formed joints do not exhibit the level of interference fit that is present in rolled or explosively expanded joints, however, when the thermal and internal pressure expansion of the tube is considered during normal operation and postulated accident conditions, appropriate conclusions regarding the need for the weld similar to those for the other two types of joint can be made. Evaluations were performed in 1996 of the effect of tube-to-tubesheet weld damage that occurred from an object in the bowl of Vogtle Unit 1 (model F SGs - also a hydraulically expanded Alloy 600TT tube SG with a similar urethane plug tack expansion and tube end weld), SG 4 with tube-to-tubesheet joints, on the structural and leakage integrity of the joint, Reference 19. It was concluded in that evaluation that the strength of the tube-to-tubesheet joint is sufficient to prevent pullout in accordance with the requirements of the performance criteria of Reference 9 and that a significant number of tubes could be damaged

[3] The actual weld is between the Alloy 600 tube and weld buttering (cladding) on the bottom of the carbon steel tubesheet.

without violating the performance criterion related to the primary-to-secondary leak rate during postulated accident conditions.

4.0 DESIGN REQUIREMENTS FOR THE TUBE-TO-TUBESHEET JOINT REGION

This section provides a review of the applicable design and analysis requirements, including the ASME Code pre-service design requirements of Section III and the operational/maintenance requirements of Section XI. The following is the Westinghouse interpretation of the applicable analysis requirements and criteria for the condition of TEW cracking. Recommendations that include code requirements and the USNRC position are expressed in References 8 and 9. Reference 8 notes that:

> *"In accordance with Section III of the Code, the original design basis pressure boundary for the tube-to-tubesheet joint included the tube and tubesheet extending down to and including the tube-to-tubesheet weld. The criteria of Section III of the ASME Code constitute the "method of evaluation" for the design basis. These criteria provide a sufficient basis for evaluating the structural and leakage integrity of the original design basis joint. However, the criteria of Section III do not provide a sufficient basis by themselves for evaluating the structural and leakage integrity of a mechanical expansion joint consisting of a tube expanded against the tubesheet over some minimum embedment distance. If a licensee is redefining the design basis pressure boundary and is using a different method of evaluation to demonstrate the structural and leakage integrity of the revised pressure boundary, an analysis under 10 CFR 50.59 would determine whether a license amendment is required."*

The industry definition of Steam Generator Tubing excludes the tube-end weld from the pressure boundary as noted in NEI 97-06 (Reference 9):

> *"Steam generator tubing refers to the entire length of the tube, including the tube wall and any repairs to it, between the tube-to-tube sheet weld at the tube inlet and the tube-to-tube sheet weld at the tube outlet. The tube-to-tube sheet weld is not considered part of the tube."*

The NRC has indicated its concurrence with this definition; see, for example, Reference 11. In summary, from a non-technical viewpoint, no specific inspection of the tube-end welds would be required because:

1. The industry definition of the tube excludes the tube-end weld,
2. The ASME Code defers the judgment regarding the redefined pressure boundary to the licensing authority under 10CFR50.59,
3. The NRC has accepted this definition; therefore, by inference, may not consider cracked welds to be a safety issue on a level with that of cracked tubes, and

4. There is no qualified technique that can realistically be applied to determine if the tube-end welds are cracked.

However, based on the discussion of Information Notice 2005-09, Reference 2, it is clear that the NRC staff has concluded that "the findings at Catawba illustrate the importance of inspecting the parent tube adjacent to the weld and the weld itself for degradation." The technical considerations documented herein obviate the need for consideration of any and all non-technical arguments.

5.0 STRUCTURAL ANALYSIS OF TUBE-TO-TUBESHEET JOINT

This section summarizes the structural aspects and analysis of the entire tube-to-tubesheet joint region, the details of which are provided in the Appendix. The tube end weld was originally designed as a pressure boundary structural element in accordance with the requirements of Section III of the ASME (American Society of Mechanical Engineers) Boiler and Pressure Vessel Code, Reference 7. The construction code for the Point Beach Unit 1 SGs is the 1965 Edition through the 1966 Summer Addenda of the ASME Code. This means that there were no strength considerations made with regard to the expansion joint between the tube and the tubesheet, including the tack expansion regardless of whether it was achieved by rolling or Poisson expansion of a urethane plug.

An empirical and analytical evaluation of the structural capability of the as-installed tube-to-tubesheet joints, considering the weld to be absent, is contained in Appendix A. For the Point Beach 1 SGs, it was conservatively assumed that there was no residual contact pressure between the tube and the tubesheet from the initial hydraulic expansion. With these significant conservatisms, calculations showed that engagement lengths of approximately [ ]^{a,c,e} were sufficient to equilibrate the axial loads resulting from consideration of 3 times the normal operating and 1.4 times the limiting accident condition pressure differences (see Appendix A).

The variation in required engagement length is a function of tube location, i.e., row and column, and decreases away from the center of the SG where the maximum value applies. The tubesheet bows, i.e., deforms, upward from the primary-to-secondary pressure difference and results in the tube holes becoming dilated above the neutral plane of the tubesheet, which is a little below the mid-plane because of the effect of the tensile membrane stress from the pressure loading. The amount of dilation is a maximum very near the radial center of the tubesheet (restricted by the divider plate) and diminishes with increasing radius outward. Moreover, the tube-to-tubesheet joint becomes tighter below the neutral axis and is a maximum at the bottom of the tubesheet[4]. In conclusion, the need for the weld is obviated by the interference fit between the tube and the tubesheet. Axial loads are not transmitted to the portion of the tube below the H* distance during operation or faulted conditions, by factors of safety of at least 3 and 1.4 respectively, including postulated loss of coolant accidents (LOCA), and inspection of the tube below the H* distance

[4] [ ]^{a,c,e}

including the tube-to-tubesheet weld is not technically necessary. Also, if the expansion joint were not present, there would be no effect on the strength of the weld from axial cracks, and tubes with circumferential cracks up to about 180° by 100% deep would have sufficient strength to meet the nominal ASME Code structural requirements, based on the margins of safety reported in Reference 12, and the requirements of RG 1.121, Reference 10.

An examination of Table A.2-1, A.2-2, and A.2-3 provides information that the holding power of the tube-to-tubesheet joint in the vicinity of the maximum inspection depth of 17 inches is much greater than at the top of the tubesheet. Note that the radii reported in these tables were picked to represent various maximum and minimum contact pressures at various depths within the tubesheet; however, the finite element analysis was conducted using 62 radial elements, each 1.1 inches or less in size. The purpose of this discussion is to illustrate the extreme conservatism associated with the holding power of the joint below the neutral surface of the tubesheet, and to identify the proper tube radii for consideration. In the center of the tubesheet the incremental holding strength in the [

]a,c,e

6.0 LEAK RATE ANALYSIS OF CRACKED TUBE-TO-TUBESHEET JOINTS

This section of the report presents a discussion of the leak rate expectations from axial and circumferential cracking confined to the tube-to-tubesheet joint region, including the tack expansion region, the tube-to-tubesheet welds and areas where degradation could potentially occur due to bulges and overexpansions within the tube. Although the welds are not part of the tube per the technical specifications, consideration is given in deference to the discussions of the NRC staff in References 2 and 8. It is noted that the application of the methods discussed below requires approval from the NRC staff to change the Technical Specification prior to returning to service for Point Beach Unit 1. With regard to the inherent conservatism embodied in the application of any predictive methods, it is noted that the presence of cracking was not confirmed through removal of a tube section followed by destructive metallurgical examination at Catawba 2 or Vogtle 1.

From an engineering standpoint, it can be expected that if there is no meaningful primary-to-secondary leakage during normal operation, there should likewise be no meaningful leakage during postulated accident conditions from indications located below the mid-plane of the tubesheet. The rationale for this is based on considerations regarding the deflection of the tubesheet with accompanying dilation and diminution of the tubesheet holes. In effect, the area presented as a leak path between the tube and tubesheet would not be expected to increase under postulated accident conditions and would really be expected to decrease for most of the SG tubes. During the development of the RPC inspection criteria for hydraulically expanded joints, consideration was

given regarding the potential for leak rate during normal operation to act as a bellwether or leading indicator with regard to the leak rate that could be expected during postulated accident conditions. For example, if it was intended to stop the RPC examination at a depth of 3 to 9 inches from the top of the tubesheet, then severe circumferential cracking would have been postulated to occur immediately below that depth and the potential leak rate as compared to that during normal operation estimated. The primary-to-secondary pressure difference during normal operation is typically 1200 to 1400 psi, while that during a postulated accident, e.g., steam line and feed line break, is typically 2560 to 2650 psi.[5] Above the neutral plane of the tubesheet the tube holes experience a dilation due to pressure induced bow of the tubesheet. This means that the contact pressure between the tubes and the tubesheet would diminish above the neutral plane in the central region of the tubesheet at the same time as the driving potential would increase, leading to an expectation of an increase in the potential leak rate through the crevice. Estimating the change in leak rate as a function of the change in contact pressure under faulted conditions on a generic basis was expected to be problematic. However, below the neutral plane of the tubesheet the tube holes diminish in size because of the upward bending and the contact pressure between the tube and the tubesheet increases. When the differential pressure increases during a postulated faulted event the increased bow of the tubesheet leads to an increase in the tube-to-tubesheet contact pressure, increasing the resistance to flow. Thus, while the dilation of the tube holes above the neutral plane of the tubesheet presents additional analytic problems in estimating the leak rate for indications above the neutral plane, the diminution of the holes below the neutral plane permits definitive statements to be made with regard to the trend of the leak rate, hence, the bellwether principle. Independent consideration of the effect of the tube-to-tubesheet contact pressure leads to similar conclusions with regard to the opening area of the cracks in the tubes, thus further restricting the leak rate beyond that through the interface between the tube and the tubesheet.

In order to accept the concept of normal operation being a bellwether for the postulated accident leak rate for indications above the neutral plane of the tubesheet, the change in leak rate had to be quantified using a somewhat complex, physically sound model of the thermal-hydraulics of the leak rate phenomenon. This is not necessarily the case for cracks considered to be present below the neutral plane of the tubesheet because a diminution of the holes takes place during postulated accident conditions below the neutral plane relative to normal operation. For example, at a radius of approximately 29 inches from the center of the SG, the contact pressure at the bottom of the tubesheet during normal operation is calculated to be about [ ]^{a,c,e}, see the last contact pressure entry in the center columns of Table A.2-2 and Table A.2-3 for the hot and cold legs, respectively. The contact pressure during a postulated steam line break would be on the order of [ ]^{a,c,e} at the bottom of the tubesheet, Table A.2-1. The analytical model for the flow through the crevice, the Darcy equation for flow through porous media, indicates that flow would be expected to be proportional to the differential pressure. Thus, a doubling of the leak rate could be predicted if the change in contact pressure between the tube and the tubesheet were ignored.

[5] The differential pressure may be on the order of 2405 psi if it is demonstrated that the power operated relief valves will be functional.

Analyses were performed for two Westinghouse SG models with different tube sizes and pitch, the Model F and D5 SGs (Reference 5 and Reference 13, respectively), that indicates that the resistance to flow per unit length (the loss coefficient) would increase by a factor of about [ ]^{a,c,e}, respectively, between SLB and NOp conditions. Applying this factor to the Point Beach SGs, and if the leak rate during normal operation was 0.100 gpm (150 gpd), the postulated accident condition leak rate would be 0.200 gpm versus the allowable limit of 0.350 gpm when considering only the change in differential pressure. However, the estimate would be reduced to [ ]^{a,c,e}. This latter value is significantly less than the allowable limit during faulted conditions of 0.35 gpm. Even without inclusion of the effect of the change in contact pressure, the predicted leak rate would be significantly less than the allowable rate of 0.35 gpm. Regardless of the difference in the magnitude of the reduction factors, it is apparent that the inclusion of the increase in resistance to flow through the tube-to-tubesheet interface would have a meaningful reducing effect on the expected leak rate during a postulated SLB event and can result in a predicted value that is less than the normal operating value for a significant number of tubes in the bundle.

The above argument considered indications located where the expectations associated with the bellwether principle would be a maximum, i.e., where the relative increase in contact pressure from normal to faulted conditions is a maximum. Thus, the conclusions of this section apply directly to indications in the tube somewhat near the bottom of the tubesheet, i.e., as a minimum to tube indications within a little more than 5 inches from the bottom of the tubesheet and to postulated indications in the tube-to-tubesheet welds. An examination of the contact pressures as a function of depth in the tubesheet from the finite element analyses of the tubesheet as reported in Appendix A of this report and Figure 5 through Figure 10 shows that the bellwether principle applies to a significant extent to all indications below the neutral plane of the tubesheet. At the neutral plane of the tubesheet (Figure 5) the increase in contact pressure is on the order of 10% relative to that during normal operation for all tubes regardless of radius. The fact that the contact pressure increases means that the leak rate would be expected to be bounded by a factor of two relative to normal operation. At a depth of 17 inches from the top of the tubesheet the contact pressure increases [ ]^{a,c,e} relative to that during normal operation. The flow resistance would be expected to increase by about 60%, thus the increase in driving pressure would be mostly offset by the increase in the resistance of the joint.

The numerical results from the finite element analyses are presented on Figure 5 at the elevation of the mid-plane of the tubesheet through Figure 8 at the bottom of the tubesheet. A comparison of the contact pressure during postulated SLB conditions relative to that during normal operation is provided for depths of 10.9, 13.9, 17.0, and 21.8 inches below the top of the tubesheet, the last being near the bottom of the tubesheet.

- At roughly the neutral surface, about 10.9 inches, the contact pressure during SLB is [ ]^{a,c,e}
- At a depth of 13.9 inches the contact pressure increase ranges from a [ ]^{a,c,e} at a radius of 50 inches, see Figure 6.

- At 17.0 inches below the top of the tubesheet the contact pressure increases by a [ ]a,c,e at a radius of about 54 inches, Figure 7.
- Near the bottom of the tubesheet, Figure 8, the contact pressure increases by about [ ]a,c,e, at about 58 inches from the center.

A similar comparison is illustrated on Figure 9 at a depth of 7.8 inches from the top of the tubesheet. Here the contact pressure decreases by [ ]a,c,e

The leak rate from any indication is determined by the total or integrated resistance of the crevice from the elevation of the indication to the top of the tubesheet, ignoring the resistance from the crack itself. Thus, it would not be sufficient to simply use the depth of 7.8 inches and suppose that the leak rate would be relatively unchanged even if the pressure potential difference were the same. [ ]a,c,e

[ ]a,c,e

[ ]a,c,e Hence, it is conservative to omit any consideration of inspection of bulges or other artifacts below a depth of 17 inches from the top of the tubesheet. Therefore, applying a very conservative inspection sampling length of 17 inches downward from the top of the tubesheet at Point Beach Unit 1 provides a high level of confidence that the potential leak rate from indications below the lower bound inspection elevation during a postulated SLB event will be bounded by twice the normal operation primary-to-secondary leak rate.

7.0 RECOMMENDATIONS FOR DISPOSITIONING TUBE CRACKS IN THE TUBE-TO-TUBESHEET JOINT

The information contained in this report provides a technical basis for bounding the potential leak rate from non-detected indications in the tube region below 17 inches from the top of the tubesheet as no more that twice the leak rate during normal operation. This applies equally to any postulated indications in the tack expansion region and in the tube-to-tubesheet welds. If cracks are found within the specified inspection depth, it is recommended that the inspection be expanded in accordance with established guidelines, using that same specified inspection depth, e.g., 17 inches. If the cracking is identified at an existing bulge or over expansion location, the scope expansion can be limited to the population of identified bulges and over expansions within the inspection region. As noted in the introduction to this report, the reporting of crack-like indications in the tube-to-tubesheet welds would be expected to occur inadvertently since no structural or leak rate technical reason exists for a specific examination to take place. Indications below 17 inch below the TTS do not need to be addressed.

8.0 CONCLUSIONS

The evaluations performed as reported herein have demonstrated, for one cycle of operation, that:

1) There is no structural integrity concern associated with tube or tube weld cracking of any extent provided it occurs below the H* distance as reported in Appendix A. The pullout resistance of the tubes has been demonstrated for axial forces associated with 3 times the normal operating differential pressure and 1.4 times differential pressure associated with the most severe postulated accident.
2) Contact forces during postulated LOCA events are sufficient to resist axial motion of the tube. Also, if the tube end welds are not circumferentially cracked, the resistance of the tube-to-tubesheet hydraulic joint is not necessary to resist push-out. Moreover, the geometry of any postulated circumferential cracking of the weld would result in a configuration that would resist pushout in the event of a loss of coolant accident. In other words, the crack flanks would not form the cylindrical surface necessary such that there would be no resistance to expulsion of the tube in the downward direction.
3) The leak rate for indications below the neutral plane of the tubesheet is expected to be bounded <u>on average</u> by twice the leak rate that is present during normal operation of the plant.
4) The leak rate for indications below a depth of about 17 inches from the top of the tubesheet would be bounded by twice the leak rate that is present during normal operation of the plant regardless of tube location in the bundle. This is apparent from comparison of the contact pressures from the finite element analyses over the full range of radii from the center of the tubesheet, and ignores any increase in the leak rate resistance due to the contact pressure changes and associated tightening of the crack flanks.

9.0 RECOMMENDED INSPECTION PLANS

The recommendations, applicable to the inspections performed for a single inspection outage, with regard to the inspection of the welds at Point Beach Unit 1, are based on the following:

1) Structural considerations support the elimination of requirements for examination of the tubes below 17 inches from the TTS as analyzed in Appendix A.
2) Similar considerations lead to the conclusion that the leak rate during postulated faulted events would be bounded by twice the leak rate during normal operation and supports the elimination of requirements for examination of the tube below 17 inches (which includes the tack expansions and the welds).
3) The prior conclusions rely on the inherent strength and leak rate resistance of the hydraulically expanded tube-to-tubesheet joint, a feature that was not considered or permitted to be considered for the original design of the SG. Thus, omission of the inspection of the weld constitutes a reassignment of the pressure boundary to the tube-to-tubesheet interface. Similar considerations for tube indications require NRC staff approval of a license amendment.

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SG - 2A +Point Indications Within the Tubesheet

Catawba EOC13 DDP D5

E 1 INDICATION WITHIN 0.25" OF HOT LEG TUBE END

66 PLUGGED TUBE

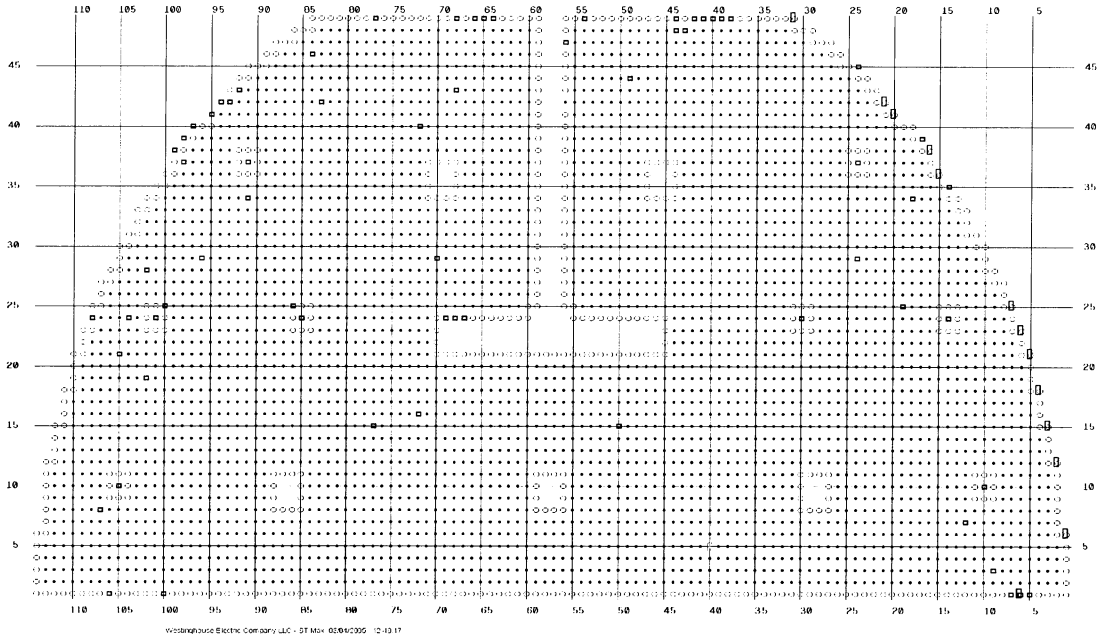

Figure 1: Distribution of Indications in SG A at Catawba 2

SG - 2B +Point Indications Within the Tubesheet

Catawba EOC13 DDP D5

Z 1 MULTIPLE INDICATIONS AT APPROXIMATELY 7" BELOW HOT LEG TOP OF TUBESHEET

W 1 INDICATIONS WITHIN 0.25" AND BETWEEN 0.26" AND 0.80" OF HOT LEG TUBE END

B 9 INDICATION BEWTEEN 0.26" AND 0.80" OF HOT LEG TUBE END

E 192 INDICATION WITH 0.25" OF HOT LEG TUBE END

58 PLUGGED TUBE

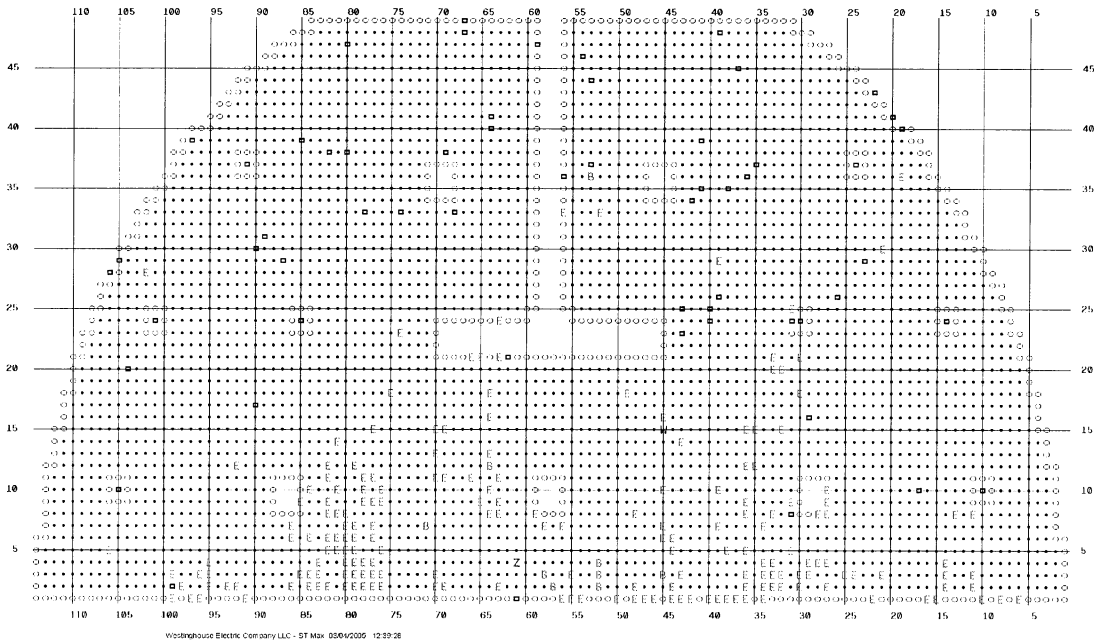

Figure 2: Distribution of Indications in SG B at Catawba 2

SG - 2D +Point Indications Within the Tubesheet

Catawba EOC13 DDP D5

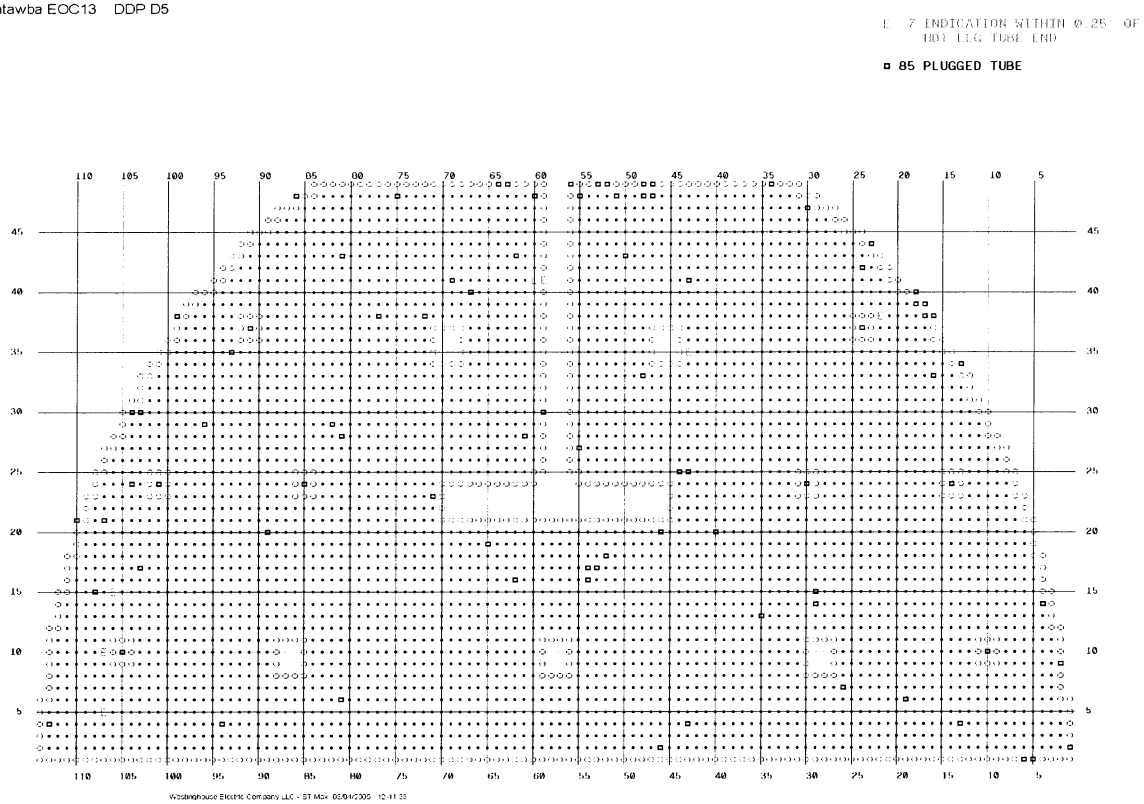

Figure 3: Distribution of Indications in SG D at Catawba 2

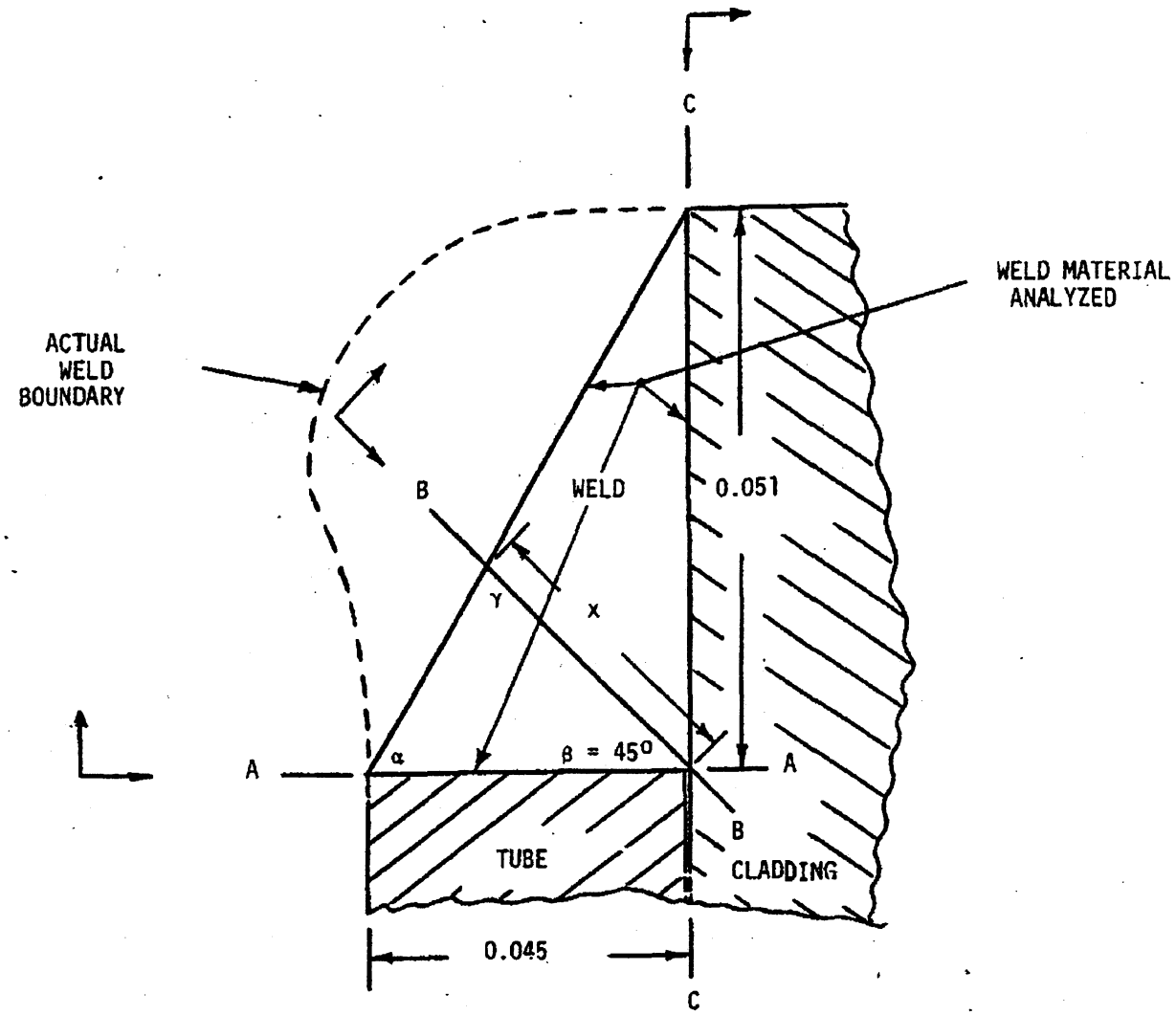

Figure 4: As-Fabricated & Analyzed Tube-to-Tubesheet Welds

a,c,e

Figure 5: Change in contact pressure at 10.9 inches below the TTS

a,c,e

Figure 6: Change in contact pressure at 13.9 inches below the TTS

a,c,e

Figure 7: Change in contact pressure at 17.0 inches below the TTS

a,c,e

Figure 8: Change in contact pressure near the bottom of the tubesheet

a,c,e

Figure 9: Change in contact pressure at 7.8 inches below the TTS

a,c,e

Figure 10: Change in contact pressure at 5.4 inches below the TTS

APPENDIX A – STRUCTURAL ANALYSIS OF THE TUBE-TO-TUBESHEET CONTACT PRESSURE

A.1 Structural Analysis of the Tube-to-Tubesheet Interface Joint

An evaluation was performed to determine the contact pressures between the tubes and the tubesheet in the Point Beach 1 steam generators. The evaluation utilized [

]^{a,c,e}, were determined.

The same contact pressure results were used [

]^{a,c,e} were also included.

A.1.1 Evaluation of Tubesheet Deflection Effects for H* and H* Leakage

A finite element model developed previously for the channel head/tubesheet/shell region was used to determine the tubesheet hole dilations in the Point Beach 1 steam generators. [

]^{a,c,e} loads in the tube.

A.1.1.1 Material Properties and Tubesheet Equivalent Properties

The material of construction for the tubing in the steam generators is a nickel base alloy, Alloy 600, in the thermally treated (TT) condition. Summaries of the applicable mechanical and thermal properties for the tube material are provided in Table A.1-1. The tubesheet material is SA-508, Class 2a, and its properties are in Table A.1-2. The shell material is SA-533 Grade A Class 2, and its properties are in Table A.1-3. The channel head material is SA-216 Grade WCC, and its properties are in Table A.1-4. The material properties are from Reference A.2.

The perforated tubesheet in the Model 44F channel head complex is treated [

]a,c,e

[

]a,c,e

[

]a,c,e in the perforated region of the tubesheet for the finite element model. The material properties of the tubes are not utilized in the finite element model, but are listed in Table A.1-1 for use in the calculations of the tube/tubesheet contact pressures.

A.1.2 Tubesheet Rotation Effects

Loads are imposed on the tube as a result of tubesheet rotations under pressure and temperature conditions. [

]a,c,e.

Previous calculations performed [

]a,c,e.

The radial deflection at any point within the tubesheet is found by scaling and combining the unit load radial deflections at that location according to:

[ ]a,c,e

This expression is used to determine the radial deflections along a line of nodes at a constant axial elevation (e.g. top of the tubesheet) within the perforated area of the tubesheet.

The expansion of a hole of diameter D in the tubesheet at a radius R is given by:

[ ]a,c,e

UR is available directly from the finite element results. dUR/dR may be obtained by numerical differentiation.

The maximum expansion of a hole in the tubesheet is in either the radial or circumferential direction. [

]a,c,e

Where SF is a scale factor between zero and one. For the eccentricities typically encountered during tubesheet rotations, [ ]a,c,e. These values are listed in the table below:

[

Initial Eccentricity	Scale Factor (SF)

]a,c,e

These data were fit to the polynomial below:

[ ]a,c,e

[

]a,c,e

The thermal expansion of the hole I.D. is included in the finite element results. The expansion of the hole I.D. produced by pressure is given by:

Pressure:

$$\Delta R_{TS}^{pr} = \frac{P_i c}{E_{TS}}\left[\frac{d^2 + c^2}{d^2 - c^2} + \nu\right]$$

Where:

E_{TS} = Modulus of Elasticity of tubesheet, psi

d = Outside radius of cylinder which provides the same radial stiffness as the tubesheet, [ ]a,c,e

If the unrestrained expansion of the tube OD is greater than the expansion of the tubesheet hole, then the tube and the tubesheet are in contact. The inward radial displacement of the outside surface of the tube produced by the contact pressure is given by: (Note: The use of the term δ in this section is unrelated to the use of it in another section of this report.)

$$\delta_t = \frac{P_2 c}{E_t}\left[\frac{c^2 + b^2}{c^2 - b^2} - \nu\right]$$

The radial displacement of the inside surface of the tubesheet hole produced by the contact pressure between the tube and hole is given by:

$$\delta_{TS} = \frac{P_2 c}{E_{TS}}\left[\frac{d^2 + c^2}{d^2 - c^2} + \nu\right]$$

The equation for the contact pressure P_2 is obtained from:

$$\delta_{to} + \delta_{TS} = \Delta R_{to} - \Delta R_{TS} - \Delta R_{ROT}$$

Where

ΔR_{ROT}= Hole expansion produced by tubesheet rotations obtained from finite element results

The ΔR's are:

$$\Delta R_{to} = c\alpha_t (T_t - 70) + \frac{P_{pri} c}{E_t}\left[\frac{(2-\nu)b^2}{c^2 - b^2}\right] - \frac{P_{sec} c}{E_t}\left[\frac{(1-2\nu)c^2 + (1+\nu)b^2}{c^2 - b^2}\right]$$

$$\Delta R_{TS} = \frac{P_{sec} c}{E_{TS}}\left[\frac{d^2 + c^2}{d^2 - c^2} + \nu\right]$$

The resulting equation is:

a,c,e

[ ]

For a given set of primary and secondary side pressures and temperatures, the above equation is solved for selected elevations in the tubesheet to obtain the contact pressures between the tube and tubesheet as a function of radius. The elevations selected ranged from the top to the bottom of the tubesheet. Negative "contact pressure" indicates a gap condition.

The OD of the tubesheet cylinder is equal to that of the cylindrical (simulate) collars [ ]a,c,e designed to provide the same radial stiffness as the tubesheet, which was determined from a finite element analysis of a section of the tubesheet (Reference A.5).

The tube inside and outside radii within the tubesheet are obtained by assuming a nominal diameter for the hole in the tubesheet (0.893 inch) and [ ]a,c,e

[

]a,c,e The table below lists the values used in the equations above, with the material properties evaluated at 600°F. (Note that the properties in the following sections are evaluated at the primary fluid temperature).

Parameter	Value
b, inside tube radius, in.	0.397
c, outside tube radius, in.	0.4465
d, outside radius of cylinder w/ same radial stiffness as tubesheet, in.	[ ]a,c,e
α_t, coefficient of thermal expansion of tube, in/in °F	7.82×10^{-6}
E_t, modulus of elasticity of tube, psi	28.7×10^{6}
α_{TS}, coefficient of thermal expansion of tubesheet, in/in °F	7.42×10^{-6}
E_{TS}, modulus of elasticity of tubesheet, psi	26.4×10^{6}

A.1.3 Point Beach Unit 1 Contact Pressures

A.1.3.1 Normal Operating Conditions

The loadings considered in the analysis are based on an umbrella set of conditions as defined in Reference A.5 and Reference A.6. The temperatures and pressures for normal operating conditions at Point Beach Unit 1 are as follows:

Loading	
Primary Pressure	2235 psig
Secondary Pressure	730.7 psig
Primary Fluid Temperature (T_{hot})	590.2 °F
Secondary Fluid Temperature	525.7 °F

The primary pressure [

]a,c,e

A.1.3.2 Faulted Conditions

Steamline Break (SLB) is the limiting faulted condition, with tube lengths required to resist push out during a postulated loss of coolant accident (LOCA) typically less than one-fourth of the tube lengths required to resist pull out during SLB. Therefore, LOCA was not considered in this analysis.

As a result of SLB, the faulted SG will rapidly blow down to atmospheric pressure, resulting in a large ΔP across the tubes and tubesheet. The entire flow capacity of the auxiliary feedwater system would be delivered to the dry, hot shell side of the faulted SG. The primary side re-pressurizes to the pressurizer safety valve set pressure. The hot leg temperature decreases throughout the transient, reaching a minimum temperature of [ ]a,c,e was used in the calculations. The pertinent parameters are listed below. The combination of parameters yielding the most limiting results is used.

Primary Pressure	=	2560 psig
Secondary Pressure	=	0 psig
[ ]a,c,e		

For this set of primary and secondary side pressures and temperatures, the equations derived in Section A.1.2 are solved for the selected elevations in the tubesheet to obtain the contact pressures between the tube and tubesheet as a function of tubesheet radius for the hot leg.

A.1.3.3 Summary of Results

The contact pressures between the tube and tubesheet for various plant conditions are plotted versus radius in Figures A.1-2 through A.1-4 and summarized in Table A.1-5.

A.2 Determination of Tube-to-Tubesheet Contact Pressures

The partial-length RPC justification relies on knowledge of the tube-to-tubesheet interfacial mechanical interference fit contact pressure at all elevations in the in the tube joint, especially in the upper half of the tube joint. The contact pressure is used for both anchorage of the tube in the tubesheet in the evaluation and for determining the leakage effects for cracks 17 inches or below the top of the tubesheet.

For the tube anchorage effect, it is necessary to demonstrate that the [

]a,c,e

[

]a,c,e

The force resisting pullout acting on a length of a tube between elevations h_1 and h_2 is given by:

$$F_i = (h_2 - h_1)F_{HE} + \mu\pi d \int_{h_1}^{h_2} P\,dh$$

Where:

F_{HE}	=	Resistance to pull out due to the initial hydraulic expansion = 0 lb/in
P	=	Contact pressure acting over segment dh
μ	=	Coefficient of friction between the tube and tubesheet, conservatively assumed to be 0.2

The contact pressure is assumed to vary linearly between adjacent elevations in the tubesheet, so that between elevations L_1 and L_2,

$$P = P_1 + \frac{(P_2 - P_1)}{(L_2 - L_1)}(h - L_1)$$

or,

[ ]a,c,e

so that,

[ ]a,c,e (1)

This equation is used to accumulate the force resisting pullout from the top of the tubesheet to each of the elevations through the thickness of the tubesheet. The above equation is also used to find the minimum contact lengths needed to meet the pullout force requirements.

For the partial-length RPC evaluation, tube-to-tubesheet contact pressures were calculated for the entire tube length in the TS, at six radii from the bundle vertical centerline. The first radius, R, was the location of greatest tubesheet hole dilation, caused by the greatest bending, R = 2.815 inches. Three radii were evaluated toward the middle of the tubesheet (R = 7.623 inches, 17.654 inches, and 28.799 inches, respectively); two radii were evaluated near the bundle periphery (R = 49.976 and 57.013 inches).

The end cap loads for Normal and Faulted conditions are:

Normal (maximum): $\pi * (2235-730.7) * (0.893)^2 / 4 = 942.17$ lbs.

Faulted (SLB): $\pi * (2560-0) * (0.893)^2 / 4 = 1659.73$ lbs.

Thus, based on the guidelines of RG 1.121, the critical end cap load is 2827 lbs., which is three times the normal operation load and is greater than 1.4 times the SLB accident load of 2245 lbs.

The top parts of Tables A.2-1 through A.2-3 list the contact pressures through the thickness at each of these sections for the given conditions.

A.3 References

A.1 NSD-E-SGDA-98-362, 11/98 (Proprietary Report).

A.2 ASME Boiler and Pressure Vessel Code Section III, "Rules for Construction of Nuclear Power Plant Components, "1989 Edition, the American Society of Mechanical Engineers, New York, NY.

A.3 "Stress Analysis of Thick Perforated Plates," Ph. D. Thesis by T. Slot, Technomic Publishing Co., Westport, CN, 1972.

A.4 "Formulas for Stress and Strain," Fifth Edition, Table 32, Cases 1a-1d, by R.J. Roark and W.C. Young, McGraw Hill Book Company, New York, NY, 1975.

A.5 PCWG-2650, "Point Beach Units 1 & 2 (WEP/WIS): Category IV Approval of PCWG Parameters to Support the Fuel Upgrade/Uprating," Westinghouse, May 18, 2001.

A.6 LTR-TA-05-189, " Point Beach Unit 1 Licensing Basis SLB Extended Data," September 21, 2005. (Proprietary Report).

A.7 Porowski, J. S. and O'Donnell, W. J., "Elastic Design Methods for Perforated Plates," Trans. ASME Journal of Engineering for Power, Vol. 100, p. 356, 1978.

Table A.1-1: Summary of Material Properties
Alloy 600 Tube Material

PROPERTY	TEMPERATURE (°F)						
	70	200	300	400	500	600	700
Young's Modulus psi x 1.0 E06	31.00	30.20	29.90	29.50	29.00	28.70	28.20
Coefficient of Thermal Expansion in/in/°F x 1.0 E-06	6.90	7.20	7.40	7.57	7.70	7.82	7.94
Density lb-sec^2/in^4 x 1.0E-04	7.94	7.92	7.90	7.89	7.87	7.85	7.83
Thermal Conductivity Btu/sec-in-°F x 1.0E-04	2.01	2.11	2.22	2.34	2.45	2.57	2.68
Specific Heat Btu-in/lb-sec^2-°F	41.2	42.6	43.9	44.9	45.6	47.0	47.9

Table A.1-2: Summary of Material Properties
SA-508 Class 2a Tubesheet Material

PROPERTY	TEMPERATURE (°F)						
	70	200	300	400	500	600	700
Young's Modulus psi x 1.0 E06	29.20	28.50	28.00	27.40	27.00	26.40	25.30
Coefficient of Thermal Expansion in/in/°F x 1.0 E-06	6.50	6.67	6.87	7.07	7.25	7.42	7.59
Density lb-sec^2/in^4 x 1.0E-04	7.32	7.30	7.29	7.27	7.26	7.24	7.22
Thermal Conductivity Btu/sec-in-°F x 1.0E-04	5.49	5.56	5.53	5.46	5.35	5.19	5.02
Specific Heat Btu-in/lb-sec^2-°F	41.9	44.5	46.8	48.8	50.8	52.8	55.1

Table A.1-3: Summary of Material Properties
SA-533 Grade A Class 2 Shell Material

PROPERTY	TEMPERATURE (°F)						
	70	200	300	400	500	600	700
Young's Modulus psi x 1.0 E06	29.20	28.50	28.00	27.40	27.00	26.40	25.30
Coefficient of Thermal Expansion in/in/°F x 1.0 E-06	7.06	7.25	7.43	7.58	7.70	7.83	7.94
Density lb-sec^2/in^4 x 1.0E-04	7.32	7.30	7.283	7.265	7.248	7.23	7.211

Table A.1-4: Summary of Material Properties
SA-216 Grade WCC Channelhead Material

PROPERTY	TEMPERATURE (°F)						
	70	200	300	400	500	600	700
Young's Modulus psi x 1.0 E06	29.50	28.80	28.30	27.70	27.30	26.70	25.50
Coefficient of Thermal Expansion in/in/°F x 1.0 E-06	5.53	5.89	6.26	6.61	6.91	7.17	7.41
Density lb-sec^2/in^4 x 1.0E-04	7.32	7.30	7.29	7.27	7.26	7.24	7.22

Table A.1-5: Summary of Tube/Tubesheet Minimum Contact Pressures Values and Maximum H* Values for Point Beach Unit 1 Steam Generators

a,c,e

Table A.2-1: Cumulative Forces Resisting Pull Out from the Top of the Tubesheet Hot Leg SLB Conditions

a,c,e

Table A.2-2: Cumulative Forces Resisting Pull Out from the Top of the Tubesheet Hot Leg Normal Conditions

a,c,e

Table A.2-3: Cumulative Forces Resisting Pull Out from the Top of the Tubesheet Cold Leg Normal Conditions

a,c,e

a,c,e

Figure A.1-1: Finite Element Model of Model 44F Tubesheet Region

a,c,e

Figure A.1-2: Contact Pressures for Hot Leg SLB Condition at Point Beach Unit 1

a,c,e

Figure A.1-3: Contact Pressures for Hot Leg Normal Operating Condition at Point Beach Unit 1

a,c,e

Figure A.1-4: Contact Pressures for Cold Leg Normal Operating Condition at Point Beach Unit 1

ENCLOSURE 5

WESTINGHOUSE DOCUMENT,
LTR-CDME-05-201-P, "LIMITED INSPECTION OF THE STEAM GENERATOR TUBE PORTION WITHIN THE TUBESHEET AT POINT BEACH UNIT 1",
REVISION 1,
DATED MAY 2006
(PROPRIETARY)

WESTINGHOUSE AUTHORIZATION LETTER
AFFIDAVIT
PROPRIETARY INFORMATION NOTICE
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(60 pages follow)

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Our ref: CAW-06-2139

May 9, 2006

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: LTR-CDME-05-201-P, Rev. 1, "Limited Inspection of the Steam Generator Tube Portion within the Tubesheet at Point Beach Unit 1" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-06-2139 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 use of the accompanying affidavit by Southern California Edison.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-06-2139, and should be addressed to B. F. Maurer, Acting Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

for B. F. Maurer, Acting Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: G. Shukla

CAW-06-2139

AFFIDAVIT

STATE OF CONNECTICUT:

ss Windsor

COUNTY OF HARTFORD:

Before me, the undersigned authority, personally appeared I. C. Rickard, 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:

I. C. Rickard, Licensing Project Manager
Systems and Safety Analysis, Nuclear Services
Westinghouse Electric Company, LLC

Sworn to and subscribed
before me this 9th day
of May, 2006

Notary Public

My Commission Expires: 8/31/09

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).

(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 other 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-05-201-P, Rev. 1, "Limited Inspection of the Steam Generator Tube Portion within the Tubesheet at Point Beach Unit 1" being transmitted by Nuclear Management Company letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted for use by Westinghouse for Point Beach Unit 1 enables Westinghouse to support utilities in identifying and applying a steam generator tubesheet inspection model and, in particular, to determine the tubesheet inspection length appropriate for the Point Beach Unit 1 steam generators, including:

(a) The identification of important factors relevant to determining the recommended steam generator tubesheet inspection length, and

(1) I am Licensing Project Manager, Systems and Safety Analysis, 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.

(b) Development of a generic methodology for applying the inspection length model to utilities with NSSS plants.

Further, this information has substantial commercial value as follows:

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

(b) Westinghouse can sell support and defense of the inspection model.

(c) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

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 inspection models 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.

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