UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

March 12, 2012

Mr. J. R. Morris
Site Vice President
Catawba Nuclear Station
Duke Energy Carolinas, LLC
4800 Concord Road
York, SC 29745

SUBJECT: CATAWBA NUCLEAR STATION, UNITS 1 AND 2, ISSUANCE OF AMENDMENTS REGARDING TECHNICAL SPECIFICATIONS AMENDMENTS FOR PERMANENT ALTERNATE REPAIR CRITERIA FOR STEAM GENERATOR TUBES (TAC NOS. ME6670 AND ME6671)

Dear Mr. Morris:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 267 to Renewed Facility Operating License NPF-35 and Amendment No. 263 to Renewed Facility Operating License NPF-52 for the Catawba Nuclear Station, Units 1 and 2, respectively. The amendments consist of changes to the Technical Specifications (TSs) in response to your application dated June 30, 2011, as supplemented by letters dated July 11, 2011, January 12, 2012, and February 1, 2012.

The amendments revise TS 3.4.13, "RCS [Reactor Coolant System] Operational LEAKAGE," TS 5.5.9, "Steam Generator (SG) Program," and TS 5.6.8, "Steam Generator (SG) Tube Inspection Report." Specifically, the TS changes accomplish the following objectives: permanently exclude portions of a steam generator (SG) tube below the top of the SG tubesheet from periodic SG tube inspections and plugging, permanently reduce the primary-to-secondary leakage limit, and permanently implement reporting requirement changes that had been previously established on a one-cycle basis.

A copy of the related Safety Evaluation is also enclosed. A Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

If you have any questions, please call me at 301-415-1119.

Sincerely,

Jon Thompson

Jon Thompson, Project Manager
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-413 and 50-414

Enclosures:
1. Amendment No. 267 to NPF-35
2. Amendment No. 263 to NPF-52
3. Safety Evaluation

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

DUKE ENERGY CAROLINAS, LLC

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

DOCKET NO. 50-413

CATAWBA NUCLEAR STATION, UNIT 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 267
Renewed License No. NPF-35

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment to the Catawba Nuclear Station, Unit 1 (the facility) Renewed Facility Operating License No. NPF-35 filed by the Duke Energy Carolinas, LLC, acting for itself, and North Carolina Electric Membership Corporation (licensees), dated June 30, 2011, as supplemented by letters dated July 11, 2011, January 12, 2012, and February 1, 2012, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. NPF-35 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 267, which are attached hereto, are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC, shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented prior to entering the applicable Modes of the affected TS at the completion of the outage.

FOR THE NUCLEAR REGULATORY COMMISSION

Nancy Salgado

Nancy Salgado, Chief
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to License No. NPF-35
and the Technical Specifications

Date of Issuance: March 12, 2012

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

DUKE ENERGY CAROLINAS, LLC

NORTH CAROLINA MUNICIPAL POWER AGENCY NO. 1

PIEDMONT MUNICIPAL POWER AGENCY

DOCKET NO. 50-414

CATAWBA NUCLEAR STATION, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 263
Renewed License No. NPF-52

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment to the Catawba Nuclear Station, Unit 2 (the facility) Renewed Facility Operating License No. NPF-52 filed by the Duke Energy Carolinas, LLC, acting for itself, North Carolina Municipal Power Agency No. 1 and Piedmont Municipal Power Agency (licensees), dated June 30, 2011, as supplemented by letters dated July 11, 2011, January 12, 2012, and February 1, 2012, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (I) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

Enclosure 2

2. Accordingly, the license is hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. NPF-52 is hereby amended to read as follows:

   (2) <u>Technical Specifications</u>

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 263, which are attached hereto, are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC, shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented prior to entering the applicable Modes of the affected TS at the completion of the outage.

FOR THE NUCLEAR REGULATORY COMMISSION

Nancy Salgado

Nancy Salgado, Chief
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to License No. NPF-52
and the Technical Specifications

Date of Issuance: March 12, 2012

ATTACHMENT TO

LICENSE AMENDMENT NO. 267

RENEWED FACILITY OPERATING LICENSE NO. NPF-35

DOCKET NO. 50-413

AND LICENSE AMENDMENT NO. 263

RENEWED FACILITY OPERATING LICENSE NO. NPF-52

DOCKET NO. 50-414

Replace the following pages of the Renewed Facility Operating Licenses and the Appendix A Technical Specifications (TSs) with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
Licenses	Licenses
NPF-35, page 4	NPF-35, page 4
NPF-52, page 4	NPF-52, page 4
TSs	TSs
3.4.13-1	3.4.13-1
3.4.13-2	3.4.13-2
5.5-7a	5.5-7a
5.5-8	5.5-8
5.6-6	5.6-6

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 267, which are attached hereto, are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC shall operate the facility in accordance with the Technical Specifications.

(3) Updated Final Safety Analysis Report

The Updated Final Safety Analysis Report supplement submitted pursuant to 10 CFR 54.21(d), as revised on December 16, 2002, describes certain future activities to be completed before the period of extended operation. Duke shall complete these activities no later than December 6, 2024, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

The Updated Final Safety Analysis Report supplement as revised on December 16, 2002, described above, shall be included in the next scheduled update to the Updated Final Safety Analysis Report required by 10 CFR 50.71(e)(4), following issuance of this renewed operating license. Until that update is complete, Duke may make changes to the programs described in such supplement without prior Commission approval, provided that Duke evaluates each such change pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

(4) Antitrust Conditions

Duke Energy Carolinas, LLC shall comply with the antitrust conditions delineated in Appendix C to this renewed operating license.

(5) Fire Protection Program (Section 9.5.1, SER, SSER #2, SSER #3, SSER #4, SSER #5)*

Duke Energy Carolinas, LLC shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report, as amended, for the facility and as approved in the SER through Supplement 5, subject to the following provision:

> The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

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*The parenthetical notation following the title of this renewed operating license condition denotes the section of the Safety Evaluation Report and/or its supplement wherein this renewed license condition is discussed.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 263, which are attached hereto, are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC shall operate the facility in accordance with the Technical Specifications.

(3) Updated Final Safety Analysis Report

The Updated Final Safety Analysis Report supplement submitted pursuant to 10 CFR 54.21(d), as revised on December 16, 2002, describes certain future activities to be completed before the period of extended operation. Duke shall complete these activities no later than February 24, 2026, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

The Updated Final Safety Analysis Report supplement as revised on December 16, 2002, described above, shall be included in the next scheduled update to the Updated Final Safety Analysis Report required by 10 CFR 50.71(e)(4), following issuance of this renewed operating license. Until that update is complete, Duke may make changes to the programs described in such supplement without prior Commission approval, provided that Duke evaluates each such change pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

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(5) Fire Protection Program (Section 9.5.1, SER, SSER #2, SSER #3, SSER #4, SSER #5)*

Duke Energy Carolinas, LLC shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report, as amended, for the facility and as approved in the SER through Supplement 5, subject to the following provision:

> The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

*The parenthetical notation following the title of this renewed operating license condition denotes the section of the Safety Evaluation Report and/or its supplements wherein this renewed license condition is discussed.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE; and

d. 150 gallons per day (Unit 1) and 45 gallons per day (Unit 2) primary to secondary LEAKAGE through any one steam generator (SG).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS operational LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> Pressure boundary LEAKAGE exists. <u>OR</u> Primary to secondary LEAKAGE not within limit.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	-----NOTES----- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE. ---------- Verify RCS Operational LEAKAGE within limits by performance of RCS water inventory balance.	-----NOTE----- Only required to be performed during steady state operation ---------- In accordance with the Surveillance Frequency Control Program
SR 3.4.13.2	-----NOTE----- Not required to be performed until 12 hours after establishment of steady state operation. ---------- Verify primary to secondary LEAKAGE is $\leq$ 150 gallons per day (Unit 1) and $\leq$ 45 gallons per day (Unit 2) through any one SG.	-----NOTE----- Only required to be performed during steady state operation ---------- In accordance with the Surveillance Frequency Control Program

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

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

1. For Unit 2 only, tubes with service-induced flaws located greater than 14.01 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 14.01 inches below the top of the tubesheet shall be plugged upon detection.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. For Unit 1, the number and portions of the tubes inspected and method of inspection shall be performed with the objective of detecting flaws of any type (for example, 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. For Unit 2, the number and portions of the tubes inspected and method of inspection shall be performed with the objective of detecting flaws of any type (for example, volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side, and that may satisfy the applicable tube repair criteria. In addition to meeting requirements d.1, d.2, d.3, and d.4 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.

(continued)

5.5.9 Steam Generator (SG) Program (continued)

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

2. For Unit 1, inspect 100% of the tubes at sequential periods of 144, 108, 72, and, thereafter, 60 Effective Full Power Months (EFPM). 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 EFPM or three refueling outages (whichever is less) without being inspected.

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

4. For Unit 1, 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 EFPM or one refueling outage (whichever is less). For Unit 2, if crack indications are found in any SG tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 EFPM 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 crack(s), then the indication need

(continued)

5.6 Reporting Requirements

5.6.8 Steam Generator (SG) Tube Inspection Report (continued)

h. For Unit 2, the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign leakage to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,

i. For Unit 2, the calculated accident leakage rate from the portion of the tubes below 14.01 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident leakage rate from the most limiting accident is less than 3.27 times the maximum primary to secondary LEAKAGE rate, the report shall describe how it was determined, and

j. For Unit 2, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO

AMENDMENT NO. 267 TO RENEWED FACILITY OPERATING LICENSE NPF-35

AND

AMENDMENT NO. 263 TO RENEWED FACILITY OPERATING LICENSE NPF-52

DUKE ENERGY CAROLINAS, LLC

CATAWBA NUCLEAR STATION, UNITS 1 AND 2

DOCKET NOS. 50-413 AND 50-414

1.0 INTRODUCTION

By application dated June 30, 2011 (Reference 1), as supplemented by letters dated July 11, 2011 (Reference 2), January 12, 2012 (Reference 3), and February 1, 2012 (Reference 4), Duke Energy Carolinas, LLC (Duke Energy, the licensee), requested changes to the Technical Specifications (TSs) for the Catawba Nuclear Station, Units 1 and 2 (Catawba 1 and 2). Portions of the letters dated June 30, 2011, July 11, 2011, and January 12, 2012, contain sensitive unclassified non-safeguards information (proprietary) and those portions have been withheld from public disclosure.

The supplemental letters dated July 11, 2011, January 12, 2012, and February 1, 2012, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the U.S. Nuclear Regulatory Commission (NRC) staff's original proposed no significant hazards consideration determination as published the *Federal Register* on January 19, 2012 (77 FR 2766).

The amendments would revise TS 3.4.13, "RCS [Reactor Coolant System] Operational LEAKAGE," TS 5.5.9, "Steam Generator (SG) Program," and TS 5.6.8, "Steam Generator (SG) Tube Inspection Report." Specifically, the proposed changes would accomplish the following objectives: permanently exclude portions of a steam generator (SG) tube below the top of the SG tubesheet from periodic SG tube inspections and plugging, permanently reduce the primary-to-secondary leakage limit, and permanently implement reporting requirement changes that had been previously established on a one-cycle basis.

2.0 BACKGROUND

Catawba 2 has four Model D5 SGs, which were designed and fabricated by Westinghouse Electric Company LLC (Westinghouse). There are 4,578 Alloy 600 thermally treated (TT) tubes in each SG and each tube has a nominal outside diameter of 0.750 inches and a nominal wall thickness of 0.043 inches. The tubes are hydraulically expanded for the full depth of the 21-inch thick tubesheet and are welded to the tubesheet at each tube end. Until the fall of 2004, no instances of stress-corrosion cracking (SCC) affecting the tubesheet region of TT Alloy 600 tubing had been reported at any nuclear power plants in the United States.

In the fall of 2004, crack-like indications were found in tubes in the tubesheet region of Catawba 2. These crack-like indications were found in a tube overexpansion (OXP) that was approximately 7 inches below the top of the tubesheet (TTS) (hot-leg side) in one tube, and just above the tube-to-tubesheet (T/TS) weld in a region of the tube known as the tack expansion region in several other tubes. Indications were also reported near the T/TS welds, which join the tube to the tubesheet. An OXP is created when the tube is expanded into a tubesheet bore hole that is not perfectly round. These out-of-round conditions were created during the tubesheet drilling process by conditions such as drill bit wandering or chip gouging. The tack expansion is an approximately 1-inch-long expansion at each tube end. The purpose of the tack expansion is to facilitate performing the T/TS weld, which is made prior to the hydraulic expansion of the tube over the full tubesheet depth.

Since the initial findings at Catawba 2 in the fall of 2004, other nuclear plants with Alloy 600 TT tubing have found crack-like indications in tubes within the tubesheet as well. These plants include Braidwood Station, Unit 2 (Braidwood 2), Byron Station, Unit 2 (Byron 2), Comanche Peak Nuclear Power Plant, Unit 2 (Comanche Peak 2), Surry Power Station, Unit 2 (Surry 2), Vogtle Electric Generating Plant, Unit 1 (Vogtle 1), and Wolf Creek Generating Station (Wolf Creek). Most of the indications were found in the tack expansion region near the tube-end welds and were a mixture of axial and circumferential primary water stress-corrosion cracking.

Over time, these cracks can be expected to become more and more extensive, necessitating more extensive inspections of the lower tubesheet region and more extensive tube plugging or repairs, with attendant increased cost and the potential for shortening the useful lifetime of the SGs. To avoid these impacts, the affected licensees and their contractor, Westinghouse, have developed proposed alternative inspection and repair criteria applicable to the tubes in the lowermost region of the tubesheets. These criteria are referred to as the "H*" criteria. H* is the minimum engagement distance between the tube and tubesheet, measured downward from the TTS, that is proposed as needed to ensure the structural and leakage integrity of the T/TS joints. The proposed H* license amendment request (LAR) would exclude the portions of tubing below the H* distance from inspection and plugging requirements on the basis that flaws below the H* distance are not detrimental to the structural and leakage integrity of the T/TS joints.

As early as 2005, requests for permanent H* amendments were proposed for a number of plants, including Catawba 2 (Reference 5). The NRC staff identified a number of issues with these early LARs and in subsequent LARs made in 2009 and was unable to approve H* amendments on a permanent basis until these issues were resolved. The NRC staff found it did have a sufficient basis to approve H* amendments on a interim (temporary) basis, based on the relatively limited extent of cracking that existed in the lower tubesheet region at the time the interim amendments were approved. The technical basis for approving the interim amendments is provided in detail in the NRC staff's safety evaluations (SEs) accompanying issuance of these amendments. Interim H* amendments were approved for Catawba 2 as early as 2006 and most recently in 2010 (Reference 6).

3.0 REGULATORY EVALUATION

In Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Section 50.36, "Technical specifications," the requirements related to the content of the TSs are established. Pursuant to 10 CFR 50.36, TSs are required to include items in the following five categories related to station operation: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) surveillance requirements (SRs); (4) design features; and (5) administrative controls. The rule does not specify the particular requirements to be included in a plant's TS.

In 10 CFR 50.36(c)(2), LCOs are stated to be "the lowest functional capability or performance levels of equipment required for safe operation of the facility." For Catawba 2, the LCO pertaining to the subject LAR is in TS 3.4.13, "RCS Operational LEAKAGE." The regulations at 10 CFR 50.36(c)(5) state 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." Administrative controls also include the programs established by the licensee and listed in Section 5.0 of the TS, "ADMINISTRATIVE CONTROLS." For Catawba 2, the pertinent requirements for performing SG tube inspections and repair are in TS 5.5.9, "Steam Generator (SG) Program," while the requirements for reporting the SG tube inspections and repair are in TS 5.6.8, "Steam Generator (SG) Tube Inspection Report."

The TSs for all pressurized-water reactor (PWR) plants require that an SG program be established and implemented to ensure that SG tube integrity is maintained. For Catawba 2,SG tube integrity is maintained by meeting the performance criteria specified in TS 5.5.9.b for structural and leakage integrity, consistent with the plant design and licensing basis. TS 5.5.9.a requires that a condition monitoring assessment be performed during each outage in which the SG tubes are inspected, to confirm that the performance criteria are being met. TS 5.5.9.d includes provisions regarding the scope, frequency, and methods of SG tube inspections. These provisions require that the inspections be performed with the objective of detecting flaws of any type that may be present along the length of a tube and that may satisfy the applicable tube repair criteria. The applicable tube repair criteria, specified in TS 5.5.9.c, are that tubes found during inservice inspection to contain flaws with a depth equal to or exceeding 40 percent of the nominal wall thickness shall be plugged, unless the tubes are permitted to remain in service through application of alternate repair criteria provided in TS 5.5.9.c.1, such as is being proposed for Catawba 2. The plant TS (TS 3.4.13) also include a limit on operational primary-to-secondary leakage (typically 150 gallons per day (gpd)), beyond which the plant must be promptly shut down. Should a flaw exceeding the tube repair limit not be detected during the periodic tube surveillance required by the plant TSs, the operational leakage limit provides added assurance of timely plant shutdown before tube structural and leakage integrity, consistent with the design and licensing bases, are impaired.

The SG tubes are part of the reactor coolant pressure boundary (RCPB) and isolate fission products in the primary coolant from the secondary coolant and the environment. For the purposes of this SE, SG tube integrity means that the tubes are capable of performing this safety function in accordance with the plant design and licensing basis. The regulations in Appendix A, "General Design Criteria for Nuclear Power Plants" (GDC) to 10 CFR Part 50 provide regulatory requirements for the RCPB including the requirement that it shall have "...an extremely low probability of abnormal leakage ... and of gross rupture" (GDC 14, "Reactor coolant pressure boundary"), "shall be designed with sufficient margin" (GDC 15, "Reactor coolant system design," and GDC 31, "Fracture prevention of reactor coolant pressure boundary"), "shall be designed ... to the highest quality standards practical" (GDC 30, "Quality of reactor coolant pressure boundary"), and shall be designed to permit "periodic inspection and testing...to assess...structural and leaktight integrity" (GDC 32, "Inspection of reactor coolant pressure boundary"). To this end, 10 CFR 50.55a(c)(1) specifies, in part, that that "Components which are part of the reactor coolant pressure boundary must meet the requirements for Class 1 components in Section III of the ASME [American Society of Mechanical Engineers] *Boiler and Pressure Vessel Code*, except as provided in paragraphs (c)(2), (c)(3), and (c)(4)..." Paragraph 10 CFR 50.55a(g)(4) further requires that throughout the service life of PWR facilities like Catawba 2, ASME Code Class 1 components "...must meet the requirements, except for design and access provisions and preservice examination requirements, set forth in Section XI ..." of the ASME Code "...to the extent practical within the limitations of design, geometry and materials of construction of the components." This requirement includes the inspection and repair criteria of Section XI of the ASME Code. The Section XI requirements pertaining to inservice inspection of SG tubing are augmented by additional requirements in the TS.

As part of the plant's licensing bases, applicants for PWR licenses are required to analyze the consequences of postulated design-basis accidents (DBAs), such as a SG tube rupture and a main steam line break (MSLB). These analyses consider primary-to-secondary leakage that may occur during these events and must show that the offsite radiological consequences do not exceed the applicable limits of 10 CFR 50.67, "Accident source term," and GDC 19, "Control room," for control room operator doses (or some fraction thereof as appropriate to the accident), or the NRC-approved licensing basis (e.g., a small fraction of these limits). No accident analyses for Catawba 2 are being changed because of the proposed amendment and, thus, no radiological consequences of any accident analysis are being changed. The use of the proposed alternate repair criteria does not impact the integrity of the SG tubes, and the SG tubes, therefore, still meet the requirements of the GDC and the requirements for Class 1 components in Section III of the ASME Code. The proposed changes maintain the accident analyses and consequences that the NRC staff has reviewed and approved for the postulated DBAs for SG tubes.

By letter dated September 27, 2010 (Reference 5), Amendment No. 257 to the Catawba 2 license modified TS 5.5.9 and TS 5.6.8 incorporating interim alternate repair criteria and associated tube inspection and reporting requirements that are applicable during the Catawba 2 End of Cycle 17 Refueling Outage and extending through subsequent Cycle 18 operation. Similar interim amendments, with H* values ranging between 13 and 18 inches, are currently approved for 11 other plants. The proposed permanent amendment is similar to the currently approved interim amendment with two exceptions. First, the H* distance would be reduced (relaxed) to 14.01 inches from the currently applicable value of 20 inches. Second, the proposed amendment would reduce the LCO limit on primary-to-secondary leakage from the current value of 150 gpd to a more restrictive value of 45 gpd.

4.0 TECHNICAL EVALUATION

4.1 Proposed Changes to the TS

In References 1 and 3, the licensee proposed the following changes to the TSs:

TS 3.4.13, RCS Operational LEAKAGE

Current LCO 3.4.13.d states:

> 150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG).

Revised LCO 3.4.13.d would state:

> 150 gallons per day (Unit 1) and 45 gallons per day (Unit 2) primary to secondary LEAKAGE through any one steam generator (SG).

Current SR 3.4.13.2 states:

> Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG.

Revised SR 3.4.13.2 would state:

> Verify primary to secondary LEAKAGE is ≤ 150 gallons per day (Unit 1) and ≤ 45 gallons per day (Unit 2) through any one SG.

TS 5.5.9, Steam Generator (SG) Program

Current TS 5.5.9.c.1 states:

> For Unit 2 only, during the End of Cycle 17 Refueling Outage and subsequent Cycle 18 operation, tubes with service-induced flaws located greater than 20 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 20 inches below the top of the tubesheet shall be plugged upon detection.

Revised TS 5.5.9.c.1 would state:

> For Unit 2 only, tubes with service-induced flaws located greater than 14.01 inches below the top of the tubesheet do not require plugging. Tubes with

service-induced flaws located in the portion of the tube from the top of the tubesheet to 14.01 inches below the top of the tubesheet shall be plugged upon detection.

Current TS 5.5.9.d states:

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. For Unit 1, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (for example, 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. For Unit 2, during the End of Cycle 17 Refueling Outage and subsequent Cycle 18 operation, the number and portions of the tubes inspected and method of inspection shall be performed with the objective of detecting flaws of any type (for example, volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from 20 inches below the top of the tubesheet on the hot leg side to 20 inches below the top of the tubesheet on the cold leg side, and that may satisfy the applicable tube repair criteria. In addition to meeting the requirements of d.1, d.2, d.3, and d.4 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.

Revised TS 5.5.9.d would state:

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. For Unit 1, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (for example, 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. For Unit 2, the number and portions of the tubes inspected and method of inspection shall be performed with the objective of detecting flaws of any type (for example, volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side, and that may satisfy the applicable tube repair criteria. In addition to meeting the requirements of d.1, d.2, d.3, and d.4 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.

Current TS 5.5.9.d.4 states:

4. For Unit 1, 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 EFPM[1] or one refueling outage (whichever is less). For Unit 2, during the End of Cycle 17 Refueling Outage and subsequent Cycle 18 operation, if crack indications are found in any SG tube from 20 inches below the top of the tubesheet on the hot leg side to 20 inches below the top of the tubesheet on the cold leg side, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 EFPM 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 crack(s), then the indication need not be treated as a crack.

Revised TS 5.5.9.d.4 would state:

4. For Unit 1, 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 EFPM or one refueling outage (whichever is less). For Unit 2, if crack indications are found in any SG tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 EFPM 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 crack(s), then the indication need not be treated as a crack.

<u>TS 5.6.8, Steam Generator (SG) Tube Inspection Report</u>

Current TS 5.6.8.h, 5.6.8.i, and 5.6.8.j state:

h. For Unit 2, following completion of an inspection performed during the End of Cycle 17 Refueling Outage (and any inspections performed during subsequent Cycle 18 operation), the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign leakage to an

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1 Effective full power months.

individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,

i. For Unit 2, following completion of an inspection performed during the End of Cycle 17 Refueling Outage (and any inspections performed during subsequent Cycle 18 operation), the calculated accident induced leakage rate from the portion of the tubes below 20 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident leakage rate from the most limiting accident is less than 3.27 times the maximum primary to secondary LEAKAGE rate, the report shall describe how it was determined, and

j. For Unit 2, following completion of an inspection performed during the End of Cycle 17 Refueling Outage (and any inspections performed during subsequent Cycle 18 operation), the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

Revised TS 5.6.8.h, 5.6.8.i, and 5.6.8.j would state:

h. For Unit 2, the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign leakage to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,

i. For Unit 2, the calculated accident induced leakage rate from the portion of the tubes below 14.01 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident leakage rate from the most limiting accident is less than 3.27 times the maximum primary to secondary LEAKAGE rate, the report shall describe how it was determined, and

j. For Unit 2, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

4.2 <u>Technical Discussion</u>

The T/TS joints are part of the pressure boundary between the primary and secondary systems. Each T/TS joint consists of the tube, which is hydraulically expanded against the bore of the tubesheet, the T/TS weld located at the tube end, and the tubesheet. The joints were designed in accordance with the ASME Code, Section III, as welded joints, not as friction joints. The T/TS welds were designed to transmit the tube end-cap pressure loads, during normal operating and

DBA conditions, from the tubes to the tubesheet with no credit taken for the friction developed between the hydraulically expanded tube and the tubesheet. In addition, the welds serve to make the joints leak tight.

This design basis is a conservative representation of how the T/TS joints actually work, since it ignores the role of friction between the tube and tubesheet in reacting the tube end-cap loads. The initial hydraulic expansion of the tubes against the tubesheet produces an "interference fit" between the tubes and the tubesheet; thus producing a residual contact pressure (RCP) between the tubes and tubesheet, which acts normally to the outer surface of the tubes and the inner surface of the tubesheet bore holes. Additional contact pressure between the tubes and tubesheet is induced by operational conditions as will be discussed in detail below. The amount of friction force that can be developed between the outer tube surface and the inner surface of the tubesheet bore is a direct function of the contact pressure between the tube and tubesheet times the applicable coefficient of friction.

To support the proposed TS changes, the licensee's contractor, Westinghouse, has defined a parameter called H* to be that distance below the TTS over which sufficient frictional force, with acceptable safety margins, can be developed between each tube and the tubesheet under tube end-cap pressure loads associated with normal operating and design basis accident conditions to prevent significant slippage or pullout of the tube from the tubesheet, assuming the tube is fully severed at the H* distance below the TTS. For Catawba 2, the proposed H* distance is 14.01 inches. Given that the frictional force developed in the T/TS joint over the H* distance is sufficient to resist the tube end-cap pressure loads, it is the licensee's and Westinghouse's position that the length of tubing between the H* distance and the T/TS weld is not needed to resist any portion of the tube end-cap pressure loads. Thus, the licensee is proposing to change the TS to not require inspection of the tubes below the H* distance and to exclude tube flaws located below the H* distance (including flaws in the T/TS weld) from the application of the TS tube repair criteria. Under these changes, the T/TS joint would now be treated as a friction joint extending from the TTS to a distance below the TTS equal to H* for purposes of evaluating the structural and leakage integrity of the joint.

The NRC staff evaluated the subject LAR to determine whether the amended TSs continue to ensure that tube integrity will be maintained, consistent with the current design and licensing basis. This includes maintaining structural safety margins consistent with the structural performance criteria in TS 5.5.9.b.1 and the design basis, as is discussed in Section 4.2.1.1 of this SE. In addition, this includes limiting the potential for accident-induced primary-to-secondary leakage to values not exceeding the accident-induced leakage performance criteria in TS 5.5.9.b.2, which are consistent with values assumed in the licensing basis accident analyses. Maintaining tube integrity in this manner ensures that the amended TS are in compliance with all applicable regulations. The NRC staff's evaluation of joint structural integrity and accident-induced leakage integrity is discussed in Sections 4.2.1 and 4.2.2 of this SE, respectively. The NRC staff's evaluation of the proposed change to the LCO limit in TS 3.4.13 for operational primary-to-secondary leakage is addressed in Section 4.2.2 of this SE since the change is intended to provide added assurance of accident leakage integrity.

4.2.1 Joint Structural Integrity

4.2.1.1 Acceptance Criteria

Westinghouse has conducted extensive analyses to establish the necessary H* distance to resist pullout under normal operating and DBA conditions. The NRC staff concurs that pullout is the structural failure mode of interest since the tubes are radially constrained against axial fishmouth rupture by the presence of the tubesheet. The axial force which could produce pullout derives from the pressure end-cap loads due to the primary-to-secondary pressure differentials associated with normal operating and DBA conditions. Westinghouse determined the needed H* distance on the basis of maintaining a factor of 3 against pullout under normal operating conditions and a factor of 1.4 against pullout under DBA conditions. The NRC staff agrees that these are the appropriate safety factors to apply to demonstrate structural integrity. These safety factors are consistent with the safety factors embodied in the structural integrity performance criteria in TS 5.5.9.b.1 and with the design basis; namely the stress limit criteria in Section III of the ASME Code.

The above approach equates tube pullout to gross structural failure which is conservative. Should the pullout load be exceeded, tube slippage would generally be limited by the presence of adjacent tubes and support structures such that the tube would not be expected to pull out of the tubesheet.

In Reference 4, the licensee provided the following commitment for tube slippage monitoring as part of the SG inspection program:

> For Unit 2, Catawba commits to monitor for tube slippage as part of the SG tube inspection program required by TS 5.5.9. The results of this monitoring will be included in the report required by TS 5.6.8.j.

Under the proposed license amendment, TS 5.6.8.j will require that the results of slippage monitoring be included as part of the 180-day report required by TS 5.6.8. TS 5.6.8.j will also require that, should slippage be discovered, the implications of the discovery and corrective action shall be included in the report. The NRC staff finds that slippage is not expected to occur for the reasons discussed in this SE. In the unexpected event it should occur, it will be important to understand why it occurred so that the need for corrective action can be evaluated. The NRC staff concludes the commitment to monitor for slippage and the accompanying reporting requirements are acceptable.

4.2.1.2 Three Dimensional Finite Element Analysis

A detailed three-dimensional (3-D) finite element analysis (FEA) of the lower SG assembly (consisting of the lower portion of the SG shell, the tubesheet, the channel head, and the divider plate separating the hot- and cold-leg inlet plenums inside the channel head) was performed to calculate tubesheet displacements due to primary pressure acting on the primary face of the tubesheet and SG channel head, secondary pressure acting on the secondary face of the tubesheet and SG shell, and the temperature distribution throughout the entire lower SG assembly. The calculated tubesheet displacements were used as input to the T/TS interaction analysis evaluated in Section 4.2.1.3 of this SE.

The tubesheet bore holes were not explicitly modeled. Instead, the tubesheet was modeled as a solid structure with equivalent material property values selected such that the solid model exhibited the same stiffness properties as the actual perforated tubesheet. This is a standard approach for analyzing perforated plates that the NRC staff finds acceptable.

Two versions of the 3-D FEA model were used to support the subject LAR, a "reference model" documented in Reference 7, which was submitted to support the interim H* amendment for Catawba 2 approved by the NRC staff in 2010 (Reference 6), and a "revised model" described in the technical support document (Reference 8) enclosed with the subject LAR.. The reference 3-D FEA model was used to provide displacement input to the thick shell T/TS interaction model described in Section 4.2.1.3.1 of this SE. The revised 3-D FEA model was used to provide displacement input to the square cell T/TS interaction model described in Section 4.2.1.3.2 of this SE.

The revised 3-D model employs a revised mesh near the plane of symmetry (perpendicular to the divider plate) to be consistent with the geometry of the square cell model such that the displacement output from the 3-D model can be applied directly to the edges of the square cell model. In addition, the mesh near the TTS was enhanced to accommodate high-temperature gradients in this area during normal operating conditions. This allowed the temperature distributions throughout the lower SG assembly, including the tubesheet region to be calculated directly in the 3-D FEA from the assumed plant temperature conditions (e.g., from the assumed primary and secondary water temperatures) for each operating condition. The NRC staff finds this a more realistic approach relative to the reference analysis where a linear distribution of temperature was assumed to exist through the thickness of the tubesheet in the 3-D FEA with an adjustment factor being applied to the H* calculations for the case of normal operating conditions to account for the actual temperature distribution in the tubesheet based on sensitivity analyses.

Some non-U.S. units have experienced cracks in the weld between the divider plate and the stub runner attachment on the bottom of the tubesheet. Should such cracks ultimately cause the divider plate to become disconnected from the tubesheet, tubesheet vertical and radial displacements under operational conditions could be significantly increased relative to those for an intact divider plate weld. Although the industry believes that there is little likelihood that cracks such as those seen abroad could cause a failure of the divider plate weld, the 3-D FEA conservatively considered both the case of an intact divider plate weld and a detached divider plate weld to ensure a conservative analysis. The case of a detached divider plate weld was found to produce the most limiting H* values. In the reference analyses (Reference 7), a factor was applied to the 3-D FEA results to account for a non-functional divider plate, based on earlier sensitivity studies. The revised 3-D FEA model assumes the upper 5 inches of the divider plate to be non-existent. The NRC staff finds this further improves the accuracy of the 3-D FEA for the assumed condition of a non-functional divider plate.

4.2.1.3 <u>T/TS Interaction Model</u>

4.2.1.3.1 Thick Shell Model

The resistance to tube pullout is the axial friction force developed between the expanded tube and the tubesheet over the H* distance. The friction force is a function of the radial contact pressure between the expanded tube and the tubesheet. In the reference analysis (Reference 7), Westinghouse used classical thick shell equations to model the interaction effects between the tubes and tubesheet under various pressure and temperature conditions for purposes of calculating contact pressure (T/TS interaction model). Calculated displacements from the 3-D FEA of the lower tubesheet assembly (see Section 4.2.1.2 of this SE above) were applied to the thick shell model as input to account for the increment of tubesheet bore diameter change caused by the primary pressure acting on the primary face of the tubesheet and SG channel head, secondary pressure acting on the secondary face of the tubesheet and SG shell, and the temperature distribution throughout the entire lower SG assembly. However, the tubesheet bore diameter change from the 3-D FEA tended to be non-uniform (eccentric) around the bore circumference. The thick shell equations used in the T/TS interaction model are axisymmetric. Thus, the non-uniform diameter change from the 3-D FEA had to be adjusted to an equivalent uniform value before it could be used as input to the T/TS interaction analysis. A two-dimensional (2-D) plane stress finite element model was used to define a relationship for determining a uniform diameter change that would produce the same change to average T/TS contact pressure as would the actual non-uniform diameter changes from the 3-D finite element analyses.

In Reference 7, Westinghouse identified a difficulty in applying this relationship to Model D5 SGs under MSLB conditions. In reviewing the reasons for this difficulty, the NRC staff developed questions relating to the conservatism of the relationship and whether the tubesheet bore displacement eccentricities are sufficiently limited so as to ensure that T/TS contact is maintained around the entire tube circumference. This concern was applicable to all SG models with Alloy 600 TT tubing. In Reference 9, the NRC staff documented a list of questions that would need to be addressed satisfactorily before the NRC staff would be able to approve a permanent H* amendment. These questions related to the technical justification for the eccentricity adjustment, the distribution of contact pressure around the tube circumference, and a new model under development by Westinghouse to address the aforementioned issue encountered with the Model D5 SGs.

On June 14 and 15, 2010, the NRC staff conducted an audit at the Westinghouse Waltz Mill Site (Reference 10). The purpose of the audit was to gain a better understanding of the H* analysis pertaining to eccentricity, to review information related to the NRC staff's questions in Reference 9, and to determine which documents would need to be provided on the docket to support any future requests for a permanent H* amendment. Based on the audit, including review of pertinent draft information related to Reference 8, the NRC staff concluded that eccentricity does not appear to be a significant variable affecting either average T/TS contact pressure at a given elevation or calculated values of H*. The NRC staff found that average contact pressure at a given elevation is primarily a function of average bore diameter change at that elevation associated with the pressure and temperature loading of the tubesheet.

Accordingly, the NRC staff concluded that no adjustment of computed average bore diameter change considered in the thick shell model is needed to account for eccentricities computed by the 3-D FEA.

The material reviewed during the audit revealed that computed H* values from the reference analyses continued to be conservative when the eccentricity adjustment factor is not applied.

4.2.1.3.2 Square Cell Model

Documentation for the square cell model (Reference 8) is included with the subject LAR for Catawba 2 (Reference 1). The square cell model is a 2-D plane stress FEA model of a single square cell of the tubesheet with a bore hole in the middle and each of the four sides of the cell measuring one tube pitch in length. Displacement boundary conditions are applied at the edges of the cell, based on the displacement data from the revised 3-D FEA model. The model also includes the tube cross-section inside the bore. Displacement compatibility between the tube outer surface and bore inner surface is enforced except at locations where a gap between the tube and bore tries to occur.

The 2-D plane stress FEA model was originally developed in response to the difficulty encountered when applying the eccentricity adjustment to Model D SGs T/TS interaction analysis under MSLB conditions using the thick shell model (see discussion in SE Section 4.2.1.3.1). Early results with this model indicated significant differences as compared to the thick shell model, irrespective of whether the eccentricity adjustment was applied to the thick shell model. The square cell model revealed a fundamental problem with how the results of the 3-D FEA model of the lower SG assembly were being applied to the tubesheet bore surfaces in the thick shell model. As discussed in Section 4.2.1.2 of this SE, the perforated tubesheet is modeled in the 3-D FEA model as a solid plate whose material properties were selected such that the gross stiffness of the solid plate is equivalent to that of a perforated plate under the primary-to-secondary pressure acting across the thickness of the plate. This approach tends to smooth out the distribution of tubesheet displacements as a function of radial and circumferential location in the tubesheet and ignores local variations of the displacements at the actual bore locations. These smoothed-out displacements from the 3-D FEA results were the displacements applied to the bore surface locations in the thick shell model. The square cell model provides a means for post-processing the 3-D FEA results such as to account for localized variations of tubesheet displacement at the bore locations as part of T/TS interaction analysis. Based on these findings, square cell models were developed for each of the SG model types including the Model D5 SGs at Catawba 2.

The square cell model is applied at nine different tubesheet elevations, from the TTS to the bottom of the tubesheet, for each tube and loading case analyzed. The square cell slices at each elevation are assumed to act independently of one another. T/TS contact pressure results from each of the nine slices are used to define the contact pressure distribution from the TTS to the bottom of the tubesheet.

The resisting force to the applied end-cap load, developed over each incremental axial distance beginning at the TTS, is obtained by taking the product of the average contact pressure measured over that incremental distance multiplied by the tubesheet bore surface area (equal to the tube outer diameter surface area) and dividing it by the product of the incremental axial distance multiplied by the coefficient of friction. The NRC staff reviewed the coefficient of friction used in the analysis and judged it to be a reasonable lower bound (conservative) estimate. The H* distance for each tube was determined by integrating the incremental friction forces from the TTS to the distance below the TTS where the friction force integral equaled the applied end-cap load multiplied by the appropriate safety factor as discussed in Section 4.2.1.1 of this SE.

The square cell model assumes an initial condition whereby each tube is fully expanded against the tubesheet bore such that the outer tube surface is in contact with the inner surface of the tubesheet bore under room temperature, atmospheric pressure conditions, with zero residual contact pressure associated with the hydraulic expansion process. The NRC staff finds the assumption of zero residual contact pressure in all tubes to be a conservative assumption.

During the reference analysis, the limiting tube locations in terms of H* were determined to lie along the plane of symmetry perpendicular to the divider plate. The outer edges of the square cell model conform to the revised mesh pattern along this plane of symmetry in the 3-D FEA model of the lower SG assembly, as discussed above in Section 4.2.1.2 of this SE. As the tubesheet bore holes were not explicitly modeled in the 3-D FEA, only the average displacements along each side of the square cell are known from the 3-D FEA. Three different assumptions with respect to applying displacement boundary conditions to the edges of the square cell model were considered in order to allow for a range of possibilities regarding how local displacements might vary along the length of each side. The most conservative assumption, in terms of maximizing the calculated H* distance, was to apply the average transverse displacement uniformly over the length of each edge of the square cell.

Primary pressure acting on the inside tube surface, and crevice pressure[2] acting on both the tube outside surface and tubesheet bore surface, are not modeled directly as in the case of the thick shell model. Instead, the primary side (inside) of the tube is assumed to have a pressure equal to the primary pressure minus the crevice pressure. Note the crevice pressure varies as a function of the elevation being analyzed, as will be discussed in Section 4.2.1.4 of this SE.

The NRC staff concludes that the square cell model provides for improved compatibility between the 3-D FEA model of the lower SG assembly and the T/TS interaction model, provides more realistic and accurate treatment of the T/TS joint geometry, and adds conservatism relative to the thick shell model used in the reference analyses.

4.2.1.4 Crevice Pressure Evaluation

The H* analyses postulate that interstitial spaces exist between the hydraulically expanded tubes and tubesheet bore surfaces. These interstitial spaces are assumed to act as crevices between the tubes and the tubesheet bore surfaces. The NRC staff finds that the assumption

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[2] Although the tubes are in tight contact with the tubesheet bore surfaces, surface roughness effects are conservatively assumed to create interstitial spaces, which are effectively crevices, between these surfaces. See Section 4.2.1.4 of this SE for more information.

regarding the crevices is conservative since the pressure inside the crevices acts to push against both the tube and the tubesheet bore surfaces, thus reducing contact pressure between the tubes and tubesheet.

For tubes which do not contain through-wall flaws within the thickness of the tubesheet, the pressure inside the crevice is assumed to be equal to the secondary system pressure. For tubes that contain through-wall flaws within the thickness of the tubesheet, a leak path is assumed to exist which extends from the primary coolant inside the tube, through the flaw, and up the crevice to the secondary system. Hydraulic tests were performed on several tube specimens that were hydraulically expanded against tubesheet collar specimens to evaluate the distribution of the crevice pressure from a location where through-wall holes had been drilled into the tubes to the top-of-the-crevice location. The T/TS collar specimens were instrumented at several axial locations to permit direct measurement of the crevice pressures. Tests were conducted for both normal operating and MSLB pressure and temperature conditions.

The NRC staff finds that the use of the drilled holes, rather than through-wall cracks, is conservative since it eliminates any pressure drop between the inside of the tube and the crevice at the whole location. This maximizes the pressure in the crevice at all elevations, thus reducing contact pressure between the tubes and tubesheet.

The crevice pressure data from these tests were used to develop a crevice pressure distribution as a function of normalized distance between the TTS and the H* distance below the TTS where the tube is assumed to be severed. These distributions were used to determine the appropriate crevice pressure at each axial location of the T/TS interaction model and the NRC staff concludes that they are acceptable.

Because the crevice pressure distribution is assumed to extend from the H* location, where crevice pressure is assumed to equal primary pressure, to the TTS, where crevice pressure equals secondary pressure, an initial assumption regarding the H* location is made in order to begin a series of iterative calculations of H* using the T/TS interaction model and the 3-D FEA model. The resulting new H* estimate becomes the initial estimate for the next iteration of H* calculations. This is continued until a final value for H* is obtained.

4.2.1.5 <u>H* Calculation Process</u>

The calculation of H* consists of the following steps for each loading case considered:

1. Develop an initial H* estimate (mean H* estimate) using the T/TS interaction and the 3-D FEA models. The estimate assumes nominal geometric and material properties. For purposes of defining the contact pressure distribution over the length of the T/TS crevice, it is assumed that the tube is severed at the bottom of the tubesheet. Two sets of mean H* estimates are pertinent to the proposed H* value. The first set of mean H* estimates are calculated using the reference T/TS interaction and 3-D FEA models, also referred to as the reference analysis. The second set of mean H* estimates are calculated using the square cell T/TS interaction and revised 3-D FEA models, also referred to as the revised analysis. The maximum mean H* estimate (for the most limiting tube) calculated using the reference analysis is 5.55 inches, using the most

limiting case (normal operating conditions with the associated factor of safety of 3, as discussed above in Section 4.2.1.1 of this SE). This mean H* estimate obtained using the reference analysis includes the adjustments described below in steps 2 and 3 of this section of the SE. The maximum mean H* estimate calculated using the square cell model, in conjunction with the revised 3-D lower SG FEA model, is 10.89 inches. The most limiting loading case for the second set of mean H* estimates is the MSLB (with its associated factor of safety of 1.4). The NRC staff finds that the difference between the two sets of mean H* estimates is due primarily to the improved post-processing of the revised 3-D FEA model displacements for application to the T/TS interaction model used in the second set of mean H* estimates.

2. Adjust the estimate of H* to account for uncertainty in the bottom-of-the-tube expansion transition (BET) location. In the first set of mean H* estimates, developed using the reference T/TS interaction and 3-D FEA models described in Reference 7, a 0.3-inch adjustment was added to the initial H* estimate to account for uncertainty in the BET location relative to the TTS. This 0.3-inch adjustment was based on an uncertainty analysis by Westinghouse regarding the BET for Model F SGs. This adjustment is not included in the revised H* analysis accompanying this LAR, as discussed and evaluated below in Section 4.2.1.5.1 of this SE.

3. Adjust the estimate of H* to correct for temperature distribution. In the first set of mean H* estimates, using the reference analysis for normal operating conditions only, an additional adjustment was added to the initial H* estimate to correct for the actual temperature distribution in the tubesheet in comparison with the linear temperature distribution assumed in the reference 3-D FEA analysis. This adjustment is no longer necessary, as discussed above in Section 4.2.1.2 of this SE, since the temperature distributions throughout the tubesheet were calculated directly in the revised 3-D FEA analysis developed to support the current LAR.

4. Develop a probabilistic estimate of H*. Steps 1 through 3 yield a so-called "mean" estimate of H*, which is deterministically based. Step 4 involves a probabilistic analysis of the potential variability of H* in relation to the mean estimate due to the potential variability of key input parameters used in the H* analyses. This leads to a "probabilistic" estimate of H* which includes the mean estimate. The NRC staff's evaluation of the probabilistic analysis of H* is provided in Sections 4.2.1.6 and 4.2.1.7 of this SE.

5. Adjust the probabilistic estimate of H* to account for crevice pressure distribution. A crevice pressure adjustment is made to the probabilistic estimate of H* developed in step 4 in order to account for the crevice pressure distribution which results from the tube being severed at the final H* value, rather than at the bottom of the tubesheet. Step 5 is discussed and evaluated by the NRC staff in Section 4.2.1.5.2 of this SE.

6. Adjust the probabilistic estimate of H* to account for the Poisson contraction effect. A new step has been added to the H* calculation process since the reference analysis to support the LAR. This step involves adjusting the probabilistic estimate of H* to account

for the Poisson contraction of the tube radius due to the axial end-cap load acting on each tube. Step 6 is discussed and evaluated by the NRC staff in Section 4.2.1.5.3 of this SE.

4.2.1.5.1 BET Considerations

The diameter of each tube transitions from its fully expanded value to its unexpanded value near the TTS. The BET region is located a short distance below the TTS so as to avoid any potential for over-expanding the tube above the TTS. As discussed in step 2 of the previous section, a 0.3-inch adjustment was added to the first set of mean H* estimates to account for the BET location being below the TTS. This adjustment was based on an uncertainty analysis of BET distances conducted by Westinghouse. This adjustment was necessary since the reference analysis did not explicitly account for the lack of contact between the tube and tubesheet over the BET distance. Meanwhile, BET measurements based on eddy current testing were performed for all tubes at Catawba 2. These measurements confirmed that the original 0.3-inch adjustment was bounding on a 95 percentile basis. The maximum values for this adjustment at Catawba 2, however, can range up to 0.62 inches.

The most recent H* analyses developed using the square cell T/TS interaction model (Reference 8) have made the need for a BET adjustment unnecessary, as the square cell model shows a loss of contact pressure at the TTS that is greater than the possible variation in the BET location. The loss of contact pressure at the TTS shown in the square cell model (which is unrelated to BET location) is compensated for by a steeper contact pressure gradient than was shown previously in the thick shell model H* analysis. The NRC staff concludes that the proposed H* value adequately accounts for the range of BET values at Catawba 2.

4.2.1.5.2 Crevice Pressure Adjustment

As discussed in Section 4.2.1.5 of this SE, steps 1 through 4 of the H* calculation process lead to a probabilistic H* estimate. These steps are performed with the assumption that the tube is severed at the bottom of the tubesheet for the purposes of calculating the distribution of crevice pressure as a function of elevation. If the tube is assumed to be severed at the initially computed H* distance and steps 1 through 4 are repeated, a new H* value may be calculated which will be incrementally larger than the first estimate. This process may be repeated until the change in H* becomes small (convergence). Sensitivity analyses conducted with the thick shell model showed that the difference between the initial H* estimate and the final (converged) H* estimate is a function of the initial estimate for the tube in question. This difference (i.e., the crevice pressure adjustment referred to above in step 5 of Section 4.2.1.5 of this SE) was plotted as a function of the initial H* estimate for the limiting loading case and tube radial location. Although the sensitivity study was conducted using the thick shell model, the differences measured in this study were used in the Reference 8 (square cell model) analysis to make the crevice pressure adjustment to H* described in step 5. Updating this sensitivity study using the square cell model would have been very resource-intensive, requiring many new 2-D FEA square cell runs.

The NRC staff questioned the licensee regarding whether it was conservative to rely on the existing sensitivity study rather than updating it to reflect the square cell model. In response, Westinghouse submitted an analysis (Reference 3) which demonstrated that if updated, the sensitivity study would show that the crevice pressure adjustment H* would be negative, not positive, as is shown by the existing study. This is because the square cell model predicts a much longer zone (6 inches) of no T/TS contact below the TTS than that predicted by the thick shell model. Therefore, the crevice pressure must reduce from primary side pressure at the iterative H* location to secondary side pressure 6 inches below the TTS. This leads to higher predicted pressure differentials across the tube wall over the iterative H* distance than exists during the initial iteration when crevice pressure is initially assumed to vary from primary pressure at the very bottom of the tubesheet to secondary pressure at the very top of the tubesheet. Based on its review of the Westinghouse analysis in Reference 3, the NRC staff concludes that the positive crevice pressure adjustment to H* used in the Reference 8 analysis, which is based on the existing sensitivity study, is conservative. The NRC staff further concludes that an updated sensitivity analysis, based on use of the square cell model, would show that a negative adjustment could be justified. Thus, the NRC staff concludes that the crevice pressure adjustment performed in support of the proposed H* amendment is conservative and acceptable.

4.2.1.5.3 Poisson Contraction Effect

The axial end-cap load acting on each tube is equal to the product of the primary-to-secondary pressure difference multiplied by the tube cross-sectional area. For purposes of resisting tube pullout under normal and accident conditions, the end-cap loads used in the H* analyses are based on the tubesheet bore diameter, which the NRC staff finds to be a conservative assumption. The axial end-cap load tends to stretch the tube in the axial direction, but causes a slight contraction in the tube radius due to the Poisson's Ratio effect. By itself, this effect tends to reduce the T/TS contact pressure and, thus, to increase the H* distance. The axial end-cap force is resisted by the axial friction force developed at the T/TS joint. Thus, the axial end-cap force begins to decrease with increasing distance into the tubesheet, reaching zero at a location before the H* distance is reached. This is because the H* distances are intended to resist pullout under the end-cap loads with the appropriate factors of safety applied as discussed above in Section 4.2.1.1 of this SE.

A simplified approach was used to account for the Poisson radial contraction effect. First, thick shell equations were used to estimate the reduction in contact pressure associated with application of the full end-cap load, assuming none of this end-cap load has been reacted by the tubesheet. The T/TS contact pressure distributions determined in step 4 of the H* calculation process, described above in Section 4.2.1.5 of this SE, were reduced by this amount. Second, the friction force associated with these reduced T/TS contact pressures was integrated with distance into the tubesheet, and the length of engagement necessary to react one times the end-cap loading (i.e., no safety factor applied) was determined. At this distance (termed "attenuation distance" by Westinghouse), the entire end-cap loading was assumed to have been reacted by the tubesheet, and the axial load in the tube below the attenuation distance was assumed to be zero. Thus, the T/TS contact pressures below the attenuation distance were assumed to be unaffected by the Poisson radial contraction effect. Finally, a revised H* distance was calculated where the T/TS contact pressures from step 4 described above in Section 4.2.1.5 of this SE were reduced only over the attenuation distance.

The NRC staff finds that the simplified approach for calculating the adjustment to H* to account for the Poisson contraction effect contains significant conservatism relative to a more detailed approach. Regarding the assumption of a safety factor of 1, Westinghouse stated that it is unrealistic to apply a safety factor to a physical effect such as Poisson's ratio. The NRC staff has not reached a conclusion on whether it is unrealistic to apply a safety factor to a physical effect such as Poisson's ratio. However, irrespective of whether a safety factor is applied or not (consistent with Section 4.2.1.1 of this SE described above), the NRC staff concludes that there is ample conservatism embodied in the proposed H* distance to accommodate the difference.

4.2.1.6 Acceptance Standard - Probabilistic Analysis

The purpose of the probabilistic analysis is to develop an H* distance that ensures with a probability of 0.95 that all tubes within the SG tube population retain margins against pullout, consistent with the criteria evaluated in Section 4.2.1.1 of this SE which assumes that all tubes are completely severed at their H* distance. The NRC staff finds that this probabilistic acceptance standard is consistent with what the NRC staff has approved previously and finds this acceptance standard acceptable. For example, the NRC approved a similar probabilistic acceptance standard for use in NRC Generic Letter 95-05 (Reference 11) which employs an upper voltage limit for the voltage-based tube repair criteria.

The NRC staff also notes that use of the 0.95 probability criterion ensures that the probability of pullout of one or more tubes under normal operating conditions, as well as the conditional probability of pullout of tubes under accident conditions, is well within tube rupture probabilities that have been considered in probabilistic risk assessments (References 12 and 13). In terms of the confidence level that should be attached to the 0.95 probability acceptance standard, it is industry practice for SG tube integrity evaluations, as embodied in industry guidelines, to calculate such probabilities at a 50 percent confidence level. The NRC staff has been encouraging the industry to revise its guidelines to call for calculating such probabilities at a 95 percent confidence level when performing operational assessments and a 50 percent confidence level when performing condition monitoring (Reference 14). In the meantime, the calculated H* distances supporting the LAR have been evaluated at the 95 percent confidence level, as recommended by the NRC staff.

Another issue relating to the acceptance standard for the probabilistic analysis is determining what population of tubes needs to be analyzed. For accidents such as MSLB or feed line break (FLB), the NRC staff and the licensee agree that the tube population in the faulted SG is of interest, since it is the only SG that experiences a large increase in the primary-to-secondary pressure differential. However, normal operating conditions were found to be the most limiting in terms of meeting the tube pullout margins described in Section 4.2.1.1 of this SE. For normal operating conditions, tubes in all SGs at the plant are subject to the same pressures and temperatures. Although there is not a consensus between the NRC staff and the licensee on which population of tubes needs to be considered in the probabilistic analysis for normal operating conditions, the calculated H* distances for normal operating conditions supporting the LAR are 0.95 probability/95 percent confidence estimates which are based on the entire tube population for the plant, consistent with the NRC staff's recommendation.

Based on the above, the NRC staff concludes that the proposed H* distance in the subject LAR is based on acceptable probabilistic acceptance standards evaluated at acceptable confidence levels.

4.2.1.7 Probabilistic Analyses

4.2.1.7.1 Reference Analyses

Sensitivity studies were conducted during the reference analyses (see Reference 7) and demonstrated that H* was highly sensitive to the potential variability of the coefficients of thermal expansion (CTE) for the Alloy 600 tubing material and the SA-508 Class 2a tubesheet material. Given that no credit was taken in the reference H* analyses (Reference 7) for residual contact pressure associated with the tube hydraulic expansion process[3], the sensitivity of H* to other geometry and material input parameters, with the exception of Young's modulus of elasticity for the tube and tubesheet materials, was judged by Westinghouse to be inconsequential and was ignored. Although the Young's modulus parameters were included in the reference H* analyses sensitivity studies, these parameters were found to have a weak effect on the computed H*. Based on its review of the analysis models and its engineering judgment, the NRC staff concurs that the sensitivity studies adequately capture the input parameters which may significantly affect the value of H*. This conclusion is based, in part, on the fact that no credit is being taken for residual contact pressure during the reference H* analyses.

These sensitivity studies were used to develop influence curves describing the change in H*, relative to the mean H* value estimate (see Section 4.2.1.5 of this SE), as a function of the variability of each CTE parameter and Young's modulus parameter, relative to the mean values of CTE and Young's Modulus. Separate influence curves were developed for each of the four input parameters. The sensitivity studies showed that of the four input parameters, only the CTE parameters for the tube and tubesheet material had any interaction with one another. A combined set of influence curves containing this interaction effect was also created.

Two types of probabilistic analyses were performed independently in the reference analyses. One was a simplified statistical approach utilizing a "square root of the sum of the squares" method and the other was a detailed Monte Carlo sampling approach. The NRC staff's review of the reference analysis relied on the Monte Carlo analysis, which provides the most realistic treatment of uncertainties. The NRC staff reviewed the implementation of probabilistic analyses in the reference analyses and questioned whether the H* influence curves had been conservatively treated. To address this concern, new H* analyses were performed as documented in References 15 and 16. These analyses made direct use of the H* influence curves in a manner that the NRC staff finds to be acceptable.

The revised reference analyses in Reference 15 divided the tubes by sector location within the tube bundle and all tubes were assumed to be at the location in their respective sectors where

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3 Residual contact pressures are sensitive to variability of other input parameters.

the initial value of H* (based on nominal values of material and geometric input parameters) was at its maximum value for that sector. The H* influence curves discussed above, developed for the most limiting tube location in the tube bundle, were conservatively used for all sectors.

The revised reference analyses also addressed a question posed by the NRC staff concerning the appropriate way to sample material properties for the tubesheet. The material properties for the tubesheet are variable, but do not vary significantly from tube to tube for a given SG. In contrast, the material properties for the tubes vary much more from tube to tube for a given SG and are more random. The licensee addressed this issue by using a staged sampling process whereby the tubesheet properties were sampled once and then held fixed, while the tube properties were sampled a number of times equal to the SG tube population. This sampling process was repeated 10,000 times and the maximum H* value from each repetition was rank ordered. The final H* value was selected from the rank ordering to reflect a 0.95 probability value at the desired level of confidence for a single SG tube population or all SG population, as appropriate. The NRC staff concludes that this approach addresses the NRC staff's question and is acceptable.

The reference analyses in References 7 and 15 indicated normal operating conditions (with an associated safety factor of 3) to be the limiting case for determining H* for Model D5 SGs. As discussed above in Section 4.2.1.5 of this SE, subsequent analyses with the more accurate square cell model and revised 3-D FEA model (due to the improved displacement compatibility between the two models) show that the MSLB (with an associated safety factor of 1.4) to be the limiting case for the Model D5 SGs. Accordingly, the reference analyses for the Model D5 SGs, including Catawba 2, were rerun for the case of MSLB to support the subject LAR.

4.2.1.7.2 Revised Analyses to Reflect Square Cell and Revised 3-D FEA Models

New Monte Carlo analyses using the square cell model to evaluate the statistical variability of H* due to the CTE variability for the tube and tubesheet materials were not performed. This was because such an approach would have been extremely resource intensive and because a simpler approach was available which achieved a good approximation. The simplified approach involved using the results of the Monte Carlo analyses from the reference analysis, which are based on the thick shell T/TS interaction model. The simplified approach identified CTE values for the tube and tubesheet associated with the probabilistic H* values near the desired rank ordering. Tube CTE values associated with the upper 10 percent rank order estimates are generally negative variations from the mean value whereas tubesheet CTE values associated with the higher ranking order estimates are generally positive variations from the mean value. For the upper 10 percent of the Monte Carlo results ranking order, a combined uncertainty parameter, "alpha," was defined as the square root of the sum of the squares of the associated tube and tubesheet CTE values for each Monte Carlo sample. Alpha was plotted as a function of the corresponding H* estimate and separately as a function of rank order. Each of these plots exhibited well-defined "break lines," representing the locus of maximum H* estimates and maximum rank orders associated with given values of alpha. From these plots, three paired sets of tube and tubesheet CTE values, located near the break line, were selected. One of these pairs was for the rank order corresponding to an upper 95/95 confidence value for H* on a per SG basis which the NRC staff finds is appropriate for MSLB (see Section 4.2.1.6 of this SE).

These CTE values were then input to the lower SG assembly 3-D FEA model and the square cell model to yield probabilistic H* estimates which approximate the H* values for these same rank orderings had a full Monte Carlo been performed with the square cell and revised 3-D FEA models. These H* estimates were then plotted as a function of rank ordering, allowing the interpolation of H* values at the other rank orders. The resulting 95/95 upper-bound H* estimate is 11.52 inches, which compares to the mean estimate of 10.89 inches as discussed above in Section 4.2.1.5 of this SE. With adjustments for Poisson's contraction (see Section 4.2.1.5.3 of this SE) and crevice pressure (see Section 4.2.1.5.2 of this SE), the final 95/95 upper-bound H* estimate is 14.01 inches which is the value in the subject LAR.

The NRC staff believes that the break line approach obtains a very good approximation of what an actual Monte Carlo analysis would show. A perfect approximation would mean that if one were to perform a square cell analysis for each paired set of tube and tubesheet CTE values associated with the top 10 percent of rank orders and then plot the resulting H* values versus the original rank ordering associated with the CTE couple, the calculated H* values should monotonically increase from rank order to rank order. Westinghouse performed additional square cell analyses with CTE pairs for five consecutive rank orders for both Model D5 and Model F SGs. The results showed deviations from monotonically increasing values of H* with rank order to be on the order of only 0.3 inches for the Model D5 SGs and 0.1 inches for the Model F SGs. The NRC staff concludes that use of the break line approach adds little imprecision to the probabilistic H* estimates and is acceptable.

4.2.1.8 <u>Coefficient of Thermal Expansion</u>

During operation, a large part of the contact pressure in a SG tube-to-tubesheet joint is derived from the difference in CTE between the tube and tubesheet. As discussed above in Section 4.2.1.7 of this SE, the calculated value of H* is highly sensitive to the assumed values of these CTE parameters. However, CTE test data acquired by an NRC contractor, Argonne National Laboratory (ANL), suggested that CTE values may vary substantially from values listed in the ASME Code for design purposes. In Reference 17, the NRC staff highlighted the need to develop a rigorous technical basis for the CTE values and their potential variability to be employed in future H* analyses.

In response, Westinghouse had a subcontractor review the CTE data in question, determine the cause of the variance from the ASME Code CTE values, and provide a summary report (Reference 18). Analysis of the CTE data in question revealed that the CTE variation with temperature had been developed using a polynomial fit to the raw data over the full temperature range of 75 degrees Fahrenheit (°F) to 1300 °F. The polynomial fit chosen resulted in mean CTE values that were significantly different from the ASME Code values from 75 °F to about 300 °F. When the raw data was reanalyzed using the locally-weighted least squares regression method, the mean CTE values determined were in good agreement with the established ASME Code values.

Westinghouse also formed a panel of licensee experts to review the available CTE data in open literature, review the ANL-provided CTE data, and perform an extensive CTE testing program on Alloy 600 and SA-508 steel material to supplement the existing data base. Two additional sets of CTE test data (different from those addressed in the previous paragraph) had CTE offsets at low temperatures that were not expected. Review of the test data showed that the first test, conducted in a vacuum, had proceeded to a maximum temperature of 1300 °F, which changed the microstructure and the CTE of the steel during decreasing temperature conditions. As a result of the altered microstructure, the CTE test data generated in the second test, conducted in air, was also invalidated. As a result of the large "dead band" region and the altered microstructure, both data sets were excluded from the final CTE values obtained from the CTE testing program. The test program included multiple material heats to analyze chemistry influence on CTE values and repeat tests on the same samples were performed to analyze for test apparatus influence. Because the tubes are strain-hardened when they are expanded into the tubesheet, strain-hardened samples were also measured to check for strain-hardening influence on CTE values.

The data from the test program was combined with the ANL data that was found to be acceptable and the data obtained from the open literature search. A statistical analysis of the data uncertainties was performed by comparing deviations to the mean values obtained at the applicable temperatures. The correlation coefficients which were obtained indicated a good fit to a normal distribution, as expected. Finally, an evaluation of within-heat variability was performed due to increased data scatter at low temperatures. The within-heat variability assessment determined that the increase in data scatter was a testing accuracy limitation that was only present at low temperature. The CTE report was included as Appendix A to Reference 7.

The testing showed that the nominal ASME Code values for Alloy 600 and SA-508 steel were both conservative relative to the mean values from all the available data. Specifically, the CTE mean value for Alloy 600 was greater than the ASME Code value and the CTE mean value for SA-508 steel was smaller than the ASME Code value. Thus, the H* analyses utilized the ASME Code values as mean values in the H* analyses. The NRC staff finds this to be conservative because it tends to lead to an over-prediction of the expansion of the tubesheet bore and an under-prediction of the expansion of the tube, thereby resulting in an increase in the calculated H* distance. The statistical variances of the CTE parameters from the combined data base were utilized in the H* probabilistic analysis.

Based on its review of the Westinghouse CTE program, the NRC staff concludes that the CTE values used in the H* analyses are fully responsive to the concerns stated in Reference 17 and are acceptable.

4.2.2 Leakage Considerations

Operational leakage integrity is assured by monitoring primary-to-secondary leakage relative to the applicable TS LCO limits in TS 3.4.13, "RCS Operational LEAKAGE." However, it must also be demonstrated that the proposed TS changes do not create the potential for leakage during DBA to exceed the accident leakage performance criteria in TS 5.5.9.b.2, including the leakage values assumed in the plant licensing basis accident analyses.

If a tube is assumed to contain a 100 percent through-wall flaw some distance into the tubesheet, a potential leak path between the primary and secondary systems is introduced between the hydraulically expanded tubing and the tubesheet. The leakage path between the tube and tubesheet has been modeled by Westinghouse as a crevice consisting of a porous media. Using Darcy's model for flow through a porous media, the leak rate is proportional to differential pressure and inversely proportional to flow resistance. Flow resistance is a direct function of viscosity, loss coefficient, and crevice length.

Westinghouse performed leak tests of T/TS joint mockups to establish loss coefficient as a function of contact pressure. A large amount of data scatter, however, precluded quantification of such a correlation. In the absence of such a correlation, Westinghouse has developed a leakage factor relationship between accident-induced leak rate and operational leakage rate, where the source of leakage is from flaws located at or below the H* distance.

Using the Darcy model, the leakage factor for a given type accident is the product of four quantities. The first quantity is ratio of the maximum primary-to-secondary pressure difference during the accident divided by that for normal operating conditions. The second quantity is the ratio of viscosity under normal operating primary water temperature divided by viscosity under the accident condition primary-water temperature. The third quantity is the ratio of crevice length under normal operating conditions to crevice length under accident conditions. This ratio equals 1, provided it can be shown that positive contact pressure is maintained along the entire H* distance for both conditions. The fourth quantity is the ratio of loss coefficient under normal operating conditions to loss coefficient under the accident condition. Although the absolute value of these loss coefficients are not known, Westinghouse has assumed that the loss coefficient is constant with contact pressure such that the ratio is equal to 1. The NRC staff agrees that this is a conservative assumption, provided there is a positive contact pressure for both conditions along the entire H* distance and provided that contact pressure increases at each axial location along the H* distance when going from normal operating to accident conditions. Both assumptions were confirmed to be valid in the H* analyses.

Leakage factors were calculated for DBAs exhibiting a significant increase in primary-to-secondary pressure differential, including MSLB, FLB, locked rotor, and control rod ejection. The design basis FLB heat-up transient was found to exhibit the highest leakage factor, 3.27, meaning that it is the transient expected to result in the largest increase in leakage relative to normal operating conditions.

The latest H* analyses by Westinghouse (Reference 8) did not show an increasing T/TS contact pressure when going from normal operating to MSLB conditions. The new analyses used the revised 3-D finite element model of the lower SG assembly and the new square cell model, discussed above in Section 4.2.1.3.2 of this SE. Although T/TS contact pressure increased over some sections of the tubing under SLB conditions, it decreased over other sections within the H* distance. This violated the assumed precondition for assuming that the ratio of loss coefficient under MSLB and normal operating conditions was at least equal to 1. As discussed above, the large scatter of the loss coefficient versus contact pressure data prevented direct use of this data in applying Darcy's leakage model. Instead, Westinghouse considered a number of mathematical functions that represented the potential functional relationship between loss coefficient and contact pressure. For each potential functional relationship, Westinghouse evaluated the ratio of loss coefficient under MSLB and normal operating conditions, at each elevation and radial location within the tubesheet. For each tube, this ratio was integrated over the length of the H* distance yielding a ratio of flow resistances for MSLB and normal operating conditions. This ratio, in conjunction with the differential pressure and viscosity ratios, was then used to compute the ratio of leakage under MSLB and normal operating conditions, at each radial location within the tubesheet. None of the potential functional relationships between loss coefficient and contact pressure considered by Westinghouse resulted in a leakage ratio value exceeding the value of 3.27 calculated for FLB.

Westinghouse performed additional analyses using parallel plate flow theory, benchmarked with the leak rate versus contact pressure data discussed above. These analyses showed that resistance to leakage under both normal operating and MSLB conditions is primarily developed in the lower portion of the H* distance and that the leak rate ratio existing in this region dominates the overall leakage ratio existing over the entire H* distance and, furthermore, that this ratio is less than 1.5. For the NRC staff, confidence that MSLB is not the limiting case for calculating leakage ratio derives from the fact that contact pressures are higher for MSLB than for normal operating conditions for the lower region of the H* distance where most of the resistance to leakage is developed. The NRC staff concludes that the calculated leakage factor of 3.27 for Catawba 2 is a reasonably conservative bound for all relevant loading conditions.

In Reference 4, the licensee provided a commitment describing how the leakage factor will be used to satisfy TS 5.5.9.a for condition monitoring and TS 5.5.9.b.2 regarding performance criteria for accident-induced leakage:

> For Unit 2, for the Condition Monitoring (CM) assessment, the component of operational leakage from the prior cycle from below the H* distance will be multiplied by a factor of 3.27 and added to the total accident leakage from any other source and compared to the allowable accident induced leakage limit. For the Operational Assessment (OA), the difference in the leakage between the allowable accident induced leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 3.27 and compared to the observed operational leakage. An administrative limit will be established to not exceed the calculated value in the event that TS 3.4.13 is no longer bounding.

Including this commitment as part of the Catawba 2 license is not required. Details of how the condition monitoring and operational assessments are performed are generally not included in the license, including the TS. Extensive industry guidance on conducting condition monitoring and operational assessments is available as part of the industry initiative NEI 97-06 (Reference 19). The commitment described above ensures that plant procedures address both the leakage factor issue described in this section, as well as the industry guidelines found in NEI 97-06.

The subject LAR would include reporting requirements (TS 5.6.8.h and 5.6.8.i) relating to operational leakage existing during the cycle preceding each SG inspection and condition monitoring assessment, and the associated potential for accident-induced leakage from the lower portion of the tubesheet below the H* distance. These reporting requirements will allow the NRC staff to monitor how the leakage factor is actually being used, and are acceptable.

Finally, per the commitment described above, the administrative limit for operational primary-to-secondary leakage can never exceed the current TS 3.4.13 LCO limit for primary-to-secondary leakage of 150 gallons per day (gpd) divided by the 3.27 leakage factor, equaling 45 gpd. Accordingly, the licensee is proposing to revise the LCO limit from 150 gpd to 45 gpd. This change provides added assurance that during a hypothetical DBA, the resulting primary to secondary leakage will be within the accident leakage performance criteria in TS 5.5.9.b.2. In addition, this change minimizes the likelihood of having to establish a reduced administrative limit as stated in the last sentence of the aforementioned commitment. The NRC staff finds this proposed change to be acceptable.

4.3 Technical Evaluation Summary

Since the initial proposal for a permanent H* amendment in 2005, the supporting technical analyses have undergone substantial revision and refinement to address NRC staff questions and issues. The current analyses supporting the proposed permanent license amendment still embody uncertainties and issues (e.g., should a factor of safety be applied to the Poisson's contraction effect) as discussed throughout this SE. However, it is important to acknowledge that there are significant conservatisms in the analyses. Some examples, also discussed elsewhere in this SE, include taking no credit for residual contact pressures associated with the hydraulic tube expansion process, the assumed value of 0.2 for coefficient of friction between the tube and tubesheet, and taking no credit for constraint against pullout provided by adjacent tubes and support structures. The NRC staff has evaluated the potential impact of the uncertainties and concludes these uncertainties to be adequately bounded by the significant conservatism within the analyses and proposed H* distance.

The NRC staff finds the proposed changes to the Catawba 2 TS ensure that tube structural and leakage integrity will be maintained with structural safety margins consistent with the design basis and with leakage integrity within assumptions employed in the licensing basis accident analyses, without undue risk to public health and safety. Based on this finding, the NRC staff further concludes that the proposed amendment meets 10 CFR 50.36 and, thus, the proposed LAR is acceptable.

5.0 FINAL NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The Commission's regulations in 10 CFR 50.92 state that the Commission may make a final determination that a license amendment involves no significant hazards consideration if operation of the facility would not: (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety.

As required by 10 CFR 50.91(a), the licensee has provided its analysis of the issue of no significant hazards consideration which is presented below.

> Criterion 1:
>
> Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed changes to TS 3.4.13, TS 5.5.9, and TS 5.6.8 have no significant effect upon accident probabilities or consequences. Of the various accidents previously evaluated, the following are limiting with respect to the proposed changes as discussed in this amendment request:

- SG Tube Rupture evaluation
- Steam Line Break/Feed Line Break evaluation
- Locked Rotor evaluation
- Control Rod Ejection evaluation

Loss of Coolant Accident conditions cause a compressive axial load to act on the tube. Therefore, since this accident tends to force the tube into the tubesheet rather than pull it out, it is not a factor in this amendment request. Another faulted load consideration is a Safe Shutdown Earthquake; however, the seismic analysis of Model D5 SGs (the SGs at Catawba) has shown that axial loading of the tubes is negligible during this event. At normal operating pressures, leakage from Primary Water Stress Corrosion Cracking (PWSCC) below 14.01 inches from the top of the tubesheet is limited by both the tube-to-tubesheet crevice and the limited crack opening permitted by the tubesheet constraint. Consequently, negligible normal operating leakage is expected from cracks within the tubesheet region. For the SG Tube Rupture event, tube rupture is precluded for cracks in the hydraulic expansion region due to the constraint provided by the tubesheet. Therefore, the margin against tube burst/pullout is maintained during normal and postulated accident conditions and the proposed change does not result in a significant increase in the probability of a tube rupture. SG Tube Rupture consequences are not affected by the primary to secondary leakage flow during the event, as primary to secondary leakage flow through a postulated tube that has been pulled out of the tubesheet is essentially equivalent to that from a severed tube. Therefore, the proposed change does not result in a significant increase in the consequences of a tube rupture.

The probability of a Steam Line Break/Feed Line Break, Locked Rotor, and Control Rod Ejection are not affected by the potential failure of a SG tube, as the failure of a tube is not an initiator for any of these events. In the supporting Westinghouse analyses, leakage is modeled as flow through a porous medium via the use of the Darcy equation. The leakage model is used to develop a relationship between operational leakage and leakage at accident conditions that is based on differential pressure across the tubesheet and the viscosity of the fluid. A leak rate ratio was developed to relate the leakage at operating conditions to leakage at accident conditions. The fluid viscosity is based on fluid temperature and it has been shown that for the most limiting accident, the fluid temperature does not exceed the normal operating temperature.

Therefore, the viscosity ratio is assumed to be 1.0 and the leak rate ratio is a function of the ratio of the accident differential pressure and the normal operating differential pressure.

The leakage factor of 3.27 for Catawba Unit 2 for a postulated Steam Line Break/Feed Line Break has been calculated as shown in the supporting Westinghouse analyses. Therefore, Catawba Unit 2 will apply a factor of 3.27 to the normal operating leakage associated with the tubesheet expansion region in the Condition Monitoring assessment and Operational Assessment. Through application of the limited tubesheet inspection scope, the proposed operating leakage limit provides assurance that excessive leakage (i.e., greater than accident analysis assumptions) will not occur. No leakage factor will be applied to the Locked Rotor or Control Rod Ejection due to their short duration, since the calculated leak rate ratio is less than 1.0.

Therefore, the proposed change does not result in a significant increase in the consequences of these accidents.

For the Condition Monitoring assessment, the component of leakage from the prior cycle from below the H* distance will be multiplied by a factor of 3.27 and added to the total leakage from any other source and compared to the allowable accident induced leakage limit. For the Operational Assessment, the difference in the leakage between the allowable leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 3.27 and compared to the observed operational leakage.

Based on the above, the performance criteria of NEI 97-06 and Regulatory Guide (RG) 1.121 continue to be met and the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

Criterion 2:

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

Response: No.

The proposed changes to TS 3.4.13, TS 5.5.9, and TS 5.6.8 do not introduce any changes or mechanisms that create the possibility of a new or different kind of accident. Tube bundle integrity is expected to be maintained for all plant conditions upon implementation of the permanent alternate repair criteria. The proposed change does not introduce any new equipment or any change to existing equipment. No new effects on existing equipment are created nor are any new malfunctions introduced.

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

Criterion 3:

Does the proposed amendment involve a significant reduction in a margin of safety?

Response: No.

The proposed changes to TS 3.4.13, TS 5.5.9, and TS 5.6.8 maintain the required structural margins of the SG tubes for both normal and accident conditions. NEI 97-06 and RG 1.121 are used as the basis in the development of the limited tubesheet inspection depth methodology for determining that SG tube integrity considerations are maintained within acceptable limits. RG 1.121 describes a method acceptable to the NRC staff for meeting GDC 14, 15, 31, and 32 by reducing the probability and consequences of a SG Tube Rupture. RG 1.121 concludes that by determining the limiting safe conditions for tube wall degradation, the probability and consequences of a SG Tube Rupture are reduced. This RG uses safety factors on loads for tube burst that are consistent with the requirements of Section III of the American Society of Mechanical Engineers (ASME) Code.

For axially oriented cracking located within the tubesheet, tube burst is precluded due to the presence of the tubesheet. For circumferentially oriented cracking, the supporting Westinghouse analyses defines a length of degradation-free expanded tubing that provides the necessary resistance to tube pullout due to the pressure induced forces, with applicable safety factors applied. Application of the limited hot and cold leg tubesheet inspection criteria will preclude unacceptable primary to secondary leakage during all plant conditions. The methodology for determining leakage as described in the supporting Westinghouse analyses shows that significant margin exists between an acceptable level of leakage during normal operating conditions that ensures meeting the accident induced leakage assumption and the TS leakage limit. Based on the above, it is concluded that the proposed change does not result in any reduction of margin with respect to plant safety as defined in the Updated Final Safety Analysis Report (UFSAR) or Bases of the plant TS.

The NRC staff has reviewed the licensee's analysis, as discussed above, and, based on its review, the staff concludes that the amendments meet the three criteria of 10 CFR 50.92(c). Therefore, the NRC staff has made a final determination that the amendments involve no significant hazards consideration.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the South Carolina State official was notified of the proposed issuance of the amendments. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20 and change surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts and no significant change in the types of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has made a final finding that the amendments involve no significant hazards consideration. Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

8.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) the amendment does not (a) involve a significant increase in the probability or consequences of an accident previously evaluated; or (b) create the possibility of a new or different kind of accident from any accident previously evaluated; or (c) involve a significant reduction in a margin of safety; (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; (3) such activities will be conducted in compliance with the Commission's regulations; and (4) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

9.0 REFERENCES

1. Morris, J. R., Duke Energy, letter to U.S. Nuclear Regulatory Commission, "Duke Energy Carolinas, LLC (Duke Energy), Catawba Nuclear Station, Units 1 and 2, Docket Numbers 50-413 and 50-414, Proposed Technical Specifications (TS) Amendment, TS 3.4.13, 'RCS Operational LEAKAGE,' TS 5.5.9, 'Steam Generator (SG) Program,' TS 5.6.8, 'Steam Generator (SG) Tube Inspection Report,' License Amendment Request to Revise TS for Permanent Alternate Repair Criteria," dated June 30, 2011 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML11188A107). This letter also transmitted Reference 8.

2. Morris, J. R., Duke Energy, letter to U.S. Nuclear Regulatory Commission, "Duke Energy Carolinas, LLC (Duke Energy), Catawba Nuclear Station, Units 1 and 2, Docket Numbers 50-413 and 50-414, Proposed Technical Specifications (TS) Amendment, TS 3.4.13, 'RCS Operational LEAKAGE,' TS 5.5.9, 'Steam Generator (SG) Program,' TS 5.6.8, 'Steam Generator (SG) Tube Inspection Report,' License Amendment Request to Revise TS for Permanent Alternate Repair Criteria," dated July 11, 2011 (ADAMS Accession No. ML11195A067).

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5. Jamil, D. M., Duke Power, letter to U.S. Nuclear Regulatory Commission, "Duke Energy Corporation, Catawba Nuclear Station, Unit 2, Docket Number 50-414, Proposed Change to Technical Specification (TS) 5.5.9, 'Steam Generator (SG) Program,'" dated December 19, 2005 (ADAMS Accession Nos. ML053630140 and ML053630145).

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7. Westinghouse Electric Company LLC, WCAP 17072-NP, Revision 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," May 2009 (ADAMS Accession No. ML101730389).

8. Westinghouse Electric Company LLC, WCAP 17330-NP, Revision 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)," June 2011 (ADAMS Accession No. ML11188A108). This report was enclosed with Reference 1 above.

9. Wright, D., U.S. Nuclear Regulatory Commission, letter to Mark J. Ajluni, Southern Nuclear Operating Company, Inc., "Vogtle Electric Generating Plant, Units 1 and 2, Transmittal of Unresolved Issues Regarding Permanent Alternate Repair Criteria for Steam Generators (TAC Nos. ME1339 and ME1340)," dated November 23, 2009 (ADAMS Accession No. ML093030490).

10. Taylor, R. M., U.S. Nuclear Regulatory Commission, memorandum to Gloria J. Kulesa, U.S. Nuclear Regulatory Commission, "Vogtle Electric Generating Plant – Audit of Steam Generator H* Amendment Reference Documents (TAC Nos. ME3003 and ME3004)," dated July 9, 2010 (ADAMS Accession No. ML093030490).

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Principal Contributor: E. Murphy, NRR

Date: March 12, 2012

If you have any questions, please call me at 301-415-1119.

Sincerely,

/RA/

Jon Thompson, Project Manager
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-413 and 50-414

Enclosures:
1. Amendment No. 267 to NPF-35
2. Amendment No. 263 to NPF-52
3. Safety Evaluation

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