Duke Energy®

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June 30, 2011 10 CFR 50.90

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

Subject: 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

Pursuant to 10 CFR 50.90, Duke Energy is requesting an amendment to Catawba Facility Operating Licenses NPF-35 and NPF-52 and the subject TS. This amendment request proposes to revise the subject TS to accomplish the following objectives for Unit 2:

- Permanently exclude portions of the 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.

Although the proposed changes only affect Unit 2, this submittal is being docketed for both Unit 1 and Unit 2 since the TS are common to both units.

The proposed amendment constitutes a redefinition of the SG tube primary to secondary pressure boundary and defines the safety significant portion of the tube that must be inspected or plugged. Tube flaws detected below the safety significant portion of the tube are not required to be plugged. Allowing flaws in the non-safety significant portion of the tube to remain in service minimizes unnecessary tube plugging and maintains the safety margin of the SGs to perform the safety function to maintain the reactor coolant pressure boundary, maintain reactor coolant flow, and maintain primary to secondary heat transfer.

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This request includes attachments as noted in the following table:

Attachment	Subject
1	Technical and Regulatory Evaluations
2	Marked-Up TS Pages
3	Marked-Up TS Bases Pages (These pages are provided for NRC information only and do not require NRC approval.)
4	Westinghouse Authorization Letter CAW-11-3172 with Accompanying Affidavit, Proprietary Information Notice, and Copyright Notice (WCAP-17330-P, Rev. 1)
5	Westinghouse WCAP-17330-P, Rev. 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)" (Proprietary)
6	Westinghouse WCAP-17330-NP, Rev. 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)" (Non-Proprietary)

As Attachment 5 contains information proprietary to Westinghouse Electric Company LLC, it is supported by an affidavit signed by Westinghouse, the owner of the information. The attached affidavit sets forth the basis on which the information may be withheld from public disclosure by the NRC and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR 2.390. Accordingly, it is requested that the information that is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390. Correspondence with respect to the copyright or proprietary aspects of the information listed above or the supporting Westinghouse affidavit should reference the applicable CAW letter and should be addressed to J.A. Gresham, Manager, Regulatory Compliance, Westinghouse Electric Company, LLC, Westinghouse Electric Company LLC, Suite 428, 1000 Westinghouse Drive, Cranberry Township, PA 16066.

This amendment request submittal has been reviewed and approved by the Catawba Plant Operations Review Committee in accordance with the requirements of the Duke Energy Quality Assurance Program.

Duke Energy requests approval of this submittal by January 31, 2012, to support implementation during the Catawba Unit 2 Spring 2012 End of Cycle 18 Refueling Outage. Once approved, the amendment will be implemented prior to entering the applicable Modes of the affected TS at the completion of the outage.

There are no regulatory commitments contained in this letter.

In accordance with 10 CFR 50.91, Duke Energy is notifying the State of South Carolina of this application for license amendment by transmitting a copy of this letter and its non-proprietary attachments to the designated state official.

Should you have any questions concerning this information, please contact L.J. Rudy at (803) 701-3084.

Very truly yours,

James R. Morris

James R. Morris

LJR/s

Attachments

James R. Morris affirms that he is the person who subscribed his name to the foregoing statement, and that all the matters and facts set forth herein are true and correct to the best of his knowledge.

James R. Morris

James R. Morris, Vice President

Subscribed and sworn to me: 6/30/11
Date

Brenda C. Albertson
Notary Public

My commission expires: 3/6/18
Date

SEAL

xc (with attachments):

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ATTACHMENT 1

Technical and Regulatory Evaluations

Subject: License Amendment Request to Revise TS for Permanent Alternate Repair Criteria

1. DESCRIPTION

Pursuant to 10 CFR 50.90, Duke Energy is requesting an amendment to Catawba Facility Operating Licenses NPF-35 and NPF-52 and the associated TS. This amendment request proposes to revise the associated TS to accomplish the following objectives for Unit 2:

- Permanently exclude portions of the 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.

Although the proposed changes only affect Unit 2, this submittal is being docketed for both Unit 1 and Unit 2 since the TS are common to both units.

This amendment request is supported by the following two Westinghouse Electric Company, LLC WCAPs:

WCAP-17072-P (as amended/supplemented), "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)"

WCAP-17330-P, Rev. 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)"

The NRC has most recently granted similar H* amendments on a one-cycle basis to other Westinghouse units for their Spring 2011 refueling outages. Catawba Unit 2 is now the lead unit for requesting NRC approval of the H* methodology on a permanent basis.

The H* analysis is based on maintaining structural and leakage integrity in the event of an accident. From a structural perspective, the value of H* ensures that tube rupture or tube pullout from the tubesheet will not occur in the event of an accident during the entire life of the plant. Even in the event that all tubes in the SG have a 360 degree sever at the H* location, structural integrity of the SG tube bundle will be maintained. This assumption bounds the current status of the Catawba Unit 2 SGs with significant margin. Tubesheet inspections with probes capable of detecting crack-like flaws have been extensively performed by Duke Energy and several other utilities with SGs similar to those installed at Catawba Unit 2 (i.e., fabricated with Alloy 600 Thermally Treated (TT) tubing). These inspections included the top of the tubesheet region, expansion anomalies within the tubesheet, and the tube end region near the weld. The industry inspections have demonstrated that flaws in the tubesheet are negligible when considering the number of tubes inspected, the severity of the degradation detected, and when compared to the conservative H* assumption that all tubes are severed.

Catawba Unit 2 reported indication of cracking following non-destructive eddy current examination of the SG tubes during the Fall 2004 Refueling Outage. NRC Information Notice (IN) 2005-09, "Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds", provided industry notification of this issue. IN 2005-09 noted that Catawba reported crack-like indications in the tubes approximately seven inches below the top of the hot leg tubesheet in one tube, and just above the tube-to-tubesheet welds in a region of the tube known as the tack expansion in several other tubes. Indications were also reported in the tube end welds, also known as tube-to-tubesheet welds, which join the tube to the tubesheet.

Based on overall industry inspections, a limited number of flaws exist in the tubesheets of SGs. The flaws that have been found are associated with residual stress conditions at either the tube ends or bulges/overexpansions within the tubesheet. No indication of a 360 degree sever has been detected in any SG. Consequently, the level of degradation in the SGs is very limited compared to the H* assumption of "all tubes severed". Therefore, structural integrity will be assured for the operating period between inspections allowed by TS 5.5.9.

From a leakage perspective, projections of accident induced SG tube leakage are based on leakage rate factors applied to leakage detected during normal operation. The acceptance criteria for Catawba Unit 2 SG tube leak rates as operated upon by the associated multiplication factor is bounded by the SG tube leak rate assumed in the relevant accident analyses. No quantifiable primary to secondary SG tube leakage has been detected during the current operating cycle at Catawba Unit 2.

For Catawba Unit 2, the number of SG tubes identified with flaws within the tubesheet is small in comparison to the input assumptions used in the development of the permanent H*. Consequently, significant margin exists between the current state of the Catawba Unit 2 SGs and the conservative assumptions used as the basis for the permanent H*. Structural and leakage integrity will continue to be assured for the operating period between inspections allowed by TS 5.5.9 with the implementation of the proposed H*.

2. PROPOSED CHANGE

The proposed changes to the TS are as follows:

TS 3.4.13 (Limiting Condition for Operation) currently states:

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 primary to secondary LEAKAGE through any one steam generator (SG).

Proposed changes:

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).

TS 3.4.13 (Surveillance Requirement 3.4.13.2) currently states:

Verify primary to secondary LEAKAGE is $\leq$ 150 gallons per day through any one SG.

Proposed changes:

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.

TS 5.5.9 item c. currently states:

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

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

1. *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.*

Proposed changes:

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

The following 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.*

TS 5.5.9 item d. currently states:

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, 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 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.*

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, 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.*

Proposed changes:

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.*

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 not be treated as a crack.

TS 5.6.8 items h. through j. currently states:

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 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 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.

Proposed changes:

h. For Unit 2, following completion of an inspection performed after each refueling outage (and any inspections performed during subsequent cycle operation), 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, following completion of an inspection performed after each refueling outage (and any inspections performed during subsequent cycle operation), 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, following completion of an inspection performed after each refueling outage (and any inspections performed during subsequent cycle 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.*

3. BACKGROUND

TS 5.5.9 requires that a SG program be established and implemented to ensure that SG tube integrity is maintained. SG tube integrity is maintained by meeting specified performance criteria for structural and leakage integrity, consistent with the plant design and licensing bases. TS 5.5.9 requires a condition monitoring assessment to be performed during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met. TS 5.5.9 also includes provisions regarding the scope, frequency, and methods of SG tube inspections. Of relevance to the amendment application, these provisions require that the number and portions of tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type that may be present along the length of a tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet (excluding the welds themselves), and that may satisfy the applicable tube repair criteria. The applicable tube repair criteria are that tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

On March 31, 2006, the NRC issued Amendment 224 for Catawba Unit 2. This amendment involved a one-cycle change regarding required SG tube repair criteria during the End of Cycle 14 Refueling Outage and subsequent Cycle 15 operation. The amendment also added a license condition requiring a reduction in the allowable normal operating primary to secondary leakage rate through any one SG and through all SGs. On October 31, 2007, the NRC issued Amendment 233 for Catawba Unit 2. This amendment involved a second one-cycle change for the End of Cycle 15 Refueling Outage and subsequent Cycle 16 operation. On April 13, 2009, the NRC issued Amendment 244 for Catawba Unit 2. This amendment involved a one-cycle change for the End of Cycle 16 Refueling Outage and subsequent Cycle 17 operation and incorporated an interim alternate repair criteria for SG tube repair. On September 27, 2010, the NRC issued Amendment 257 for Catawba Unit 2. This amendment involved a one-cycle change for the End of Cycle 17 Refueling Outage and subsequent Cycle 18 operation.

The industry has been actively working toward a permanent solution to this issue using the Westinghouse H* methodology. However, due to outstanding technical issues, no permanent TS change has yet been approved by the NRC.

Catawba Unit 2 is a four loop Westinghouse designed plant with Model D5 SGs having 4570 tubes in each SG (for a total of 18,280 tubes). A total of 329 tubes are currently plugged in all four SGs. The design of the SGs includes Alloy 600 thermally treated tubing, full depth hydraulically expanded tubesheet joints, and stainless steel tube support plates with broached hole quatrefoils.

In addition to TS 5.5.9, the SG inspection scope is currently governed by the following documents:

- Nuclear Energy Institute (NEI) 97-06, “Steam Generator Program Guidelines”, Revision 2, May 2005 (Note: Revision 3 has been issued but has not yet been adopted by Duke Energy. It is anticipated that by the time this amendment request submittal is approved, Duke Energy will have adopted Revision 3.)
- Electric Power Research Institute (EPRI) 1013706, “Pressurized Water Reactor Steam Generator Examination Guidelines”, Revision 7
- EPRI 1012987, “Steam Generator Integrity Assessment Guidelines”, Revision 3
- Duke Energy’s SG Management Program

10 CFR 50, Appendix B, Criterion IX, “Control of Special Processes”, requires in part that non-destructive testing be accomplished by qualified personnel using qualified procedures in accordance with the applicable criteria. The inspection techniques and equipment are capable of reliably detecting the known and potential specific degradation mechanisms applicable to Catawba Unit 2. The inspection techniques, essential variables, and equipment are qualified to Appendix H, “Performance Demonstration for Eddy Current Examination”, of EPRI 1013706 or to Appendix I, “NDE System Measurement Uncertainties for Tube Integrity Assessment”.

4. TECHNICAL EVALUATION

The Westinghouse analyses supporting this amendment request submittal are contained in the following two WCAPs:

Westinghouse WCAP-17072-P (as amended/supplemented), "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)"

Westinghouse WCAP-17330-P, Rev. 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)"

Duke Energy's submittal for Catawba Unit 2 for the most recent one-cycle amendment (Amendment 257 for the End of Cycle 17 Refueling Outage and subsequent Cycle 18 operation), which was dated April 28, 2010 and supplemented September 9, 2010, included copies of the following documents listed below. Since these documents were previously docketed, they are hereby being incorporated by reference into this amendment request submittal.

1. Westinghouse Authorization Letter CAW-09-2585 with Accompanying Affidavit, Proprietary Information Notice, and Copyright Notice (WCAP-17072-P)

2. Westinghouse WCAP-17072-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)" (Proprietary)

3. Westinghouse WCAP-17072-NP, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)" (Non-Proprietary)

4. Westinghouse Letter LTR-SGMP-09-79, "WCAP-17072 Errata and Clarifications"

5. Westinghouse Letter LTR-RCPL-09-133, "WCAP-17072-P, Rev. 0 Proprietary Information Clarification"

6. Westinghouse Authorization Letter CAW-09-2637 with Accompanying Affidavit, Proprietary Information Notice, and Copyright Notice (LTR-SGMP-09-100 P-Attachment)

7. Westinghouse Letter LTR-SGMP-09-100 P-Attachment, "Response to NRC Request for Additional Information on H*; Model F and Model D5 Steam Generators" (questions 1 through 20 and 24 of the NRC RAI) (Proprietary)

8. Westinghouse Letter LTR-SGMP-09-100 NP-Attachment, "Response to NRC Request for Additional Information on H*; Model F and Model D5 Steam Generators" (questions 1 through 20 and 24 of the NRC RAI) (Non-Proprietary)

9. Westinghouse Letter LTR-SGMP-09-121, "Replacements for Illegible Pages in Prior RAI Response (LTR-SGMP-09-100)"

10. Catawba Unit 2 Site Specific Response to (Industry) NRC RAI Questions 21, 22, and 23

11. Westinghouse Authorization Letter CAW-09-2664 with Accompanying Affidavit, Proprietary Information Notice, and Copyright Notice (LTR-SGMP-09-109 P-Attachment)

12. Westinghouse Letter LTR-SGMP-09-109 P-Attachment, "Response to NRC Request for Additional Information on H*; RAI #4; Model F and Model D5 Steam Generators" (Proprietary)

13. Westinghouse Letter LTR-SGMP-09-109 NP-Attachment, "Response to NRC Request for Additional Information on H*; RAI #4; Model F and Model D5 Steam Generators" (Non-Proprietary)

14. Westinghouse Letter LTR-SGMP-10-34 Rev. 2, "An Assessment of the Impact of Revised Normal Operating Conditions on the Catawba Unit 2 H* Calculations" (Non-Proprietary)

In addition to the fourteen documents above, the following documents have also been previously submitted to the NRC by Westinghouse. Since these documents were also previously docketed, they are hereby being incorporated by reference into this amendment request submittal as well.

1. LTR-SGMP-09-104-P-Attachment, "White Paper on Probabilistic Assessment of H*"

2. LTR-SGMP-10-78-P-Attachment, "Effects of Tubesheet Bore Eccentricity and Dilation on Tube-to-Tubesheet Contact Pressure and Their Relative Importance to H*"

3. LTR-SGMP-10-33-P-Attachment, "H* Response to NRC Questions Regarding Tubesheet Bore Eccentricity"

4. LTR-SGMP-09-111-P-Attachment, "Acceptable Value of the Location of the Bottom of the Expansion Transition (BET) for Implementation of H*"

5. LTR-SGMP-10-95-P-Attachment, Rev. 1, "H*: Alternate Leakage Calculation Methods for H* for Situations When Contact Pressure at Normal Operating Conditions Exceeds Contact Pressure at Accident Conditions"

Finally, the following Vogtle related correspondence is also applicable to Catawba:

1. March 28, 2011 letter from the NRC to Southern Nuclear Operating Company (ADAMS Accession No. ML110660648) documented the summary of a February 16, 2011 public meeting regarding SG tube inspection permanent alternate repair criteria. Enclosure 3 of the NRC letter provided technical NRC staff questions developed at the meeting. Responses to these questions have been incorporated into Attachments 5 and 6 of this submittal.

2. Section 1.3 of Attachments 5 and 6 of this submittal identifies revisions in the report to address recommendations from the independent review of the H* analysis performed by MPR Associates. Related to the independent review, a May 26, 2011 letter from the NRC to Southern Nuclear Operating Company (ADAMS Accession No. ML11140A099) included a pre-submittal review Request for Additional Information (RAI). The response to the RAI is provided in Southern Nuclear Operating Company letter NL-11-1178, dated June 20, 2011.

To preclude unnecessarily plugging tubes in the Catawba Unit 2 SGs, tube inspections will be limited to identifying and plugging degradation in the portion of the tube within the tubesheet necessary to maintain structural and leakage integrity during both normal and accident conditions. The technical evaluation for the inspection and repair methodology is provided in WCAP-17072-P, as amended/supplemented and in WCAP-17330-P, Rev. 1, as indicated above. The evaluation is based on the use of finite element model structural analysis and a bounding leak rate evaluation based on contact pressure between the tube and the tubesheet during normal and postulated accident conditions. The limited tubesheet inspection criteria were developed for the tubesheet region of the Catawba Unit 2 Model D5 SGs considering the most stringent loads associated with plant operation, including transients and postulated accident conditions. The limited tubesheet inspection criteria were selected to prevent tube pullout from the tubesheet due to axial end cap loads acting on the tube and to ensure that the accident induced leakage limits are not exceeded. The H* analysis provides technical justification for limiting the inspection in the tubesheet expansion region to less than the full depth of the tubesheet.

The basis for determining the portion of the tube which requires eddy current inspection within the tubesheet is evaluation and testing programs that quantified the tube-to-tubesheet radial contact pressure for bounding plant conditions as described in the H* analysis. The tube-to-tubesheet radial contact pressure provides resistance to tube pullout and resistance to leakage during plant operation and transients.

Primary to secondary leakage from tube degradation is assumed to occur in several design basis accidents: Main Steam Line Break, Locked Rotor, and Control Rod Ejection. (In addition, for the SG Tube Rupture, primary to secondary leakage is also assumed to occur in the intact SGs.) The radiological dose consequences associated with this assumed leakage are evaluated to ensure that they remain within regulatory limits (e.g., 10 CFR 50.67, General Design Criterion (GDC) 19). The accident induced leakage performance criteria are intended to ensure the primary to secondary leak rate during any accident does not exceed the primary to secondary leak rate assumed in the accident analysis. Radiological dose consequences define the limiting accident condition for the H* justification.

The constraint that is provided by the tubesheet precludes tube burst for cracks within the tubesheet. The criteria for tube burst described in NEI 97-06 and in NRC Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes", are satisfied due to the constraint provided by the tubesheet. Through application of the limited tubesheet inspection scope as described below, the existing operating leakage limit provides assurance that excessive leakage (i.e., greater than accident analysis assumptions) will not occur. The accident analysis calculations assume a primary to secondary leakage equivalent to the TS operational leak rate limit of 150 gallons per day through any one SG and 600 gallons per day through all SGs. The maximum accident leak rate ratio for Catawba Unit 2 is 2.65 (LTR-SGMP-09-100-P-Attachment, Table RAI24-2). Per LTR-SGMP-10-34 Rev. 2, the leak rate ratio has been increased to 3.27.

Plant-specific operating conditions are used to generate the overall leakage factor ratios that are used in the Condition Monitoring and Operational Assessments. The plant-specific data provide the initial conditions for application of the transient input data. The results of the analysis of the plant-specific inputs to determine the bounding plant for each model of SG and to assure that the design basis accident contact pressures are greater than the normal operating pressure contact pressure are contained in Section 6 of WCAP-17072-P.

The leak rate ratio (accident induced leak rate to operational leak rate) is directly proportional to the change in differential pressure and inversely proportional to the dynamic viscosity. Since dynamic viscosity decreases with an increase in temperature, an increase in temperature results in an increase in leak rate. However, for both the postulated Steam Line Break and Feed Line Break events, a plant cooldown event would occur and the subsequent temperatures in the reactor coolant system would not be expected to exceed the temperatures at plant no load conditions. Thus, an increase in leakage would not be expected to occur as a result of the temperature change. The increase in leakage would only be a function of the increase in primary to secondary pressure differential. The resulting leak rate ratio for the Steam Line Break and Feed Line Break events is 2.65. The leak rate ratio has been increased to 3.27 per LTR-SGMP-10-34 Rev. 2.

The other design basis accidents, such as the postulated Locked Rotor and the Control Rod Ejection events, are conservatively modeled using the design specification transients that result in increased temperatures in the SG hot and cold legs for a period of time. As previously noted, dynamic viscosity decreases with increasing temperature. Therefore, leakage would be expected to increase due to decreasing viscosity and increasing differential pressure for the duration of time that there is a rise in reactor coolant system temperature. For transients other than a Steam Line Break and a Feed Line Break, the length of time that a plant with Model D5 SGs will exceed the normal operating differential pressure across the tubesheet is less than 30 seconds. As the accident induced leakage performance criteria is defined in gallons per minute, the leak rate for a Locked Rotor event can be integrated over a minute for comparison to the limit. Time integration permits an increase in acceptable leakage during the time of peak pressure differential by a factor of two because of the short duration (less than 30 seconds) of the elevated pressure differential. This translates into an effective reduction in the leakage factor by the same factor of two for the Locked Rotor event. Therefore, for the Locked Rotor event, the leakage factor of 1.48 (LTR-SGMP-09-100-P-Attachment, Table RAI24-2) for Catawba Unit 2 is adjusted downward to a factor of 0.74. Similarly, for the Control Rod Ejection event, the duration of the elevated pressure differential is less than 10 seconds. Thus, the peak leakage factor is reduced by approximately a factor of six, from 2.19 to 0.37. Due to the short duration of the transients above Normal Operating Pressure (NOP) differential, no leakage factor is required for the Locked Rotor and Control Rod Ejection events (i.e., the leakage factor is under 1.0 for both transients).

The plant transient response following a full power double-ended main feedwater line rupture corresponding to "best estimate" initial conditions and operating characteristics indicates that the transient exhibits a cooldown characteristic instead of a heatup transient as is generally presented in the SG design transients and in the Chapter 15 safety analyses. The use of either the component design specification transient or the Chapter 15 safety analysis transient for the leakage analysis for Feed Line Break is overly conservative because:

- The assumptions on which the Feed Line Break design transient is based are specifically intended to establish a conservative structural design basis for reactor system components; however, since H* does not involve component structural and fatigue issues, the best estimate transient is considered more appropriate for use in the H* leakage calculations.

- For the Model D5 Feed Line Break SG design transient, using the Feed Line Break design transient curve, the maximum reactor coolant system temperature can exceed the saturation temperature which is predicted to occur by the worst-case Feed Line Break heatup Chapter 15 Safety Analysis transient response.

- The assumptions on which the Feed Line Break safety analysis is based are specifically intended to establish a conservative basis for minimum auxiliary feedwater capacity requirements and combines worst-case assumptions which are exceptionally more severe when the Feed Line Break occurs inside containment. For example, environmental errors that are applied to reactor trip and engineered safety feature actuations would no longer be applicable. This would result in a much earlier reactor trip and greatly increase the SG liquid mass available to provide cooling to the reactor coolant system.

A Steam Line Break event would have similarities to a Feed Line Break except that the break flow path would include the secondary separators which could only result in an increased initial cooldown (because of retained liquid inventory available for cooling) when compared to the Feed Line Break transient. A Steam Line Break could not result in more limiting temperature conditions than a Feed Line Break.

In accordance with plant emergency operating procedures, it is expected that the operator would take action following a high energy secondary line break to stabilize the reactor coolant system conditions. The expectation for a Steam Line Break or Feed Line Break with credited operator action is to stop the system cooldown through isolation of the faulted SG and control temperature by the auxiliary feedwater system. Steam pressure control would be established by either the SG safety valves or steam dump or power operated relief valves. For any of the steam pressure control options, the maximum temperature would be approximately the no load temperature and would be well below the normal operating temperature for the plant.

Subsequently, the operator would initiate a cooldown and depressurization of the reactor coolant system which would continue to be well bounded by the selected conditions for the H* leakage calculations.

Precedent exists to credit operator action. The SG Tube Rupture event in the Updated Final Safety Analysis Report (UFSAR) permits operator action to mitigate the expected leakage. No operator action to reduce SG tube leakage is credited in the analyses of any accident scenario including fission product releases with SG boiloff. The analyses for all of these accident scenarios demonstrate that the radiological consequences are within the appropriate NRC acceptance criteria.

Since the best estimate Feed Line Break transient temperature would not be expected to exceed the normal operating temperature, the viscosity ratio for the Feed Line Break transient is set to 1.0.

As a conservative basis for calculating the leakage for the Feed Line Break transient, the maximum Feed Line Break design basis transient pressure is used in the calculation of H* Feed Line Break leakage.

The leakage factor of 2.65 for Catawba Unit 2 for a postulated Steam Line Break/Feed Line Break has been calculated in WCAP-17072-P. The leakage factor has been increased to 3.27 per LTR-SGMP-10-34 Rev. 2. Specifically, 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 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.

The H* analysis redefines the primary pressure boundary. The tube-to-tubesheet weld no longer functions as a portion of this boundary. The hydraulic expansion of the tube into the tubesheet over the H* distance now functions as the primary pressure boundary in the area of the tube and tubesheet, maintaining the structural and leakage integrity over the full range of SG operating conditions, including the most limiting accident conditions. WCAP-17072-P determined that degradation in tubing below 13.8 inches from the top of the tubesheet does not require inspection or repair (plugging). The 13.8-inch value of H* is based on normal operating pressure as being the limiting condition and consequently this H* value is based on 95/50 whole plant analysis. WCAP-17330-P, Rev. 1, determined that the Steam Line Break is the limiting condition and the calculated H* is 14.01 inches based on 95/95 whole bundle analysis. The inspection of the portion of the tubes above the H* value from the top of the tubesheet for tubes that have been hydraulically expanded in the tubesheet provides a high level of confidence that the structural and leakage performance criteria are maintained during normal operating and accident conditions.

WCAP-17072-P determined the H* inspection 95/50 whole plant depth of 13.8 inches from the top of the tubesheet, and WCAP-17330-P, Rev. 1 determined the 95/95 whole bundle depth of 14.01 inches from the top of the tubesheet. Duke Energy is therefore using the value of 14.01 inches.

WCAP-17072-P provides a review of leak rate susceptibility to tube slippage and concluded that the tubes are fully restrained against motion under very conservative design and analysis assumptions such that tube slippage is not a credible event for any tube in the bundle. However, in response to an NRC staff request, Duke Energy has included monitoring for tube slippage as part of the SG tube inspection program.

Finally, in conjunction with the most recent one-cycle amendment (Amendment 257), the NRC staff had requested that licensees determine if there were any significant deviations in the location of the bottom of the expansion transition (BET) relative to the top of the tubesheet that would invalidate assumptions in WCAP-17072-P. Therefore, Duke Energy performed a one-time verification of the tube expansion to locate any significant deviations in the distance from the top of the tubesheet to the BET. No significant deviations were found.

5. REGULATORY EVALUATION

5.1 Applicable Regulatory Requirements/Criteria

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

The following NEI 97-06 performance criteria, which are included in the TS for Catawba Unit 2, are the basis for this amendment request submittal. (Note: The actual performance criteria as stated in the Catawba Unit 2 TS are shown below.)

The structural integrity performance criterion is:

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

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

The accident induced leakage performance criterion is:

The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 150 gallons per day through each SG for a total of 600 gallons per day through all SGs.

Primary to secondary leakage is a factor in the calculated dose due to releases outside containment resulting from a limiting design basis accident. The potential primary to secondary leak rate during postulated design basis accidents shall not result in exceeding the offsite radiological dose consequences as limited by 10 CFR 50.67 or the radiological consequences to control room personnel as limited by GDC 19.

The H* distance for the tubesheet region has been developed to meet the above criteria. The structural criterion regarding tube burst is inherently satisfied because the constraint provided by the tubesheet to the tube prohibits burst.

The proposed change defines the portion of the tube that is engaged in the tubesheet from the secondary face that is required to maintain structural and leakage integrity over the full range of SG operating conditions, including the most limiting accident conditions. WCAP-17072-P determined the H* inspection 95/50 whole plant depth of 13.8 inches from the top of the tubesheet, and WCAP-17330-P, Rev. 1, determined the 95/95 whole bundle depth of 14.01 inches from the top of the tubesheet. Duke Energy is therefore using the value of 14.01 inches. As such, the Catawba Unit 2 inspection program provides a high level of confidence that the structural and leakage criteria are maintained during normal operating and accident conditions.

5.2 Precedent

This amendment request is similar to amendments that the NRC granted for other Westinghouse plants. Catawba Unit 2 is currently the lead unit for requesting approval of this amendment on a permanent basis. The precedent cited below represents the most recent one-cycle amendment for units with Model D5 SGs using the H* methodology prior to this Catawba Unit 2 permanent amendment request.

1. Braidwood Station, Units 1 and 2 and Byron Station, Unit Nos. 1 and 2 - Issuance of Amendments re: Changes to Technical Specification

Sections 5.5.9, "Steam Generator (SG) Program" and 5.6.9 "Steam Generator (SG) Tube Inspection Report" (TAC Nos. ME5198, ME5199, ME5200, and ME5201), April 13, 2011 (ADAMS Accession No. ML110840580)

5.3 No Significant Hazards Consideration

This amendment request proposes to revise Technical Specification 3.4.13, TS 5.5.9, and TS 5.6.8 to accomplish the following objectives for Unit 2:

- Permanently exclude portions of the 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.

Although the proposed changes only affect Unit 2, this submittal is being docketed for both Unit 1 and Unit 2 since the TS are common to both units. Application of the structural analysis and leak rate evaluation results, to exclude portions of the tubes from inspection and repair, is interpreted to constitute a redefinition of the primary to secondary pressure boundary.

The proposed change defines the safety significant portion of the tube that must be inspected and plugged. A justification has been developed by Westinghouse to identify the specific inspection depth below which any type of degradation can be shown to have no impact on the Nuclear Energy Institute (NEI) 97-06 performance criteria.

Duke Energy has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by analyzing the three standards set forth in 10 CFR 50.92(c) as discussed 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.

Based on the above, Duke Energy concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of no significant hazards consideration is justified.

5.4 Conclusions

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

6. ENVIRONMENTAL CONSIDERATION

Duke Energy has determined that the proposed amendment does change requirements with respect to the installation or use of a facility component located within the restricted area, as defined by 10 CFR 20. It also represents a change to an inspection or surveillance requirement. Duke Energy has evaluated the proposed amendment and has determined that it does not involve: (1) a significant hazards consideration, (2) a significant change in the types or a significant increase in the amounts of any effluents that may be released offsite, or (3) a significant increase in individual or cumulative occupational radiation exposures. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

ATTACHMENT 2

Marked-Up TS Pages

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;

(Unit 1) and 45 gallons per day (Unit 2)

c. 10 gpm identified LEAKAGE; and

d. 150 gallons per day 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. OR Pressure boundary LEAKAGE exists. OR Primary to secondary LEAKAGE not within limit.	B.1 Be in MODE 3. AND 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 ≤ 150 gallons per day (Unit 1) and ≤ 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 (continued)

5.5.8 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports. The program shall include the following:

a. Testing frequencies applicable to the ASME Code for Operations and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as follows:

ASME OM Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies and to other normal and accelerated Frequencies specified as 2 years or less for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME OM Code shall be construed to supersede the requirements of any TS.

5.5.9 Steam Generator (SG) Program

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

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the

(continued)

5.5.9 Steam Generator (SG) Program (continued)

condition of the tubing during a SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

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

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

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 150 gallons per day through each SG for a total of 600 gallons per day through all SGs.

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

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

(continued)

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, 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.

14.01

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, 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 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.

14.01

(continued)

5.5 Programs and Manuals

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.

14.01

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, 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

(continued)

5.5.9 Steam Generator (SG) Program (continued)

not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation and low pressure turbine disc stress corrosion cracking. The program shall include:

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

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

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

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

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

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems in accordance with Regulatory Guide 1.52, Revision 2, and ANSI N510-1980, with exceptions as noted in the UFSAR.

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

(continued)

5.6 Reporting Requirements (continued)

5.6.7 PAM Report

When a report is required by LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.8 Steam Generator (SG) Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of the inspection. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Non-destructive examination techniques utilized for each degradation mechanism,

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

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

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

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

(continued)

5.6 Reporting Requirements

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

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 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,

after each refueling outage (and any inspections performed during subsequent cycle operation),

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 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.

14.01

ATTACHMENT 3

Marked-Up TS Bases Pages

NO CHANGES THIS PAGE.
FOR INFORMATION ONLY

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND	Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS. During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE. 10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems. The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public. A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection. This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).
APPLICABLE SAFETY ANALYSES	Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event.

APPLICABLE SAFETY ANALYSES (continued)

The safety analysis (Ref. 3) for an event resulting in steam discharge to the atmosphere assumes that primary to secondary LEAKAGE from each steam generator (SG) is 150 gallons per day. Any event in which the reactor coolant system will continue to leak water inventory to the secondary side, and in which there will be a postulated source term associated with the accident, utilizes this leakage value as an input in the analysis. These accidents include the rod ejection accident, locked rotor accident, main steam line break, steam generator tube rupture and uncontrolled rod withdrawal accident. The rod ejection accident, locked rotor accident and uncontrolled rod withdrawal accident yield a source term due to postulated fuel failure as a result of the accident. The main steam line break and the steam generator tube rupture yield a source term due to perforations in fuel pins causing an iodine spike. Primary to secondary side leakage may escape the secondary side due to flashing or atomization of the coolant, or it may mix with the secondary side SG water inventory and be released due to steaming of the SGs. The rod ejection accident is limiting compared to the remainder of the accidents with respect to dose results. The dose results for each of the accidents delineated above are below the 10 CFR 50.67 limits (Ref. 9) and the limits in Regulatory Guide 1.183 (Ref. 10) for these accidents.

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36 (Ref. 4).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE.

Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment

BASES

LCO (continued)

can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified or total LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE captured by the pressurizer relief tank and reactor coolant drain tank, as well as quantified LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Any One SG

(Unit 1) and 45 gallons per day (Unit 2)

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, "Steam Generator Program Guidelines" (Ref. 6). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states: "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day."

The limit for Unit 2 has been permanently reduced as a result of the SG tube alternate repair criteria that has been implemented for this unit.

The primary to secondary LEAKAGE measurement is based on the methodology described in Ref. 5.

The operational LEAKAGE rate limit applies to LEAKAGE in any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the LEAKAGE should be conservatively assumed to be from one SG.

The limit in this criterion is based on operating experience gained from SG tube degradation mechanisms that result in tube LEAKAGE. The operational LEAKAGE rate criterion in conjunction with implementation of the Steam Generator Program is an effective measure for minimizing the frequency of SG tube ruptures.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable unidentified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE or identified LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists, or if primary to secondary LEAKAGE is not within limit, or if unidentified LEAKAGE or identified LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance. For this SR, the volumetric calculation of unidentified LEAKAGE and identified LEAKAGE is based on a density at room temperature of 77 degrees F.

The Surveillance is modified by two Notes. The RCS water inventory balance must be performed with the reactor at steady state operating conditions and near operating pressure. Therefore, Note 1 indicates that this SR is not required to be completed until 12 hours of steady state operation near operating pressure have been established.

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and Note 1 requires the Surveillance to be met when steady state is established. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day or lower cannot be measured accurately by an RCS water inventory balance.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. A Note under the Frequency column states that this SR is only required to be performed during steady state operation.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.13.2

(Unit 1) and less than or equal to 45 gallons per day (Unit 2)

This SR verifies that primary to secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.18, "Steam Generator (SG) Tube Integrity," should be evaluated. The 150 gallons per day limit is based on measurements taken at room temperature. The primary to secondary leak rate assumed in the safety analyses is taken also at room temperature.

(Unit 1) and 45 gallons per day (Unit 2)

The Surveillance is modified by a Note which states that this SR is not required to be completed until 12 hours of steady state operation near operating pressure have been established. During normal operation the primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. A Note under the Frequency column states that this SR is only required to be performed during steady state operation.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. UFSAR, Section 15.
4. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).
5. EPRI TR-104788-R2, "PWR Primary-to-Secondary Leak Guidelines," Revision 2.
6. NEI 97-06, "Steam Generator Program Guidelines."
7. UFSAR, Section 18, Table 18-1.
8. Catawba License Renewal Commitments, CNS-1274.00-00-0016, Section 4.27.
9. 10 CFR 50.67.

REFERENCES (continued)

10. Regulatory Guide 1.183, July 2000.

ATTACHMENT 4

Westinghouse Authorization Letter CAW-11-3172 with Accompanying Affidavit,
Proprietary Information Notice, and Copyright Notice
(WCAP-17330-P, Rev. 1)

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Cranberry Township, PA 16066
USA

U.S. Nuclear Regulatory Commission
Document Control Desk
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Proj letter: DPC-11-40

CAW-11-3172

June 6, 2011

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: WCAP-17330-P, Revision 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-11-3172 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by Duke Energy.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-11-3172, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance, Westinghouse Electric Company LLC, Suite 428, 1000 Westinghouse Drive, Cranberry Township, PA 16066.

Very truly yours,

J. A. Gresham, Manager
Regulatory Compliance

Enclosures

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF BUTLER:

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

J. A. Gresham, Manager
Regulatory Compliance

Sworn to and subscribed before me
this 6th day of June 2011

Cynthia Olesky
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cynthia Olesky, Notary Public
Manor Boro, Westmoreland County
My Commission Expires July 16, 2014
Member. Pennsylvania Association of Notaries

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

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

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

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

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

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

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

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of

Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in WCAP-17330-P, Revision 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)" (Proprietary), dated June 2011, for submittal to the Commission, being transmitted by Duke Energy Letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted by Westinghouse for Catawba Unit 2, is that associated with the technical justification of the H* Alternate Repair Criteria for hydraulically expanded steam generator tubes and may be used only for that purpose.

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

(a) License the H* Alternate Repair Criteria.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of the information to its customers for the purpose of licensing the H* Alternate Repair Criteria.

(b) Westinghouse can sell support and defense of the H* criteria.

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

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

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

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

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

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

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

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