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L-2009-151
10 CFR 50.90

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

Re: Turkey Point Units 3 and 4
Docket Nos. 50-250 and 50-251
License Amendment Request No. 197 for H*: Alternate Repair Criteria for Steam Generator Tubesheet Expansion Region

Pursuant to 10 CFR 50.90, Florida Power and Light Company (FPL) requests to amend Technical Specifications (TS) of Facility Operating Licenses DPR-31 and DPR-41 for Turkey Point Units 3 and 4.

The proposed change would revise the TS 6.8.4.j, Steam Generator (SG) Surveillance Program and TS 6.9.1.8, Steam Generator Tube Inspection Report. The purpose of these modifications is to revise the scope of the inservice inspections required in the tubesheet regions of the Turkey Point Units 3 and 4 SGs.

Enclosure 6 contains information proprietary to Westinghouse Electric Company LLC, and is supported by an affidavit signed by Westinghouse, the owner of the information and provided in Enclosure 7. The affidavit 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 Section 2.390 of the Commissions' regulations. Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10CFR 2.390 of the Commission's regulations.

Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse affidavit should reference CAW-09-2601 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

The license amendments proposed by FPL have been reviewed by the Turkey Point Plant Nuclear Safety Committee. In accordance with 10 CFR 50.91(b)(1), a copy of the proposed license amendment is being forwarded to the State Designee for the State of Florida.

FPL requests approval of the proposed amendment by October 20, 2009 to support the fall 2009 Turkey Point Unit 4 steam generator inspections. Once approved, the amendment shall be implemented prior to HOT SHUTDOWN conditions following refueling outage 25 for Turkey Point Unit 4.

This letter makes the following commitments, which are included in Enclosure 8:

1. Turkey Point Nuclear Plant commits to monitor for tube slippage as part of the steam generator tube inspection program.

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2. Turkey Point Nuclear Plant commits to perform a one-time verification of tube expansion locations to determine if any significant deviations exist from the top of the tubesheet to the bottom of the expansion transition (BET). If any significant deviations are found, the condition will be entered into the plant corrective action program and dispositioned.

Please contact Mr. Robert Tomonto, Licensing Manager at 305-246-7327 if there are any questions about this submittal.

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

Executed on July 23, 2009

Very truly yours,

William Jefferson, Jr.
Vice President
Turkey Point Nuclear Plant

cc: Regional Administrator, Region II, USNRC (w/o enclosures 5, 6 and 7)
USNRC Project Manager, Turkey Point (enclosures 5 and 6 on disk)
Senior Resident Inspector, USNRC, Turkey Point (w/o enclosures 5, 6 and 7)
W. A. Passetti, Florida Department of Health (w/o enclosures 5, 6 and 7)

ENCLOSURES

1. Description and assessment of the proposed changes.
2. Marked-up Technical Specification pages and inserts.
3. Retyped Technical Specification pages with the proposed changes incorporated.
4. Marked-up pages and inserts for the Technical Specification Bases Control Program.
5. Copy of the non-proprietary WCAP-17091-NP dated June 2009, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model 44F)."
6. Copy of the proprietary WCAP-17091-P dated June 2009, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model 44F)."
7. Copy of the Westinghouse Letter CAW-09-2601, "Application for Withholding Proprietary Information from Public Disclosure"
8. List of Regulatory Commitments for this request

ENCLOSURE 1

DESCRIPTION AND ASSESSMENT OF THE PROPOSED CHANGES

Turkey Point Units 3 & 4
License Amendment Request for H*: Alternate Repair Criteria for Steam Generator Tubesheet Expansion Region

1.0 DESCRIPTION

Florida Power & Light Company proposes to revise Turkey Point Units 3 and 4 Technical Specification (TS) 6.8.4.j, "Steam Generator (SG) Program," to exclude portions of the SG tube below the top of the SG tubesheet from periodic SG tube inspections. In addition, this amendment request proposes to revise TS 6.9.1.8, "Steam Generator Tube Inspection Report," to provide reporting requirements specific to the permanent alternate repair criteria. Application of the supporting structural analysis and leakage evaluation results to exclude portions of the tubes from inspection and repair of tube indications is interpreted to constitute a redefinition of the primary to secondary pressure boundary.

The NRC previously granted license amendments 231 and 226 for Turkey Point Units 3 and 4 [Reference 1] to exclude the portion of the tubes below 17 inches from the top of the hot leg tubesheet on a one-time basis. These amendments expire at the end of the current operating cycle (cycle 24) for both Units 3 and 4. This permanent request for amendment would replace the existing one-time amendments.

This request for a permanent change is supported by Westinghouse Electric Company LLC, WCAP-17091-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model 44F), June 2009" [Reference 2]. WCAP-17091-P, Section 8.0, recommended a final 95% probability/50% confidence H* value of 13.31 inches below the top of the tubesheet for the entire bundle of tubes (Case S-2 in Table 8-4). However, Turkey Point Units 3 and 4 have chosen to use an H* value of 17.28 inches. This requires inspection with a probe qualified to detect stress corrosion cracking in the tubesheet region from the top of the tubesheet (TTS) to the H* value 17.28 inches below the TTS.

Approval of this amendment application for Turkey Point Units 3 and 4 is requested by October 20, 2009 to support the Turkey Point Unit 4 Cycle 25 Refueling Outage SG inspections as the existing one-time amendment [Reference 1] expires at the end of the current operating cycle.

2.0 PROPOSED CHANGE

TS 6.8.4.j.a. is revised as follows to correct a typographical error (Deleted text is struck through and ***added text is in bold italic***):

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results ~~of~~***for*** 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.

TS 6.8.4.j.c. is revised as follows:

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

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

~~1. For Unit 3 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, and for Unit 4 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, flaws found in the portion of the tube below 17 inches from the top of the hot leg tubesheet do not require plugging.~~

~~For Unit 3 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, and for Unit 4 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, all tubes with flaws identified in the portion of the tube within the region from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be plugged.~~
Tubes with service-induced flaws located greater than 17.28 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 17.28 inches below the top of the tubesheet shall be plugged upon detection.

TS 6.8.4.j.d is revised as follows:

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, ~~from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet~~ ***from 17.28 inches below the top of the tubesheet on the hot leg side to 17.28 inches below the top of the tubesheet on the cold leg side***, and that may satisfy the applicable tube repair criteria. ~~For Unit 3 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, and for Unit 4 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled~~

~~inspection, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded from inspection when the alternate tube repair criteria in specification 6.8.4.j.c.1 is implemented.~~ The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tube may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

TS 6.8.4.j.d.3 is revised as follows:

3. If crack indications are found in any SG tube, ***from 17.28 inches below the top of the tubesheet on the hot leg side to 17.28 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 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

TS 6.9.1.8 is revised to add reporting requirements i, j, and k:

STEAM GENERATOR TUBE INSPECTION REPORT

6.9.1.8 A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 6.8.4.j, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

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

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

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

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

h. The effective plugging percentage for all plugging in each SG~~.~~,

i. The primary to secondary leakage rate observed in each SG (if it is not practical to assign the leakage to an individual SG, the entire primary to

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

j. The calculated accident induced leakage rate from the portion of the tubes below 17.28 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 1.82 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

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

3.0 BACKGROUND

Turkey Point Units 3 and 4 are three loop Westinghouse designed plants. Each unit has three replacement Model 44F SGs that were installed in 1982 and 1983 respectively. Each SG has 3214 tubes. Turkey Point Units 3 and 4 are both currently in cycle 24 operation and have a total of 170 tubes and 53 tubes plugged respectively. The design of the SG includes Alloy 600 thermally treated tubing, full depth hydraulically expanded tubesheet joints, and stainless steel tube support plates with broached hole quatrefoils.

The SG inspection scope is governed by TS 6.8.4.j "Steam Generator (SG) Program"; Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines" [Reference 3]; EPRI 1013706, "Pressurized Water Reactor Steam Generator Examination Guidelines" [Reference 4]; EPRI 1012987, "Steam Generator Integrity Assessment Guidelines" [Reference 5]; the Florida Power & Light Steam Generator Integrity Program and the results of the degradation assessments required by the SG Program. Criterion IX, "Control of Special Processes" of 10 CFR Part 50, Appendix B, requires in part that nondestructive 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 known and potential specific degradation mechanisms applicable to Turkey Point Units 3 and 4. The inspection techniques, essential variables and equipment are qualified to Appendix H, "Performance Demonstration for Eddy Current Examination" of the EPRI Steam Generator Examination Guidelines [Reference 4].

Catawba Nuclear Station, Unit 2, (Catawba) reported indications of cracking following nondestructive eddy current examination of the SG tubes during their fall 2004 outage. In April 2005, NRC Information Notice (IN) 2005-09, "Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds" [Reference 6], provided industry notification of the Catawba 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.

The Florida Power & Light Company Steam Generator Integrity Program requires the use of applicable industry operating experience in the operation and maintenance of Turkey Point Units 3 and 4. The recent experience at Catawba, as noted in IN 2005-09, shows the importance of monitoring all tube locations (such as bulges, dents, dings, and other anomalies from the manufacture of the SGs) with techniques capable of finding potential forms of degradation that may be occurring at these locations as discussed in NRC Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections, August 30, 2004." Since the Turkey Point Units 3 and 4 Westinghouse Model 44F SGs were fabricated with Alloy 600 thermally treated tubes similar to the Catawba Unit 2 Westinghouse Model D5 SGs, a potential exists for Turkey Point Units 3 and 4 to identify tube indications similar to those reported at Catawba within the tubesheet region if similar inspections are performed at the next scheduled inspection of the SGs.

Potential inspection plans for the tubes and tube welds underwent intensive industry discussions in March 2005. The findings in the Catawba SG tubes present two distinct issues with regard to the SG tubes at Turkey Point Units 3 and 4:

1) Indications in internal bulges and overexpansions within the hot leg tubesheet; and
2) Indications at the elevation of the tack expansion transition.

Prior to each SG tube inspection, a degradation assessment, which includes a review of operating experience, is performed to identify degradation mechanisms that have a potential to be present in the Turkey Point Units 3 and 4 SGs. A validation assessment is also performed to verify that the eddy current techniques utilized are capable of detecting those flaw types that are identified in the degradation assessment. Based on the Catawba operating experience, Turkey Point Units 3 and 4 revised the SG inspection plans for the refueling outage 23 inspections at Unit 3 (fall 2007) and the refueling outage 23 inspections at Unit 4 (fall 2006) to include sampling of bulges and over expansions within the tubesheet region on the hot leg side. The sample was based on the guidance contained in EPRI 1013706, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 7 [Reference 4], and TS 6.8.4.j, "Steam Generator (SG) Program." According to EPRI SG examination guidelines, the inspection plan is expanded if necessary due to confirmed degradation in the region required to be examined (i.e. a tube crack). No crack-like indications were detected in the Unit 3 or 4 refueling outage 23 inspections.

To address the potential impact of the Catawba inspection results, Turkey Point Units 3 and 4 were granted a one-time TS change in November 2006 (amendments 231 and 226) to limit inspection depth to 17 inches below the top of the hot leg tubesheet [Reference 1]. Reference 1, however, applies only to the inspections conducted during refueling outage 23 at each unit, which are the only inspections conducted since IN 2005-09 was

issued. Further, Reference 1 expires at the next scheduled inspection of each unit, which is in the fall of 2009 at Unit 4 and in the fall of 2010 at Unit 3. Therefore, FPL is applying for a permanent alternate repair criteria, known as H*, based on Westinghouse WCAP-17091-P, and is proposing changes to Turkey Point Units 3 and 4 TS 6.8.4.j, "Steam Generator (SG) Program" to limit the SG tube inspection and repair (plugging) to the portion of tubing from 17.28 inches below the top of the tubesheet. This amendment request also proposes to revise TS 6.9.1.8, "Steam Generator Tube Inspection Report," to provide reporting requirements specific to the permanent alternate repair criteria.

4.0 TECHNICAL ANALYSIS

To preclude unnecessarily plugging tubes in the Turkey Point Units 3 and 4 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 in both normal and accident conditions. The technical evaluation for the inspection and repair methodology is provided in Westinghouse Electric Company LLC, WCAP-17091-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model 44F), June 2009". 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 Turkey Point Units 3 and 4 Model 44F SG considering the most stringent loads associated with plant operation, including transients and postulated accident conditions. The limited tubesheet inspection criteria were selected to prevent pull out of a severed tube 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. WCAP-17091-P provides the technical justification for limiting the inspection in the tubesheet expansion region to less than the full depth of the tubesheet.

The determination of the portion of the tube that requires eddy current inspection within the tubesheet is based upon evaluation and testing programs that quantified the tube-to-tubesheet radial contact pressure for bounding plant conditions as described in WCAP-17091-P. The tube-to-tubesheet radial contact pressure provides resistance to tube pull out and resistance to leakage during plant operation and transients.

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 [Reference 3] and NRC Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," [Reference 7] are satisfied by the constraint provided by the tubesheet. Through application of the limited tubesheet inspection scope as described below, the existing operational leakage limit provides assurance that excessive leakage (i.e., greater than accident analysis assumptions) will not occur.

Primary to secondary leakage from tube degradation is assumed to occur in several design basis accidents: steam line break (SLB), locked rotor, and control rod ejection

events. The radiological dose consequences associated with this assumed leakage are evaluated to ensure that they remain within regulatory limits (e.g. 10 CFR Part 100, 10 CFR 50.67, 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* value. The current UFSAR assumed primary to secondary accident induced leak rate is 500 gallons per day (gpd) through any one SG for SLB, and 1 gpm total for each of the rod ejection and locked rotor events. Thus, the limiting accident is SLB. It should be noted that both of the above leak rate values are at accident conditions. The 500 gpd SLB assumed accident induced leak rate adjusted from accident conditions to room temperature is 355 gpd.

The SLB leak rate factor for Turkey Point Units 3 and 4 is 1.82 (Table 9-7 in WCAP-17091-P). Multiplying this factor by the TS operational leak rate limit of 150 gpd (at room temperature) through any one SG indicates that an assumed primary to secondary accident induced leak rate of 273 gpd or greater through any one SG is required to ensure that the limiting design basis accident assumption is not exceeded. This condition is satisfied by the current UFSAR assumed primary to secondary accident induced leak rate of 500 gpd (355 gpd adjusted to room temperature) through any one SG for SLB.

The other design basis accidents, such as the postulated locked rotor event and the control rod ejection event, 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 RCS temperature. For transients other than a SLB, the length of time that a plant with Model 44F SGs will exceed the normal operating differential pressure across the tubesheet is less than 30 seconds for the locked rotor event, and less than 10 seconds for the control rod ejection event. 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 approximately a factor of two for the locked rotor event because of the short duration (less than 30 seconds) of the elevated pressure differential, and by a factor of six for the control rod ejection event (less than 10 seconds). This translates into an effective reduction in the leakage factor by the same factor for each event. Therefore, the locked rotor event leak rate factor of 1.66 for Turkey Point Units 3 and 4 is adjusted downward to a factor of 0.83 (Table 9-7, Reference 2). Similarly, the control rod ejection event leak rate factor is reduced by a factor of six, from 2.45 to 0.41 (Table 9-7, Reference 2). Due to the short duration of the transients above 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). Thus, SLB remains the limiting accident and 1.82 remains the limiting leak rate factor for Turkey Point Units 3 and 4 (Table 9-7 in WCAP-17091-P).

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 contact pressure are contained in section 6 of WCAP-17091-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 the postulated SLB event, a plant cool down event would occur and the subsequent temperature in the reactor coolant system (RCS) 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 SLB event is 1.82 for Turkey Point Units 3 and 4 (Table 9-7 of WCAP-17091-P).

The leak rate factor of 1.82 for Turkey Point Units 3 and 4 for a postulated SLB has been calculated as shown in Table 9-7 of Reference 2. Turkey Point Units 3 and 4 will apply a factor of 1.82 to the normal operating leakage associated with the tubesheet expansion region in the condition monitoring (CM) and operational assessment (OA). The leak rate factor of 1.82 in Table 9-7 of Reference 2 applies to both hot and cold legs. Specifically, for the CM assessment, the component of leakage from the prior cycle from below the H* distance will be multiplied by a factor of 1.82 and added to the total leakage from any other source and compared to the assumed accident induced leak rate. For the OA, the difference between the allowable leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 1.82 and compared to the observed operational leakage.

Reference 2 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 from the top of the tubesheet down to 17.28 inches below the top of the tubesheet 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. The evaluation in Reference 2 determined that degradation in tubing below 13.31 inches from the top of the tubesheet does not require inspection or repair (plugging). The inspection of the portion of the tubes above 13.31 inches below the top of hot and cold 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-17091-P, Section 8.0, recommended a final H* value of 13.31 inches from the top of the tubesheet for the entire bundle of tubes. However, Turkey Point Units 3 and 4 has chosen to use an H* value of 17.28 inches.

WCAP-17091-P, section 9.8, 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 a NRC staff request, Turkey Point Units 3 and 4 commits to monitor for tube slippage as part of the SG tube inspection program. A proposed change to TS 6.9.1.8, "Steam Generator Tube Inspection Report" adds a new reporting requirement for slippage monitoring. If no tube slippage is identified as a result of the monitoring, the Steam Generator Tube Inspection Report would indicate no tube slippage was detected.

In addition the NRC staff has requested that licensees determine if there are any significant deviations in the location of the bottom of the expansion transition (BET) relative to the top of tubesheet compared to the assumptions in WCAP-17091-P. Therefore, Turkey Point Units 3 and 4 commits to perform a one time verification of tube expansion locations to determine if any significant deviations exist from the top of tubesheet to the BET. If any significant deviations are found, the condition will be entered into the plant corrective action program and dispositioned.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Consideration

This amendment application proposes to revise TS 6.8.4.j, "Steam Generator (SG) Program," to exclude portions of the tubes within the tubesheet from periodic SG inspections. In addition, this amendment proposes to revise TS 6.9.1.8, "Steam Generator Tube Inspection Report" to provide reporting requirements specific to the permanent alternate repair criteria. 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 repaired. A justification has been developed by Westinghouse Electric Company LLC, to identify the specific inspection depth below which any type of degradation can be shown to have no impact on the performance criteria in Nuclear Energy Institute (NEI) 97-06 (Reference 3), "Steam Generator Program Guidelines," and TS 6.8.4.j.b, "Performance criteria for SG tube integrity."

Florida Power & Light Company has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. *The proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.*

Of the applicable accidents previously evaluated, the limiting transients with consideration to the proposed change to the SG tube inspection and repair criteria are the SG tube rupture (SGTR) event and the steam line break (SLB) postulated accident.

During the SGTR event, the required structural integrity margins of the SG tubes and the tube-to-tubesheet joint over the H* distance will be maintained. Tube rupture in tubes with cracks within the tubesheet is precluded by the constraint provided by the presence of the tubesheet and the tube-to-tubesheet joint. Tube burst cannot occur within the thickness of the tubesheet. The tube-to-tubesheet joint constraint results from the hydraulic expansion process, thermal expansion mismatch between the tube and tubesheet, and from the differential pressure between the primary and secondary side, and tubesheet rotation. Based on this design, the structural margins against burst, as discussed in Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes" [Reference 7] and NEI 97-06, "Steam Generator Program Guidelines", [Reference 3] are maintained for both normal and postulated accident conditions. For the portion of the tube outside of the tubesheet, the proposed change also has no impact on the structural or leakage integrity. Therefore, the proposed change does not result in a significant increase in the probability of the occurrence of a SGTR accident.

At normal operating pressures, leakage from tube degradation below the proposed limited inspection depth is limited by the tube-to-tubesheet crevice. Consequently, negligible normal operating leakage is expected from degradation below the inspected depth within the tubesheet region. The consequences of an SGTR event 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, which would constitute a failure to meet H*, is considered to be equivalent to a tube rupture. Therefore, the proposed change does not result in a significant increase in the consequences of an SGTR event. In addition, the selected H* value envelopes the depth within the tubesheet required to prevent a tube pullout.

The probability of a SLB is unaffected by the potential failure of a SG tube as the failure of a tube is not an initiator for a SLB event.

The leak rate factor of 1.82 for Turkey Point Units 3 and 4, for a postulated SLB, has been calculated as shown in Table 9-7 of Reference 2. Turkey Point Units 3 and 4 will apply the factor of 1.82 to the normal operating leakage associated with the tubesheet expansion region in the condition monitoring (CM) and operational assessment (OA). Through application of the limited tubesheet inspection scope, the existing operating leakage limit provides assurance that excessive leakage (i.e., greater than accident analysis

assumptions) will not occur. Multiplying the leak rate factor of 1.82 by the TS operational leak rate limit of 150 gpd (at room temperature) through any one SG indicates that an assumed primary to secondary accident induced leak rate of 273 gpd or greater through any one SG is required to ensure that the limiting design basis accident assumption is not exceeded. This condition is satisfied by the current UFSAR assumed primary to secondary accident induced leak rate of 500 gpd (355 gpd adjusted to room temperature) through any one SG for SLB. Since the existing limits on operational leakage continue to ensure that the SLB assumed accident induced leakage will not be exceeded, the consequences of a SLB accident are not increased.

For the CM assessment, the component of leakage from the prior cycle from below the H* distance will be multiplied by a factor of 1.82 and added to the total leakage from any other source and compared to the allowable accident induced leak rate. For the OA, the difference in the leakage between the allowable leakage and the calculated accident induced leakage from sources other than the tubesheet expansion region will be divided by 1.82 and compared to the observed operational leakage.

The previously analyzed accidents are initiated by the failure of plant structures, systems, or components. The proposed change that alters the SG inspection and reporting criteria does not have a detrimental impact on the integrity of any plant structure, system, or component that initiates an analyzed event. The proposed change will not alter the operation of, or otherwise increase the failure probability of any plant equipment that initiates an analyzed accident.

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

2. *The proposed changes do not create the possibility of a new or different kind of accident from any previously evaluated.*

   The proposed change that alters the SG inspection and reporting criteria does not introduce any new equipment, create new failure modes for existing equipment, or create any new limiting single failures. Plant operation will not be altered, and all safety functions will continue to perform as previously assumed in accident analyses. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. *The proposed changes do not involve a significant reduction in the margin of safety.*

The proposed change defines the safety significant portion of the tube that must be inspected and repaired. WCAP-17091-P identifies the specific inspection depth below which any type of tube degradation is shown to have no impact on the performance criteria in NEI 97-06 Rev. 2, "Steam Generator Program Guidelines" [Reference 3] and TS 6.8.4.j, "Steam Generator (SG) Program."

The proposed change that alters the SG inspection and reporting criteria maintains the required structural margins of the SG tubes for both normal and accident conditions. Nuclear Energy Institute 97-06, "Steam Generator Program Guidelines" [Reference 3], and NRC Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes" [Reference 7], are used as the bases 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 for meeting General Design Criteria (GDC) 14, "Reactor Coolant Pressure Boundary," GDC 15, "Reactor Coolant System Design," GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," and GDC 32, "Inspection of Reactor Coolant Pressure Boundary," by reducing the probability and consequences of a SGTR. RG 1.121 concludes that by determining the limiting safe conditions for tube wall degradation, the probability and consequences of a SGTR are reduced. This RG uses safety factors on loads for tube burst that are consistent with the requirements of Section III of the 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, Westinghouse WCAP-17091-P 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 SLB leak rate factor for Turkey Point Units 3 and 4 is 1.82 (Table 9-7 in WCAP-17091-P). Multiplying this factor by the room temperature TS operational leak rate limit of 150 gpd through any one SG indicates that an assumed primary to secondary accident induced leak rate of 273 gpd or greater through any one SG is required to ensure that the limiting design basis accident assumption is not exceeded (at room temperature). This condition is satisfied by the current UFSAR assumed primary to secondary accident induced leak rate of 500 gpd (355 gpd adjusted to room temperature) through any one SG for SLB.

Therefore, the proposed change does not involve a significant reduction in any margin of safety.

Based on the above, Turkey Point Units 3 and 4 concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

General Design Criteria (GDC) 1, 2, 4, 14, 30, 31, and 32 of 10 CFR 50, Appendix A, define requirements for the reactor coolant pressure boundary (RCPB) with respect to structural and leakage integrity.

GDC 19 of 10 CFR 50, Appendix A, defines requirements for the control room and for the radiation protection of the operators working within it. Accidents involving the leakage or burst of SG tubing comprise a challenge to the habitability of the control room.

10 CFR 50, Appendix B, establishes quality assurance requirements for the design, construction, and operation of safety related components. The pertinent requirements of this appendix apply to all activities affecting the safety related functions of these components. These requirements are described in Criteria IX, XI, and XVI of Appendix B and include control of special processes, inspection, testing, and corrective action.

10 CFR 100, Reactor Site Criteria, establishes reactor site criteria, with respect to the risk of public exposure to the release of radioactive fission products. Accidents involving leakage or tube burst of SG tubing may comprise a challenge to containment and therefore involve an increased risk of radioactive release.

10 CFR 50.67, Accident Source Term, establishes limits on the accident source term used in design basis radiological consequence analyses with regard to radiation exposure to members of the public and to control room occupants.

Under 10 CFR 50.65, the Maintenance Rule, licensees classify SGs as risk significant components because they are relied upon to remain functional during and after design basis events. SGs are to be monitored under 10 CFR 50.65(a) (2) against industry established performance criteria. Meeting the performance criteria of NEI 97-06, Revision 2, and TS 6.8.4.j.b provides reasonable assurance that the SG tubing remains capable of fulfilling its specific safety function of maintaining the reactor coolant pressure boundary. The SG tube performance criteria in NEI 97-06, Revision 2, and TS 6.8.4.j.b are:

- All in-service SG tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, cool down, and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation

primary to secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary to secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design 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 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.

- The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day.

The proposed change defines the portion of the tube 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 design basis accident conditions. The evaluation in Reference 2 determined that degradation in tubing below 13.31 inches from the top of the tubesheet portion of the tube does not require plugging and serves as the bases for the SG tube inspection program. As such, the Turkey Point Units 3 and 4 inspection program provides a high level of confidence that the structural and leakage criteria are maintained during normal operating and accident conditions.

The hydraulically expanded portion of the tube 13.31 inches below the top of the tubesheet is the length of tube that is engaged within the tubesheet to the top of the tubesheet (secondary face) that is required to maintain structural and leakage integrity over the full range of SG operating conditions, including the most limiting design basis accident conditions. WCAP-17091-P determined that degradation below this distance from the top of the tubesheet does not require plugging and serves as the basis for the limited tubesheet inspection criteria. WCAP-17091-P also shows that, upon implementation of the H* criterion, that the TS leakage limit of 150 gpd precludes unacceptable leakage during postulated design basis accidents that model primary to secondary leakage.

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

6.0 ENVIRONMENTAL CONSIDERATION

Turkey Point Units 3 and 4 has evaluated the proposed amendment for environmental considerations. The review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, and would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendments meet the eligibility criterion for categorical exclusion set for in 10 CFR 51.22(c) (9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment needs to be prepared in connection with the proposed amendment.

7.0 PRECEDENTS

The proposed changes to Technical Specifications 6.8.4.j and 6.9.1.8 are similar to changes recently submitted by Vogtle Electric Generating Plant, Seabrook Station, Braidwood Station, Byron Station and Comanche Peak Steam Electric Station listed below.

1. Vogtle Electric Generating Plant License Amendment Request to Revise Technical Specification (TS) Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report" for Permanent Alternate Repair Criteria, dated May 19, 2009.

2. Seabrook Station, License Amendment Request to Revise Technical Specification (TS) 6.7.6.k., "Steam Generator (SG) Program", for Permanent Alternate Repair Criteria (H*), dated May 28, 2009.

3. Comanche Peak Steam Electric Station (CPSES) License Amendment Request 09-007, Model D5 Steam Generator Alternate Repair Criteria, Dated June 9, 2009.

4. Braidwood Station Units 1 and 2, Byron Station Units 1 and 2, "License Amendment Request to Revise Technical Specifications (TS) for Permanent Alternate Repair Criteria", Dated June 24, 2009.

8.0 REFERENCES

1. NRC letter dated November 1, 2006, "Turkey Point Plant, Units 3 and 4 – Issuance of Amendments Regarding Steam Generator Alternate Repair Criteria (TAC Nos. MD 1380 and MD 1381)."
2. Westinghouse Electric Company WCAP-17091-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model 44F)" June, 2009 (included as Enclosure 6).
3. NEI 97-06, "Steam Generator Program Guidelines," Revision 2, May 2005.
4. EPRI 1013706, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 7.
5. EPRI 1012987, "Steam Generator Integrity Assessment Guidelines," July 2006.
6. NRC Information Notice 2005-09, "Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds," April 7, 2005.
7. NRC Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," August 1976.

ENCLOSURE 2

Marked-up Technical Specification (TS) Pages and Inserts

Refer to the attached markup of the TS showing the proposed changes. The attached markups reflect the currently issued version of the TS and Facility Operating License. At the time of submittal, the Facility Operating License was revised through License Amendments 239 and 234 to Facility Operating Licenses DPR-31 for Turkey Point Unit 3 and DPR-41 for Turkey Point Unit 4.

The following TS pages are included in the enclosed markup:

TS Section	Title	Page
6.8.4	PROCEDURES AND PROGRAMS (Continued)	6-14 (info only)
6.8.4.j	STEAM GENERATOR (SG) PROGRAM	6-18 (correct typo) 6-18a 6-18b
6.9.1.8	STEAM GENERATOR TUBE INSPECTION REPORT	6-22 (info only) 6-22a

INSERT 1

Tubes with service-induced flaws located greater than 17.28 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 17.28 inches below the top of the tubesheet shall be plugged upon detection.

INSERT 2

from 17.28 inches below the top of the tubesheet on the hot leg side to 17.28 inches below the top of the tubesheet on the cold leg side

INSERT 3

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

j. The calculated accident induced leakage rate from the portion of the tubes below 17.28 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 1.82 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

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

This page contains no changes and is included for information only.

ADMINISTRATIVE CONTROLS

PROCEDURES AND PROGRAMS (Continued)

6.8.4 The following programs shall be established, implemented, and maintained:

a. Primary Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include the Safety Injection System, Chemical and Volume Control System, and the Containment Spray System. The program shall include the following:

(1) Preventive maintenance and periodic visual inspection requirements, and

(2) Integrated leak test requirements for each system at least every 18 months.

The provisions of Specification 4.0.2 are applicable.

b. DELETED

c. Secondary Water Chemistry

A program for monitoring of secondary water chemistry to inhibit steam generator tube degradation. This program shall include:

(1) Identification of a sampling schedule for the critical variables and control points for these variables,

(2) Identification of the procedures used to measure the values of the critical variables,

ADMINISTRATIVE CONTROLS

PROCEDURES AND PROGRAMS (Continued)

- The combined As-left leakage rates determined on a maximum pathway leakage rate basis for all penetrations shall be verified to be less than 0.60 L_a, prior to increasing primary coolant temperature above 200°F following an outage or shutdown that included Type B and Type C testing only.

- The As-found leakage rates, determined on a minimum pathway leakage rate basis, for all newly tested penetrations when summed with the As-left minimum pathway leakage rate leakage rates for all other penetrations shall be less than 0.6 L_a, at all times when containment integrity is required.

3) Overall air lock leakage acceptance criteria is $\leq$ 0.05 L_a, when pressurized to P_a.

The provisions of Specification 4.0.2 do not apply to the test frequencies contained within the Containment Leakage Rate Testing Program.

i. Technical Specifications (TS) Bases Control Program

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

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

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

1. Change in the TS incorporated in the license or

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

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

d. Proposed changes that meet the criteria of Specification 6.8.4 i.b. above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

j. Steam Generator (SG) Program

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

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results ~~of~~ 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.

ADMINISTRATIVE CONTROLS

PROCEDURES AND PROGRAMS (Continued)

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

1. Structural integrity performance criterion: All in-service 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 SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm total through all SGs and 500 gallons per day through any one SG.

3 The operational leakage performance criterion is specified in LCO 3.4.6.2, "Reactor Coolant System Operational Leakage."

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

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

INSERT 1

~~1. For Unit 3 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, and for Unit 4 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, flaws found in the portion of the tube below 17 inches from the top of the hot leg tubesheet do not require plugging.~~

~~For Unit 3 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, and for Unit 4 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, all tubes with flaws identified in the portion of the tube within the region from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be plugged.~~

ADMINISTRATIVE CONTROLS

PROCEDURES AND PROGRAMS (Continued)

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, ~~from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet~~, and that may satisfy the applicable tube repair criteria. ~~For Unit 3 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, and for Unit 4 during Refueling Outage 23 and the subsequent operating cycles until the next scheduled inspection, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded from inspection when the alternate tube repair criteria in Specification 6.8.4.j.c.1 is implemented.~~ The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tube may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

INSERT 2

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

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

INSERT 2

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

e. Provisions for monitoring operational primary-secondary leakage.

6.8.5 Administrative procedures shall be developed and implemented to limit the working hours of personnel who perform safety-related functions, e.g. licensed Senior Operators, licensed Operators, health physicists, auxiliary operators, and key maintenance personnel. The procedures shall include guidelines on working hours that ensure that adequate shift coverage is maintained without routine heavy use of overtime for individuals.

Any deviation from the working hour guidelines shall be authorized by the applicable department manager or higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation. Controls shall be included in the procedures to require a periodic independent review be conducted to ensure that excessive hours have not been assigned. Routine deviation from the working hour guidelines shall not be authorized.

This page contains no changes and is included for information only.

3. WCAP-10054-P, Addendum 2, Revision 1 (proprietary), "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection in the Broken Loop and Improved Condensation Model," October 1995.*

4. WCAP-12945-P, "Westinghouse Code Qualification Document For Best Estimate LOCA Analysis," Volumes I-V, June 1996.**

5. USNRC Safety Evaluation Report, Letter from R. C. Jones (USNRC) to N. J. Liparulo (W), "Acceptance for Referencing of the Topical Report WCAP-12945(P) 'Westinghouse Code Qualification Document for Best Estimate Loss of Coolant Analysis,' " June 28, 1996.**

6. Letter dated June 13, 1996, from N. J. Liparulo (W) to Frank R. Orr (USNRC), "Re-Analysis Work Plans Using Final Best Estimate Methodology."**

7. WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report," S. L. Davidson and T. L. Ryan, April 1995.

The analytical methods used to determine Rod Bank Insertion Limits and the All Rods Out position shall be those previously reviewed and approved by the NRC in:

1. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

The ability to calculate the COLR nuclear design parameters are demonstrated in:

1. Florida Power & Light Company Topical Report NF-TR-95-01, "Nuclear Physics Methodology for Reload Design of Turkey Point & St. Lucie Nuclear Plants."

Topical Report NF-TR-95-01 was approved by the NRC for use by Florida Power & Light Company in:

1. Safety Evaluation by the Office of Nuclear Reactor Regulations Related to Amendment No. 174 to Facility Operating License DPR-31 and Amendment No. 168 to Facility Operating License DPR-41, Florida Power & Light Company Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251.

The AFD, $F_Q(Z)$, $F_\Delta H$, K(Z), and Rod Bank Insertion Limits shall be determined such that all applicable limits of the safety analyses are met. The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector, unless otherwise approved by the Commission.

STEAM GENERATOR TUBE INSPECTION REPORT

6.9.1.8 A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 6.8.4.j, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

*This reference is only to be used subsequent to NRC approval.
**As evaluated in NRC Safety Evaluation dated December 20, 1997.

ADMINISTRATIVE CONTROLS

STEAM GENERATOR TUBE INSPECTION REPORT (Cont'd)

c. Nondestructive examination techniques utilized for each degradation mechanism,

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

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

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

INSERT 3

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

h. The effective plugging percentage for all plugging in each SG.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report as stated in the Specifications within Sections 3.0, 4.0, or 5.0.

ENCLOSURE 3

RETYPED TS PAGES WITH THE PROPOSED CHANGES INCORPORATED

- The combined As-left leakage rates determined on a maximum pathway leakage rate basis for all penetrations shall be verified to be less than 0.60 L_a, prior to increasing primary coolant temperature above 200°F following an outage or shutdown that included Type B and Type C testing only.

- The As-found leakage rates, determined on a minimum pathway leakage rate basis, for all newly tested penetrations when summed with the As-left minimum pathway leakage rate leakage rates for all other penetrations shall be less than 0.6 L_a, at all times when containment integrity is required.

3) Overall air lock leakage acceptance criteria is $\leq$ 0.05 L_a, when pressurized to P_a.

The provisions of Specification 4.0.2 do not apply to the test frequencies contained within the Containment Leakage Rate Testing Program.

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

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

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

1. Change in the TS incorporated in the license or

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

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

d. Proposed changes that meet the criteria of Specification 6.8.4 i.b. above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

j. Steam Generator (SG) Program

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

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

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

1. Structural integrity performance criterion: All in-service 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 SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm total through all SGs and 500 gallons per day through any one SG.

3. The operational leakage performance criterion is specified in LCO 3.4.6.2, "Reactor Coolant System Operational Leakage."

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

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

Tubes with service-induced flaws located greater than 17.28 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 17.28 inches below the top of the tubesheet shall be plugged upon detection.

PROCEDURES AND PROGRAMS (Continued)

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from 17.28 inches below the top of the tubesheet on the hot leg side to 17.28 inches below the top of the tubesheet on the cold leg side, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tube may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

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

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

3. If crack indications are found in any SG tube from 17.28 inches below the top of the tubesheet on the hot leg side to 17.28 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 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary-secondary leakage.

6.8.5 Administrative procedures shall be developed and implemented to limit the working hours of personnel who perform safety-related functions, e.g. licensed Senior Operators, licensed Operators, health physicists, auxiliary operators, and key maintenance personnel. The procedures shall include guidelines on working hours that ensure that adequate shift coverage is maintained without routine heavy use of overtime for individuals.

Any deviation from the working hour guidelines shall be authorized by the applicable department manager or higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation. Controls shall be included in the procedures to require a periodic independent review be conducted to ensure that excessive hours have not been assigned. Routine deviation from the working hour guidelines shall not be authorized.

STEAM GENERATOR TUBE INSPECTION REPORT (Cont'd)

c. Nondestructive examination techniques utilized for each degradation mechanism,

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

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

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

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

h. The effective plugging percentage for all plugging in each SG.

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

j. The calculated accident induced leakage rate from the portion of the tubes below 17.28 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 1.82 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

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

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report as stated in the Specifications within Sections 3.0, 4.0, or 5.0.

ENCLOSURE 4

Marked-up pages for the Technical Specification Bases Control Program

Turkey Point Units 3 and 4 Administrative Procedure

0-ADM-536, "Technical Specification Bases Control Program"

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ATTACHMENT 1
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TECHNICAL SPECIFICATION BASES

3/4.4.5 (Cont'd)

Limiting Condition for Operation (LCO)

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During a SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall, from 17.28 inches below the top of the tubesheet on the hot leg side to 17.28 inches below the top of the tubesheet on the cold leg side ~~between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet~~. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 6.8.4.j and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational leakage. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, the gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation. Tube collapse is defined as, for the load displacement curve for a given structure, collapse occurs at the top of the load verses displacement curve where the slope of the curve becomes zero. The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term significant is defined as an accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse to be established. For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.