May 30, 2006

Mr. Dale E. Young, Vice President
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ATTN: Supervisor, Licensing and Regulatory Programs
15760 W. Power Line Street
Crystal River, FL 34428-6708

SUBJECT: CRYSTAL RIVER UNIT 3 - SUMMARY OF CONFERENCE CALLS WITH FLORIDA POWER CORPORATION REGARDING THE FALL 2005 STEAM GENERATOR INSPECTION (TAC NOS. MC8535 AND MC9562)

Dear Mr. Young:

On November 7 and November 15, 2005, the Nuclear Regulatory Commission (NRC) staff participated in conference calls with Florida Power Corporation staff (also doing business as Progress Energy-Florida) regarding the steam generator (SG) tube inspection activities at Crystal River Unit 3 during the fall 2005 refueling outage 15. The conference calls were strictly voluntary on your part and occurred after the majority of the tubes had been inspected, but before the SG inspection activities were completed. A summary of the conference calls is provided in Enclosure 1.

This completes the NRC staff's efforts under TAC Nos. MC8535 and MC9562.

If you have any questions regarding this matter, please contact me at (301) 415-2020.

Sincerely,

/RA/
Brenda L. Mozafari, Senior Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-302

Enclosures:
1. Summary of Conference Call
2. Licensee Facsimile

cc w/encls: See next page

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SUMMARY OF CONFERENCE CALLS

WITH FLORIDA POWER CORPORATION

REGARDING FALL 2005 STEAM GENERATOR INSPECTION RESULTS

AT CRYSTAL RIVER UNIT 3

On November 7, 2005, the Nuclear Regulatory Commission (NRC) staff participated in a conference call with Florida Power Corporation (FPC or the licensee, also doing business as Progress Energy - Florida). The licensee's representatives from Crystal River Unit 3 discussed some initial results from steam generator (SG) tube inspections within the upper tubesheet region. Crystal River Unit 3 has two once through SGs (OTSGs).

Rotating probe examinations in the tubesheet were scheduled to be performed at the tube ends, the rolled region, and the roll transition. As part of these inspections, data is acquired in the unexpanded region of tubing. During these exams, three indications were identified in the unexpanded portion of tubing in the upper tubesheet region. These indications were detected with a rotating probe, but were not detected with the bobbin probe. All three indications are attributed to intergranular attack associated with grooves on the tube. All three locations with indications have a small absolute drift signal associated with them; however, the size of the drift is such that the drift signal would not be called by the average analyst. The tubes at Crystal River Unit 3 are pilgered. None of the three tubes with indications leaked during a secondary side nitrogen pressure test performed at 100 pounds per square inch gage (psig).

In SG B, two indications were detected within the upper tubesheet (UTS). One of these indications was estimated to extend 5.5-inches axially along the length of the tube with a depth varying from 40-percent to 60-percent through-wall. This indication was approximately 0.25-inch below the roll transition. The second indication was estimated to extend 1.5-inches axially along the length of the tube with a depth varying between 60-percent and 80-percent through-wall. The size estimates are based on rotating probe data (however, the rotating probe data is not qualified for sizing these indications). During the last outage, there were no flaw-like indications at this location.

In SG A, one indication was detected in the UTS. This indication was reported to be smaller than the indications detected in SG B.

As a result of these initial findings, the licensee indicated the scope of the examinations in the tubesheet region was expanded to include a rotating probe examination of the entire tube length within the upper and lower tubesheet region for 100 percent of the active tubes in the steam generators. Results from the expanded scope exams were to be discussed during the routine outage call that had been scheduled prior to the outage.

On November 15, 2005, the NRC staff participated in a second phone call with the licensee to further discuss the results of its 2005 SG tube inspections at Crystal River Unit 3. To facilitate the discussion, the licensee provided some written information on steam generator design, examination scope, inspection expansion criteria, and primary system-to-secondary system leak rate history (Enclosure 2).

A summary of the November 15, 2005, phone call is provided below. Primary-to-secondary leakage averaged between 2 and 2.5 gallons per day in the cycle prior to the shutdown for the 2005 outage, which is consistent with the leakage observed during the previous cycle. Before starting tube inspections, the licensee performed a tube leak test by pressurizing the secondary side with nitrogen to approximately 100 psig and filling the primary side of the tubes to a level approximately 1-inch above the upper tubesheet. During this test, 3 tubes in SG A and 34 tubes in SG B were observed to have bubbles coming from the tube. Of these 37 tubes, tube end cracks were detected in one SG A tube and 4 SG B tubes. Two additional SG B tubes contained circumferential cracks within the roll transition region. The source of the leakage in the remaining tubes was not clear, although the licensee indicated that previous tube end damage had resulted from loose parts. All tubes that were observed to have bubbles during the secondary side pressure test were to be repaired or plugged.

During the call, the licensee indicated that they had taken one exception to Revision 6 of the Electric Power Research Institute Steam Generator Examination Guidelines. A secondary side visual exam was not performed as recommended by the industry guidelines due to design differences between the OTSG's generators and other SG designs.

Based on inspection data as of November 14, 2005, the licensee had completed 100 percent of the bobbin coil examinations. Rotating probe examinations were in progress with special interest, dent inspections, and approximately 7000 lower tubesheet exams remaining. The inspection scope included a bobbin coil inspection of 100 percent of the in-service tubes from secondary face of the UTS to the secondary face of the lower tubesheet (LTS). In addition, a rotating probe (+Point™) was used to inspect several regions of the tube, including, but not limited to the following:

- 100 percent of the in-service tubing within the UTS and LTS
- 34 percent of the tubes in the sludge pile (kidney region) from the secondary face of the LTS to 4-inches above the secondary face of the LTS
- 34 percent of the non-sleeved tubes immediately adjacent to the sleeved tubes in the lane/wedge region
- 34 percent of tube boundary around lane/wedge region (tubes with and without sleeves) at support #15 elevation
- 100 percent of the dents greater than or equal to 2.5 volts
- 100 percent of the dents in tubes adjacent to tubes that had explosive plugs installed the rolled joints in 34% of the installed sleeves
- 100 percent of Alloy 600 rolled plugs
- 100 percent (167 tubes) containing intergranular attack (IGA) in the first tube span of SG B

- 100 percent of dents not previously inspected in the following regions (1) sludge pile tubes from LTS-8 inches to lower tube end and (2) tubes outside the sludge pile from LTS+4 inches to lower tube end

The dominant tube degradation mechanism detected during the 2005 outage was tube end cracking in the UTS and LTS. Approximately 1300 tubes (about 1700 indications) in SG A and 950 tubes (approximately 1200 indications) in SG B contained tube end cracks. None of these tube end cracks were reported to extend beyond the Inconel™ cladding on the primary face of the UTS. At the time of the call, the licensee stated there were approximately 110 axial indications in SG A and 50 axial indications in SG B. Approximately 140 indications in SG A and 50 indications in SG B had a circumferential orientation and were mostly associated with the tube end or the roll transition. In SG B, Tube 73, 55 contained two short (35^{o} extent) circumferential indications near the secondary face of the tubesheet (i.e., not associated with a rolled region). These indications were coincident with a concentric 3-volt dent, were not detected by the bobbin coil probe, and were attributed to preferentially oriented IGA. This tube was located two rows from the lane region in an area of high cross flow. The rotating probe measured these indications as 1.28-volt and 70 percent through-wall. Consistent with past outages, the licensee detected IGA along the length of tube between the secondary face of the lower tubesheet and the first tube support plate (i.e., in the first span) in SG B. In SG A, axial oriented (groove) IGA was detected in approximately six tubes above the 10th and 11th support plate and in the unexpanded portion of one tube inside the UTS. In SG B, axial oriented IGA was detected in six tubes above the 10th and 11th support plate and in the unexpanded portion of approximately four tubes inside the UTS. Although axial oriented IGA has been previously detected in the Crystal River SGs, the current outage was the first time this degradation was detected in the unexpanded tube within the UTS. A few axial indications were also detected in tubes at the upper support plate intersections. In addition to the results above, SG A and SG B each contained five volumetric indications, none of which were greater than 40 percent through-wall.

The licensee intended to apply the tube end cracking alternate repair criteria to the tube end cracking indications. The licensee also applied an alternate repair criteria to the tubes with IGA between the secondary face of the lower tubesheet and the first tube support plate in SG B. For other degradation mechanisms, the licensee planned to repair (reroll) or plug all tubes with indications, as necessary. At the time of the call, in situ pressure testing was planned for two tubes: (1) the tube containing an approximately 4-inch long axial oriented IGA indication with a maximum depth of 39-percent through-wall and a voltage of 0.6 volts, and (2) the tube containing two short circumferential indications with a maximum depth equal to 70-percent through-wall. No sleeve repairs were planned. Two loose parts were removed from the SGs during the outage. In SG A, a piece believed to be from a bridge strap in an older style fuel assembly was retrieved from the primary side of the upper tubesheet. A magnetic piece measuring approximately 1/8-inch wide, 1-inch long, and 1/16-inch thick was removed from the upper annulus steam space of SG B. This piece had a rusty appearance and was not in contact with the tube bundle. Some possible loose part signals were present at other locations within the tube bundle, but there was no evidence of tube degradation and the OTSG design was not conducive to a foreign object search and retrieval exam in these locations.

The licensee indicated they performed a visual exam on all welded tube plugs. They will continue to monitor plant cycles to ensure they do not exceed the plug replacement schedules recommended by Framatome for the Babcock & Wilcox Owners Group. Current plans would result in SG replacement prior to the need for any weld plug replacement.

In the previous outage, based on screening criteria developed by Framatome, the licensee had identified previously plugged tubes in a high cross flow velocity region that were potentially susceptible to a tube severance similar to that observed at another plant. At that time, the licensee plugged and stabilized some of the tubes surrounding the previously plugged tubes. As a follow-up during the current outage, the licensee inspected those tubes surrounding the potentially susceptible plugged tubes that were not plugged and stabilized in the previous outage.

The licensee indicated three items would be entered into their corrective action program. A nonconformance report would be written regarding the bobbin coil qualification within the UTS and LTS. A second item is related to a tube that was inadvertently rerolled in 1999 and not entered into the repair database. This tube did not receive a rotating probe inspection in 2001 and 2003. The final item was the detection of three indications in Alloy 600 tube plugs.

At the conclusion of the November 15 telephone call, the staff requested the licensee notify the NRC if a new degradation mode was identified or the in situ pressure tests resulted in tube failure or leakage exceeding the test pump capacity.

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