August 12, 2004

Mr. Christopher M. Crane, President
and Chief Nuclear Officer
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: SUMMARY OF CONFERENCE CALL WITH EXELON GENERATION COMPANY, LLC REGARDING THE RESULTS OF THE SPRING 2004 STEAM GENERATOR INSPECTIONS AT BYRON STATION, UNIT 2 (TAC. NO. MC2597)

Dear Mr. Crane:

On April 9, 2004, the U.S. Nuclear Regulatory Commission participated in a conference call with representatives of Exelon Generation Company, LLC (Exelon) to discuss the results of Exelon's inspection of the Byron Station, Unit 2 steam generators (SGs) which was conducted during refueling outage 11. The plant was in Mode 1 following plant restart from the refueling outage at the time of the conference call.

The discussion topics included the SG tube inspection scope and associated results. The call focused on the potential for loose parts to be generated as a result of degradation of the water box cap plate in the "A" SG.

During inspection of the "A" SG, Exelon identified that three two-inch "backing" bars were missing from a repair to the waterbox cap plate region. Two of the missing bars were located and removed from the SG. The third bar (the smallest one) was not located. The backing bars were part of a repair to a region of the waterbox cap that was cut out and replaced. The other three SGs do not have the same type of modification as does the "A" SG.

Given that three backing bars detached during the cycle and the condition of the weld of the cut out region in steam generator "A," the licensee evaluated the consequences of a failure of the cutout region and the consequences associated with failure of the remaining backing bars (i.e., the two long and three short backing bars remaining). The two main concerns associated with failure of these regions are that feedwater flow can bypass the preheater and loose parts can damage the tubes. As a consequence of the evaluation, 91 tubes, which could be affected by loose bars, were plugged. Exelon, also, evaluated the consequences of the cutout region coming free from the cap plate and concluded that the net result would be a 3 percent loss of power which would not be significant. In addition operators were given additional training regarding plant response to failure of the cutout region and what actions to take.

Enclosed is a summary of the conference call and written material provided by Exelon staff in support of the discussions. If there are questions, please contact me at 301-415-3019.

Sincerely,

/RA/

George F. Dick, Jr., Project Manager
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Enclosure: As stated

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CONFERENCE CALL SUMMARY

2004 STEAM GENERATOR TUBE INSPECTIONS

EXELON GENERATION COMPANY, LLC

BYRON STATION, UNIT 2

DOCKET NO. STN 50-455

On April 9, 2004, the NRC staff participated in a conference call initiated by representatives for Byron, Unit 2 to discuss their 2004 steam generator tube inspection results. The discussion topics included the steam generator (SG) tube inspection scope and the associated results. The call focused on the potential for loose parts to be generated as a result of degradation of the water box cap plate. In support of the phone call, the licensee provided two sketches: a tubesheet map and the waterbox cap plate. This material is attached.

Byron, Unit 2 entered refueling outage (RFO) 11 on March 23, 2004. The outage duration was scheduled for 18 days. At the time of the call, the plant was operating in Mode 1 (i.e., RFO 11 was complete).

Byron, Unit 2 has four Westinghouse model D5 steam generators. Each steam generator contains 4,570 thermally treated Alloy 600 tubes. Each tube has a nominal outside diameter of 0.750-inch and a nominal wall thickness of 0.043-inch. The tubes were hydraulically expanded at both ends for the full length of the tubesheet and are supported by a number of stainless steel tube supports with quatrefoil shaped holes. The U-bend region of the tubes installed in rows 1 through 9 was thermally stress relieved after bending. The hot–leg temperature is 611 °F.

At the commencement of RFO 11, the steam generators had operated for 14.23 effective full power years (EFPY), and a total of 240 tubes was plugged in the four steam generators. There was no evidence of primary-to-secondary leakage during Cycle 11 (fall 2002 to spring 2004).

During the 2004 outage, the licensee performed the following tube inspections in each of the four steam generators:

Bobbin probe inspection of 100 percent of the tubes from tube-end to tube-end

Rotating probe inspection (+Point™ coil) of the hot-leg expansion transition region of 25 percent of the tubes

Rotating probe inspection (+Point™ coil) of the U-bend region of 25 percent of the row 1 and 2 tubes

ENCLOSURE

Rotating probe inspection (+Point™ coil) of the 25 percent of the hot-leg dents and dings with bobbin voltage amplitudes greater than 5 volts

Visual examination of all hot-leg and cold-leg plugs

In addition to the above examinations, a rotating probe was used to inspect 25 percent of the tube expansions at preheater baffles “B” and “D” (i.e., cold-leg tube support plate 2C and 3C, respectively) in steam generators “A” and “D”. In addition, foreign object search and retrieval (FOSAR) was performed in all four steam generators after sludge lancing. The FOSAR was performed on the top of the tubesheet after sludge lancing and in the preheater region of the steam generators. This was the first time that FOSAR was performed in the preheater region in three of the four steam generators at Byron, Unit 2 (i.e., “A”, “B”, and “D”). Visual inspections were also performed at the eighth and eleventh tube support in steam generator “B”. This inspection was performed to assess the deposit loading conditions in the steam generators.

Prior to the commencement of the steam generator tube inspections, the licensee for Byron, Unit 2 had used a low frequency bobbin coil eddy current screening technique to identify tubes that may have an eddy current offset similar to that observed at Seabrook. At Seabrook, several tubes were identified to have crack-like indications associated with this offset (refer to NRC Information Notice 2002-21, “Axial Outside Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing” dated June 25, 2002, and its Supplement dated April 1, 2003, for additional details).

The technique for detecting the eddy current offset was similar to that used at Braidwood, Unit 2 in the fall of 2003 (refer to ML033580377). The technique for detecting the offset was a quantitative technique for the tubes in rows 1 through 9 and a semi-qualitative technique for the tubes in rows 10 and above (there are 49 rows of tubes in the steam generator). For the low-row tubes (i.e., rows 1 through 9, inclusive), the thermal stress relief of the U-bend region of the tube should result in consistently low stresses throughout the tube (i.e., there should be no eddy current offset). Any significant eddy current offset would be indicative of higher stresses in the straight span section of the tube. In the higher row tubes (i.e., greater than row 9), an eddy current offset is expected since the U-bend region of the tube is not stress relieved after bending. As a result, the methodology for the higher-row tubes involved calculating the average eddy current offset along with the standard deviation associated with the higher-row tubes. To identify tubes with an offset that may be a precursor for cracking, tubes were “flagged” that had an offset whose magnitude was less than the mean minus two standard deviations. That is, for the higher-row tubes, the absence of an offset may indicate higher stresses in the straight span portion of the tube.

As a result of applying this low frequency bobbin coil screening technique to their previous bobbin coil examination results (i.e., RFO 10 results) from each steam generator, the licensee identified 40 tubes with possibly high residual stresses in the straight span portion of the tube (these higher stresses may result in a higher likelihood for cracking). All of these 40 tubes were in higher-row tubes (i.e., greater than row 9). These tubes were inspected full length with a bobbin coil probe, and were inspected with a rotating probe at the hot-leg expansion transition region.

No crack-like indications were found at any location during the steam generator tube inspections at Byron, Unit 2.

During the outage, mechanical wear was observed at the anti-vibration bars (AVBs) and at the preheater and support plates. In addition, wear attributed to loose parts in the secondary side of the steam generators was also observed. The maximum depth reported for the AVB wear indications was 40-percent through-wall. This tube was plugged. No other tubes were plugged as a result of AVB wear. The maximum depth for the wear observed at the tube support plates was 22-percent through-wall. No tubes were plugged for this degradation mechanism. The maximum depth for the wear associated with loose parts was 57-percent through-wall. This tube and an adjacent tube were plugged as a result of degradation caused by a loose part. The tube with the 57-percent through-wall degradation was in-situ pressure tested and no leakage was observed at a differential pressure associated with three times the normal operating differential pressure (i.e., approximately 4500 pounds per square inch) indicating the tube had adequate structural and leakage integrity. The in-situ pressure test was a local test spanning the region of the defect. The defect was located slightly above preheater baffle plate “B". The loose part (i.e., backing bar) causing the damage to these two tubes was retrieved from preheater baffle plate “B” (and is discussed further below).

As mentioned above, the licensee performed FOSAR in all four steam generators during the 2004 outage. The FOSAR was performed on the top of the tubesheet after sludge lancing and in the preheater region of the steam generators. This was the first time that FOSAR was performed in the preheater region of steam generators “A”, “B”, and “D”. Numerous objects (e.g., hard scale/sludge rocks, washers, pieces of flexitallic gaskets) were found during these inspections. Most of these parts were retrieved and did not result in any appreciable tube wear. Three tubes had minor tube wear measuring 6 percent, 8 percent, and 11 percent through-wall. There were a few parts that could not be removed, but these parts did not result in any indicated tube wear. These latter parts are discussed further below.

There were nine small wires and one hard sludge rock that could not be removed from the steam generators. In addition, four loose parts that have been present in the steam generator for many years could not be removed. The potential for these parts to cause tube damage was evaluated by the licensee and they concluded that there is no tube integrity concern for at least two cycles. For most parts, they concluded there is no tube integrity concern associated with these parts for six years or more.

In steam generator “A”, two carbon steel “backing” bars measuring 10.5-inch long by 0.75-inch wide by 0.25-inch thick were found in the preheater region (i.e., the cold-leg of the steam generator). One of these bars was located in the periphery and resulted in tube wear while the other was located deeper in the tube bundle and did not result in any tube damage (refer to Figure 1). The backing bar in the periphery damaged two tubes: row 49, column 50 had a 57 percent through-wall flaw; row 49, column 51 had a 17 percent through-wall flaw. These two tubes were plugged and stabilized. Backing bar 1, the one that caused the tube damage (refer to Figure 1) was identified by eddy current examination. Backing bar 2 was removed prior to performing the eddy current examination.

The two backing bars found in steam generator “A” came from the waterbox cap plate region (refer to Figure 2). The waterbox cap plate region is near the lower feedwater inlet and is associated with the preheater region of the steam generator. The cap plate (i.e., the top portion of the waterbox) was modified during initial steam generator fabrication to allow access to the waterbox. The modification involved cutting out two rectangular sections measuring 10-inches long and 2-inches wide and then welding these cutout regions back into the cap plate once access to the waterbox was no longer needed. To facilitate the welding of the cutout region into the cap plate, backing bars were used on the underside of each of the cutout regions of the cap plate. Two long backing bars (10.5-inch by 0.75-inch by 0.25-inch) and two small backing bars (or tabs) were used for each cutout region. These backing bars were secured to the underside of the cutout with tack welds. The cutout region was then welded to the cap plate from the top.

As a result of visual inspections performed in 2004, it was discovered that for one of the two cutout regions in steam generator “A”, all four backing bars were present while for the other cutout region both long backing bars and one of the short (1.25-inches) backing bars were missing. The two long backing bars were located and retrieved while the short backing bar was not found despite the 100 percent bobbin coil inspection and a visual inspection of all high flow regions. In addition to the degradation of the tack welds securing these three backing bars, erosion of the weld associated with the cutout region was discovered.

As a result of these findings, previous eddy current data was reviewed to ascertain when the backing bars detached from the cap plate. Since no wear was detected during the last outage in Fall 2002 when a 100 percent bobbin coil inspection was performed, the licensee concluded that the backing bars detached during the cycle (i.e., cycle 11 - between Fall 2002 and Spring 2004).

To ascertain the extent of condition, the fabrication records were reviewed and visual inspections were performed of the cap plate region in all four steam generators. These efforts resulted in the conclusion that the waterbox cap plate was not modified in steam generators “B” and “C”, but that the cap plate in steam generators “A” and “D” were modified. However, the inspections and record review indicated that the modifications in steam generator “D” were different than that in steam generator “A.” Namely, in steam generator “D”, a full penetration weld with no “permanent” backing bars was used to reinstall the cut out region into the cap plate (a removable backing bar may have been used). In addition, the cutout region for steam generator “D” was not rectangular shaped, but rather was 3-sided and involved the edge of the cap plate. Based on the visual inspections, the licensee concluded there is no integrity concern with the weld of the cut out region in steam generator “D” (i.e., no evidence of erosion of the cap plate/cutout region weld and no evidence that backing bars was used). The weld was inspected from the underside of the cap plate (i.e., no visual inspections were performed from the top of the cap plate).

Given that three backing bars detached during the cycle and the condition of the weld of the cutout region in steam generator “A”, the licensee evaluated the consequences of a failure of the cutout region and the consequences associated with failure of the remaining backing bars (i.e., the two long and three short backing bars remaining). The two main concerns associated with failure of these regions are that feedwater flow can bypass the preheater and loose parts can damage the tubes.

The licensee determined that if the cutout region or the backing bars detached from the cap plate, loose parts could result in unacceptable tube damage. As a result, the licensee plugged and stabilized 91 tubes in steam generator “A”. These 91 tubes included all peripheral tubes in rows 40 and higher (including all tubes in row 49) and several tubes in the T-slot region of the steam generator (refer to Figure 1). Row 40 was selected since there is a physical barrier in this region that would restrict the passage of these parts. The licensee’s evaluation concluded that wear with the edge of the backing bars was more limiting than wear with the side of the backing bar. This was supported not only by analysis but also on the lack of degradation associated with backing bar 2 (refer to Figure 2). Backing bar 1 damaged two tubes as a result of edge wear on one tube and flat wear on an adjacent tube.

If the cutout region were to come free from the cap plate, there would be less flow through the preheater region (i.e., the feedwater would bypass the preheater). This condition would result in a decrease in thermal efficiency and would alter the nominal ratio of flow coming into the steam generator through the upper and lower feedwater nozzles. As a result, the licensee evaluated: (1) the potential for flow induced vibration to affect the tubes, (2) waterbox structural integrity, (3) the affect on normal operating parameters, and (4) the impact on safety analysis for design basis transients and accidents. The licensee concluded that failure of the cutout regions of the cap plate would not result in flow induced vibration of the tubes, would not affect the structural integrity of the waterbox, and did not affect the safety analyses for design basis transients and accidents. Upon failure of the cutout region, the licensee indicated that a small feedwater transient could occur possibly resulting in a feedwater flow (high/low) alarm. Failure of the cutout regions would also result in changes to steam generator secondary pressure (12 pounds per square inch pressure drop). The primary water temperature across the steam generator would also change (i.e., nominal loop ΔT would change). The net result of a failure could result in a loss of 3 percent thermal power. The licensee concluded that any changes to operating parameters would be acceptable from a safety standpoint (including changes to the core power distribution).

In summary, the licensee concluded that operation with the current condition of the waterbox is acceptable since if failure were to occur the results would be acceptable. The licensee currently plans to inspect this region during the next steam generator inspection and is currently developing a long-term strategy for addressing this issue. In addition, the licensee has trained (or is training) the operators on the expected plant response and their actions if the cutout plate becomes loose. With respect to plant response, the licensee indicated that there was no indication of these loose parts from their loose part monitoring system during the past cycle.

A total of 92 tubes was plugged in steam generator “A” during the 2004 outage. No tubes were plugged in steam generators “B”, “C”, or “D”. The total steam generator tube plugging to date is 332 tubes which is approximately 1.8 percent of the total number of tubes.