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U. S. Nuclear Regulatory Commission
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Washington, DC 20555-0001

Braidwood Station, Unit 2
Facility Operating License Number NPF-77
NRC Docket Number 50-457

Subject: Response to Request for Additional Information Regarding the Braidwood Station Unit 2 Spring 2005 Steam Generator Inspection

References: (1) Letter from K. J. Polson (Exelon Generation Company, LLC) to NRC, "April 2005, Eleventh Refuel Outage Steam Generator Inservice Inspection Report," dated May 10, 2005

(2) Letter from K. J. Polson (Exelon Generation Company, LLC) to NRC, "Braidwood Station, Unit 2, Eleventh Refueling Outage Steam Generator Inservice Inspection Summary Report," dated July 27, 2005

(3) E-mail from R. F. Kuntz (NRC) to D. J. Chrzanowski (Exelon Generation Company, LLC), "Braidwood Unit 2 Steam Generator Tube Inspection Summary Reports for the Spring 2005 Outage," dated December 15, 2005

Based on the review of the Reference 1 and 2 submittals, the NRC determined that additional information was required in order to complete their evaluation of the Braidwood Station Unit 2 Spring 2005 (i.e., refueling outage 11) steam generator inspection report. The NRC requested a response to three questions contained in the Reference 3 correspondence. The attachment to this letter provides the Exelon Generation Company, LLC response to these NRC questions.

A001

Should you have any questions concerning this letter, please contact Mr. Dale Ambler, Regulatory Assurance Manager, at (815) 417-2800.

Respectfully,

Keith J. Polson
Site Vice President
Braidwood Nuclear Generating Station

Attachment: Response to NRC Request for Additional Information Regarding the Braidwood Station Unit 2 Spring 2005 Steam Generator Inspection

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Braidwood Station
Illinois Emergency Management Agency – Division of Nuclear Safety

**Attachment**

**Braidwood Station, Unit 2**

**Docket Number STN 50-457**
**License Number NPF-77**

**Response to NRC Request for Additional Information Regarding the Braidwood Station Unit 2 Spring 2005 Steam Generator Inspection**

## Attachment

## Response to NRC Request for Additional Information Regarding the Braidwood Station Unit 2 Spring 2005 Steam Generator Inspection

Question 1

*On page five of your July 27, 2005, report (ML052140465), you indicated that +Point™ examinations were performed at dents/dings and at U-bend regions. Please clarify whether you performed random sampling of these locations. If so, clarify the scope of these examinations.*

Response:

The inspection scope is identified in the Section 1.0 "Introduction" of the Inspection Report. The examination techniques in Section 4.1 "Examination Techniques" of the report discuss the techniques used during the inspection period, not necessarily specific to the inspections performed during the eleventh refueling outage.

The Steam Generator (SG) eddy current inspection scope as performed during the Braidwood Unit 2 eleventh refueling outage (A2R11) in the Spring of 2005 did not include sampling of the population of the low row U-bend regions or dent/ding population within the SGs. As determined by the Braidwood Unit 2 A2R11 degradation assessment, performed prior to the start of inspections, both the low row U-bend region and population of hot leg dents and dings were not classified as having an "active damage mechanism" as defined in the Electric Power Research Institute Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 6 (EPRI SG Guidelines), Section F, "Terminology." Therefore, sampling of these regions using specialized inspection techniques (i.e., +Point™ ) is performed at the frequency defined in the EPRI SG Guidelines.

In accordance with the EPRI SG Guidelines, Section 3.3.10, "Subsequent Examination of Alloy 800 or Alloy 600 Thermally Treated Tubing," Braidwood Unit 2 is classified as being in the second inspection period which is 90 Effective Full Power Months (EFPM) in length. As stated in the EPRI Guidelines, Section 3.3.10: "Examine at least 50% of tubes in each SG by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period." Refer to Table 1-1 below for the current Braidwood Station Unit 2 second period inspection status.

## Response to NRC Request for Additional Information Regarding the Braidwood Station Unit 2 Spring 2005 Steam Generator Inspection

### Table 1-1
### Braidwood Unit 2 Examination Status
### Second SG Inspection Period

| | A2R08 (Fall 2000) | A2R09 (Spring 2002) | A2R10 (Fall 2003) | A2R11 (Spring 2005) | A2R12 (Fall 2006) | A2R13 (Spring 2008) |
|---|---|---|---|---|---|---|
| 2nd Period EFPM | 0 EFPM (Start of 2nd Period) | 16.8 EFPM | 33.6 EFPM (Midpoint Outage) | 50.4 EFPM | 67.2 EFPM | 84 EFPM (End of 2nd Period) |
| Row 1 and 2 U-Bend +Point™ Inspection Status | 50% | 0% | 50% [1] | 0% | TBD [2] | TBD [2] |
| Dents (> 5 Volts) Inspection Status | 50% | 0% | 50% [3] | 0% | TBD [4] | TBD [4] |
| Dings (> 5 Volts) Inspection Status | 50% | 0% | 50% [3] | 0% | TBD [4] | TBD [4] |

[1] Braidwood Unit 2 completed 100% inspection of the Row 1 and Row 2 U-Bends using specialized examinations by the midpoint outage in the 2nd SG Inspection Period. This exceeds the requirement to perform 50% inspection of this region by the midpoint outage.

[2] The percentage is to be determined; however, Braidwood Station will perform an additional 50% U-Bend specialized inspection on or before the Braidwood Station Unit 2 2nd inspection endpoint outage (i.e., A2R13).

[3] Braidwood Unit 2 completed 100% inspection of the dent and ding population using specialized examinations by the midpoint outage in the 2nd SG Inspection Period. This exceeds the requirement to perform 50% inspection of these locations by the midpoint outage.

[4] The percentage is to be determined; however, Braidwood Station will perform an additional 50% dent and ding specialized inspection on or before the Braidwood Station Unit 2 2nd inspection endpoint outage (i.e., A2R13).

As can be seen from Table 1-1, Braidwood exceeded the EPRI Guideline inspection requirement of 50% of the susceptible tubing for the subject potential damage mechanisms by the inspection period midpoint (A2R10) and will inspect an additional 50% inspection on or before the inspection period end point outage (A2R13).

Question 2

*Given the potential for cracks to develop in wear scars, clarify whether you performed rotating probe inspections to confirm that no cracking was occurring. If rotating probe inspections were not performed, discuss your basis for not doing so. In addition, address whether any of the wear scars were in any of the tubes with "increased residual stress" (i.e., as evaluated by an eddy current offset).*

Response:

## Response to NRC Request for Additional Information Regarding the Braidwood Station Unit 2 Spring 2005 Steam Generator Inspection

The Braidwood Station Unit 2 steam generator eddy current inspection program requires a 100% full-length bobbin coil inspection of all four SGs. All bobbin coil indications that are classified as non-quantifiable indications (i.e., I-Codes) require additional specialized inspection methods, typically +PointTM, in order to disposition. Additionally, all freespan indications of wear, typically associated with secondary side foreign objects, require additional inspection by +PointTM, in order to disposition. Wear at support structures other than at Anti-Vibration Bars (AVBs) also requires additional inspection by +PointTM when first identified. This is in order to assure these signals are associated with normal wear at support structures such as those associated with the cold leg preheater region support plates. Wear that occurs at the intersection of the tube and the AVBs typically does not receive an additional diagnostic inspection unless it is identified as an I-Code or displays an unusually large growth rate.

EPRI SG Guidelines Section 3.4.3 "Selection of Volumetric Indications in the Presence of Cracking for Follow-Up Characterization" states, "Bobbin coil is capable of sizing volumetric wear, thinning, pitting and impingement indications. However, it is not capable of differentiating between these indications and cracking. Therefore, when bobbin coil indications occur in the same region of the SG that cracking has been identified, then the bobbin coil volumetric indications in the overlapping regions shall be examined using techniques that provide for signal characterization such that the appropriate repair criteria can be applied." Throughout the industry units containing Thermally Treated Alloy-600 tubing have not identified Stress Corrosion Cracking (SCC) at volumetric indications. Therefore diagnostic inspection of this region is not required per the EPRI SG Guidelines at this time. The additional diagnostic testing that Braidwood Unit 2 currently performs of volumetric indications in the straight portions of the tubing coupled with the scheduled +Point™ inspection of the hot leg tubesheet region and dent / ding population provide an indicator if additional inspection of volumetric indications in the AVB regions is warranted.

Braidwood Station Unit 2 currently has 71 tubes in service that have been classified as containing "increased residual stress" as determined by their eddy current offset signal. Based on the most recent Braidwood Station Unit 2 SG inspections performed during the A2R11 refueling outage, none of these tubes contained indications of reportable wear; therefore, they did not require additional diagnostic inspections.

Question 3

*On page 9 of your July 27, 2005, report, you indicated that a visual inspection of the secondary side moisture separator region of steam generator D revealed erosion of the tangential nozzles, downcomer barrels and swirl vanes. In addition, you stated that the erosion in the affected areas was not projected to penetrate through wall over the next operating cycle. With regard to the above, please answer the following questions:*

a. *Provide additional details regarding the areas affected and the extent of degradation.*

Response:

**Response to NRC Request for Additional Information Regarding the Braidwood Station Unit 2 Spring 2005 Steam Generator Inspection**

During the Braidwood Unit 2 A2R11 refueling outage, visual inspection of the 2D SG secondary side moisture separator region was performed. All areas that are accessible through the upper manways were visually inspected down through the lower deck plate (refer to Figure 3a-1). No degradation, erosion, corrosion, deformation or weld cracking was observed other than the erosion identified in the primary moisture separator region as described below.

During visual inspection of the primary separator assembly region, visual inspection identified that there were areas where the normally present magnetite layer was missing, thus providing areas for erosion to develop. The areas included portions of the tangential nozzles, portions of the inner surface of the primary moisture separator barrels and a number of swirl vanes within the primary separator assemblies (refer to Figure 3a-2). This condition existed in varying degrees on 12 of the 16 primary separators assemblies. The components identified with the magnetite layer missing are carbon steel, typically American Society for Testing and Materials standard specification A-285, "Pressure Vessel Plates, Carbon Steel, Low and Intermediate-Tensile Strength," Grade C, material. The manufacturing nominal wall thickness for these components was 0.250-inch. To supplement the visual inspection observations, ultrasonic (UT) thickness measurements were taken in areas of magnetite loss with most apparent erosion.

Two of the tangential nozzles with the most apparent erosion were UT inspected. The minimum thickness reading for the horizontal region of the tangential nozzles was 0.234-inch. The minimum thickness reading for the vertical region of the tangential nozzles was 0.177-inch.

Three of the riser barrels with the most apparent erosion were UT inspected. The minimum thickness reading was 0.183-inch.

Three of the swirl vanes with the most apparent erosion were UT inspected. The minimum thickness reading was 0.184-inch.

In summary, the overall nominal thickness value for the primary separators assemblies is 0.250-inch with a minimum UT thickness reading for the components inspected of 0.177-inch. No areas of through wall erosion were identified.

b. *Discuss the basis for your conclusion that the erosion in the affected areas is not projected to penetrate through wall over the next operating cycle. In addition, confirm that the integrity of the components will be maintained for the period of time between inspections*

Response:

An analysis of the eroded regions of the primary separator components was performed by Westinghouse that concluded that the as-found condition of the SG is acceptable and is projected to be acceptable over the next cycle of operation. The analysis is summarized below.

<u>SG Thermal Performance</u>

No through wall degradation was identified in any of the components inspected. As identified by UT thickness measurements, some of the components in SG 2D that had an original nominal thickness of 0.250-inch have been reduced to approximately 0.177-inch with a reduction of approximately 0.073-inch. Braidwood Station Unit 2 has been in operation for approximately 17 calendar years, or 14.2 effective full power years (EFPY). There is an incubation period of time prior to the initiation of the erosion process on metal surfaces. For the carbon steel in the environment of the primary separator system, the incubation time could be short or long depending on the water chemistry conditions. In a worst-case scenario (which has an extremely low probability), if the 0.073-inch wall loss occurred in just a single operating cycle, operating one additional 18-month cycle would reduce the original 0.250-inch wall thickness an additional 0.073-inch (i.e., from the as-found 0.177-inch to 0.104-inch). If such a reduction in wall thickness were to occur the reduced thickness would still maintain the thermal and hydraulic conditions of the SG within the originally specified designed requirements and therefore it would be acceptable to operate for another fuel cycle under the current conditions identified during the A2R11 SG inspection.

Structural Adequacy:

The degradation identified in the SG moisture separator region will have a negligible impact upon the structural adequacy of the components affected. Most material loss has thus far been observed to exist in specific localized areas that do not have significant applied loadings (i.e., tangential nozzles). The amount of observed material loss is not currently considered to be significant with respect to the major load conditions; steam line break, and seismic. Prior analysis performed by Westinghouse for similar Westinghouse model SG's with more significant erosion indicate that large margins are typically present for erosion of this type when occurring at these specific locations. As a result of the observed levels of material loss and prior analysis performed for other similar model steam generators, it is expected that any operational or postulated faulted loads imposed upon these components considering further erosion potential will not adversely impact or compromise their structural integrity.

Loose Parts Assessment:

The components found to be degraded in SG 2D, which include the tangential nozzles on the downcomer barrels, the primary moisture separator barrels, and the swirl vane assemblies (within the primary separators), are non-nuclear safety class parts. The design of non-nuclear safety class equipment must resist failure that could prevent safety class equipment from performing its nuclear safety function. In the case of the erosion of the identified components, the most significant condition, from a safety perspective, would be the potential for the generation of a loose part and subsequent impacting and sliding wear on the steam generator tubes.

A review of the material loss to date has been made of the affected areas to assess the impact of the loss of metal on the structural integrity of the identified components. Based on the geometry of the components, no loss of structural integrity is expected due to the material loss predicted for an additional cycle of operation.

A review of the material loss to date does not indicate the potential for generation of a fragment of sufficient size to cause tube wear should such a fragment migrate to the tube bundle. Also, if continued wall loss were to cause thinned areas to link up, the fragment generated would not be expected to be of sufficient size to wear a tube to the minimum allowable wall thickness during the next fuel cycle.

c. *Discuss whether these areas were previously inspected and whether this erosion was observed in the past. In addition, discuss the extent to which this degradation could be attributed to your power uprate in 2001*

Response:

This region of the Braidwood Station Unit 2 SGs had not been previously inspected. At the time of the A2R11 refueling outage inspection, the Braidwood Unit 2 SGs had operated approximately 17 calendar years or 14.2 Effective Full Power Years (EFPY). Until such time that reinspection of the eroded areas occurs, it is not possible to determine an accurate growth rate and determine if the observed erosion has any connection to power uprate conditions.

d. *Discuss the prevalence of this degradation (if known) and whether these findings were communicated to the industry.*

Response:

Wall loss in these regions has been observed in other Westinghouse model SGs, most notably in two plants with Model 51 SGs, one plant with Model D4 SGs (which has since been replaced) and in one plant with Model F SGs. This is based upon historical inspections as performed by Westinghouse. Analysis was performed in each case with no immediate repairs required. In addition, none of these SGs experienced any operational/performance issues or generation of foreign objects over subsequent cycles of operation. Refer to response contained in 3.b for additional information on prevalence of this degradation.

The Braidwood Unit 2 inspection results were shared with the industry during the EPRI Steam Generator Technical Advisory Group meeting on August 11, 2005. Additionally, the inspection results were discussed at the recent Westinghouse Steam Generator Workshop in January 2006.

e. *Discuss the extent to which the other steam generators at Braidwood Unit 2 were inspected to determine whether the same degradation is occurring. If not, discuss the basis for not inspecting.*

Response:

The Braidwood Station Unit 2 secondary side chemistry program is consistent with the EPRI Secondary Chemistry Guidelines. Since the secondary side water chemistry has been similar within each SG at Braidwood Station Unit 2, it is expected that SGs 2A, 2B, and 2C would be in similar condition and are also acceptable, at a minimum, for an additional cycle of operation. The 2D SG inspection results did not indicate any

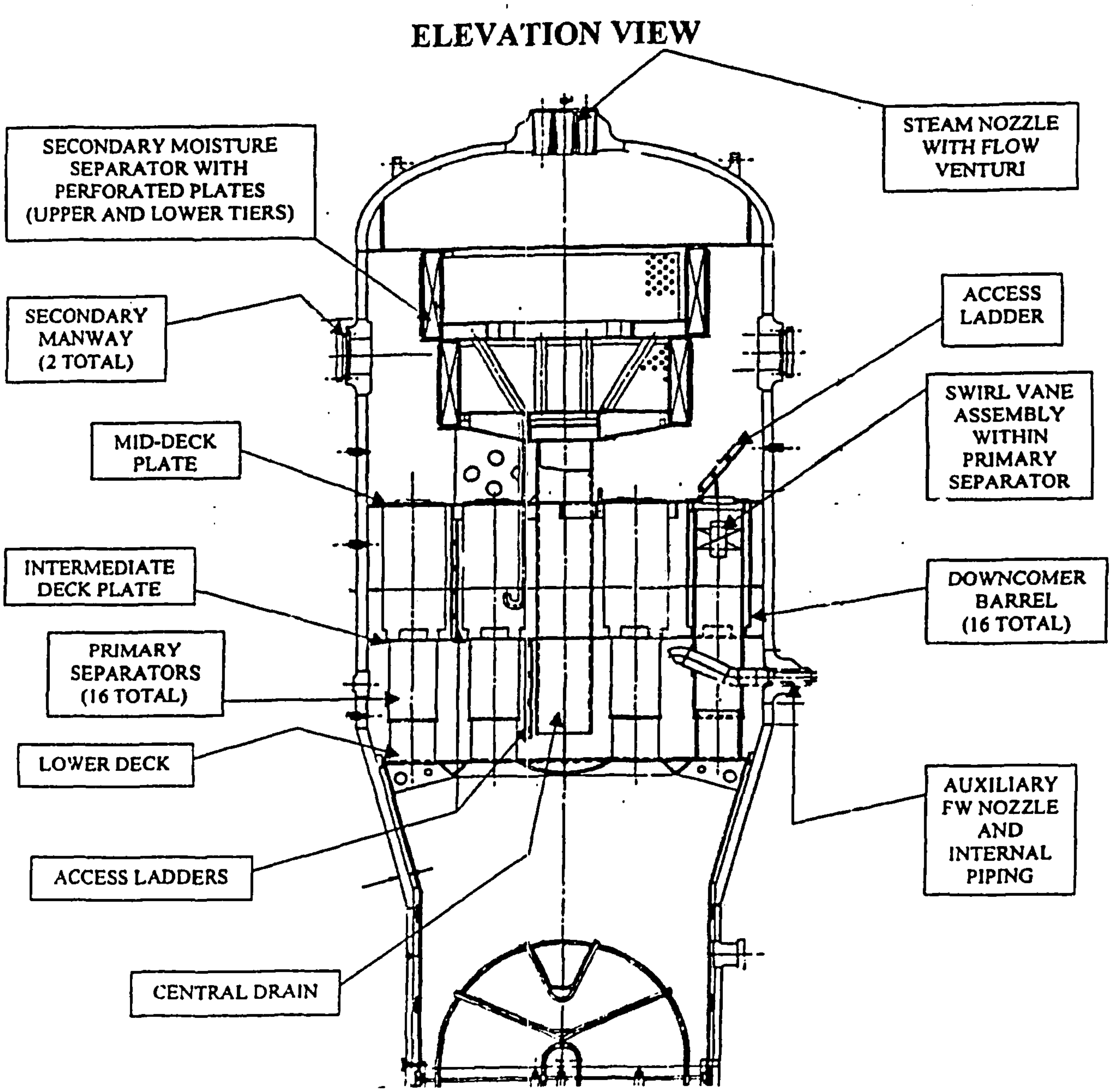
immediate issues relating to thermal performance, structural integrity or the possible generation of loose parts. The 2D SG inspection results are not considered unusual considering the SGs have been inservice approximately 14.2 EFPY.

The current plan for the upcoming Braidwood Station Unit 2 refueling outage in the Fall of 2006 (A2R12) is to reinspect the 2D SG. This inspection will provide additional data points to develop a degradation rate and determine if scope expansion into the additional SGs is warranted. If unexpected degradation or unacceptable degradation rates are identified in the 2D SG, scope expansion into the remaining SGs will be evaluated. Inspection of the secondary moisture separator region of 2A, 2B and 2C SGs is currently planned for the Braidwood Station Unit 2 refueling outage in the Spring of 2008 (A2R13).

Figure 3a-1

## MODEL D-5 STEAM GENERATOR

## BRAIDWOOD UNIT 2 STEAM DRUM COMPONENTS



Attachment

**Response to NRC Request for Additional Information Regarding the Braidwood Station Unit 2 Spring 2005 Steam Generator Inspection**

Figure 3a-2

Primary Separator Assembly

**BRAIDWOOD UNIT 2 - PRIMARY SEPARATOR (RISER BARREL) ASSEMBLIES**