December 15, 2000

MEMORANDUM TO: Ashok C. Thadani, Director
Office of Nuclear Regulatory Research

FROM: Samuel J. Collins, Director ***/RA/***
Office of Nuclear Reactor Regulation

SUBJECT: INDEPENDENT REVIEWS OF MAY 26, 1999, SAFETY EVALUATION REGARDING STEAM GENERATOR TUBE INSPECTION INTERVAL AND FEBRUARY 13, 1995, SAFETY EVALUATION REGARDING F* REPAIR CRITERIA FOR INDIAN POINT NUCLEAR GENERATING UNIT NO. 2

In my memorandum to you dated February 28, 2000 (Attachment 1), the Office of Nuclear Reactor Regulation (NRR) requested that the Office of Nuclear Regulatory Research (RES) perform an independent technical review of an NRR staff safety evaluation (SE) that approved an extension of the steam generator (SG) tube inspection interval for Indian Point Nuclear Generating Unit No. 2 (IP2). In addition, my memorandum requested that RES perform an independent review of an SE that allowed the repair of SG tubes at IP2 via implementation of the F* criteria.

The independent reviews were requested as part of the actions taken by NRR subsequent to the SG tube failure at IP2 on February 15, 2000. The purpose of these independent reviews was to determine if the conclusions in the SE's were technically sound and if the data presented by the licensee provided reasonable assurance that the delayed inspection and use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next scheduled inspection. In your memorandum dated March 16, 2000 (Attachment 2), RES provided the results of the independent reviews.

The issues raised by RES in the independent reviews were considered as part of the Lessons-Learned Task Group review that was recently completed. The Task Group review was documented in an October 23, 2000, report titled, "Indian Point 2 Steam Generator Tube Failure Lessons-Learned Report," (Accession No. ML003762242). Sections 6.2, 6.4, 7.0, and 8.1 of the report discuss the issues raised in the RES review.

Some of the same issues raised by RES were also addressed in an inquiry performed by the Office of the Inspector General (OIG) as documented in their August 29, 2000, report titled "NRC's Response to the February 15, 2000, Steam Generator Tube Rupture at Indian Point Unit 2 Power Plant" (Accession No. ML003746663). The staff review and analysis of the issues raised in the OIG report were documented in a memorandum from the Executive Director for Operations to the Commission dated November 3, 2000 (Accession No. ML003753067). The issues raised by the OIG were also considered as part of the Lessons-Learned Task Group review discussed above.

CONTACT: R. Ennis, NRR/DLPM
415-1420

As you are aware, there are many recently completed and ongoing activities by both the NRC and industry that relate to SG tube integrity. In order to consolidate the observations and recommendations from these efforts, NRR has developed a “Steam Generator Action Plan” (Attachment 3). Some of the recommendations in the Action Plan relate to the issues raised by RES in your independent reviews. The Action Plan states that NRR will work with RES as an internal stakeholder in order to ensure our decisions are consistent with research results and to incorporate your insights on these issues into the regulatory framework.

We appreciate the efforts by your staff in performing the independent reviews as well as continuing activities related to improving SG programs. Please let us know if you would like to discuss any of these issues further.

Docket No. 50-247

Attachments:

1) Memorandum (not including associated attachments) from S. Collins to A. Thadani dated February 28, 2000, “Request for Independent Reviews of May 26, 1999, Safety Evaluation Regarding Steam Generator Tube Inspection Interval and February 13, 1995, Safety Evaluation Regarding F* Repair Criteria for Indian Point Station Unit 2".

2) Memorandum (including associated attachment) from A. Thadani to S. Collins dated March 16, 2000, “Request for Independent Reviews of May 26, 1999, Safety Evaluation Regarding Steam Generator Tube Inspection Interval and February 13, 1995, Safety Evaluation Regarding F* Repair Criteria for Indian Point Station Unit 2".

3) Memorandum (including associated attachments) from B. Sheron/J. Johnson thru R. Zimmerman to S. Collins dated November 16, 2000, “Steam Generator Action Plan”.

As you are aware, there are many recently completed and ongoing activities by both the NRC and industry that relate to SG tube integrity. In order to consolidate the observations and recommendations from these efforts, NRR has developed a “Steam Generator Action Plan” (Attachment 3). Some of the recommendations in the Action Plan relate to the issues raised by RES in your independent reviews. The Action Plan states that NRR will work with RES as an internal stakeholder in order to ensure our decisions are consistent with research results and to incorporate your insights on these issues into the regulatory framework.

We appreciate the efforts by your staff in performing the independent reviews as well as continuing activities related to improving SG programs. Please let us know if you would like to discuss any of these issues further.

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2) Memorandum (including associated attachment) from A. Thadani to S. Collins dated March 16, 2000, “Request for Independent Reviews of May 26, 1999, Safety Evaluation Regarding Steam Generator Tube Inspection Interval and February 13, 1995, Safety Evaluation Regarding F* Repair Criteria for Indian Point Station Unit 2".

3) Memorandum (including associated attachments) from B. Sheron/J. Johnson thru R. Zimmerman to S. Collins dated November 16, 2000, “Steam Generator Action Plan”.

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February 28, 2000

MEMORANDUM TO: Ashok Thadani, Director
Office of Nuclear Regulatory Research

FROM: Samuel J. Collins, Director ***/ra by RPZimmerman for/***
Office of Nuclear Reactor Regulation

SUBJECT: REQUEST FOR INDEPENDENT REVIEWS OF MAY 26, 1999, SAFETY EVALUATION REGARDING STEAM GENERATOR TUBE INSPECTION INTERVAL AND FEBRUARY 13, 1995, SAFETY EVALUATION REGARDING F* REPAIR CRITERIA FOR INDIAN POINT STATION UNIT 2

In follow up to discussions with your staff on February 18, 2000, concerning the recent steam generator tube failure event at Indian Point Station Unit 2 (IP-2), this memorandum documents the Office of Nuclear Reactor Regulation's request that the Office of Nuclear Regulatory Research (RES) perform an independent review of the attached safety evaluation (SE) regarding the steam generator (SG) tube inspection interval for this Unit. In addition, this memorandum requests that RES perform an independent review of the attached safety evaluation allowing the F* repair criteria to be used at IP-2.

As you are aware, IP-2 shut down February 15, 2000, because of a sudden increase in primary to secondary leakage in SG 24. In 1999 the staff approved a license request to extend the SG tube inspection interval beyond the 24 calendar months required by the plant technical specifications. In particular, by letter dated December 7, 1998, as supplemented by letter dated May 12, 1999, Consolidated Edison Company of New York, Inc. (the licensee), proposed to amend the technical specifications for the Indian Point Station Unit 2. These letters are also attached. This was to allow a one-time extension of the SG inspection interval and remove the requirement of receiving NRC concurrence on the licensee's proposed SG examination program. By letter dated June 9, 1999, the staff issued the requested amendment and forwarded the SE of the licensee's proposed amendment request to the licensee (TAC No. MA4526).

In addition, by letter dated March 13, 1995, the staff issued an amendment allowing the repair of SG tubes via the implementation of an F* criteria, and forwarded the related February 13, 1995, SE (TAC No. M89373). The SE is attached. The F* criteria allowed tubes that are degraded in a location not affecting structural integrity of the tube to remain in service as an alternative to removal from service through the use of tube plugs. The amendment was issued in response to an application from the licensee transmitted by letter dated April 13, 1994, and supplemented by letters dated December 20, 1994, January 12, 1995, and January 31, 1995.

CONTACT: L. Lund, EMCB/DE
415-2786

ATTACHMENT 1

We request that you perform an independent review of that part of the SE regarding the extension of the inspection interval, transmitted to the licensee on June 9, 1999. A written response is requested by March 8, 2000.

We also request that you perform an independent review of the SE regarding the implementation of the F* repair criteria, transmitted to the licensee on March 13, 1995. A written response is also requested by March 8, 2000.

The purpose of these independent reviews is to determine if the staff's conclusions are technically sound and that the data presented by the licensee provided reasonable assurance that the delayed inspection and the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next scheduled inspection. Your support for this quick response is greatly appreciated.

Docket No.: 50-247

Attachments: As stated

March 16, 2000

MEMORANDUM TO: Samuel J. Collins, Director
Office of Nuclear Reactor Regulation

FROM: Ashok C. Thadani, Director /RA/
Office of Nuclear Regulatory Research

SUBJECT: REQUEST FOR INDEPENDENT REVIEWS OF MAY 26, 1999, SAFETY EVALUATION REGARDING STEAM GENERATOR TUBE INSPECTION INTERVAL AND FEBRUARY 13, 1995, SAFETY EVALUATION REGARDING F* REPAIR CRITERIA FOR INDIAN POINT STATION UNIT 2

This memorandum is in response to your memorandum of February 28, 2000, requesting an independent review of safety evaluations regarding steam generator tube inspection and repair issues for the Indian Point Station, Unit 2. Staff in the Division of Engineering Technology, RES, had initiated a review of these issues based on a verbal request from your staff on February 18, 2000. We expanded our review to include the F* criteria based on your memorandum.

You stated that the purpose of the independent reviews was to “determine if the staff’s conclusions are technically sound and that the data presented by the licensee provided reasonable assurance that the delayed inspection and the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next scheduled inspection.” Consequently, our review has not addressed regulatory process issues.

We based our review on the staff’s Safety Evaluation of May 26, 1999, and other written documentation pertinent to that evaluation. In performing our review, we addressed the specific question of granting the extended inspection interval with the assumption that the original inspection interval was justified, and then evaluated the technical basis for the original interval. Details of our assessment are provided in the attachment to this memorandum.

With regard to the use of the F* repair criteria, we did not identify any issues related to the staff’s evaluation or the information submitted by the licensee. The evaluation and the information submitted by the licensee do provide reasonable assurance that the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next inspection interval.

With regard to the extended inspection interval, working from the assumption that the original inspection interval was justified, we concur that the licensee’s lay-up procedures for the steam generators were appropriate, and granting the requested 48 day extension of the inspection interval would not have appreciably increased the probability of tube failure.

ATTACHMENT 2

However, In our review of the original inspection interval for cycle 14, we cannot reconcile several statements and conclusions in the safety evaluation (SE) with the request for additional information (RAI) and the information we reviewed, particularly with respect to the operational assessments conducted for stress corrosion cracking in the second row U-bend region and at the top of the tubesheet under the sludge. In its review of the licensee request, the NRR staff recognized the importance for maintaining required tube structural and leakage integrity for the entire cycle 14, and in a request for additional information, posed the following question (question 1): "[F]or each degradation mechanism, please provide a general description of the operational assessment methodology used to ensure that SG tube integrity will be maintained for the entire fuel cycle (cycle 14). The description should include an explanation of the predictive methodology, flaw growth rates, and NDE uncertainty used to determine structural and accident leakage integrity."

We find the licensee's response to the staff's question weak and incomplete. For example the licensee provided only a very short discussion regarding their operational assessment for stress corrosion cracking at the row 2 U-bend. No predictive methodology was discussed nor were growth rates or NDE uncertainty applied in their evaluation. The licensee simply stated that the indication was below the in-situ screening threshold (i.e., small) and "[A]s this represented the first detected U-bend indication after approximately 23 years of operation, any growth rates associated with this indication would be considered minimal." While more detailed discussions regarding the weakness of the analyses conducted by the licensee are included in the attachment, we disagree with the licensee's contention because it is inconsistent with the evolution of stress corrosion cracking and with other industry experience.

The SE states that "[T]he licensee assessed the SG tube integrity for the remainder of the present operating cycle (cycle 14) on the basis of the end of cycle 13 inspection and testing results. The severity of degradation at the end of cycle 14 was projected considering BOC degradation status, degradation growth rates, and EOC allowable degradation. The severity of degradation at the EOC 14 was projected to determine if required structural and leakage integrity margins would be maintained." Contrary to our findings, the SE indicates that the licensee conducted more thorough operational assessments than were described in the licensee's response to the RAI, and concludes that the tubes would meet structural and leakage integrity through the end of operating cycle 14.

Based on the information we have reviewed, we believe the licensee's assessment of two forms of degradation found in their generators was inadequate: (1) ODSCC above the top of the tubesheet location (sludge pile); and (2) PWSCC at a row 2 U-bend. We believe that a more thorough operational assessment for these forms of degradation would have predicted an increased probability of tube leakage or rupture by the end of cycle 14.

If you or your staff would like to further discuss our findings please let us know. For additional technical information regarding this review, please contact Dr. Joseph Muscara, (JXM8) of my staff on 415-5844.

Attachment: As stated
cc: C.J. Paperiello
F.J. Miraglia

REVIEW OF SAFETY EVALUATIONS REGARDING STEAM GENERATOR TUBE INSPECTION INTERVAL AND F* CRITERIA FOR INDIAN POINT STATION 2

INSPECTION INTERVAL EVALUATION

The RES evaluation is based on review of the following documentation:

(1) The May 26, 1999 Safety Evaluation;
(2) The original licensee submittal dated December 7, 1998;
(3) The licensee response dated May 12, 1999 to the NRR request for additional information (RAI);
(4) The licensee report dated July 29, 1997, of the steam generator tube inservice examination conducted during the 1997 refueling outage.

The licensee was effectively requesting a one time extension of the steam generator inspection interval from June 1999 to June 2000. Upon return to service following the 1997 refueling outage, Indian Point 2 (IP2) was shut down on October 25, 1997 for an unscheduled maintenance outage that lasted 304 days. In effect, because of the period the plant was shut down, the licensee was requesting an extension of the inspection interval of 48 days. Because the licensee followed industry guidelines for maintaining the wet lay-up chemistry to minimize corrosion of the generators during the outage, any degradation that would have occurred during this period would have been negligible. Further, the licensee had conducted an extensive inspection program during the 1997 refueling outage. Therefore, if the issue is reduced to an assessment of whether the additional 48 days of operation would significantly adversely affect the integrity of the steam generators, given that the required integrity is maintained during the 24-month cycle of operation, RES would conclude that no appreciable increase in the probability of tube failure would result.

In its review of the licensee request, the NRR staff recognized the importance for maintaining required tube structural and leakage integrity for the entire fuel cycle 14. In this context, a request for additional information was issued with two of four questions relating to tube structural integrity. Question 1 stated “[F]or each degradation mechanism, please provide a general description of the operational assessment methodology used to ensure that SG tube integrity will be maintained for the entire fuel cycle (cycle 14). The description should include an explanation of the predictive methodology, flaw growth rates, and NDE uncertainty used to determine structural and accident leakage integrity.” In discussing the licensee’s steam generator tube integrity assessment for the eight forms of degradation that were detected at the end of fuel cycle 13, the SE states that “[T]he licensee assessed the SG tube integrity for the remainder of the present operating cycle (cycle 14) on the basis of the end of cycle 13 inspection and testing results. The severity of degradation at the end of cycle 14 was projected considering BOC degradation status, degradation growth rates, and EOC allowable degradation. The severity of degradation at the EOC 14 was projected to determine if required structural and leakage integrity margins would be maintained.”, and “[T]he licensee’s evaluation determined that the forms of degradation listed above did not present a challenge to the 3ΔP structural margin criteria for the expected operating cycle length of 21.4 effective full power months (EFPM). Based on a review of this portion of the licensee’s assessment the staff expects the steam generator tubes will continue to satisfy structural and leakage integrity requirements under normal and accident conditions through the end of the current operating cycle (cycle14).”

Regarding the licensee's operational assessment in general, RES found it to be incomplete and the arguments presented to be weak. For most of the degradation mechanisms addressed, the operational assessment was more of a condition monitoring evaluation. The condition at the end of cycle 14 was assumed to be similar to the condition at the end of cylcle13. Since the structural and leak integrity were met at the end of cycle 13, the licensee concluded they would also be met at the end of cycle 14.

However, the behavior of stress corrosion cracks is expected to differ from one operating cycle to the next especially when the cracks first initiate or are detected. The appearance of a 'first' stress corrosion crack typically indicates that an incubation phase has passed and that more cracks are likely. Studies from service experience indicate that once stress corrosion cracks initiate, the number of future indications will initially increase exponentially with time. Further, in the relatively early stages of crack growth, the growth rate is dependent on crack size and loading. For the relatively constant loading for steam generator tubes, this means that as the crack size increases, the growth rate will increase. There will be a transition from this increasing growth rate to a more constant growth rate as the cracks get larger. However, given the first indication of stress corrosion cracking in steam generator tubes, the physics of the process and service experience suggest that both the number of cracks and their rate of growth will increase. Thus it cannot be expected that the number and sizes of cracks, for the degradation mechanisms first identified during cycle 13, would be the same at the end of cycle 14.

RES considers the licensee's May 12, 1999 response to the RAI related to the operational assessment for two important forms of degradation found in their generators to be particularly inadequate. These forms of degradation are stress corrosion cracks above the top of tubesheet under the sludge pile, and primary water stress corrosion cracks at the row 2 U-bend.

<u>ODSCC Above Top of Tubesheet (Sludge Pile)</u>

The licensee reported that ODSCC in the sludge pile was detected for the first time in the 1997 inspection, and that 22 indications of this type were detected. The licensee contended that the bounding growth rate for these cracks was such that 40% to 50% throughwall cracks that might not have been detected during the inspection would still meet the integrity requirements at the end of cycle 14. Based on the following discussion, RES concludes that this contention is not credible.

The limiting indication of this type was identified as having a maximum depth of 69%, average depth of 48%, and a length of 0.55 inch. The tube with this indication was inspected in 1995 with the Cecco-5 probe and no indication was detected at that time. The licensee reports that the growth in average depth for cycle 13 is bounded by about 18% to 28% for sludge pile ODSCC indications. This was determined by assuming that the indication was 20% to 30% throughwall at the beginning of cycle 13. But the tube with this indication was inspected at the end of cycle 12 and no indications were detected. Therefore, another plausible assumption is that the crack started to grow in cycle 13, either at the beginning of the cycle or even later in the cycle. In addition, the licensee assumed that the +Point depth profile was accurate, i.e., no NDE sizing uncertainty was applied to the detected crack size even after the licensee has stated that "[R]ecent +Point depth sizing evaluations performed by Westinghouse for axial

ODSCC indicate that flaw average depth standard deviation measurement error is about 10% through-wall."

Certainly, assuming that the crack was 20% or 30% throughwall at the beginning of the cycle and not allowing for inspection sizing error, did not provide a bounding estimate, as claimed by the licensee, of the crack growth rate. If the crack had started to grow at the beginning of cycle 13 and a one standard deviation sizing error had been applied to the detected crack, then the growth in average depth would have been 58% for the cycle. The licensee did not discuss the growth for the maximum depth of the crack which was 69% at the end of the cycle. The licensee stated that "[T]he modest growth would lead to acceptable end-of-cycle (EOC) structural integrity even if 40% to 50% average depth indications were not detected." However, if one applies the higher growth rate (58% for one cycle) that is obtained assuming that the crack had initiated at the beginning of cycle 13 and makes some adjustment for sizing error, then the undetected cracks with average depth indications of 40% to 50% would penetrate throughwall during one operating cycle, and potentially not meet the structural integrity requirements at the end of cycle. Furthermore, if these cracks with average depths of 40% to 50% have similar morphology to the crack found during the inspection, i.e., the maximum depth is 21% greater than the average depth, and the growth during the cycle is added to the maximum depth, then the cracks would grow throughwall during the cycle and the tubes would leak even if the growth rate of 28% is applied as estimated by the licensee.

The licensee stated that "[W]hile ODSCC in the sludge pile region is a new mechanism at Indian Point 2, the 22 indications detected represent 0.17% of the total tube population. Therefore, based upon the observed sludge pile flaw eddy current characteristics at IP-2 and in-situ testing results, from more limiting flaws at similar plants, it can be concluded that this corrosion mechanism would not represent either a burst or steam line break leakage potential at EOC 14." This implies that the condition of the generator with respect to this cracking phenomenon will be similar at the end of cycle 14 to that at the end of cycle 13. The fact that the licensee detected 22 ODSCCs in the sludge pile indicated that the incubation period for this phenomenon had been reached and that increasing numbers of cracks could now initiate and grow during subsequent plant operation. The licensee did not conduct a thorough operational assessment with respect to estimating the crack distribution at the beginning of cycle 14, i.e., the cracks left in the generator because they were not detected by NDE. They did not determine the number of new cracks that would initiate during the cycle; this number would likely be greater than was experienced during the previous cycle since the phenomenon was still relatively new at IP-2. They did not apply crack growth rates to the undetected cracks and the newly initiated cracks so that they could estimate the crack distribution at the end of cycle 14. Therefore, there was not a good basis for estimating the structural and leak integrity at the end of cycle 14.

PWSCC at Row 2 U-Bend

The stress corrosion cracking process involves two separate steps, an initiation or incubation period, and a growth period. Once cracks initiate, the growth rates are similar for cracks in tubes that take either a short time or long time to initiate. The crack growth rates can be quite high for U-bend regions because of the high residual stresses induced by fabrication and/or strain induced by the tube denting process during operation.

The licensee cites that PWSCC at the row two U-bend was detected for the first time in the June 1997 inspection. The licensee further states that "[A]s this represents the first detected

U-bend indication after 23 years of operation, any growth rates associated with this indication would be considered minimal." Based on the stress corrosion cracking process, this conclusion is not credible.

The detection of the first row 2 U-bend crack at IP2 was an important finding in that it indicated the incubation period for crack initiation had been reached, and now the cracks could begin to appear and grow. Further, in addition to the residual stresses present from the fabrication of the tube, inspection results for IP2 have shown the tubes to be locked in the support plates by the denting that has occurred at this plant. The 1997 inspection showed that several tubes at the upper support plate, including row 2 tubes, were locked in the support plate as evidenced by the 610 mil or 640 mil diameter probe not being able to pass through the tube from either, or both, the cold leg side or the hot leg side at the upper support plate elevation. When the tight U-bend tubes are locked in the upper support plate, the legs of the tube begin to move closer together as the denting process continues, the support plate deforms and cracks, and the flow slots begin to deform and close, commonly known as hourglassing. The motion of the U-bend tube legs causes ovalization and operation-induced straining of the upper portion of the tube at the U-bend. This straining leaves the tube region highly susceptible to stress corrosion cracking.

The 1997 inspection also found evidence that the tube U-bend was being deformed by the denting process due to the inability of the 610 mil probe to pass through 20 row 2 U-bends. Secondary side inspection (as reported in the licensee's inspection report) of the upper support plate in 1997 also found some small cracks in the support plate not previously observed. Leakage from stress corrosion cracking at tight U-bend locations has occurred in operating plants, including two cases of tube rupture in row 1 U-bends. Some licensees have preventively plugged rows of tight-radius U-bend tubes in their steam generators before placing the generators in service, during service, or upon detection of the first crack(s) to avoid stress corrosion cracking incidences during service at these locations.

The results and observations discussed above appear to be in conflict with the licensee's assessment and the staff's safety evaluation.

F* EVALUATION

In evaluating the F* criterion approved for IP-2 in 1995, RES reviewed the 1995 SE and the December 24, 1994 licensee response to an NRR RAI. F* is a repair criterion that allows defects to remain a specified distance (the F* distance) below the end of the roll transition region in the tubesheet of the SG. For proper implementation, the F* distance must be shown to be sufficient to resist operational and transient pull-out forces on the tube, and primary to secondary leakage should be maintained in accordance with the plant technical specifications. The minimum F* distance is calculated based on consideration of the shear stress developed at the tube-tubesheet interface, the area of contact, and the coefficient of friction between the tube and tubesheet. The licensee provided calculations, and results of tests on mock-up tube-tubesheet assemblies to validate the calculations. The mock-up test conditions reasonably simulated the conditions that would be expected in the SGs (e.g., variations in tube yield strengths, variations in tubesheet bore surface roughness and diameter). The minimum calculated F* distance was increased to account for the limited sample size in the testing, statistical scatter in the data, and for NDE uncertainty. The evaluation and the information submitted by the licensee do provide reasonable assurance that the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next inspection interval.

November 16, 2000

MEMORANDUM TO: Samuel J. Collins, Director
Office of Nuclear Reactor Regulation

FROM: Brian W. Sheron, Associate Director ***/ra/***
for Project, Licensing and Technical Analysis

Jon Johnson, Associate Director ***/ra/***
for Inspection and Programs

THRU: Roy P. Zimmerman, Deputy Director ***/ra/***
Office of Nuclear Reactor Regulation

SUBJECT: STEAM GENERATOR ACTION PLAN

Steam generator tube integrity issues continue to arise. As a result, many organizations within the NRC have evaluated portions of the regulatory process associated with steam generator tube integrity and have made some insightful observations and/or recommendations. To ensure safety from a steam generator tube integrity standpoint is maintained, that public confidence in the steam generator tube integrity area is improved, and the NRC and stakeholder resources are effectively and efficiently utilized, the attached steam generator action plan was developed. The action plan is intended to direct and monitor the NRC's effort in this area and to ensure the issues are appropriately tracked and dispositioned. The action plan is also intended to ensure the NRC's efforts result in an integrated steam generator regulatory framework (license review, inspection and oversight, research, etc.) which is effective and efficient. To this end, periodic "integration" meetings will be held as needed.

As indicated above, this plan consolidates numerous activities related to steam generators including: 1) the NRC's review of the industry initiative related to steam generator tube integrity (i.e., NEI 97-06); 2) GSI-163 (Multiple Steam Generator Tube Leakage); 3) the NRC's Indian Point 2 (IP2) Lessons Learned Task Group recommendations; 4) the Office of the Inspector General report on the IP2 steam generator tube failure event; and 5) the differing professional opinion (DPO) on steam generator issues. The plan does not address plant-specific reviews or industry proposed modifications to the Generic Letter 95-05 (voltage-based tube repair criteria) methodology. For those issues which the NRC's IP2 Lessons Learned Task Group recommended the industry take action (as indicated in the IP2 lessons learned task group report), the NRC will discuss these items with the industry, report the industry's status on these items, and consider these issues in its review of NEI 97-06.

As can be inferred from the action plan milestones in Attachments 1 and 2, many milestones in the plan represent a grouping of various recommendations and observations made in the source documents discussed above. Attachment 1 contains steam generator tube integrity related milestones and Attachment 2 contains milestones that have broader implications than steam generators but arose out of recent steam generator related activities (e.g., guidance for communications between resident inspectors and local officials). The recommendations from the NRC's Indian Point 2 Lessons Learned Task Group are contained in Attachment 3.

CONTACT: R. Ennis, DLPM/LPD1
415-1420

ATTACHMENT 3

Completing the milestones in Attachments 1 and 2 may result in revisions to the steam generator portions of the baseline and supplemental inspection programs, may include development of a standard review plan for certain steam generator reports/amendments, and/or the approval of a generic technical specification change package for steam generator tube integrity. Existing processes will be followed for these types of activities.

To ensure adequate documentation is maintained and for promoting public confidence, the final product for each major milestone will be a memorandum/report provided by the lead division to the associate directors in the Office of Nuclear Reactor Regulation documenting the disposition of each of the milestones in Attachments 1 and 2. The documentation of the disposition of Attachments 1 and 2 milestones shall also address how each of the applicable recommendations in Attachment 3 were addressed. Periodic updates and correspondence relative to this action plan will be made available via a public NRC web page. Additional public meetings will be held, as appropriate.

Many of the items in the action plan are presently being addressed; however, for those items which are new, one of the first steps of this plan is to meet with the industry and other stakeholders to discuss those aspects of the action plan and address any concerns/comments they may have. Following this meeting, the NRR staff will identify key technical and management personnel responsible for completing the milestones and estimate the resources for completing the milestone (including any revision to the target completion date based on stakeholder involvement). Once the leads are determined and the resources estimated, the information will be provided to the NRR leadership team for processing the “new work” according to the planning, budgeting, and performance management (PBPM) process. The resources and technical leads are not provided in this memorandum since we believe more realistic estimates of resources can be made after initial discussions with the stakeholders. Subsequent to these efforts, the NRC staff will update the action plan to identify lead responsibilities and resource estimates.

In addition to working with external stakeholders, we will also be working with internal stakeholders on these issues. For example, any changes to the inspection program will be coordinated with the regions, and we will work with the Office of Nuclear Regulatory Research to ensure our decisions are consistent with research results and to incorporate their insights on these issues into the regulatory framework.

Consistent with current practice, it is our intent to update the action plan milestones on a quarterly basis and publish the results in the Director’s Quarterly Status Report. Since there currently exists an action plan for the staff review of NEI 97-06 in the Director’s Quarterly Status Report, the NRR staff will take the pertinent information from this memorandum and replace/update the information in that action plan (e.g., background, regulatory assessment, etc.), as appropriate. The overall management of this plan will be the responsibility of NRR’s Division of Licensing Project Management (DLPM).

As indicated in your November 1, 2000, memoranda (Collins to Travers, “Transmittal of the Indian Point 2 Steam Generator Failure Lessons-Learned Report”), there are no safety concerns that have been identified that require immediate action with respect to the industry. On-going staff and industry activities in this area, such as those discussed in a memorandum

from William D. Travers to the Commission dated November 3, 2000, “Staff Review of OIG Report on the NRC’s Response to the Steam Generator Tube Failure at Indian Point 2 and Related Issues,” provide reasonable assurance that safety will continue to be maintained while the activities in this plan are pursued.

If you need any additional information or would like to be briefed on this matter, please contact Mr. Rick Ennis of the staff at (301) 415-1420.

Attachments: As stated

Approved: ***/ra b RPZimmerman for***/ 11/17/00
Samuel J. Collins Date

ATTACHMENT 1

STEAM GENERATOR ACTION PLAN MILESTONES[1,2,3]

Item #	Milestone	Completion Date	Lead
1	Issue Regulatory Information Summary on SG Lessons Learned (TG: 8; page 2 of Ref. 2)	11/00	DE
2	Discuss steam generator action plan and IP2 lessons learned with industry and other external stakeholders (TG: 2a-2o, 3a, 3b, 4a, 4b , 4c, 8)	12/00	DE
3	Subsequent to item 2, identify technical and management leads for each item and develop initial resource estimates	12/00	DLPM (DE, IIPB support)
4	Brief management on resource estimates and invoke PBPM process as appropriate	12/00	DLPM (DE, IIPB support)
5	Staff review of ACRS recommendations on DPO and develop detailed milestones and evaluate impact on other action plan milestones (GSI-163 and DPO)	01/01	DE
6	Determine GSI-163 resolution strategy and revise steam generator action plan milestones, as appropriate (GSI-163)	01/01	DE
7	Determine need to incorporate new steam generator performance indicators into Reactor Oversight process (page 2 of Ref. 2; TG: 5e, 5f)	01/01	DE/IIPB/ DSSA
8	Recommence work on NEI 97-06 (page 3 of Ref. 2; TG: 7)	01/01	DE
9	Review NRC inspection program and, if necessary, revise guidance to inspectors on overseeing facilities with known steam generator tube leakage. (Attachment 3 to Ref. 1)	02/01	IIPB (DE and DSSA support)
10	Reassess the NRC treatment of licensee steam generator inspection results summary reports and conference calls during outages. Evaluate need for review guidance. (Attachment 3 to Ref. 1; TG: 5d, 6c; page 4 and 5 (top and bottom) of Ref. 1)	02/01	DE (IIPB support)

11	Review the NRC inspection program and, if necessary, revise guidance to inspectors on overseeing facility eddy current inspection of steam generators. (Attachment 3 to Ref. 1; TG: 5a, 5b, 5c)	02/01	IIPB (DE support)
12	Determine need for formal written guidance for technical reviewers to utilize in performing steam generator tube integrity license amendment reviews (TG: 6a)	04/01	DE
13	Staff provides EDO with update on status of action plan (page 8 of Ref. 1)	5/01	DLPM
14	Staff completes review and draft safety evaluation of NEI 97-06 including addressing issues raised in OIG report and IP2 lessons learned report (NEI 97-06, TG: 2, 3, 4, 7)	05/01	DE
15	Hold steam generator workshop with stakeholders (page 2 of Ref. 1; page 2 of Ref. 2)	06/01	DE
16	Staff briefs CRGR on NEI 97-06 (NEI 97-06)	07/01	DE
17	Publish SE on NEI 97-06 in FR for public comment (NEI 97-06)	07/01	DE
18	ACRS review of NEI 97-06 (NEI 97-06)	08/01	DE
19	Issue generic communication related to steam generator operating experience and status of steam generator issues	09/01	DE
20	Staff briefs Commission on endorsing NEI 97-06 (NEI 97-06, and WITS Item 199400048)	10/01	DE
21	Staff issues endorsement package on NEI 97-06 (Regulatory Issue Summary and safety evaluation including the approval of the generic technical specification change	10/01	DE

[1]Notes contained within parentheses in the above table indicate the source for the milestone. For example “TG” identifies the IP2 lessons learned task group’s recommendation number as identified in Attachment 3. NEI 97-06 indicates it is a milestone associated with the review of NEI 97-06. Similarly “GSI-163" and “DPO” indicate they are milestones associated with resolving these issues.

[2]In performing the next quarterly update on the status of the current Steam Generator Action Plan contained in the Director’s Quarterly Status Report, the staff will update the description, historical background, proposed actions, originating documents, regulatory assessment, schedule and milestones, priority, resource requirements, contacts, references and status sections to incorporate the information contained within this document.

[3]DLPM = Division of Licensing Project Management; DE = Division of Engineering; DSSA = Division of Systems Safety and Analysis; IIPB = Inspection Program Branch; ACRS = Advisory Committee on Reactor Safeguards

References:

1. Memorandum from William D. Travers, Executive Director for Operations to the Commission dated November 3, 2000, “Staff Review of OIG Report on the NRC’s Response to the Steam Generator Tube Failure at Indian Point 2 and Related Issues”

2. Memorandum from Samuel J. Collins, Director, NRR to William D. Travers, Executive Director for Operations dated November 1, 2000, “Transmittal of the Indian Point 2 Steam Generator Failure Lessons-Learned Report”

NON-STEAM GENERATOR RELATED ACTION PLAN MILESTONES[1,2,3]

Item #	Milestone	Completion Date	Lead
1	Evaluate the need for a new communication protocol with the US Secret Service that would cover emergency situations at all NRC licensed facilities (Attachment 3 of Ref. 1)	11/00	IRO
2	Establish NRC web site for Steam Generator Action Plan	01/01	DLPM
3	Review and revise, as appropriate, the policy for project manager involvement with the morning call between the resident inspectors and the region. (Attachments 3 and 4 of Ref. 1)	03/01	DLPM
4	Review program requirements for routine communications between the resident inspectors and local officials based on public interest. Based on weighing current resident inspector responsibilities (e.g., inspection requirements, following up on plant events) against this review, revise program requirements if needed. (Attachment 3 of Ref. 1)	03/01	IIPB
5	Develop, revise, and implement, as appropriate, a process for the timely dissemination of technical information to inspectors for inclusion in the inspection program (TG: 5g)	04/01	IIPB
6	Incorporate experience gained from the IP2 event and the SDP process into planned initiatives on risk communication and outreach to the public (TG: 9)	05/01	DE
7	Investigate possibility of establishing protocol with OIG regarding review of draft reports for factual/contextual errors (page 8 of Ref. 1)	06/01	DLPM
8	Review and revise, as appropriate, the amendment review process, including concurrence responsibilities, supervisory oversight, and second-round requests for additional information. (Attachment 3 of Ref. 1; TG: 6b, 6d, 6e; page 6 of Ref. 1)	06/01	DLPM

[1]Notes contained within parentheses in the above table indicate the source for the milestone. For example “TG” identifies the IP2 lessons learned task group’s recommendation number as identified in Attachment 3.

[2]In performing the next quarterly update on the status of the current Steam Generator Action Plan contained in the Director’s Quarterly Status Report, the staff will update the description, historical background, proposed actions, originating documents, regulatory assessment, schedule and milestones, priority, resource requirements, contacts, references and status sections to incorporate the information contained within this document.

[3]DLPM = Division of Licensing Project Management; IIPB = Inspection Program Branch; IRO = Incident Response Organization; DRIP = Division of Regulatory Improvement Programs

References:

1. Memorandum from William D. Travers, Executive Director for Operations to the Commission dated November 3, 2000, “Staff Review of OIG Report on the NRC’s Response to the Steam Generator Tube Failure at Indian Point 2 and Related Issues”

2. Memorandum from Samuel J. Collins, Director, NRR to William D. Travers, Executive Director for Operations dated November 1, 2000, “Transmittal of the Indian Point 2 Steam Generator Failure Lessons-Learned Report”

IP2 TASK GROUP RECOMMENDATIONS

No.	Recommendation	Action For	Report Reference Section	Report Reference No.
1	Con Ed must correct the deficiencies in its SG tube integrity program that led to the degraded SG condition during IP2 cycle 14. Otherwise, the long-term risk of SGTR at IP2 could be affected.	Con Ed	5.4	1
2	The EPRI guidelines and the licensees implementation of the guidelines should be improved based on lessons-learned from the IP2 experience. Specific recommendations are listed below as items 2(a) through 2(o).			
2a	Industry should update the EPRI SG Examination Guidelines to incorporate data quality criteria. Guidelines should explicitly discuss how to identify excessive noise in the data, how to identify the source of the noise, and what to do about the noise after the source is identified.	Industry EPRI	6.1.4 6.4.4	1 1
2b	Industry should consider the issue of noise in newer tubes in the revision to the EPRI SG examination guidelines.	Industry EPRI	6.4.4	4
2c	The EPRI guidelines should address the use of noise minimization techniques such as filtering algorithms.	Industry EPRI	6.4.4	5
2d	Licensees should review generic industry guidelines carefully to ensure that the conditions/assumptions supporting the guidelines apply to their plant-specific situation (for example, site-specific performance demonstrations for examination techniques).	Industry EPRI	6.1.4	2
2e	Industry should update the EPRI SG Examination Guidelines to incorporate guidance on how to evaluate flow slots for hour-glassing and the impact of hour-glassing on PWSCC in low row U-bends.	Industry EPRI	6.1.4	3
2f	The licensee and NRC staff should agree on a measurable definition of “significant” for hour-glassing.	Industry NRC	6.3.4	2

No.	Recommendation	Action For	Report Reference	
			Section	No.
2g	Site validation of techniques should be used for each detection technique, focusing on the most challenging areas of degradation.	Industry EPRI	6.2.4	1
2h	Licensees should use a conservative approach to screening tubes for in-situ testing, and should include tubes with new forms of degradation even if the screening threshold is not met. Industry should modify guidelines on the screening criteria to include new forms of degradation.	Industry EPRI	6.2.4	2
2i	Industry guidelines should caution licensees not to rely heavily on assessments based on sizing techniques that are not qualified.	Industry EPRI	6.2.4	3
2j	Licensees should consider the effect of the threshold of detection and sizing accuracy on the growth rate assumptions.	Industry EPRI	6.2.4	4
2k	Industry should update the EPRI SG Examination Guidelines to incorporate guidelines on prudent measures to be followed when evaluating the first occurrence of a new type of degradation for SG tubes.	Industry EPRI	6.4.4	2
2l	Licensees should recognize the potential for new forms of degradation and use robust techniques to look for problems that may exist, and not focus solely on degradation that has been found in the past. When a new type of SG tube degradation occurs for the first time, licensees should determine the implications on SG condition monitoring and operational assessment (e.g., potential for the tube to rupture before leaking, such as at the apex of a small radius U-bend).	Industry EPRI	6.2.4 7.4	5 1
2m	The EPRI Steam Generator Integrity Assessment Guidelines should be revised to address that care should be taken in relying on predictive models for PWSCC, and that licensees should maintain an aggressive approach in evaluating inconsistencies with predicted and observed SG degradation behavior.	Industry EPRI	6.4.4	3
2n	In addition to using two human analysts for the primary and secondary analysts, industry should consider developing guidelines for using computers to screen the test data.	Industry EPRI	6.4.4	6

No.	Recommendation	Action For	Report Reference	
			Section	No.
2o	The Task Group notes that its recommendations on eddy current testing and tube inspection guidelines were focused on a particular situation that existed at IP2 (i.e., a specific type of degradation and location within the SG). While incorporation of the IP2 lessons into industry guidelines is important, further development of industry guidelines should also address all SG tube degradation modes and degradation locations in order to be generally applicable.	Industry EPRI	6.5.4	3
3	The PWR TSs should be improved based on lessons-learned from the IP2 experience. Specific recommendations are listed below as items 3(a) and 3(b).			
3a	PWR TSs (or the regulatory framework currently being developed via the industry initiative) should ensure the technical requirements are strengthened to reflect the current knowledge of the SG degradation mechanisms, examination techniques, and methodology.	Industry NEI	6.3.4	1
3b	The industry should assess the adequacy of the TS regarding operational leakage limits.	Industry NEI	6.3.4	4
4	The NEI 97-06 initiative should be improved based on lessons-learned from the IP2 experience. Specific recommendations are listed below as items 4(a) through 4(c).			
4a	The licensees should ensure that contractors supporting the SG examination perform in an acceptable manner. The industry initiative should provide reasonable assurance of contractor oversight by licensees.	Industry NEI	6.3.4	5
4b	In the near term, industry should ensure that lessons-learned from the IP2 experience are being used to ensure that effective SG tube integrity programs are being implemented by licensees. NEI should provide feedback to the NRC on the status of licensee implementation of IP2 lessons-learned.	Industry NEI	6.5.4	1
4c	In the longer term, industry should also use lessons-learned from the IP2 experience to strengthen the NEI initiative. NEI should provide feedback to the NRC on the specific changes planned to the 97-06 initiative based on the IP2 experience, including a schedule for implementation of the changes.	Industry NEI	6.5.4	2

No.	Recommendation	Action For	Report Reference	
			Section	No.
5	Over the long-term, the NRC should improve the oversight of licensee SG tube integrity programs based on the generic character of some of the lessons-learned from the IP2 experience. In addition, improvements should be made to the inspection process. Specific recommendations are listed below as items 5(a) through 5(g).	NRC	5.4	2
5a	The staff should develop additional guidance on when and how much of its inspection of licensees' SG tube examination should be completed in the NRC baseline inspection program.	NRC	8.2.4	1
5b	The staff should review the training requirements for NRC inspectors for the SG baseline inspection program. The review should include the guidance contained in the SG inspection procedure to determine the required training for NRC inspectors to successfully complete the objectives of the NRC inspection program.	NRC	8.2.4	2
5c	The NRC should take steps to ensure that SG expertise is available to support the objective of the NRC's licensing and inspection programs. This could be done through formal training and/or transferring knowledge from in-house SG experts to other staff through written guidance documents or a mentoring program.	NRC	7.4	2
5d	The technical interaction between the licensees and NRR (outage phone calls) during the licensees' SG tube examinations can be effective and should be factored into the inspection program. The phone calls should involve the regional inspectors and should be used as part of the preparation for NRC inspections. This will afford NRR the opportunity to help focus the inspections on the appropriate issues.	NRC	8.2.4	3
5e	The staff should assess how the baseline inspection program and/or performance indicators (PIs) could be revised to adequately identify adverse trends in primary-to-secondary leakage during power operation, which could indicate a degradation of the SG tube integrity. The staff should ensure that any PI reporting requirements for primary-to-secondary leakage take into account potential differences in license requirements to ensure that all licensees would be required to report primary-to-secondary leakage for both normal and failed SG conditions.	NRC	8.2.4	5

No.	Recommendation	Action For	Report Reference Section	Report Reference No.
5f	The staff should establish risk-informed thresholds, either through the PIs or the significance determination process (SDP), that can be applied to the results of the periodic SG inspections to identify SG tube degradation that warrants increased NRC attention.	NRC	8.2.4	6
5g	The staff should develop, revise, and implement, as appropriate, the process for timely dissemination of technical information to the inspectors to ensure that relevant technical information is reviewed and considered for inclusion in the inspection program.	NRC	8.2.4	4
6	The NRC should make improvements in the licensing review process. Specific recommendations are listed below as items 6(a) through 6(e).			
6a	The NRC staff should develop formal written guidance for technical reviewers to utilize in performing license amendment reviews related to SG tube integrity. The guidance should provide specific criteria to identify when the staff should review previous licensee SG inspection reports.	NRC	8.1.4	3
6b	The NRC staff safety evaluations should be specific as to what information is relied on to form the basis for its conclusions (i.e., basis for approving the amendment). In addition, if the NRC staff is aware of significant information in the licensee's application that is incorrect, these issues should be discussed in the staff's SE even if the information was not relied upon to form a staff conclusion. This will help to identify those issues not otherwise addressed in the SE that later could be misinterpreted to imply that the staff concurred with the licensee's analysis/conclusions. OL No. 803 should be revised accordingly.	NRC	8.1.4	1
6c	The staff should assess the need for, and the process for the staff review of, the TS required reports that document the results of licensee's SG tube examinations. If the staff determines that such reports should be required, then the staff should also determine the information to be included in such reports, and the timing for submittal of the reports to the NRC. The staff should also develop a well-defined process to review such reports, and the specific purposes and objectives of such reviews. The revised reactor oversight process, including the SDP and the telephone calls with the licensee during an outage, should be considered in the process.	NRC	6.3.4	3

No.	Recommendation	Action For	Report Reference	
			Section	No.
6d	The NRC staff should revise OL No. 803 to add a discussion regarding interface between NRR and Regional staff during SE development. The discussion should state that in limited cases it may be of value to get input from the Region (e.g., if the NRR SE relies heavily on a statement from the licensee on a risk-significant issue, NRR could request that the Region perform an inspection to verify the statement).	NRC	8.1.4	2
6e	When NRR requests that RES perform an independent technical review of a staff's SE, NRR and RES should develop a process for handling the request and response.	NRC	7.4	3
7	The NRC should assign a high priority to its review of the NEI SG initiative and the associated EPRI guidelines. The NRC should use the SECY-00-0116 process, once approved, to expedite the review of the NEI 97-06 initiative.	NRC	8.3.4	1
8	In the interim, the NRC should issue a generic communication to clarify the current NRC position on industry guidance and to highlight SG tube integrity program weaknesses manifested by the IP2 experience that could exist at other plants.	NRC	8.3.4	2
9	The NRC should incorporate experience gained from the IP2 event and the SDP process into planned initiatives on risk communication and outreach to the public.	NRC	5.4	3