This is a very sensitive matter and this memo ~~is very~~ was not thoughtfully prepared in a manner that would be commensurate w/ its importance. It appears to be close to a first draft. It needs much more care, particularly in regard to the regulatory context that we operate in.

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

FROM: Ashok C. Thadani, Director
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 REGRADING F* REPAIR CRITERIA FOR INDIAN POINT STATION UNIT 2

[redacted]

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. [redacted]

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."

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.

We get these operational assessments after restart! If plant had operated without a shutdown for 2 years, this rupture would have occurred independent of this amendment. Issue then becomes do we shut a plant down if we find problems with OA. Not now part of reg. process.

However, in our review of the original inspection interval for cycle 14, we cannot reconcile several statements and conclusions in the SE with the 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."

? Regulatory

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. Contrary to our findings, the SE indicates that the licensee conducted more thorough operational assessments than we have identified and concluded that the tubes would meet structural and leakage integrity through the end of operating cycle 14.

Regulatory

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 proper operational assessment for these forms of degradation might have revealed an increased probability of tube leakage or rupture by the end of cycle 14 based on the findings and actions taken at the end-of-cycle 13.

what do about this either then or now?

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 of my staff.

ATTACHMENT

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'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)."

A proper Q,

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

Note: It was not a regulatory reqmt that IP-2 do an OA. Because they did a weak one is of no sequence in regulatory space.

How detailed a review of OA was req'd during appl timeframe? This statement implies staff missed the boat.

end of cycle 14 was assumed to be similar to the condition at the end of cylcle 13.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. 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 suggests 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.

Weak operational assessment if this is common knowledge is it?

There were two aspects of the licensee's May 12, 1999, response to the RAI related to the operational assessment that RES considers could have warranted further evaluation. These were stress corrosion cracking above the top of tubesheet under the sludge pile, and primary water stress corrosion cracking at the row 2 U-bend.

(1) ODSCC Above Top of Tubesheet (Sludge Pile)

Do we need to address this before restart?

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 percent 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. RES' projections are not credible either.

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% through wall 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 "Recent +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% through-wall at the beginning of the cycle and not allowing for inspection sizing error, did not provide a bounding estimate of the crack growth rate. If the crack had started to grow at the beginning of cycle 13 and a one standard deviation biased to have merit, Detached from reg. framework.

full cycle regardless of the test results. Pursuing this line of argument would be →

If we regulated based on these assumptions, no plant that has to do in situ

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 "the 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 making some adjustment for sizing error, then the undetected cracks with average depth indications of 40 to 50% would penetrate through-wall 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 through-wall during the cycle and the tubes would leak even if the growth rate of 28% is applied as estimated by the licensee. Further, if the cracks maintain an aspect ratio similar to the limiting crack analyzed by the licensee, the crack length when it fully penetrates the wall could be close to the critical length under steam line break pressure conditions thus increasing the probability of tube rupture under these conditions.

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.

In-situ testing guidelines not included

(2) 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 high residual stresses and dynamic strain caused by either or both fabrication and 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 [redacted] Inflammatory and unconnected to regulatory framework.

considered minimal." Based on the stress corrosion cracking process, this conclusion is not credible. strong and not [redacted] the basis for our conclusions.

The detection of the first row 2 U-bend crack at IP2 was an important finding in that it indicated that 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 hourglass. 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. [redacted]

Speculative at this point.

Regulatory

[redacted]

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 <u>in 1997 also found some small cracks in the support plate not previously observed.</u> 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. Row 1s are preventatively plugged & this point is omitted.

The results and observations discussed above appear to be in conflict with the licensee's assessment and the staff's safety evaluation. (See note on p. 1)

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 maintain primary to secondary leakage 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.

has not accentuated a PWSCC concern, and may be attributed in part to the relatively low T_{hot} value of the Unit.

ODSCC at Dented Tube Support Plate Intersections

A total of eleven cold leg dented tube support plate intersections were identified with the Cecco-5 probe as possible indications; all were +Point inspected. Two were found to contain ODSCC indications and one was reported to contain a volumetric indications based on the +Point responses. As with the hot leg intersections, the tube support plates would be expected to remain adjacent to the indication, thereby precluding burst during a postulated steam line break event. Only one of these dented intersections restricted passage of the 0.640 inch diameter Cecco-5 probe, due to a restriction at a lower elevation support plate. None of the indications at dented tube support plate (either ID or OD initiated) confirmed by the +Point extended out of the plate while the longest indication was reported at 0.37 inch.

PWSCC at Row 2 U-bend

NO op assessment conducted

For the first time, a Row 2 U-bend PWSCC indication was found. The dimension of the indication by +Point characterization was below the in-situ screening threshold for Row 2 U-bend flaws. All Row 1 tubes were preventively plugged prior to operation for a non-tube related issue. As this represents the first detected U-bend indication after approximately 23 years of operation, any growth rates associated with this indication would be considered minimal.

Question 2

Please discuss the results of your condition monitoring assessment conducted during your most recent inspection. Include, what degradation mechanisms were evaluated using the Westinghouse and/or EPRI screening criteria? What mechanisms were not evaluated using the screening criteria? What assurance is provided that the structural integrity would be maintained?

Response

All of the above listed mechanisms were evaluated to the Westinghouse screening parameters, with the exception of sludge pile pitting (pitting above top of tubesheet). The pit indications were not assessed against the Westinghouse screening criteria since screening criteria specifically for pits is not included. As discussed above, pit indications generally do not represent structural or leakage integrity issues, and as such, in-situ testing of such indications will not provide additional support for tube integrity assessments. Pit indications during the outage were assessed for in-situ testing based on a maximum bobbin coil depth of 50% and voltage of 3 volts. No indications met this criteria. Discussions of the approaches used for each mechanism, including sludge pile pitting, are provided as part of the Question 1 response.