INDIAN POINT 2 (IP2) STEAM GENERATOR (SG) TUBE FAILURE LESSONS-LEARNED TASK GROUP (TAC NO. MA9163)

TASK GROUP NOTES - DISCUSSION WITH CON ED AND WESTINGHOUSE

DATE: August 29, 2000

TIME: 8:00 am -11:00 am

LOCATION: Con Ed's Park Place Office, Peekskill, NY

ATTENDEES:

Scott Newberry	NRC - Lessons-Learned Task Group
Louise Lund	NRC - Lessons-Learned Task Group
Jimi Yerokun	NRC - Lessons-Learned Task Group
Rick Ennis	NRC - Lessons-Learned Task Group
Jack Parry	Con Ed - Project Management
John McCann	Con Ed - Licensing Manager
D. Curt Ingram	Con Ed - System Engineering
Jim Mark	Con Ed - R&D
Mike Galler	Con Ed
Jim Maris	Westinghouse - Site Engineering Manager
Rick Mauric	Westinghouse - Level III Analyst

PURPOSE:

The purpose of the discussion was for Con Ed and Westinghouse to provide their views on lessons learned and observations related to the Indian Point 2 steam generator tube failure event on February 15, 2000. The discussion did not include any specific or general regulatory decisions or actions, or discussions to reach agreement on lessons learned.

RESULTS:

The following was discussed:

Steam Generator Examination Program

1. From the last steam generator (SG) inspection in 2000, the most important difference was the use of the 800 kHz probe.

2. Westinghouse recommends the use of filtering algorithms (commercially available software), such as a circumferential averaging filter to remove ovality (i.e., geometry effects). Byron/Braidwood used an axial filter on a batch of 10 tubes which increased the probability of detection (POD).

3. An area based POD may be a more reasonable criteria to use rather than a crack depth POD criteria. This may give more risk significant information (e.g., crack depth may be 60-70% but crack length is short). They tried this approach during the 2000 analysis, and felt that the staff was supportive. This was discussed in a July 28, 2000 meeting with the NRC staff.

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4. Insights came out of their 2000 stress analysis performed by Altran. They knew the materials properties of the tubes well, and their analysis of the tubes showed that there was stress relief due to strain happening during the primary water stress corrosion cracking (PWSCC). In particular, during hourglassing, the stress was almost invariant with hourglassing so PWSCC in Row 3 would be delayed for 8 to 10 years (i.e., after initial deformation, there is not much further effect from hourglassing).

5. The 800 kHz probe is good for detecting PWSCC but it's not good for detecting outside diameter stress corrosion cracking (ODSCC).

6. It's not clear if the 800 kHz probe will be helpful in the U-bends that have been stress relieved due to permeability concerns - the studies have not been done.

7. There were no noise standards in 1997. Analysts determine if noise levels are acceptable based on their own experience. In 2000 at IP2, they set up data quality standards.

8. Other utilities are taking a more rigorous view of site qualification to look at data quality as a result of the IP2 event.

9. Revision 6 to the EPRI Steam Generator Examination Guidelines will give additional direction on site validation of probes.

10. Only a handful of plants were using the +Point probes in the U-bends by 1997. It was the state of the art in 1997.

11. Because sizing of indications is not as precise as you would want, they in-situ tested every axial indication that was cracked in 2000 examination. The in-situ test shows whether the tube integrity is there. Their recommendation is that utilities consider more tubes (rather than less) for in-situ testing (i.e., expand scope to include tubes with lower % thru-wall indications).

12. An indication that was sized at around 40% at another Westinghouse plant in U-bends leaked during in-situ testing. It had been considered a geometry call. They went back and looked at it harder after IP2. They were more confident in length than depth. The lesson here is to be very conservative about screening out indications for in-situ testing in tight radius u-bends.

13. They believe the current level of resources are appropriate for NRC inspections. The NRC inspection program conclusions are based on a sampling program. The NRC inspections can't cover everything, and ultimately the licensee is responsible for the work done. They would like to see current operating experience factored into the NRC inspection.

14. Con Ed believes that there is a great deal of value in the phone calls with the staff during the steam generator inspections. It is more efficient than swapping letters from the utility and staff and back. They understood that the phone calls must done in accordance with existing NRC policies and procedures with respect to making information publically available (i.e., material information needs to be docketed). From the utility standpoint, the phone calls offer the utility an opportunity to discuss NDE findings. Con Ed thinks that the phone calls should continue to take place.

15. With respect to the phone calls from DE staff - Con Ed indicated that they were aware of information that the NRC staff uses for structuring the phone calls and what they ask the licensees. This information should be reviewed and may need to be updated based on recent operating experience.

16. There was an independent Level III in 1997 to check resolution calls (i.e., did not focus on the whole process). In 2000, there was a independent Level III to not only review resolution calls but to also to spot check primary and secondary analysts work.

17. Some utilities have an experienced Level III on site that can review. They would recommend on-site and at the vendor. There is a requirement for an independent QDA capabilities - most utilities interpret this as one Level II individual. More than one QDA would be prudent when you have lots of degradation to review, especially to make spot checks of primary and secondary analyst calls as well as review resolution calls. If there is only one QDA, it is easy to get overwhelmed with the volume of data if there is a lot of degradation found during the inspection.

18. The Condition Monitoring/Operational Assessment (CMOA) in 1997 was done for practice, there was no requirement to perform a CMOA or submit it to the NRC.

19. Vendors were not invited to participate in the development of Rev. 6 of the EPRI Steam Generator Examination Guidelines.

20. The QDA exam provides an assurance of a minimal level of performance. The analyst takes the exam, and requalifies every 3 years on a smaller database. The QDA is expected to have 5 hours of training every year.

21. There is no official vehicle for getting ambiguous data into next site specific QDA exam. It would be a good idea to put data containing missed flaws, different probes, etc. on the site specific exams, not the general exam.

22. On the content of annual QDA training, supplemental training should focus on generic industry topics such as Row 2 tubes, egg crate flaws, and other challenging inspection areas. The NEI guidance should be more specific with respect to the content of the annual training.

23. Licensee staff experts at a single-unit site are more limited compared to multi-unit sites. There is more often a challenge to have the proper level of expertise, which sometimes leads to one vendor be used to provide a second opinion to another vendor.

24. Another enhancement that was made to the 2000 inspection was to use separate teams to look at the Cecco and bobbin data. In 1997, the same team looked at both. This helps because there is no guideline to decide how much data is too much for the analyst to handle.

25. Northern States Power (NSP) presented a noise study at a recent seminar and at the NRC/NEI meeting in July. The study compared U-bend noise at Kewaunee, Prairie Island, and IP2. Kewaunee and Prairie Island have lower noise levels than IP2 therefore they didn't see the benefit in using the 800 kHz probe. NSP concluded that if you're not bounded by the EPRI qualification data you may want to use the high frequency probe. Westinghouse believes that for plants with deposits on the tubes, the high frequency probe is a good idea. Westinghouse is looking at average noise levels to determine the criteria for when to use the high frequency probe.

26. Westinghouse looked at the IP2 data from 1997 and they think the noise levels at IP2 are similar to noise levels at other plants. IP2 may be an outlier with respect to Kewaunee and Prairie Island but Westinghouse is not sure if they are an outlier with respect to the rest of the industry. Noise levels at Maine Yankee were about the same as at IP2. The average noise levels encountered at IP-2 were about 0.6 volts, and in many plants the average is around 0.4 volts. Westinghouse is concerned about permeability variations in the tubes leading to increased noise, and they don't know of any high frequency probes (800 kHz) that have a magnetically biased coil to reduce noise from permeability. Up to this point, there have been no requirements to quantify noise.

27. Some indications found in the past that appeared to be due to geometry (e.g., tube out of round), have grown and leaked. Westinghouse recommends geometry indications be preventively plugged.

28. Westinghouse believes that their internal communication process is adequate to ensure that all their analysts have the recent lessons-learned information needed for the fall outages. However, Westinghouse believes that NEI needs to get out lessons-learned information so all vendors and utilities have this information in a timely manner.

29. Westinghouse is planning on looking at average noise levels in Row 1 and Row 2 data. This has to be approached carefully, because plants that are up and running are sensitive to them looking at their inspection data.

30. Westinghouse will be using UT to determine the nature of circumferential cracks, to determine if eddy current results are truly indicative of a geometry change, and to evaluate/quantify damage mechanisms such as pitting.

31. At IP2, they used UT to try to get past where the NRC reviewer had no confidence in the eddy current probability of detection.

32. Potential problems with UT - there are relatively few Level III UT analysts and there is not an equivalent QDA test for UT examiners. Therefore, the analysts are not always equivalent to QDA analysts. However, Appendix J does qualify the technique. They are currently doing Appendix J qualification for pits in EPRI NDE center this week. There is not enough data available for performance demonstrations in statistical sense. Often utilities will test around 10 tubes or so. They need a statistical database for QDA test.

33. In 1997, tube R2C5 was viewed as a geometry issue, as if the tube was out of round and caused the probe to stop spinning. In hindsight (i.e., in 2000) they realized that it was not a geometry issue, but a noise issue. They would have had to do more in 1997, similar to what they did in 2000, to identify the flaw in R2C5.

34. The flaw in the row 2 U-bend tube that they did find in 1997 gave them a false sense of security since it was an easy call.

35. In 1997, they were one of a handful of plants that used +Point in the U-bends. The analysts would have only had seen the +Point data at one or two plants at the most before they analyzed the 1997 data. The only data that they would have had access to for training at the beginning of the 1997 outage was from flawed U-bend tubes that had been plugged. Other plants would not have provided good or marginal data for

reexamination while they were up and running because there would have been the potential of finding flaws that were missed during the inspection.

36. Dominion Engineering did a study for Con Ed on steam generator degradation in 1995 that made PWSCC predictions, but didn't predict that a PWSCC flaw in the U-bends would occur until 1999. When they found the PWSCC flaw in the U-bends during the 1997 outage, they contacted Dominion Engineering after the outage to get them to update the report based on inspection findings. The projection for PWSCC indications was one additional indication per cycle, not exponential. Since the projections were based on the midrange probe findings, the use of the high range probe would have led to a different result based on the increased number of indications found (i.e., not just one indication as was found with the midrange probe).

37. With respect to the wording in IP2 technical specification (TS) 4.13.C.2 which states: "[a] significant increase in the rate of denting or significant change in steam generator condition shall be reportable immediately," Con Ed indicated that this wording was added after a new denting phenomenon (hourglassing) was observed in the IP2 SGs. The word "significant" has not been quantified by Con Ed or the NRC.

Regulatory Framework

38. Con Ed believes that NEI is headed in the right direction.

39. They think all plants are committed to TS changes thru NEI 97-06. Con Ed will be changing the IP2 TSs regardless of what NEI does.

40. Con Ed thinks the NRC should continue working with NEI.

Views on the NRC's Memo from RES to NRR Dated March 16, 2000

41. About the RES memo - They were surprised that it came out with no interaction with the licensee and well in advance of any inspection activity. This type of memo makes it necessary for there to be a response in a highly visible document. Without having already performing the inspection, it could have been difficult to explain differences in the inspection findings and the RES review. This could lead to questions about the objectivity of the follow-on work, i.e. the inspection. They would have preferred that RES talk to the licensee before issuing the memo.

42. In general about the RES memo - In a highly visible situation, there is an urgency for conclusions. A problem in reaching conclusions too quickly is that a conclusion reached is difficult to retract. Conclusions should be reached with full and complete examination of the data. It wouldn't have mattered if this review had been conducted internally in the NRC or outside the agency, the same concerns would apply. The timing of the release of the RES memo surprised them, because all the data was not available to reach conclusions.

43. About whether they agreed with the technical content of the RES memo - they understand that they gave a rather perfunctory response to the question about PWSCC degradation and growth rates. Since they had Dominion Engineering look at this issue, they believed that they had a technical basis for their conclusion, but this part of the CMOA was not described in detail in the RAI response. This is one example of something they could have explained to RES before the memo was issued.

Risk Insights on Tube Failure

44. They believe that the risk significance of the event was at most in the white category. The loss of power event in August was a more serious event, was considered a yellow (happened before new oversight process), and was mitigated by condensate feed. The steam generator tube failure was bounded by the safety analysis and the plant was analyzed to handle this event.

45. Con Ed is struggling to understand why the risk analysis would support a potential red finding. Since it wasn't a tube rupture, the a priori probabilities are not played out. For the testing done in 2000, all row 2 tubes other than R2C5 that had indications from the 1997 data were in-situ tested. Some leaked but all passed the burst criteria test. Once you've performed the in-situ test, you've demonstrated tube integrity (i.e., you shouldn't postulate that they might burst during the cycle).

46. They are having additional work performed by MIT and Altran, which will be a fracture mechanics approach to see if the crack in R2C5 would have grown to burst. They believe that it would have not gone to tube rupture, and want to see if analysis supports this.

47. They do not agree that this tube failure leads to large early release. The LERF basis is that some valve is open during the event. If they can make the case without challenging the basis, they will, otherwise they will present a challenge to the assumptions.

Communication with Public

48. Interaction with media was a process that didn't serve either side very well.

49. If we are speaking with different voices, public doesn't think any of us know what is going on. They are particularly concerned with the leaks to Inside NRC that seem to be coming from the NRC staff, and the impacts to utilities through the financial community.

50. The set-up for the May 3 meeting was not ideal. The room used for the meeting set a negative public relations tone. The administrative judge quarters made it look like a court room drama rather than a technical exchange. In contrast, the other working group meetings (such as the one held on July 28) worked out well. They got past the spotlight and got down to work. They had all the right players, and it was held at the Con Ed site Energy Education Center.

51. They liked the IP2 web page, and would have preferred that the information got posted quicker.

52. Neither side did a good job in educating/communicating to the public about the release. Both Con Ed and NRC needs to communicate this in a consistent way. For example, what does it mean to the public when Region I says there is no significant release, Con Ed says there is no significant release, and there is a red finding that discusses a large early release. This is a communication challenge.

53. Another public issue - when a highly public event like this one occurs, it is easy for external issues that are not connected to the issue to get caught up into the fray (e.g., Hopenfeld DPO, emergency planning issues, etc.)

Other Lessons-Learned/Observations

54. Con Ed believes that there is more division than normal between the utility and NRC staff positions on the integrity of their steam generators.

55. Immediate industry involvement was very important to them during the time right after the tube failure. It's important to get this help as early as possible after an event, and at various points afterwards. INPO sent teams three times, and they sent the cream of the crop from the NDE standpoint.

56. Another lesson is that the licensee can't put too much stake in leak limits in keeping tube failures from occurring - new leak limits would not have kept R2C5 from failing.

57. Con Ed fundamentally does not agree with the NRC conclusions reached by the A.I.T inspection. You need to take into account what the requirements were in 1997.