Joe
Category 5 - 119

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

October 12, 2000

MEMORANDUM TO: Scott F. Newberry, Leader
Lessons Learned Task Group

FROM: Michael E. Mayfield, Director
Division of Engineering Technology
Office of Nuclear Regulatory Research

SUBJECT: INDIAN POINT 2 STEAM GENERATOR TUBE FAILURE LESSONS-LEARNED REPORT (TAC NO. MA9163)

In your October 3, 2000, memorandum on this subject, you requested that RES review and comment on the subject report and provide comments as markups of the affected pages. The report was reviewed in each of the RES Division's and our comments have been discussed with the Office Director. Per your request we have focused our comments on (1) factual errors, (2) inconsistencies, and (3) significant issues. Our detailed review has progressed only as far as page 117. If needed, we could discuss the comments with you.

Because the report is predecisional and not for public release, we made very few copies and have controlled those copies.

Attachment: Markups of the affected pages

X/16

October 12, 2000

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Lessons Learned Task Group

FROM: Michael E. Mayfield, Director /RA/
Division of Engineering Technology
Office of Nuclear Regulatory Research

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DATE	10/12/00	10/ /00	10/ /00	

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DOCUMENT DATE: October 3, 2000
DUE TO RES: **October 10, 2000**

RECEIVED BY RES: October 4, 2000
Lessons Learned Task Group
DUE TO [redacted]: **October 11, 2000**

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FOR SIGNATURE OF: **A. Thadani, Dir RES**

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RES FRONT OFFICE REVIEW

ACTION: Mike - please take the lead for reviewing with input from other divisions: re procedural / factual errors, inconsistencies + significant issues.

WITS / GREEN TICKET #: ______ **DUE DATE:** 10/11/00 Prepare response for Ashok's signature

ASSIGN TO: ☐ DSA&RE ☐ DRA&A ☑ DET ☐ FMPAS ☐ F.O.

CONCUR WITH: ☐ NRR ☐ NMSS ☐ AEOD ☐ OGC ☐ CFO ☐ CIO ☐ ____ ☐ ____

MEET EARLY TO RESOLVE ISSUES WITH CONCURRING OFFICES? ☐ YES ☐ NO

	To be Reviewed by:	Signature Block:	To be Signed by:
A. Thadani	☑	☐	☑
M. Federline	☑	☐	☐
B. Morris	☐	☐	☐
C. Ader	☐	☐	☐

DATE DUE TO F.O. 10/10 **DATE RECEIVED IN F.O.** ______

F.O. GUIDANCE: ☐ None. **Specify:** ______

2000 326

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October 3, 2000

MEMORANDUM TO: Bruce A. Boger, Director, NRR/DIPM
Karen D. Cyr, General Counsel, OGC
Gary M. Holahan, Director, NRR/DSSA
David B. Matthews, Director, NRR/DRIP
Hubert J. Miller, Regional Administrator, Region I
Jack R. Strosnider, Director, NRR/DE
Ashok C. Thadani, Director, RES 10 of 12
John A. Zwolinski, Director, NRR/DLPM

FROM: Scott F. Newberry, Lessons-Learned Task Group Leader

SUBJECT: INDIAN POINT 2 STEAM GENERATOR TUBE FAILURE LESSONS-LEARNED REPORT (TAC NO. MA9163)

The Indian Point 2 Steam Generator Tube Failure Lessons-Learned Task Group effort is nearing completion and a final report is scheduled to be issued by October 19, 2000. A copy of the latest draft of the report is attached for your review and comments. Please limit your comments to: (1) factual errors, (2) inconsistencies, and (3) significant issues.

It is requested that your comments be provided as markups of the affected pages and that all comments be provided to me no later than October 11, 2000.

The attached draft report is pre-decisional and is not for public release. Therefore, I request that you handle it accordingly. Thank you for your continuing support on this effort.

Attachment: IP2 SG Tube Failure Lessons-Learned Report, Draft 5

DISTRIBUTION (all w/o attachment)
B. Sheron
J. Donoghue
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EXECUTIVE SUMMARY

The February 15, 2000 Steam Generator Tube Failure Event

A single tube in one of four steam generators (SGs) at Consolidated Edison's (Con Ed's) Indian Point 2 (IP2) plant failed leading to a transient and shutdown of the reactor. In addition to the reactor itself, the SGs are the major components that transfer reactor heat into steam to drive the electric turbine at a nuclear power plant. They are located inside the containment structure and are equipped with safety features to detect and initiate automatic protection actions and provide indications to the plant operators if problems develop. The tube failure consisted of a small through-wall crack in one of the 3,260 SG tubes that allowed reactor cooling water to flow through the crack into the steam generating side of the SG at the rate of about 150 gallons per minute. The reactor was safely shutdown by the plant systems and operators. The event resulted in a minor radiological release to the environment that was well within regulatory limits.

small?

Charter

The IP2 SG Tube Failure Lessons-Learned Task Group and Charter were proposed by the Director of the Office of Nuclear Reactor Regulation (NRR) and approved by the Executive Director for Operations in June 2000. The objective of the effort was to evaluate the NRC staff's regulatory processes related to assuring SG tube integrity in order to identify and recommend areas for improvements applicable to the NRC and/or the industry. A multi-disciplined Task Group was set up in accordance with the charter consisting of staff from the Office of Research, Region I and NRR. Support was provided by the Office of the General Counsel.

The Task Group was not expected to identify the processes for resolving areas of potential weakness. The responsibility for dealing with the recommendations would be with the applicable line organization.

The charter directed that the Task Group review the staff safety evaluation report (SER) associated with restart of IP2 with their current SGs and provide concerns or issues to the staff for action. This activity was terminated when Con Ed decided to replace their SGs.

Report

This report is the result of the Task Group effort. Conclusions and recommendations were developed by the Task Group based on reviews of documents and discussions with NRC staff, nuclear industry representatives involved in SG programs, and NRC SG expert consultants. Public input was not sought as part of the Task Group effort based on the understanding that the report and other efforts would be integrated into an activity that would allow for input from a broad range of stakeholders.

The Task Group was directed to focus attention on issues directly related to the February 15, 2000 tube failure event and operation of the current SGs at IP2. Documents reviewed by the Task Group included Con Ed SG examination and NRC SG inspection procedures and reports, nuclear industry generic SG examination guidance and associated NRC review information, NRC and Con Ed license amendment proposals and safety evaluation reports, and the Con Ed event root cause analysis and the associated NRC Special Inspection Report.

2) During the 1997 SG examination, forms of degradation called tube denting and hour-glassing, were identified when restrictions were encountered as the eddy current probes were inserted into the U-bend portion of similar tubes. Con Ed did not evaluate the potential for, and significance of, this degradation.

3) During the 1997 examination significant eddy current signal interference (noise) was encountered in the data obtained from a number of tubes similar to the tube that failed and Con Ed's program was not adjusted to account for the noise, particularly when the new PWSCC defect was found in this area of the SG.

The Task Group believes that the findings of the Special Inspection Team are reasonable and that corrective actions at IP2 should proceed in accordance with the ongoing inspection and enforcement process.

Industry / NEI / EPRI

Along with the plant specific examinations conducted by Con Ed at IP2 during 1997, the Task Group reviewed the industry SG examination guidance used by Con Ed during the 1997 outage and concluded that weaknesses in the guidance contributed to the inadequate examinations. The guidance was developed and is maintained by the Electric Power Research Institute (EPRI). Since the EPRI guidance is a cornerstone of the industry initiative now being coordinated with the Nuclear Energy Institute (NEI), the Task Group believes that the industry should be requested by the NRC to expeditiously ensure that the lessons-learned from the IP2 event are incorporated into the guidelines and implemented by all licensees and that feedback be provided to the NRC on the status.

Particular improvements to the EPRI guidelines to improve the effectiveness of SG examinations are discussed in detail in Section 6 of this report. The Task Group believes that the guidance in use during the 1997 IP2 examinations are vague with respect to the quality of eddy current data and the significance of noise in the data. The need for increased licensee attention when "new" types of degradation are found is not emphasized. The Task Group understands that industry is already taking steps to make improvements and believe they should be discussed with the staff, and schedules determined for incorporation.

The following additional issues that should be pursued with the industry for improvements in the guidance and implementation by licensees were identified by the Task Group:

1) Licensees should review generic industry guidelines carefully to ensure that the conditions/assumptions supporting the guidelines apply to their plant-specific situation. The plant-specific qualification of eddy current probes to perform inspections is fundamental to an adequate inspection.

Unclear how are POD & unqualified techniques related here? (statement also on p. 64)

2) Parameters that are needed to assess SG tube structural integrity such as probability of detection of certain flaw size and growth rates are based on unqualified sizing techniques. This leads to a lack of consideration of uncertainties when licensee's determine flaws that are left in service or select tubes for in-situ pressure testing.

3) A noise study performed by NEI indicates that SG tube U-bend noise may be significant regardless of tube age or outside deposits. Flaw detection capabilities in the U-bend region should be assessed, for all SGs.

Comments from J. Muscara p.4

2. Unclear how are POD & unqualified sizing techniques related here?
(Statement~~s~~ also on pg. 64)

As discussed above, the 1997 SG examination performed by Con Ed, which has now been determined to be ineffective, was the underlying basis for the SG examination extension being proposed in 1998 by Con Ed to the NRC. Thus, the Con Ed proposal and NRC licensing review provided an opportunity for Con Ed and the NRC to reevaluate the adequacy of the 1997 examination. After the February tube failure event, NRR requested RES to review this extension request along with the associated NRR safety evaluation of the proposal. The RES technical review was provided in a report dated March 16, 2000. The OIG also evaluated this licensing review and provided their findings in its report dated August 29, 2000. Both of these reports were considered in detail by the Task Group, along with the specific licensee and staff documents and review guidance, in reaching conclusions and recommendations. These reports and the detailed conclusions and recommendations are discussed in Sections 7.0 and 8.1 of this report.

The significant conclusions from the Task Group review of the licensing review process associated with the Con ed amendment request to extend the SG inspection interval are:

1) In hindsight, this licensing review provided an opportunity for the NRC staff to pursue questions on the licensee's 1997 inspection further. The licensee's proposal was weak in several areas. In particular, PWSCC degradation information on a similar tube to the one that failed was provided by the licensee in their inspection report which was available to the staff. response to the RAI ?

additional questions not required. The good quality of the answers to the RAI might have convinced the staff that an adequate [illegible] [illegible] [illegible] [illegible] the extension would/should have been denied

2) Based on a review of 1997 information available to the licensee and the staff, it is not clear to the Task Group if additional staff questions posed during the licensing review would have changed the outcome of the license amendment request or uncovered the issues related to the root cause of the tube failure. For example, Con Ed had performed an examination of all other similar tubes using an inspection plan previously reviewed and approved by the staff.

3) The IP2 tube failure occurred on February 15, 2000, which was approximately 8 months after the originally scheduled inspection date (i.e., less than the duration justified by the 10 month shutdown). Therefore, the extension of approximately 2 months did not contribute to the tube failure event.

4) While the staff used existing NRC review guidance in performing the review, no specific guidance exists for SG examination extensions, especially how to consider previous inspection reports, or how to consider or reference the inspection program.

While the Task Group did not evaluate the area of staff SG expertise in detail, this was brought up by the OIG report, and was mentioned in conversations with NRC staff and managers responsible for these programs. The Task Group believes that agency SG expertise is limited and focused primarily at headquarters. The Task Group recommends that NRC take steps to evaluate SG expertise needs to support the licensing (as well as inspection) program.

In summary, the Task Group believes that the real problem relates back to the quality of the Con Ed 1997 examination. Improvements to industry SG examinations (discussed above) and NRC regulatory inspection processes that focus on these examinations (discussed below) will maintain plant safety and improve the efficiency and effectiveness of NRC programs. The

Comments from J. Muscara p.6

1. In particular, PWSCC degradation information on a similar tube to the one that failed was provided by the licensee in their ~~inspection report~~ which was **response to the RAI** - available to the staff. ?

2. Additional questions not required. A good review of the answers to the RAI might have concluded that an adequate case for ~~providing~~ OPERATING a full ~~report~~ CYCLE had not been made. Therefore, extension could/should have been denied.

Task Group believes that additional review guidance for SG examination license amendments will improve the effectiveness and efficiency of these reviews.

Inspection

The objective of the NRC inspection program is to obtain factual information providing objective evidence that power reactor facilities are operated safely. The SG tube failure at IP2 occurred at a time when the NRC was transitioning to a new reactor oversight process (ROP). Effective April 2, 2000, the NRC implemented this new process for all plants. The Task Group reviewed both the old and new NRC inspection processes to develop lessons-learned and recommendations.

The baseline inservice inspection (ISI) in the new ROP is to be performed at all operating reactors, once every two years during a refueling outage. Supplemental inspections are performed as a result of risk-significant licensee performance issues that are identified by either PIs, baseline inspections, or event analysis. The risk characterization of inspection findings is performed using the SDP. The SDP was developed as a new tool in the ROP to allow risk-informed thresholds to be applied to inspection findings on a risk scale similar to PIs.

Prior to April 2000, an NRC ISI was performed at each facility in accordance with the core inspection program. This program was in effect during the NRC inspection of IP2 in 1997. The scope of the inspector's review was based on a judgement regarding current significant issues and also as directed by the inspector's supervisor. The planning did not usually involve NRC headquarters personnel. It did not require that industry information be factored in, although it sometimes was. New industry and generic information, such as Information Notices and Generic Letters, did not always get to the regional inspectors in time enough to be factored into their inspection activities. The site inspection involved one inspector for a period of one week and was not necessarily limited to SG activities, but it could also include non-destructive examination (NDE) activities on other components.

NRR has routinely held conference calls with each licensee during their refueling outage to assess the adequacy of the licensee SG tube eddy current inspections. These conference calls involve regional participation on occasion and discuss the results of the licensee generator inspections and repair plans. This effort has not been part of the inspection program, and the results are not documented in inspection reports. During consideration of the NRC inspection activities, the Task Group interviewed NRC staff involved in the phone calls and reviewed some of the records of the 1997 outage NRC/Con ED telephone calls held on June 2, 3, and 29, 1997. There was no indication that the crack discovered in the tube similar to the tube that failed was discussed. The timing of the phone calls relative to when the flaw was identified was not clear. The Task Group determined that these calls are important activities that should be factored into the inspection process.

The new ROP baseline inspection procedure for ISI does not require that licensee SG examinations be inspected by the NRC. The inspection procedure contains significantly less guidance for conduct of the inspection than the previous core inspection procedure. Available supplemental procedures contain considerably more detail. Under the new ROP, risk-informed thresholds are to be applied to inspection findings to determine when a significant degraded condition has occurred that warrants additional NRC interaction and supplemental inspection above the baseline program. Such thresholds do not currently exist to identify when the number or types of SG tube defects have reached a level that warrants additional NRC action.

2.0 SCOPE OF REVIEW

2.1 Scope

The scope of the Indian Point 2 (IP2) Steam Generator (SG) Tube Failure Lessons-Learned Task Group's effort involved technical areas as well as the regulatory processes involved in assuring SG tube integrity. The Task Group considered the following information: (1) Consolidated Edison's (Con Ed's) SG examination results and findings; (2) the licensee's root cause evaluation for the February 15, 2000, tube failure event; (3) the review by the NRC's Office of Research presented in its memorandum of March 16, 2000; (4) observations and findings of the NRC's Augmented Inspection Team and its follow-up inspection; (5) the NRC special inspection report conducted to review the causes of the SG tube failure, and (6) licensing amendments related to the extension of the SG inspection period since 1995. The Task Group also reviewed and assessed the regulatory process involved in assuring SG tube integrity. This included: (1) the NRC inspection program related to the SG tube integrity; (2) the SG examination and assessment methods implemented at IP2; and (3) the license amendment process utilized for the applications related to IP2 SG tube examinations. In addition, the Task Group reviewed how industry guidelines for assuring SG integrity were applied at IP2 and the implication of the IP2 event on the guidelines. The Task Group did not conduct a thorough technical review of the industry guidelines or determine their adequacy, though certain inadequacies became apparent. As indicated in SECY 00-0078, "Status and Plans for Revising the Steam Generator Tube Integrity Regulatory Framework," dated March 30, 2000, the review of the guidelines is a separate effort, and the NRC plans to issue a safety evaluation on the industry guidelines in the future.

The Task Group reviewed the NRC's Office of the Inspector General (OIG) report dated August 29, 2000, titled "NRC's Response to the February 15, 2000, Steam Generator Tube Rupture at Indian Point Unit 2 Power Plant," and considered the OIG findings for lessons-learned. The findings relate primarily to the inspection and licensing processes and are discussed later in this report.

The Task Group also reviewed the Strategic Plan Nuclear Reactor Safety Arena goals, measures, and strategies to assess the implications of the event and the associated findings.

The Task Group review did not include an existing internal NRC Differing Profession Opinion (DPO) related to generic SG issues or a 10 CFR 2.206 petition related to IP2 SG issues that was submitted to the NRC by the Union of Concerned Scientists (UCS) on March 14, 2000. The existing NRC processes developed for handling these issues are being used, and review of these issues were outside the scope of the Task Group charter.
was

Also, the Task Group scope did not include the NRC and Con Ed follow-up of the event that was not specifically related to SG tube integrity, such as emergency planning and degraded equipment issues.

2.2 Assumptions and Constraints

Prior to proceeding with this effort, the Task Group reviewed the group's charter and discussed the scope, objective and specifics of the charter with NRC staff management. This was performed to clearly establish the assumptions and constraints that were applicable for this

Steam Generator Degradation Mechanisms

There are several mechanisms by which SG tube degradation occurs. Stress corrosion cracking (SCC) in SG tubes is caused by the simultaneous presence of a tensile stress, a specific corrosive medium, and a susceptible material. This degradation mechanism can initiate from either the tube's ID or OD. When initiated on the ID, it is referred to as PWSCC, and, on the OD, it is referred to as ODSCC. PWSCC in particular is associated with areas of high stresses and thus are most commonly found in the tubesheet expansion transitions, in the U-bend transition and apex regions of the low-row tubes, and in the TSP intersections (especially if the tubes are dented).

most corr of C steel [illegible] [illegible] [illegible] [illegible] denting due to larger volume of the magnetite

Denting of the tubes is the direct result of secondary side corrosion of the TSP in the area between the tube outer wall and the drilled hole in the TSP that the tube passes through. When the SG is shut down and cool, there is a circumferential gap between the tube outer wall and its hole in the TSP. The gap is there by design to allow for tube thermal expansion as the RCS temperature is increased prior to a reactor startup. However, while the SG is shut down, corrosion products can form and harden in that gap. As the RCS and the tubes heat up, tube expansion at the TSP is restricted due to the hardened corrosion products. ??X

The forces generated on the tube due to these corrosion products cause several things to happen. ~~As the tube tries to expand~~ during heat up, it becomes permanently dented in the area of the TSP. Eventually, the denting process can continue until the tube ID is so closed that an ECT probe will not pass through. This is called a restricted tube. The denting also induces tensile stresses in the tube ID or OD near the dented region, leading to localized SCC. Y

The forces causing the denting also act against the TSP. In the area of the flow slots where the structural resistance is low enough, deformation and/or cracking of the TSP can occur. If this happens on both sides of the flow slot, the sides of the flow slot are forced inward at the middle, causing the previously rectangular shaped flow opening to develop the shape of an hour-glass. This is referred to as hour-glassing, with a typical example shown in Figure 3-3. In the low-row U-bends, PWSCC is significantly more likely to occur if hour-glassing forces the tube legs closer together, since a small movement of the tube legs will concentrate sufficient tensile stress at the apex of the U-bend.

IP2 Steam Generator History

Throughout the plant's operating history, the IP2 SGs have experienced a broad range of tube degradation modes, requiring plugging of tubes. The causes are common to the industry and include: tube sheet roll transition PWSCC, ODSCC in the area between the roll transition and the top of the tube sheet (crevice), ODSCC in the sludge pile area (at the top of the tube sheet), ODSCC and PWSCC and probe restrictions in dented areas, and U-bend ODSCC. ← or IGSCC? Typical examples of these types of degradation mechanisms are shown in Figure 3-4.

Due to the composition of some secondary system components at IP2, deposits on the OD wall of the tubes contain hematite (Fe_2O_3), interspersed with metallic copper. These deposits ~~generally do not promote severe tube corrosion. However, they can have the effect of~~ ~~increasing~~ the noise in an ECT signal.

Copper does play a role in the cracking of tubes

Prior to the February 2000 tube failure, the last SG ECT inspection was completed in June 1997 during refueling outage (RFO) 13. This SG inspection included an examination of all

Comments from J. Muscara p. 15
Steam Generator Degradation Mechanisms

(pp2) Most corrosion of carbon steel plates takes place at high temperatures. Denting is due to larger volume of the...MAGNETITE

IP2 Steam Generator History

(pp1) or IDSCC ? ~~correction from ODSCC~~

(pp2) Copper does play a role in the CRACKING ~~corroding~~ of tubes.

low-row U-bend tubes and identified the first indication of PWSCC in the apex of the U-bend of tube R2C67 in SG 24. This tube was plugged prior to restart. Also during this examination, Con Ed identified the first instances of probe restrictions caused by denting at the upper tube* support plate in some of low-row U-bend tubes. These tubes were also plugged because an examination could not be completed. Following the completion of RFO 13 Con Ed returned IP2 to operation in early July 1997. A timeline of plant events associated with the February 2000 SG tube failure is shown in Appendix A.

Primary-to-secondary leakage during the operating periods following RFO 13 remained low (less than 2 gallons per day (gpd)) through December 1999). By early February 2000, total leakage was approximately 2.1 gpd, with 1.2 gpd attributed to SG 24. On February 15, 2000, initial primary-to-secondary leakage was 3.1 gpd and increased following the failure of tube R2C5 in SG 24 to approximately 150 gpm.

* Not sure this was the first time time they had restrictions due to denting at the support plates

Of even more significance was the report of restrictions in the tight row U-bends, this probably was the first time it was reported. This was significant because it implied that the legs may just be moving closer together due to hourglassing and the "squashing" of the tube ~~[illegible]~~ left the U bend susceptible to SCC.

Comments from J. Muscara p. 16

IP2 Steam Generator History (cont.)

Not sure this was the first time they had restrictions due to denting at the support plate. Of even more significance was the report of restrictions in the tight row U-bends, this probably was the first time it was reported. This was significant because it implied that the legs might be moving closer together due to hour-glassing and the "squashing" of the tube left the U-bend susceptible to SCC.

4.0 REGULATORY FRAMEWORK

4.1 Introduction

In recent years, the NRC staff has examined the regulatory programs which comprise the framework for ensuring the integrity of steam generator (SG) tubes. In the early to mid-1990's, existing programs were thought to be prescriptive, out of date, and not fully effective. In SECY-95-131 (May 22, 1995), the staff informed the Commission that it intended to continue with the development of a rule which would address SG tube integrity. The rule would have required the development and implementation of a risk-informed, performance-based program to maintain SG tube integrity. Following a regulatory analysis, however, the staff concluded that existing regulations provided an adequate regulatory basis for dealing with SG issues but that SG tube surveillance technical specifications (TSs) should be upgraded. Therefore, in 1997, the staff informed the Commission that a SG rule was not necessary, but that the staff would develop a generic letter: (1) containing model technical specifications for SG tube surveillance and maintenance and (2) requesting licensees to address current TS problems and develop guidance to support model TSs, or pursue alternate SG tube repair criteria based on an appropriate risk assessment. That same year, the Commission approved the staff's approach and the Nuclear Energy Institute (NEI) voted to adopt NEI 97-06 as a formal industry initiative to provide a consistent industry approach for managing SG programs and for maintaining SG tube integrity.

In 1998, the staff informed the Commission of its intent to delay issuance of the generic letter while the staff worked with industry to resolve staff concerns about the industry initiative and with the objective of avoiding duplication by endorsing the industry initiative as an acceptable approach for maintaining SG tube integrity, consistent with the Commission's Direction-Setting Initiative 13 (DSI-13), "The Role of Industry." The staff also indicated that it intended to issue for public comment a draft regulatory guide, DG-1074, "Steam Generator Tube Integrity." The Commission approved this revised approach. Subsequently, in March 2000, the staff informed the Commission that, on the basis of progress with the NEI initiative, and assuming no new significant issues, it intended to cancel work on the generic letter. This also was approved by the Commission.

Thus, in the five years preceding the Indian Point 2 (IP2) tube failure on February 15, 2000, the staff's plans to develop an appropriate regulatory framework to assure SG tube integrity has devolved from rulemaking to generic letter to substantial reliance on an industry initiative to develop and commit to its own guidance. In light of the IP2 tube failure, as well as other recent SG tube integrity issues at other facilities, whether this trend remains appropriate is an overarching issue to which the Lessons-Learned Task Group gave careful consideration. "A" (attached)

4.2 NRC Regulations

The regulation of commercial nuclear power facilities is governed by, among other authorities, the regulations codified in 10 C.F.R. Part 50. 10 C.F.R § 50.34 requires nuclear reactors to be designed to meet the principal design criteria of Appendix A to Part 50 ("General Design Criteria for Nuclear Power Plants"). Among others, the General Design Criteria (GDC) applicable to PWR SGs are Criterion 1 (Quality standards and records), Criterion 14 (Reactor coolant pressure boundary), Criterion 15 (Reactor coolant system design), Criterion 30 (Quality of reactor coolant system boundary), Criterion 31 (Fracture prevention of reactor coolant pressure boundary), and Criterion 32 (Inspection of reactor coolant pressure boundary).

"A": Comment on P. 21 last paragraph in Section 4.1

This paragraph describes an important issue - that in the five years prior to the IP2 SG failure, the staff had started with a proposed SG rulemaking and "devolved" to "substantial reliance on an industry initiative." It goes on to say that this is an "overarching issue to which [the TG] gave careful consideration."

The remainder of the report [from my modest reading] fails to pick up on this issue. It needs to discuss this directly.

complete perspective of historical SG tube performance. The tube leaks listed in Table 5-1 were situations where operators were forced to shut down the plant due to the leak rates involved. Table 5-2 lists forced outages because of tube leaks at US PWRs for the 9-year period ending in 1999 (see Reference 6). Except for the 1993 Palo Verde tube failure from Table 5-1, the events in Table 5-2 were instances when SG tube leakage did not reach the level to force plant shut downs, but operators elected to shut down to address the leakage. Notable features from the table are the large number of leaks over the 9-year span (total of 28) and the marked decline in the annual rate of leaks during the second half of the period. Of the 28 total, only 4 occurred from 1995 through 1999.

The Task Group drew some general conclusions from the information in Table 5-2. First, it appears that from a long-term perspective, SG tube leaks that prompt forced outages occurred on a somewhat frequent basis of several per year over much of the last decade. Focusing on the most recent 5 years, however, shows that tube leaks may have become less frequent events, with about one occurring per year. Because the IP2 event is the fifth in the past five years, the event at IP2 is not out-of character in terms of the overall number of SG tube-related events at US PWRs.

The apparent improvement in the rate of SG tube leaks could partially be the result of SG replacements completed by licensees during the last decade. Table 5-3 shows the annual number of replaced SGs and the number of SG-related forced outages from 1990 to 1999. It appears that as the number of replaced SGs increased, especially after 1995, the number of tube failures noticeably decreased.

The other factors play a role only if the material is susceptible to cracking; it is

The Task Group noted that most tube leaks occurred in tubes made of mill-annealed Inconel Alloy 600, but this may only be an indication that this is the predominant tube material in earlier plants and has therefore seen the longest service history. Other factors in addition to tube material play a role in tube degradation, such as water chemistry and reactor coolant temperature, and ~~the~~ it is difficult to meaningfully correlate tube leaks to tube material without evaluating the other contributing factors.
meaningful to correlate tube leaks to material

SG Tube Failure Risk at IP2 Compared to Other PWRs

One way to understand the potential generic risk impact attributable to the tube failure at IP2 is to compare the potential for consequences of SG tube failure at IP2 with that of other plants. NUREG/CR-6365, "Steam Generator Tube Failures," (Reference 4) provides a comparison of the IPE results for PWRs in terms of core damage frequency attributed to internal events and gives the percent of the total core damage frequency attributed to spontaneous SG tube ruptures[7].

The values in the third column of Table 5-4 showing the contribution to CDF from spontaneous tube ruptures range from 0.02 percent of CDF to 22 percent. The values of the forth column showing the percent of containment bypass fraction from spontaneous tube ruptures varies over a wider range, from 2 percent to 99 percent.

The contribution of the spontaneous SGTR to total CDF is not the measure used to determine the risk significance of various SG degraded conditions. This is because tube failures present the potential for containment bypass, and therefore, the offsite risk profile is much more

[7] IPEs evaluated tube ruptures rather than the broader category of events that are termed tube failures.

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IP2 Event in Context of Previous SG Tube Failures

(pp4) The other factors play a role ~~and~~ only if the material is susceptible to cracking, So it is still meaningful to correlate tube leaks to material.

The staff assessment was a conservative evaluation of the impact of degraded SG tube conditions on tube failure risk, consistent with the SDP. Under the revised reactor oversight program, the initial significance determination, based on the staff's risk assessment, is not finalized until after the licensee has an opportunity to present amplifying information that could supplement the significance determination. An SDP panel was held in which the preliminary findings were ~~was~~ upheld, with a final determination pending further review steps in the reactor oversight process.

Licensee Risk Assessment

The licensee conducted an assessment of the risk impact of the event. The assessment concluded that the February 2000 tube failure was substantially less severe than the tube rupture event analyzed in the plant's IPE. The lower leak rate provided additional time for operator response and implementation of alternate mitigation strategies. Based on this, the licensee found that the potential for the event leading to core damage and large early release is reduced, with the analysis showing a reduction of more than an order of magnitude from the SGTR analyzed in the IPE. The revised licensee analysis yielded a core damage frequency of 4.8E-6/ry as compared to the 7.7E-5/yr from the IPE SGTR analysis.

The licensee argued that the tube failure event did not present a large early release potential because of the ample time available for evacuation of the local population. The licensee also used the low leak rate to justify a reduction in the human error probabilities that were used in the IPE analysis which is based on the higher leak rate associated with SGTR.

The licensee's analysis differed from the NRR assessment in the following respects.

1) The licensee used a modified human reliability analysis based on the fact that the leak rate from the tube failure was less than the assumed SGTR leak rate in the IPE;

2) The licensee did not estimate a modified tube failure probability based on the degraded state of SG tubes during the operating cycle associated with the failed tube; and

3) The licensee did not consider the risk contribution from SG tube rupture induced by main steam line break or severe accidents.

The staff assessed the licensee analysis and made the following comments:

1) The licensee calculated conditional core damage probability (CCDP) rather the change in risk in terms of a change in CDF or large early release frequency (LERF) attributable to the degraded condition of the SG tubes associated with the failed tube.

2) The licensee used a questionable basis for changing the operator response assumptions from the IPE analysis on the grounds that the leak rate was lower than that from a SGTR. The staff felt that the nature of the tube failure did not appear to preclude the chance that the leak rate could have increased during the event.

3) The licensee assessment did not assess the risk contribution from tube failures other than spontaneous failures (e.g., main steam line break or severe accidents).

Effect of Cycle 14 SG Conditions on Tube Failure Risk at IP2

Safety margins for SG tubes have traditionally been based on maintaining tube integrity under normal operating conditions and during postulated accidents such as LOCA, MSLB, and feedline break, by satisfying tube structural criteria (see Regulatory Guide 1.121). The risk estimate for spontaneous SGTR in the IP2 IPE assumes that tube conditions meet some minimal expectation for leakage and burst integrity compatible with the margins associated with the traditional structural criteria (e.g., 3 times normal operating differential pressure). The causes for previous tube failures are given in Table 5-1 and are, in most cases, considered to be random events that could not have been predicted. Such events are never "anticipated events" but have occurred at a frequency of about one every 3 years over the past 25 years. Also, except for those caused by loose parts wear, previous failures could not be easily grouped by commonalities in contributing factors, thus supporting the "random event" premise. The NRR risk assessment takes the position that the IP2 SG conditions before the event adversely affected tube failure risk. The staff provided an estimate of the probability of tube failure because of the degraded condition for Cycle 14 based on experience that large flaws will not always lead to tube rupture or significant failure. In some cases where a large flaw develops, substantial leakage will prompt operators to intercede before tube rupture. In summary, the staff estimated that the probability of tube failure was much larger than that generally accepted during previous operating history for IP2, and greater than the value used in the IPE.

The Task Group concluded that the staff's preliminary assessment was reasonable, in that it is based on knowledge that a tube failure occurred because of a degraded tube condition that existed during Cycle 14. The Task Group agrees with the staff's conclusion that the IP2 tube failure event resulted from degraded conditions. The degraded condition could have been avoided if reasonable, prudent engineering practices had been followed (see Sections 6.1 and 6.2 of this report and the NRC Special Inspection Report). Further, the type of failure and contributing factors, such as degradation type, failure location, and stress intensification from hour-glassing, point to a failure at IP2 that had occurred in a previous SG tube failure event (Surry 1976), were not random, and could have been avoided. This leads to the Task Group's judgment, in agreement with the staff's assessment, that conditions existed in the IP2 SGs before the tube failure that contributed to a higher level of tube failure risk for some period of time.

Con Ed's assessment, discussed previously in this section, did not assume any effect on tube failure probability from deficiencies in the SG tube integrity program because, in the view of the licensee, there were no such deficiencies. The NRC Special Inspection Report disagrees with the licensee's position.

As documented elsewhere in this report, The Task Group concluded that a number of programmatic deficiencies contributed to the tube conditions that led to the tube failure event. These tube conditions exposed IP2 to a significantly greater level of risk from SGTR than during periods of operation without such degradation. Therefore, the IP2 risk profile was altered during Cycle 14 operation. Provided that the contributing factors to the degraded conditions at IP2 are addressed as a result of the follow-up to the event, there should not be a long-term continuing impact on the IP2 SGTR risk profile. SG replacement addresses the degraded SG tube condition, because the degradation mechanisms from the old SGs are eliminated. However, the programmatic deficiencies that led to the problems at IP2, as related

"B" attached

"B": Comment on P. 36 last paragraph on page

This paragraph says that the task group "concluded that a number of programmatic deficiencies contributed to the tube conditions that led to the tube failure event." This section also concludes that the significance of the failure is not close to the performance measure in the strategic plan for important precursors. Presumably, this conclusion is based on the assumption that the programmatic deficiencies affecting the tube conditions did not affect other aspects of plant operations (e.g., reliability of high pressure injection, operator training in response to a SGTR). Does the TG have a basis to justify its (apparent) assumption on the lack of more systemic programmatic deficiencies? If not, I suggest that they qualify their conclusions as to risk significance.

the public is informed about details of the event, including its safety significance, in easy-to-understand terms.

5.3 Conclusions/Lessons-Learned

The Task Group noted that SG tube degradation during IP2 operating Cycle 14 resulted in an increased risk of SG tube failure. Further, the Task Group found that the factors contributing to the situation at IP2 could have generic implications on SG tube integrity practices at other PWRs, and therefore, on the overall risk of tube failure. The following lessons-learned developed by the Task Group are drawn from the IP2 experience and its generic implications.

1) The staff's risk assessment based on the SG tube conditions leading to the IP2 event resulted in a frequency of core damage with large early release on the order of 1E-4 per year. This conservative result is well within the accepted performance measure for maintaining reactor safety in the NRC Strategic Plan of 10E-3 per year for events identified as significant precursors to nuclear accidents.

2) The degraded condition during IP2 Cycle 14 significantly affected the plant's risk for that operating cycle. There were a number of contributing factors stemming from deficiencies in the licensee's SG tube integrity program that led to the degraded condition. Provided that the contributing factors are corrected through the NRC SDP process, the long-term risk at IP2 should be unaffected. "C" (attached)

3) The IP2 event did not significantly change our understanding of the risk of tube rupture events on an industry-wide basis. However, since SG tube rupture can be an important risk consideration at all PWRs, generic SG tube integrity program concerns discussed elsewhere in the report, if not addressed, could impact risk at other plants.

4) Communicating the safety significance of the IP2 experience is difficult. During the NRC significance determination process related to the IP2 tube failure, the staff found that the SG tube condition during Cycle 14 was risk significant due to the loss of safety margin. Notwithstanding the loss of safety margin, IP2 is designed to mitigate the effects of SG tube failure or tube rupture, IP2 shut down safely following the tube failure, and the IP2 event resulted in no adverse consequences to the public health and safety. This distinction may not be understood by all stakeholders. NRC will probably face this communications challenge again because SG tube failures and ruptures have occurred before and will likely occur again.

5.4 Recommendations

Based on the conclusions/lessons-learned discussed above, the Task Group developed the following recommendations:

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.

2) Over the long-term, NRC and industry 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.

<u>"C": Comment on P. 38</u>   <u>conclusion 2; last sentence</u>

It's not clear how the NRC's SDP process will correct licensee problems. Does the TG mean the licensee's CAP (not NRC's SDP)?

6.0 STEAM GENERATOR TUBE INTEGRITY PROGRAMS

6.1 Con Ed's SG Tube Examination Methods/Practices

6.1.1 Background

The licensee's management of their steam generators (SGs) is directly dependent on the quality of their examination of the SG tubes and associated internals. In the area of SG tube examination methods and practices, there has been improvement and change in the industry since the last SG tube examination at Indian Point 2 (IP2) prior to the SG tube failure (1997). The changes in SG tube examination methods and practices are discussed in this section, and recommendations are made for both industry practices and NRC process. Industry recommendations for changes in SG tube examination methods and techniques through the Electric Power Research Institute (EPRI) guidelines associated with NEI 97-06 (Reference 1), are anticipated as a result of heightened awareness of SG examination issues following this tube failure.

The EPRI Steam Generator Examination Guidelines (Reference 2) have been widely accepted by the commercial nuclear industry for many years and were cited by Con Ed in the proposed 1997 SG tube examination program, dated February 7, 1997 (Reference 3). During the early 1980s, the Electric Power Research Institute and the Steam Generator Owners Group informally issued nondestructive evaluation (NDE) guidelines to provide reliable NDE strategies for the damage mechanisms known at that time. The guidelines were originally issued in 1981, and subsequently revised in 1984, 1988, 1992, 1996, and 1997. Another revision, Revision 6, is planned for the near future. The guidelines were intended to standardize the NDE programs and provide guidance on developing robust SG NDE programs.

When reviewing the SG examination methods and practices from the Con Ed SG examinations, the Task Group considered the scope of the IP2 SG examinations performed in 1997 and 2000 and the use of other available examination techniques.

6.1.2 Observations

The Scope of the Indian Point 2 SG Examinations Performed in 1997 and 2000

1997 SG Examination

For each scheduled SG examination, the plant technical specification (TSs) specifies the minimum number of SGs and the minimum number of tubes that need to be sampled. The EPRI Steam Generator Examination Guidelines (Reference 2), which IP2 referenced in their 1997 SG examination plan, stipulate that 100% of the tubing and 100% of each type of repair shall be examined within a rolling 60 effective-full-power-month time frame. However, based on prior degradation found in the SGs, industry experience with degradation from similar SGs, or degradation found in the current examination, the minimum sample may need to be expanded. The minimum sample of tubes is often expanded on the basis of critical areas, which are defined by the type of degradation, the cause of the degradation, and the boundary of the degradation. Critical areas are determined on the basis of examination results, engineering evaluation, and related experience. The EPRI Steam Generator Examination Guidelines provide guidance in determining the critical areas for each nuclear steam supply system vendor (i.e., Westinghouse, Combustion Engineering, and Babcock and Wilcox).

KH2

of-record (the primary probe used to determine whether a tube would need repair) and a mid-range frequency Plus Point probe that typically operated at multiple frequencies between 50 and 400 Hz was used for characterizing indications, as needed. Con Ed's proposed examination plan had stated that the Cecco-5/bobbin probe had been qualified to the EPRI PWR Steam Generator Examination Guidelines and its Appendix H (Reference 2). Section 7.3 in the guidelines, Qualified Techniques, states that probes and degradation methods for which industry peer review has been satisfied could be used for the qualification of the examination technique.

Section 7.3 of Appendix H further states that new probes and techniques should have been subjected to the performance measures. Performance measures should be verified for the application of new techniques and the intent of Appendix H demonstrated through a site specific program. Section 4.4.2 discusses the possible distortion that can occur to bobbin coil signals as a result of their proximity to tube diameter changes due to denting, roll expansions, etc., or of the presence of secondary side deposits or support members. Supplement H2, Qualification Requirements for Examination of Steam Generator Tubing requires that the examination techniques and equipment used to detect and size flaws be qualified by performance demonstration.

Based on Con Ed's interpretation of the EPRI SG examination guidance in 1997, Con Ed depended on a generic qualification for the probes used and did not site qualify the examination methods. The Task Group observed that the SE made no reference to issues with deposits, signal to noise ratio, probe qualification, or data quality, nor did it mention how hour-glassing would be evaluated, because these issues were not discussed in the examination plan that was submitted by Con Ed.

A full discussion of the expansion of the scope of the 1997 SG examination is contained in the 1997 SG examination report submitted by Con Ed to the NRC, dated July 29, 1997 (Reference 7). The original examination program was expanded to include full length examination of <u>all</u> SG tubes. The examination was expanded because of the indications found by the Cecco-5 probe at the hot leg and cold leg upper support plate locations. During the 1997 examination, Con Ed found the following degradation: pitting above the top of the tubesheet; outside diameter stress corrosion cracking (ODSCC) above the top of the tubesheet (sludge pile); ODSCC in the tubesheet crevice; roll transition PWSCC; PWSCC at dented tube support plate intersections; ODSCC at dented tube support plate intersections; and one PWSCC indication at a Row 2 U-bend.

Of the types of degradation observed during the 1997 examination, two forms of degradation were observed for the first time: ODSCC indications above the top of the tubesheet (in the sludge pile) and a single PWSCC indication at the apex of a Row 2 U-bend (at Row 2, Column 67). The July 29, 1997 examination report from Con Ed presented information about the locations of the tubes that were plugged, and provided codes that represented the reasons that the tube needed to be repaired by plugging the tube. Other than providing the location and reason for the repair, the examination report did not discuss the two new forms of degradation, or note that this was the first time that these types of degradation had been observed at IP2. The Con Ed response to a request for additional information (RAI) from the NRC, dated May 12, 1999 (Reference 8), was the first time that Con Ed noted that these two forms of degradation had been observed for the first time during the 1997 examination. This RAI (Reference 9), was sent to Con Ed by the NRC to gain additional information to evaluate

Con Ed's December 7, 1998 license amendment request seeking a one-time extension of Con Ed's SG examination frequency (Reference 10).

Weren't these instances of plugging because probe would not go through the U-Bend?

The July 29, 1997 SG examination report listed SG tubes that contained indications that were evaluated at 40 percent or larger of the wall thickness, and were repaired by plugging according to Con Ed's TSs. Other tubes were plugged for the types of degradation listed previously in this section and some others were plugged based upon an IP2 tube support plate study. An additional twenty tubes were plugged, not due to finding indications by eddy current, but due to restrictions in the tubes that prevented the 610 mil diameter probe from moving completely through the tube. There were seventeen tubes administratively plugged because the restrictions permitted passage of a 610 or 640 mil diameter bobbin probe, but did not permit characterization of the restriction location by a Plus Point probe.

Finding these restrictions was significant, because the 1997 SG examination was the first time Con Ed had observed the restrictions to the 610 mil diameter probe moving through the tube. In retrospect, finding these tube restrictions could have warned Con Ed about increased levels of denting, but no discussion of the significance of the restrictions was presented in the 1997 SG examination report. There was also no discussion of the 610 mil probe restrictions in the May 12, 1999 RAI response from Con Ed or the December 7, 1998 license amendment request for the SG examination interval extension. The May 12, 1999 RAI response did discuss the restriction of a 640 mil diameter probe through a dented tube support plate intersection, but the discussion was limited to the potential for ODSCC at the intersection.

Along with restrictions to probe movement noted in the SG examination report, Con Ed could also gain additional information about whether degradation processes were increasing by evaluating the flow slots for hour-glassing. Con Ed was also required to evaluate the flow slots for significant hour-glassing according to their TSs, but the TSs don't identify whether this evaluation should be a quantitative measure or qualitative evaluation. Con Ed provided a discussion about the qualitative hour-glassing examination performed and the results obtained in the text of the 1997 report.

Con Ed used visual techniques for assessing significant hour-glassing, comparing videos taken during the 1997 exam with photographs from previous outages. In 1995, photographs were taken of the lower support flow slots only in Steam Generators 23 and 24, and video of the uppermost support plate only in Steam Generator 22. The examinations for hour-glassing were made using fiber optics by either 35mm photography or video. According to Con Ed, this examination has been performed fourteen times over approximately 25 years.

Con Ed concluded that one flow slot was found to be closed, and was deemed to be acceptable because there was no change in the general flow slot cracking that had been previously observed. Con Ed's report discusses how they were able to access the lower support plate flow slots by lower handholes in all four SGs, but was limited to examining the uppermost support plates only in Steam Generators 22 and 23 because they were the only generators with "hillside ports", located just above the top tube support plate, in the SG shells. Hillside ports were installed in Steam Generators 21 and 24 during the outage in 2000, to improve Con Ed's ability to examine the flow slots for hour-glassing.

In Con Ed's June 16, 2000 response (Reference 11), to an NRC RAI dated April 28, 2000 (Reference 12), on Con Ed's root cause analysis, the licensee's interpretation of "significant" hour-glassing is discussed. Con Ed's interpretation was readily visible hour-glassing, such as

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The May 29, 1997, NRC SE approved the following Con Ed SG examination, as a minimum:

re
(pp2) weren't the~~s~~e instances of plugging because probe ~~the~~ would not go through the U-bend?

and the probe size would have had to been altered to enable passage through the tight radius U-bends. The Task Group was also told of additional barriers to use of UT in the U-bends due to difficulties in directing and detecting the sound waves in curved surfaces.

The Task Group learned of other potential hurdles to substituting UT for ECT in SGs from Westinghouse. Westinghouse suggested that there were relatively few Level III UT analysts and there is not a test for UT examiners that is equivalent to the Qualified Data Analyst test for the eddy current analysts. However, the technique can be qualified through Appendix J of the EPRI SG examination guidelines. In addition, there is currently not enough statistically significant data available for performance demonstrations. As more utilities use UT, more data will be generated to fill this need.

Based on the information submitted to the NRC, the Task Group learned that Con Ed also tried ultrasonic testing (UT) in the freespan sludge pile region to see if they could enhance the SG examinations in that region, and concluded that UT confirmed the eddy current results.

6.1.3 Conclusions/Lessons-Learned

Based on the observations discussed above, the Task Group reached the following conclusions:

even though 100% of U bends were inspected, the data was not fully analyzed. Even with the high noise level a full analysis could've identified additional flaws

1) The limitations of Con Ed's 1997 SG examination were due to limitations in data quality, not due to inadequate sample scope (i.e., 100 percent of the tubes were inspected with the Cecco-5 probe). Similar data quality issues persisted into the 2000 SG examination, leading to the use of a high frequency probe to improve data quality in the U-bends.

2) Explicit data quality standards were not included in the EPRI SG examination guidelines used in 1997.

3) Conditions in Con Ed's SGs deviated markedly from the assumed condition in EPRI's generic technique qualification, which indicates that a site-specific qualification strategy should be used. Qualification standards should, to the extent possible, represent the actual flaw conditions expected at a plant.

4) A more quantitative criterion for hour-glassing, rather than just relying on visual observations, could have assisted Con Ed in detecting sufficient movement in Row 2 tubes that would result in stress in the tubes above the threshold necessary for PWSCC.

6.1.4 Recommendations

Based on the conclusions/lessons-learned discussed above, the Task Group developed the following recommendations:

1) The EPRI guidelines should provide data quality measures. 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.

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6.1.3 Conclusions/Lessons-Learned

(#1) even though 100% of U-bends were inspected, the data was not <u>fully</u> analyzed. Even with the high noise level, A FULL analysis could have identified additional flaws.

6.2 Con Ed's Condition Monitoring/Operational Assessment

6.2.1 Background

One of the means for licensees to communicate information on the present condition of their steam generators (condition monitoring) and predicted condition of the steam generators (operational assessment) during the next cycle is by providing reports that describe the condition monitoring assessment and the operational assessment. Condition monitoring and operational assessment reports have evolved to become a vital part of the steam generator (SG) integrity assessment process, for both licensees and the NRC. However, at the time of the last inspection at Indian Point 2 (IP2) before the tube failure (1997), there was no regulatory requirement nor licensee commitment to perform or submit the results to the NRC from a condition monitoring or operational assessment. Instead, the limited information that was provided in the licensee's inspection report summaries was based on reporting requirements in their technical specifications (TSs). As part of the licensee commitment to the NEI 97-06 Steam Generator Regulatory Framework (Reference 1), the licensees will be expected to adopt a generic set of SG TSs that will require them to perform these assessments.

Although the conceptual framework for condition monitoring and operational assessments was established in draft Regulatory Guide 1.121, issued for comment in August 1976 (Reference 2), the terms "condition monitoring" and "operational assessment" were developed much later during work on the SG rule. Some discussion of the assessments can be found in draft Regulatory Guide DG-1074, issued for comment in December 1998 (Reference 3). An Electric Power Research Institute (EPRI) guideline developed for the NEI 97-06 SG framework, "Steam Generator Integrity Assessment Guidelines: Revision 0" (Reference 4), provides industry standards for performing these assessments.

The condition monitoring involves monitoring and assessing the "as found" condition of selected tubes relative to tube integrity performance criteria. Structural integrity, accident induced leakage, and operational leakage are evaluated relative to performance criteria. The structural integrity criterion specifies that team generator tubing shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cooldown and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a margin of 3.0 against burst under normal steady state full power operation and a margin of 1.4 against burst under the limiting design basis accident concurrent with a safe shutdown earthquake.

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The operational assessment demonstrates that the tube integrity performance criteria will be satisfied throughout the next operating cycle and scheduled tube inspection. The purpose of the assessment is to show that all structurally significant degradation has been detected and that which is undetected will not grow to be structurally significant during the next operating cycle. In effect, the operational assessment determines the allowable operating time for the upcoming cycle. The success of the operational assessment is dependent on things such as the probability of detection (POD) of actual flaws found by the eddy current testing, the growth rate determinations of the flaws, and the estimated sizing of the flaws. If the integrity performance criteria will not be met, the licensee must decide whether additional tests, repairs, inspections, or other actions are necessary. Other actions may include limiting the run time or considering other operational parameters. The assessment guidelines state that all active degradation mechanisms must be considered appropriately in the analysis.

Consistent with the Task Group's Charter, the Task Group reviewed the documents containing the condition monitoring and operational assessments made by Con Ed to evaluate the potential for improvement in this area. This review was performed for both the 1997 and 2000 inspections, and the documentation from the two inspections are discussed separately below. The areas that were considered are as follows:

1) Evaluation of new types of degradation;

2) Basis and uncertainties for detection of degradation;

3) Basis and uncertainties for degradation growth rates;

4) Use of in-situ pressure tests; and

5) Assessment methodology and decision criteria.

6.2.2 Observations

1997 Inspection

<u>Evaluation of New Types of Degradation</u>

The Task Group reviewed the following documents from Con Ed:

1) July 29, 1997 Steam Generator Inservice Examination 1997 Refueling Outage Report (Reference 5);

2) December 7, 1998 Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency (Reference 6); and

3) May 12, 1999 Response to Request for Additional Information - Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency (Reference 7).

This review was to evaluate and compare the condition monitoring and operational assessments performed by Con Ed and to assess how this information was documented in Con Ed's submittals to the NRC staff. A discussion of the documents is presented below in chronological order. The condition monitoring assessment was prepared for Con Ed by Westinghouse. The Task Group learned from Con Ed that the Condition Monitoring/Operational Assessment was performed in 1997 to gain practice in performing these assessments. As there was not a requirement to submit these assessments, it was kept internally by Con Ed. Also, in 1997, the guidance for these types of assessments wasn't provided in the EPRI guidance documents. This guidance was subsequently issued in December 1999 as the EPRI Steam Generator Integrity Assessment Guidelines (Reference 4).

In 1997 W knew how to conduct a decent assessment

The 1997 Con Ed SG tube examination report discussed the actual (as compared to planned) scope and examination techniques used during the 1997 refueling outage. The report was divided into a section containing text and a section containing tables. The following information is given in tables in the report:

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Evaluation of New Types of Degradation

(pp 2) In 1997 WESTINGHOUSE ~~we~~ knew how to conduct a decent operational assessment.

1) tables of the tubes that were plugged, with the reasons for plugging included in the comment section of the table;

2) the tubes, test locations, depth of flaw, length orientation and maximum pressure for the *in-situ* burst tests;

3) results of a blind comparison study with the Cecco-5 probe and the Plus Point probe; and

4) the types and quantities of plugs in the tubes.

The text of the inspection report discussed the results of the inspection in broad terms, discussing plugging based on the presence of sludge pile pit indications, AVB wear indications, tube roll transition indications, and passage restrictions for probes in the tubes. Tubes were chosen in the tube sheet crevice area, tube roll transition region, and above the top of the tubesheet (freespan) for in-situ burst tests based on exceeding EPRI and Westinghouse screening criteria for testing. No change in the hour-glassing of the flow slots was reported.

The Task Group review of the inspection report showed that there was no discussion in the text of the indication found in the apex of the U-bend for the tube in Row 2 and Column 67, even though it was the first time Con Ed had found PWSCC in the U-bend region of the tubes. The Task Group also noted that the tube with the U-bend flaw (which was subsequently plugged) was not chosen for in-situ burst testing.

Even though there was no regulatory requirement to submit a formal condition monitoring or operational assessment, the licensee's inspection report notes that a condition monitoring report was performed for the just completed Cycle 13, but there was no mention made of completing an operational assessment. The inspection report did conclude, however, that the condition monitoring assessment performed for Cycle 13 had established the end-of-cycle structural and leakage integrity of the SG tubing. The inspection report further concluded that since the time interval for Cycle 14 was essentially equal to Cycle 13, Cycle 14 would be bounded by the acceptable end-of-Cycle 13 conditions, as demonstrated by in-situ testing and the eddy current examination.

Con Ed's December 7, 1998, Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency (Reference 6), was based on a technical argument that a comprehensive inspection had been performed in 1997. The request further stated that the SGs were determined to be acceptable for continued service at full power based on the results of inspections, assessments, and associated tube repairs. The request discussed a review of past SG eddy current data from 1993, 1995, and 1997 and concluded that the review indicated no appreciable growth trend. Again, there was no discussion of the indication found in 1997 in the apex of the U-bend for a tube in Row 2, Column 67, and how that was assessed.

check the dates

Con Ed sent a May 12, 1999 response (Reference 7), to a April 19, 1999 request for additional information (RAI) for their proposed amendment request dated December 7, 1998. To better understand the condition of the IP2 SG tubes, the staff had requested additional information on the operational assessment methodology for each degradation mechanism, including an explanation of predictive methodology, flaw growth rates, and NDE uncertainty. The staff had

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(pp5) Check the dates ... May 12, 1999 & Dec. 7, 1998 also requested additional information on Con Ed's condition monitoring assessment, degradation mechanisms evaluated using the Westinghouse screening criteria, and an assessment of the water chemistry performance during the extended period of wet lay-up and during the current cycle of operation.

It was in this response to the RAI (Reference 7), that Con Ed first discussed the indication found in the apex of the U-bend for the tube in Row 2 and Column 67, and the growth rates that could be predicted for PWSCC. This RAI response contained the first discussion and results of the operational assessment. The Task Group noted that there was no information provided in this response on the data quality in the U-bends (e.g., eddy current noise levels in the U-bends). Con Ed's response discussed the following degradation mechanisms: pitting above the top of the tubesheet, ODSCC above the top of the tubesheet (sludge pile), ODSCC in the tubesheet crevice, roll transition PWSCC, PWSCC at dented tube support plate intersections, ODSCC at dented tube support plate intersections, and PWSCC at a Row 2 U-bend. Two of the degradation mechanisms had been detected for the first time in the 1997 examination:

1) ODSCC in the sludge pile region above the top of the tube sheet was detected for the first time in 1997, with a possible precursor signal from the 1995 eddy current data.

2) PWSCC was found in a Row 2 U-bend for the first time during the 1997 outage. The response noted that the U-bend tubes that were the most susceptible to PWSCC, row 1 tubes, were taken out of service before the plant was initially put into operation by preventively plugging the tubes.

Basis and Uncertainties for Detection of Degradation

As noted above, the Task Group found that Con Ed's 1997 inspection report (Reference 5), did not provide a discussion for the basis and uncertainties for detection of various types of degradation. In summary, the inspection report was used to discuss the actual inspection scope during the outage, provide a list of tubes repaired, report on hour-glassing as required by their TSs, report on foreign object inspection, present in-situ burst test results, discuss plug replacement, provide results from a blind study comparing probes, and list the amount of sludge removed. "D" (attached)

Similarly, the December 7, 1998 Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency (Reference 6), did not discuss the basis and uncertainties for detection in much more detail than the inspection report. When compared with the inspection report, the proposed amendment request repeated much of the information in the inspection report with very little additional discussion about the detection of degradation. As the result of a direct question about the operational assessment methodology and the related NDE uncertainty, Con Ed's May 12, 1999 response (Reference 7), to an April 19, 1999 RAI for their proposed amendment request provided the most complete discussion of the active degradation and how it was detected.

The three reports show a heavy reliance on the Cecco-5 probe for detection and characterization of indications, and it was identified in the examination plan submitted to the NRC as the probe of record. Con Ed preferred this probe due to the faster data acquisition time when compared to rotating pancake coil technology such as Plus Point. The NRC staff had expressed concerns about the capability of the Cecco probes compared to Plus Point

"D": Comment on P. 57-58 (general discussion in section entitled "basis and uncertainties for detection of degradation")

This section makes a number of points that the staff "requested" things from the licensee, "recommended" more indications, etc. To the outside reader, this would suggest that the staff either has no authority to make the licensee do anything, or has the authority and doesn't use it. Is this what the TG wants to convey? [by the way, this impression of staff authority (or lack thereof) shows up in a number of other places in the report.]

probes in an April 24, 1997 meeting between Con Ed and NRC staff to discuss the upcoming SG examinations. The Task Group learned that the staff requested that Con Ed perform additional blind tests to assure the performance of the Cecco probes. In a May 6, 1997 letter from Con Ed to the NRC staff (Reference 8), Con Ed stated that the Plus-Point results would be used as the basis for determining that the required minimum threshold for detection would be met by the Cecco-5 probe during the blind study (i.e., 80% probability of detection at a 90% confidence level).

Con Ed reported more indications with the Cecco-5 probe than were detected by the Plus Point probe in a blind study of the two probes, so they were confident in their ability to detect significant indications with this probe. The Task Group learned from the NRC staff that the discrepancy in the performance of the Cecco-5 and Plus Point probes had been discussed with Con Ed during the 1997 SG examinations, and the staff questioned Con Ed about the calibration of the Plus Point probe. In the May 12, 1999 RAI response, Con Ed discussed the lack of Plus Point confirmation of some of the Cecco-5 calls that indicated PWSCC at dented tube support plate intersections, which Con Ed attributed to some mechanism such as interference from outer tube deposits. During the rest of the tube examination in 1997, the Plus Point probe was used in situations where the Cecco-5 probe was limited in travel due to tube restrictions.

Con Ed's blind study was not performed for tubes in all regions of the SG, however. The study was limited to tube support plate intersections, tubesheet crevice locations, and the top of the tubesheet. The Task Group learned that the NRC staff recommended during the SG examinations that more indications be included in the test sample in order to support a valid test.

Based on the concerns expressed by the licensee and the NRR staff on the use of the Cecco probe, the Task Group believes that it would be prudent to develop a blind study protocol for the use of any new probe that includes all areas of the SG that would be challenging to inspect. Since different probes have different capabilities, it may not be possible for one probe to fulfill all the inspection needs for areas that would present inspection challenges, especially in the U-bend regions. Issues with the detection capabilities of the Cecco-5 probe were also raised during the 2000 inspection, as well as NRC staff concerns about the calibration of the Plus Point probe in 1997.

<u>Basis and Uncertainties for Degradation Growth Rates</u>

The Task Group review of Con Ed's 1997 inspection report (Reference 5), revealed that growth rate data was not provided. The December 7, 1998 Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency provided conclusions on growth rates during a period that the plant had been shut down for an extended period of time. During this period, the plant was kept in a wet lay-up condition, which refers to the controlled secondary water chemistry condition that is expected to inhibit corrosion processes. Con Ed discussed the wet lay-up period to support the contention that no appreciable degradation had occurred during that time. The amendment request concluded that a review of past SG eddy current wear data indicated no appreciable growth trend.

The amendment request noted that of the 21 indications identified in 1993 and 1995, seven indications showed no change, four disappeared, four decreased in depth, and six increased in depth. The Task Group noted that indication size measurements are always limited by measurement accuracy, which can account for the supposed "disappearance" of indications. The discussion indicated that this nominal increase or decrease was 3 - 4%, which was stated as within the accuracy of the eddy current measurements. The amendment request also concluded that since the SGs were maintained in cold shutdown temperature conditions, the environment for corrosion was reduced to an inconsequential level. No appreciable SG tube wear or degradation was expected as a result of the inspection interval extension. The amendment request did not address growth rates outside of the wet lay-up period.

The May 12, 1999, RAI response (Reference 7), provided limited information on the degradation growth rates resulting from the period of plant operation before the last inspection (1997 inspection). As requested in the RAI, the licensee discussed growth rates for each type of degradation. Growth rate information was only provided for the following three degradation mechanisms:

1) Pitting Above the Top of the Tubesheet: The response stated that while specific growth rate analyses of pit indications were not performed for the last cycle, historical information suggests that the average growth characteristics of pits are less than 10% through-wall per cycle.

2) ODSCC Above the Top of the Tubesheet (Sludge Pile): The response stated that average depth detection thresholds for axial ODSCC are in the range of 20% to 30% through-wall with a probability of detection of about 0.2 to 0.5 for both the Cecco-5 and Plus Point. Therefore, assuming the Plus Point depth profile to be accurate, the growth in average depth for Cycle 13 is bounded by about 18% to 28% for sludge pile ODSCC indications. The response also notes that recent Plus Point depth sizing evaluations performed by Westinghouse for axial ODSCC indicate that flaw average depth standard deviation measurement error is about 10% through-wall. A 20% measurement uncertainty allowance is provided in the in-situ screening parameters.

3) PWSCC at Row 2 U-bend: The response stated that this was the first time that a Row 2 U-bend PWSCC indication was found. The response concluded that as 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.

The Task Group found that the independent review by the NRC's Office of Research (RES) of this amendment request, dated March 16, 2000 (Reference x9) discussed the adequacy of the information provided by Con Ed in the RAI response. The RES review found Con Ed's response to the staff's question about the results of Con Ed's operational assessment for each degradation mechanism weak and incomplete. The review pointed out that Con Ed did not apply growth rates or NDE uncertainty in their operational assessment for stress corrosion cracking at the row 2 U-bend. The RES review disagreed with the contention by Con Ed that growth rates associated with the U-bend flaw would be minimal because this was the first detected U-bend indication after approximately 23 years of operation. RES stated that this contention was inconsistent with the evolution of stress corrosion cracking and with other industry experience. In discussions with the Task Group, Con Ed considered that, in retrospect, that they had provided a rather perfunctory remark about the growth rates of flaws in the U-bends, but felt that they had a technical basis for this remark based on SG lifetime prediction studies performed by Dominion Engineering. NRR staff agreed that the contention flaws. According to a June 15, 2000 Con Ed response to an NRC RAI (Reference 10), the indication was sized at 0.4 inches in length and approximately 50% in depth. Therefore, an in-situ pressure test was not performed for the tube in Row 2 Column 67.

The NRC staff sent a question in a April 28, 2000 RAI to Con Ed (Reference 11), about Con Ed's decision not to select the tube with the PWSCC flaw at the Row 2 U-bend for in-situ testing. The NRC staff noted that the screening criteria for in-situ testing was intended to account for measurement error, and asked if the assumed measurement error was applicable to the level of noise experienced in that tube. The NRC staff considered that, similar to Con Ed's treatment of the other new type of degradation noted in the 1997 inspection, ODSCC in the sludge pile, Con Ed should have considered this indication for in-situ testing based on the NDE uncertainty arising from the noise in the signal, sizing uncertainties, and the tube burst potential for flaws in the apex of the U-bend.

The Task Group observed that Con Ed had an opportunity to obtain additional information about the integrity of tube R2C67 by performing an in-situ pressure test during the 1997 SG examinations. This would have been consistent with Con Ed's selection of a tube for in-situ testing that had ODSCC at the top of the tubesheet, another form of degradation that had also been observed for the first time during the 1997 SG tube examinations. As noted above, none of the tubes that experienced degradation new to IP2 were required to be selected because of the screening criteria for testing. Nevertheless, Con Ed selected a tube representative of the ODSCC at the top of the tubesheet to conservatively assess this new type of degradation, but did not choose tube R2C67 for the same reason. It is not clear that in-situ pressure testing tube R2C67 would have resulted in additional information on the integrity of the tube, but the Task Group notes that Con Ed had the opportunity to gain additional information on a new degradation finding in their plant.

Assessment Methodology and Decision Criteria

Based on the above discussion, the assessment methodology and decision criteria presented in the response to the RAI was often limited, and as discussed in Section 7.0 of this report, in some cases not consistent with other industry experience. As discussed in Section 8.1 of this report, the NRR staff based its technical conclusions on the basis that the results from the 1997 inspections established appropriate safety margins, not on some of the weak technical arguments presented in the May 12, 1999 response to the RAI.

what basis did NRR have for making this finding with regard to IGSCC at the U-Bend? This degradation was listed in the inspection report

2000 Inspection

Evaluation of New Types of Degradation

For the 2000 inspection, three reports were submitted. The reports consisted of a specific report concerning PWSCC in the U-bend, a report discussing the remaining degradation mechanisms, and a report that compares the corrosion performance of the IP2 SGs to industry experience with Model 44 and Model 51 SGs. Unlike the 1997 inspection, Con Ed and Westinghouse were able to use the EPRI Steam Generator Integrity Assessment Guidelines, Revision 0 , issued in December 1999 (Reference 4), to prepare the condition monitoring and operational assessments. Once again, the condition monitoring and operational assessments were performed by the same contractor that performed the inspections, Westinghouse, who provided the same services to Con Ed for the SG outage in 1997.

W had the capability to do adequate op. assessments in 97 as well as 2000. W pioneered the process/tech. for conducting op. assessments long before the EPRI guidelines — an example of this is the V freed [illegible]

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<u>Assessment Methodology and Decision Criteria</u>

What basis did NRR have for making this finding with respect to IGSCC at the U-bend? This degradation was listed in the inspection report.

<u>Evaluation of New Types of Degradation</u>

Westinghouse had the capability to do adequate operational assessments in 97 as well as 2000. Westinghouse pioneered the process/techniques for conducting OP assessments long before the EPRI guidelines - an example of this is in the voltage-based criterion developed by Westinghouse.

In comparison to what was submitted in 1997, Con Ed submitted a comprehensive collection of information about the degradation mechanisms, including sizing information and voltages of indications detected. Rather than just providing conclusions about the tubes that needed repair, as given in Con Ed's 1997 SG examination report, Con Ed provided the results of the the different types of analyses, along with the inputs for the 2000 examination.

Basis and Uncertainties for Detection of Degradation

Con Ed's original SG examination plans after the plant shut down due to the tube failure proposed using the same inspection methodology as with the 1997 SG outage, using the combined Cecco-5/bobbin probe and the mid-frequency Plus Point probe. Based on NRC staff recommendations and concerns about noise levels in the data, the inspection plans expanded to use a 800 kHz high frequency probe. The staff listed their recommendations in the March 24, 2000 RAI regarding Con Ed's proposed SG tube examination program (Reference 12). The staff recommended: (1) using a high frequency Plus Point probe, (2) using the midrange Plus Point run at 500 kHz, (3) trying a 400/100 kHz mix, and/or (4) analyze using the 400 kHz channel. The staff also suggested improving the analyst guidelines (e.g., clear setup guidelines, clear and objective noise criteria) and developing a formal training program to incorporate "lessons-learned."

Even with the improvement in the inspection data from using the higher frequency probe, the NRC staff had concerns regarding the NDE uncertainty arising from Con Ed's inspections. The staff expressed many of these concerns in a July 20, 2000 letter to Con Ed conveying an RAI regarding Con Ed's SG operational assessment (Reference 13). The concerns were divided into three areas: assumed probability (threshold) of detection (POD), use of eddy current sizing data, and assumed material properties.

The NRC staff concerns arose primarily for the indications found in the sludge pile region and U-bends, and were based on Con Ed's reliance on POD and sizing validation in areas that didn't necessarily include the areas where the uncertainty would be applied. The largest uncertainty was expected from the results of the U-bend inspections, but the validation technique had been performed in the sludge pile region of the SG. Evaluating the uncertainties properly was especially important, because uncertainties of 5 to 10% could lead to a large difference in the burst pressures that would be calculated from the data. This increased the level of staff concerns in how structural integrity in the U-bends could be assured for the operating cycle. In the July 20, 2000 letter, NRC staff told Con Ed that, in light of the lack of a qualified eddy current method for sizing PWSCC in U-bends, it is important to account for the uncertainties associated with sizing stress corrosion cracks from eddy current data.

In addition, there were concerns about the probability of detection (POD) of flaws in the noisy regions, the sludge pile region and the U-bends. Since the operational assessment is based on "growing" flaws that were not detected during the current inspection, to see if they would challenge leakage or structural integrity, this assessment is dependent on a reliable POD. NRC Information Notice 97-26 "Degradation in Small-Radius U-bend Regions of Steam Generator Tubes," issued May 19, 1997 (Reference 14), notes that due to the relatively high detection thresholds in the U-bends, the depth of cracks may be in excess of 50% through-wall when first detected. The IN notes that the industry standard bobbin coil has proven unreliable for detecting U-bend cracks and , in addition, is not qualified for this application under the EPRI technique protocol. The notice warned the industry that there continued to be an absence of pulled tube information to confirm that the detection threshold for these cracks is better than 40 or 50-percent through-wall. This IN suggests that licensees ensure that inspection sensitivity to U-bend cracks is sufficient to allow flaws to be removed from service before tube integrity is impaired. While it is certainly not conservative to assume that the flaw size from the last inspection is at the detection threshold, overly large growth rates can be predicted by assuming that the flaw grew from a zero depth because it could not be detected. [illegible] even if [illegible] detected because it wasn't there or it was well below the detection threshold

The Task Group observed that an important aspect of accurate condition monitoring and operational assessments is how uncertainties, threshold of detection, and probability of detection are considered. Therefore, the Task Group concludes that licensees must take care to consider the effects of unqualified sizing techniques on operational assessments. To enhance the effectiveness of the tube examination, the probability of detection, uncertainties, and sizing should be as closely representative of the actual examination conditions as possible. ??

The Task Group learned that RES has an ongoing research effort at Argonne National Laboratory to evaluate and quantify the capabilities of currently practiced and advanced eddy current and other NDE methods, probes, and signal analysis techniques. In this research effort, eddy current examination teams from industry participated in a round-robin examination of tubes with known flaws in a SG mock-up. The results of the round-robin examination will be used to provide estimates of probability of detection and sizing accuracy to NRR for use in evaluating licensee SG examination programs. The Task Group anticipates that information from this round-robin examination will provide the NRC and industry with realistic values of NDE reliability.

Basis and Uncertainties for Degradation Growth Rates

change in voltage cannot be used to determine crack growth rate if [illegible] does not relate [illegible] to crack size

The growth rates were based on looking back at the 1997 data for precursors to the indications found in 2000, and evaluating the change in voltages. This task was complicated by the noisy data and the fact that the high frequency probe was not used in 1997 (had to compare the 1997 data at 400 kHz, which was noisier data than the 800 kHz high frequency data). Because none of the techniques used are qualified for sizing, reasonable estimates of error must be assigned to bound the expected growth rates calculated from the flaw sizes. As noted in the above section, detection thresholds could be as high as 40 – 50%, which reduces the amount of flaw data available to predict growth rates.

Use of In-Situ Pressure Tests

The in-situ pressure tests provide another measure of leakage and structural integrity of the SG tubes. Although none of the tubes burst at pressures less than three times the normal operating pressure, an ODSCC indication in the sludge pile region and some PWSCC indications in the U-bends exhibited leakage. The July 20, 2000 letter to Con Ed from the NRC staff discussed some concerns about correlating the sizing of the flaws with the in-situ test results from a tube that leaked during the testing. Tube R2C74 was sized during the spring 2000 inspections as being less than 40% in maximum depth, and the tube would have not been expected to leak during in-situ testing. The staff observed that the tube did leak during pressure testing, which indicated to the staff that some portion of the crack was much deeper than indicated by the eddy current examination.

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(pp1) it is quite possible that it wasn't detected because it wasn't there or it was well below the detection threshold.

Basis and Uncertainties for Degradation Growth Rates

changes in voltage cannot be used to obtain crack growth rate. Voltage does not relate ~~uniformly~~ UNIQUELY to crack size.

The Task Group observes that this example of a lack of a direct correlation crack sizing with in-situ pressure testing performance should encourage licensees to be conservative in their selection of candidate tubes for in-situ testing. This example should also encourage licensees to consider new forms of degradation for in-situ pressure testing, even when the flaw is sized below the screening criteria for in-situ pressure testing.

Assessment Methodology and Decision Criteria

The assessment methodology and decision criteria submitted to the staff for the 2000 inspection was far more complex than what was provided in 1997. The methodologies relied on Monte Carlo treatments to predict probabilities of burst and leakage for the next operating period. The analysis of the NDE was far more complex, with topographical visual displays called C-scans and eddy current profiles provided as a visual representation in addition to the voltages from the eddy current signals. The methodologies still were dependent on the data input on growth rates, probability of detection, and uncertainties.

by the way - what does qualified sizing technique mean? there is no particular criteria for "passing" a sizing test

The Task Group observed that the outcomes of the condition monitoring and operational assessments are still dependent on factors such as the uncertainties and difficulties in detection. Parameters that are needed to assess structural integrity such as growth rates and probability of detection of a certain flaw size are based on unqualified sizing techniques. This has led to a problem discussed by an NRC staff member during a July 26, 2000 public meeting with NEI which is that licensees believe in the reliability of the results of their eddy current to a much higher degree than they should. The Task Group concludes that licensees should consider ways to independently verify that their eddy current inspection data is providing an accurate assessment of the integrity of the SG tubes.

not clear, probably not correct what is meant by POD is based on unqualified sizing technique

To enhance the reliability of the program, the licensees should consider evaluation programs that provide "checks and balances" to the detection process. An example of such a program is the Judas Tube Evaluation. The evaluation would consist of collecting tubes from the test and current inspection that had defects in them. The tubes would be recycled back into the data stream with the identifying information disguised to match the other tubes in the group. In this way, the licensee could provide reliability data on the performance of the analysts and the inspection quality.

6.2.3 Conclusions/Lessons-Learned

Based on the observations discussed above, the Task Group reached the following conclusions:

current perf demo does not establish POD values, nor could site validation

1) Site validation of NDE techniques is important for establishing probability of detection values, uncertainties, and inspection thresholds that are representative of the plant-specific inspection capability.

2) An expanded screening criteria for selecting SG tubes for in-situ testing could provide the opportunity to evaluate new types of degradation at a plant. Con Ed should have considered SG 24 tube R2C67 for in-situ pressure testing during the 1997 SG inspection.

3) An important aspect of an accurate Condition Monitoring and Operational Assessment is how uncertainties, threshold of detection, and probability of detection are considered.

sizing accuracy, crack growth rate estimations

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Assessment Methodology and Decision Criteria

(pp2) By the way-what does qualified sizing technique mean? There is no particular criteria for "passing" a sizing test.

(pp2) not clear, possibly not correct, what is meant by POD is based on unqualified sizing technique.?

6.2.3 Conclusions/Lessons-Learned

(1) current performance demo does not establish POD values, nor could ~~sit~~ SITE validation.

(3) sizing accuracy, crack growth rate ~~information~~/estimations.

4) New forms of degradation need to be evaluated aggressively and thoroughly.

6.2.4 Recommendations

Based on the conclusions/lessons-learned discussed above, the Task Group developed the following recommendations:

1) Site validation of techniques should be used for each detection technique, focusing on the most challenging areas of degradation.

2) 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.

3) Industry guidelines should caution licensees not to rely heavily on assessments based on sizing techniques that are not qualified. what does qualified imply?

how?

also sizing accuracy is needed

4) Licensees should consider the effect of the threshold of detection on the growth rate assumptions. this is not enough, not conservative and not even best estimate. It is quite possible that the flaw was not there or well below the threshold during the prior inspection

5) 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.

6.2.5 References

The following References were used for Section 6.2:

1) NEI 97-06 (Rev. 1B), "Steam Generator Program Guidelines," Nuclear Energy Institute, January 2000.

2) NRC Draft Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," dated August 1976.

3) NRC Draft Regulatory Guide DG-1074, "Steam Generator Tube Integrity," dated December 1998.

4) EPRI "Steam Generator Integrity Assessment Guidelines: Revision 0," EPRI Report TR-107621-R0, dated December 1999.

5) Letter, S. Quinn (Con Ed) to Document Control Desk (NRC), "Steam Generator Inservice Examination 1997 Refueling Outage," dated July 29, 1997.

6) Letter, A. Blind (Con Ed) to Document Control Desk (NRC), "Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency," dated December 7, 1998.

7) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Response to Request for Additional Information - Proposed Amendment to Technical Specifications

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6.2.4 Recommendations

(3) What does qualified imply?

(4) also sizing accuracy is needed. how? (should consider)
(Threshold of detection) this is not enough, not conservative and not even best estimate. It is quite possible that the fl~~o~~w was not there or well below the threshold ~~running~~ the prior inspection. A DURING

There are other sections of 10 CFR Part 50 that apply to SG tube integrity management. Those sections and the reasons why they apply are discussed in Section 4.2 of this report.

Technical Specifications

TS Section 4.13, Steam Generator Tube Inservice Surveillance, provides the examination requirements for the SGs. The IP2 TSs require examination of all four SGs at a 12 to 24 month interval and specified the examination sample size that is to increase with identification of degraded or defective tubes. The TSs define "degraded tube" as a tube with imperfections large enough to be reliably detected by eddy current inspection. This is considered to be 20% degradation for wastage type defects. Defective tubes (degradation depth 40% or higher) are required to be removed from service (e.g., by plugging) or repaired (e.g., sleeving). SG tubes are considered acceptable if degradation depth is less than 40% of the tube wall thickness and the tube permits the passage of a 0.610 inch diameter probe (or a 0.540 inch diameter probe with the tube wall strain less than a certain number). The basis section of the TS concluded that with an allowance of 10% degradation during an operating cycle, the tube minimum wall thickness will not exceed the acceptable limit of 50% of the normal wall thickness, thus providing adequate margin of safety against failure. not clear ???

IP2 did not apply sleeving as a repair method but used the F* technique of leaving a defective tube in service as long as the defect in the tube is below 1.25 inches from the bottom of the roll transition at the tube sheet. The TSs specify the selection criteria and the examination technique for tubes to be examined. There is no requirement in the IP2 TSs on data quality. The TS 4.13 basis states that the licensee's program for SG examination exceeds the Regulatory Guide (RG) 1.83, Revision 1, July 1975 requirements.

The TSs further require the licensee to submit the proposed SG examination program for NRC review 60 days prior to the scheduled examination, and results of the examination are required to be reported to the NRC within 45 days of completion of the examination. NRC reporting and prior NRC approval for restart is required if inspection needs to be expanded to 100% of the tubes in all SGs as a result of finding more than 1% defective or 10% degraded tubes, or if tubes in two or more SGs leaked, or leaks are attributable to two or more SGs due to denting. Significant increases in the rate of denting and significant changes in SG conditions are to be reported immediately. There is lack of specificity in the TSs with respect to the definition of significant. There is no discussion in the TSs regarding the format or level of detail that needs to be included in the report. The requirement for NRC approval of restart was incorporated in a TS amendment during the 1970s time frame. This requirement goes beyond the RG 1.83 guidance related to NRC reporting per facility license and NRC approval of the proposed remedial actions. The NRC approval of the restart requirement appears to be unique for IP2 and its sister plant IP3, in that most PWR licensees' TSs contain the NRC reporting requirement but not the NRC approval of plant restart.

As discussed in Section 8.2 of this report, although the NRC staff performed onsite inspection of the licensee's examination of the SG tubes and obtained information regarding the examination results via telephone calls with the licensee during the 1997 outage, the licensee report containing examination results submitted per the TS requirements was not reviewed by the staff. The Task Group concluded that unless reports provide information that supports the NRC's inspection and licensing processes, such reports should not be required. If reports are required from the licensees, the staff review process should be defined.

The TS basis recognizes "denting " as a degradation mechanism that may induce strain and stress corrosion cracking in tubes. Although the TS does not specify any specific requirement for measurement of hour-glassing of the tube support plate flow slots, it requires a 60-day report to the NRC upon finding of significant hour-glassing (closure) of upper support plate flow slots. The report is to contain an evaluation of the long term integrity of small radius U-bends (beyond row 1). As noted in NRC Special Inspection Report 50-247/2000-010 (Reference 1), a recently developed method of measurement by the licensee showed that stress level in the row 2 tube that failed in February 2000 was above the threshold of primary water stress corrosion cracking (PWSCC) as a result of hour-glassing. Con Ed's engineering study determined the required movement of the row 2 tubes to cause abnormal stress at the apex of the U-bend to be 0.1 inch. The inspection report noted that 0.46 inch deflection had occurred near the failed tube. Additionally, as pointed out in NRC Inspection Report 50-247/2000-010, although tubes were preventively plugged following the TS requirement, Con Ed did not recognize the first occurrence of 19 low-row U-bend restrictions due to denting at the upper tube support plate, potential for hour-glassing, and the PWSCC indication at the apex of a row 2 U-bend as significant conditions.

IP2 TS, Section 3.1.F.2a, Primary-to-Secondary Leakage, contains the operational leakage limits for the SG tubes. It establishes a limit of 0.3 gallons per minute (gpm), or 432 gallons per day (gpd) in any SG which does not contain tube sleeves, or 150 gpd for any SG that contains sleeves. The TS also requires that if the limit is exceeded, or if leakage from two or more SGs in any 20-day period is observed, the reactor shall be brought to cold shutdown within 24 hours. As indicated in the basis section of the TSs, the intent of such safety measures is to prevent small leaks from developing into larger ones and possible gross failure. Although the licensee experienced increased SG leakage prior to the February 2000 tube failure, the leakage did not exceed or come close to the TS limit until the tube actually failed.

As documented in NRC Inspection Reports, 50-247/2000-001 (Reference 2), and 50-247/2000-002 (Reference 3), IP2 experienced primary-to-secondary leakage in 1998 of about 0.5 to 2.0 gpd; in 1999 (October - December) of about 2 to 4 gpd and in 2000 (January - February) of about 3 to 4 gpd before the failure occurred. During cycle 14 operation, in 1999, the baseline leakage of less than 1 gpd was detected by the N-16 monitors from three of the four SGs. Leakage from SG 24 increased from about 1 gpd to less than 4 gpd over the course of two weeks preceding the tube leak. There was no additional leakage identified from the other SGs. Following the event, the failed tube was identified as R2C5 in SG 24.

Con Ed procedures require operators to identify and quantify SG primary-to-secondary leaks and implement contingency actions to mitigate adverse consequences. At the time of the February 2000 event, various actions such as increased monitoring were required at various leakage values but ultimately, a leakage greater than 150 gpd would require a plant shutdown. Con Ed revised this leakage limit to 30 gpd following the February 2000 tube failure. The EPRI guidelines on primary-to-secondary leakage, effective February 2000, had a 75 gpd limit that would require a plant shutdown. The licensee's response to the SG leakage is discussed in detail in NRC inspection reports (References 2 and 3).

The experience from the IP2 event where the SG leakage did not exceed the TS limit before a tube failed indicates that IP2 TS leakage limits, by themselves, are not always sufficient to prevent such a failure or provide meaningful indication of an impending failure. Additionally, the IP2 TS did not reflect the current knowledge regarding the degradation mechanism and experience found at the plant or in the industry. It did not prescribe the types of information to examinations. The oversight of ISI activities was also routinely provided by the Quality Control unit through surveillance. Overall, the licensee's oversight of contractor activities was assessed to be good. However, as pointed out in the NRC Special Inspection Report (Reference 1), proper evaluation of the examination findings by the licensee and its contractors to determine the degradation mechanisms and their impact on SG integrity was significantly lacking. Specifically, the NRC team determined that during the 1997 examination, Con Ed should have taken additional actions in response to ECT noise levels and increased susceptibility to PWSCC reflected by tube denting and the apex flaw at a U-bend, to assure that the plant was not returned to service with SG tubes that contained detectable PWSCC indications in the low-row U-bend area. Multiple existing indications of PWSCC in the row 2 U-bend area were missed. The Task Group concluded that this raised reasonable doubt as to the adequacy of the performance of the contractor and Con Ed oversight of the 1997 SG examination activities.

Upon re-review of the 1997 data, and with the benefit of the data and defect locations from the 2000 examination, both Con Ed and the NRC found indications in the U-bends of tubes other than R2C5 that were not called during the 1997 inspection. This raised concerns with the performance of the 1997 data analysts. As documented in NRC Inspection Report 50-247/2000-010, the other tubes were: R2C69 in SG 24, R2C72 in SG 24, and R2C87 in SG 21.

Several suggestions were offered to the Task Group by NRC staff and contractors and the industry as to how data analyst performance could be improved. One suggestion was for automated screening to be used as an additional check. This would not help in the case of noisy data, but would reduce the chance of overlooking an indication. Another suggestion was to have a "Judas Tube" test that would test the analysts during the production run. A known tube would be disguised and put into the data stream to the analysts. If they miss the call on this tube, their other calls for that day would be re-reviewed. Licensees could also consider employing more than one Level III qualified data analyst (QDA) if there will be a large quantity of information to review, due to large numbers of degraded tubes. The QDA can spot check the primary and secondary analyst calls, as well as their primary function of reviewing the resolution analyst calls. Licensees could also consider obtaining ambiguous data for site specific examinations for the analysts, such as data containing missed flaws, different probes, etc. Supplemental training of the analysts should cover new types of degradation and challenges to conventional inspection techniques.

Con Ed made an enhancement to the analysis of the IP2 data during the 2000 SG tube examination by using separate teams to look at the Cecco and bobbin data. In 1997, the same team looked at both sets of data. This enhancement may help, but there are no guidelines currently to decide how much data is too much for the analyst to handle. The licensee needs to incorporate all applicable lessons-learned from the IP2 event to the analyst performance.

Con Ed's Personnel Qualifications and Certification Levels

The Task Group did not perform an independent review of the qualifications and certification of Con Ed's personnel that conducted the SG Tube examinations. However, the NRC addressed this issue in NRC Inspection Report 50-247/97-07 (Reference 5), and also in the NRC Special Inspection Report (Reference 1). The Task Group found that, according to the information in Reference 5, the 1997 examination personnel met the qualification and certification requirements stated in the pertinent supplement of SNT-TC-1A, the American Society of Non-

Destructive Testing, Personnel Qualification and Certifications, and ASME Code Section XI. This was in accordance with the industry guidelines. However, during the NRC's inspection in 2000, the NRC special team identified instances where the 1997 examination did not meet certain portions of the EPRI guidelines. The team also identified weaknesses in the training and data analysis guidance provided to the data analysts in 1997. The issues are described in detail in the NRC Special Inspection Report.

Extension Requests from Con Ed's Involving the SG since 1995

In an application, submitted on February 14, 1997 (Reference 6), the licensee asked for an extension of the 24-month maximum interval of SG tube examination by approximately three weeks, from April 14, to May 2, 1997, to capture primarily the time the plant was in cold shutdown due to a 49 day maintenance outage. This short term extension of the TS required surveillance interval was approved by the NRC in an amendment dated April 9, 1997 (Reference 7). The technical basis for the staff's approval was that during the maintenance outage, the reduced temperature of the reactor coolant system was not conducive to SG degradation.

In a letter dated December 7, 1998 (Reference 8), Con Ed again asked for an extension of the 24 month SG examination interval beyond June 13, 1999, the date an inspection would be due according to the TS requirement. The intent of this request was to capture a cumulative duration of approximately 10 months of non-operating time during which the SGs were maintained in a wet lay-up condition plus an additional period of approximately 2 months (see Appendix A timeline). Further details of the NRC review of the amendment request is contained in Section 8.1 of this report.

Con Ed's SG Tube Examination Results

1997 Examination

By a letter dated February 7, 1997(Reference 9), Con Ed submitted a proposed SG tube examination program for the 1997 refueling outage at IP2 for NRC review. On April 24, 1997, Con Ed provided additional information to the staff in a meeting held at the NRC headquarters in Rockville, MD. An NRC letter dated May 29, 1997 (Reference 10), notified Con Ed that NRC found the proposed examination plan acceptable based on the information submitted and that the number of tubes being examined exceeded the IP2 TS requirements.

The number of SG tubes examined by Con Ed during the 1997 refueling outage exceeded the TS requirements. Con Ed expanded their examination to inspect all support plate intersections with a Cecco-5 probe and the full length of all tubes with a bobbin coil probe. The examination, completed in June 1997, identified the first low-row U-bend PWSCC indication (at the apex of tube R2C67 in SG24). That tube was plugged in 1997. The tube that failed in February 2000, R2C5 in SG 24, had been examined over its full length, but the licensee failed to identify the existing indications. Also during the 1997 examination, Con Ed identified the first instances of probe restrictions IN THE U BEND caused by denting at the upper tube support plate in multiple low-row U-bend tubes. Those tubes were also plugged. NOT CLEAR IT IS IMPORTANT TO NOTE THE RESTRICTIONS IN THE U BEND ITSELF

Con Ed submitted the SG examination results to the NRC in a letter dated July 29, 1997 (Reference 11). The report contained no analysis of the above mentioned results as to a trend or degradation mechanisms involved. The report indicated that video examination of the flow

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<u>1977 Examination</u>

(pp2) Also during the 1997 examination, Con ED identified the first instances of probe restrictions **in the U-bend** caused by denting at the upper tube support plate in multiple low-row U-bend tubes. **(Not clear It is important to note the restrictions ~~in the restrictions~~ in the U-bend itself.)**

AT LOWER SUPPORT PLATES

THEY ALSO REPORTED FOR THE FIRST TIME SUPPORT PLATE CRACKING AT THE UPPER SUPPORT PLATE

slots showed essentially no change in "hour-glassing" of the flow slots and cracks in the tube support plates previously observed. As noted in the NRC Special Inspection Report (Reference 1), other than the visual examination (during the 1997 examinations), the licensee had no method of measuring or criteria for determining when hour-glassing was significant. As a result, as the recent measurement and evaluation (in 2000) indicated, the deflection and resulting stress to the tube (R2C5) that failed exceeded the threshold for PWSCC.

The level of detail provided in the 1997 examination report submitted by Con Ed was not sufficient to identify the technical and implementation problems, such as the low signal-to-noise ratio (data quality), discussed in Section 6.1 of this report. As noted in this report, the licensee's report was not reviewed by the NRC. The Task Group noted that the tube that failed in February 2000 was not identified in the report as a degraded tube, since it was not identified by the licensee as such during the 1997 examination. The NRC's Office of Inspector General's (OIG) report of August 29, 2000, titled "NRC's Response To The February 15, 2000 Steam Generator Tube Rupture At Indian Point 2 Power Plant," concluded that had the NRC staff or contractor with technical expertise evaluated the 1997 results of the IP2 SG inspection, the NRC could have identified the flaw in the U-bend of row 2, column 5, in SG 24 that was indicated in the licensee's inspection (examination) report. After careful review, the Task Group concluded that the NRC staff could not have identified the tube that failed from its review of the licensee's examination report. The report did not indicate that there was a flaw in the row 2, column 5 tube in SG 24 or provide any information on this tube. Even if the staff should have been prompted by the report's identification of a new degradation mechanism (PWSCC) in a similar tube that was plugged, it would have required further discussion with the licensee, additional staff review of the 1997 raw eddy current data of the failed tube, and identification of the flaw from the data, which clearly was of poor quality due to noise and about which experts are not in agreement whether anyone could have reasonably been expected to identify that flaw. Licensees' reports in general, and this report in particular, do not provide information related to the data quality. In order for the NRC to have this information, an eddy current specialist has to review the raw data independently. This is not typically included within the scope of NRC inspection or review.

While the flaw was identified and the tube plugged, Con Ed did not flag the discovery of the low-row U-bend apex indication as a significant new SG degradation mechanism or provide any further analysis. Identification of this flaw was significant because it was the first observation of this type of degradation in the U-bend area in SG tubes at IP2. There was no specific review as to the significance of this flaw or the possible extent of the condition at other tubes provided in Con Ed's report.

1995 Examination

The Task Group also reviewed some aspects of the 1995 SG examination. Con Ed submitted the 1995 examination plan on December 16, 1994 (Reference 12). The plan was to use standard 700 mil bobbin coil eddy current probe. A 610 mil probe would be used if necessary. If the 610 mil probe could not pass through the tube, the tube would be plugged. In SG 21, 204 tubes were to be examined with Cecco-5 array probe that had been qualified to Appendix H of EPRI PWR Steam Generator Examination Guidelines, Revision 3, to detect axial and circumferential cracks at dented support plates and tube roll transitions. Con Ed submitted the 1995 results to the NRC on June 14, 1995 (Reference 13).

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1997 Examination (cont)

slots showed essentially no change in "hour-glassing" of the flow slots and cracks in the tube support plates **at lower support plates** previously observed. **They also reported for the first time support plate cracking at the upper support plate.**

6.4 Con Ed's Root Cause Evaluation and NRC's Special Inspection Team Report

6.4.1 Background

The Task Group considered the results of the licensee's Indian Point 2 (IP2) steam generator (SG) inspections and root cause evaluation, the prior review by the NRC's Office of Research (RES) presented in its memorandum of March 16, 2000, and the observations and findings from the Augmented Inspection Team. The Task Group discussion of the RES independent technical review is provided in Section 7.0 of this report. Pertinent issues from that discussion concerning the root cause analysis are presented in this section. The Task Group evaluated Con Ed's root cause analysis in the context of the licensee's results of the IP2 inspections and the observations and findings from the Special Inspection Team. In addition, discussions with technical experts both inside and outside the NRC have been considered to put the technical findings into context.

Based on the SG tube failure on February 15, 2000, Con Ed performed a technical root cause evaluation of the leaking tube in Row 2 Column 5 in Steam Generator 24. This evaluation, dated April 14, 2000 (Reference 1), was submitted by Con Ed to the NRC staff. The NRC staff sent Con Ed a Request for Additional Information (RAI) dated April 28, 2000 (Reference 2), regarding Con Ed's root cause evaluation and discussed the root cause findings with Con Ed in a May 3, 2000 public meeting between Con Ed, Westinghouse, Altran, and the NRC staff.

Con Ed's Root Cause Evaluation

In their evaluation, Con Ed confirmed that the leak occurred in tube R2C5 in SG 24 as the result of primary water stress corrosion cracking (PWSCC) at the apex of the tube. Overall, Con Ed concluded that the cause for the R2C5 crack was axial PWSCC with the potential for cracking enhanced by increased U-bend stress resulting from hour-glassing at the top TSP. They attributed the PWSCC to denting of the tubes, which is continuing at a slow rate at IP2. Con Ed based this assumption on the number of restricted tubes identified in the 2000 inspection compared with the 1997 inspection.

Con Ed concluded that hour-glassing of the TSP 6 in SG24 had occurred, based on direct measurements of the Row 1 straight leg spacing at the surface of TSP 6. In the flow slot that is adjacent to R2C5, Con Ed measured the maximum closure at 0.47 inch after 27 years of service. Con Ed found that the results of the stress analysis of the low row U-bends support the observation of axial PWSCC at the tube apex. The row 3 and row 4 tubes exhibit the same trends as in row 2, except at a reduced maximum stress level.

Upon review of their records and data from 1997, Con Ed found that this U-bend indication was not detected in the 1997 examination of tube R2C5 due to background noise associated with outside tube deposits and tube geometry effects (ovality) masking the flaw. As discussed in Section 3.0 of this report, noise in eddy current testing is defined as any non-relevant signal that tends to interfere with the normal reception or processing of a desired flaw signal. Signal-to-noise ratio is a way of evaluating the magnitudes of a relevant signal (defect) to the non-relevant signal (noise). The higher the signal-to-noise ratio, the easier it is to detect a defect. The inability to detect the indication in 1997 inspection due to noise in the signal led to the tube failure. Con Ed concluded that the growth of the indication between 1997 and 2000 was moderate and was not the principal root cause of the failure.

(looking at the amplitude variation along the length of the tube)

This is true for the first step, i.e. the screening phase but since Con Ed had identified one U-bend SCC during the inspection - they should have taken the second step and looked at the lissajous patterns (phase) of the U-bend tubes at several locations along the bend. If they had ... then would have identified other flaws as have other people done

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<u>Con Ed's Root Cause Evaluation</u>

This is true for the first step, ~~in~~ i.e. the screening phase (looking at the amplitude variation along the length of the tube). But since Con Ed had identified one U-bend SCC during the inspection they should have taken the second step and looked at the ...... patterns (phase) of the U-bend tubes at several locations along the bend. If they had only looked they would have identified other flaws as ~~have~~ other people have done using the 97 data without any additional improvements.

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own contractors and consultants were able to call other U-bend flaws from the 97 data

Although Con Ed's re-review of the R2C5 data from the 1997 examination showed an anomalous indication, their review of the data by eddy current experts concurred that the flaw would not have been called by accepted eddy current (EC) practices in 1997. Con Ed concluded that the problem in detecting this flaw was due to the background noise in the signal related to geometry effects and deposits including copper. Even with the difficulty in detection in the U-bends, Con Ed did identify PWSCC at a Row 2 U-bend at IP2 in 1997, and the tube was plugged. This 1997 examination finding was the first indication of PWSCC at a Row 2 U-bend at IP2. With further re-review of the 1997 Plus Point U-bend data in 2000, Con Ed discovered a PWSCC flaw in tube R2C69 that had not been identified in 1997.

Due to the missed indications in 1997, Con Ed instituted changes during the 2000 inspection to the analysis process intended to improve the capability to detect degradation. These changes included more stringent data quality criteria, changes to the analysis setup process to achieve better resolution, and supplementary instructions to the analysts to assist them in identifying degradation in the low row U-bends. In addition, Con Ed used a 800 kHz Plus Point probe designed to more critically interrogate the inner surface of the tubes and perform in a manner less sensitive to the effects of geometry and outside deposits. Con Ed found that the use of the 800 kHz probe yielded an improvement in detectability of PWSCC in the U-bends.

Con Ed performed a review of industry experience with low row U-bend PWSCC. This review indicated that Row 2 indications have been reported at other operating plants; however, the occurrence has been sporadic and infrequent.

Con Ed confirmed that a report of leakage from R2C5 at the tube support plate 1 elevation was not correct, based on eddy current verification that no flaws existed at this or any nearby location on the tube. The reported leakage was several drops per minute, and attributed to condensation in the tube.

Based on the above findings in their evaluation, Con Ed developed a corrective action plan that was presented in the root cause analysis report. This plan focused on demonstrating improved ability to detect flaws in the low row U-bends. Con Ed supplemented the analysis guidelines for the 2000 SG examination with more stringent criteria for data quality, an improved analysis setup process, and supplementary instructions for using information in the eddy current strip chart displays. To gain a better ability to detect PWSCC in the U-bends, Con Ed qualified and used a high frequency, 800 kHz Plus Point probe to supplement the conventional mid-range frequency Plus Point low row U-bend examinations. Con Ed discussed a possible laboratory program to develop the probability of detection of flaws as a function of crack depth and NDE sizing uncertainties for the PWSCC indications.

As part of their operational assessment, Con Ed performed a complete stress analysis of the low row U-bends to assess the effects of TSP deformation (hour-glassing) on the relative susceptibility of the row 2, row 3, and row 4 tubes to cracking. Con Ed also performed an additional structural evaluation to assess the effects of support plate compression and hour-glassing on the U-bends, and to assess the overall integrity of the TSPs with respect to tube integrity (e.g., loss of tube support, generation of loose parts). Based on the current inspection data, augmented by industry experience and the analysis described above, Con Ed intended to prepare a Condition Monitoring Assessment and Operational Assessment to assure structural integrity of the tubes and TSPs for the next operating cycle.

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Con Ed's Root Cause Evaluation (cont.)

(pp 1) Our contractors and consultants were able to call other U-bend flows from the 97 data.

NRC's Special Inspection Team Report Findings

A special inspection was conducted by an NRC inspection team from March through July 20, 2000 to review the causes of the failure of the SG tube on February 15, 2000. The NRC team members included personnel from Region I and the Office of Nuclear Reactor Regulation, as well as NRC-contracted specialists in SG eddy current testing. The team reviewed the adequacy of Con Ed's performance during the 1997 SG inspections and assessed Con Ed's root cause evaluation, dated April 14, 2000. The results of the team findings were discussed with Con Ed on July 20, 2000, and preliminary team findings were sent by letter dated July 27, 2000 (Reference 3). The special inspection report, NRC Inspection Report No. 05000247/2000-010, was sent to Con Ed by letter dated August 31, 2000 (Reference 4).

The special inspection report concluded that the team's inspections led to a preliminary red finding in the significance determination process (SDP). In addition, the team inspections led to a green finding and a no color finding. The risk significance of a finding is determined by its color and is determined by the SDP in Inspection Manual Chapter 0609. The SDP is discussed in more detail in Section 8.2 of this report. "E" attached,

The Special Inspection Team summarized their findings, concluding that the overall direction and execution of the 1997 SG inservice examinations were deficient in several respects. The team found that despite opportunities, Con Ed did not identify and correct a significant condition adverse to quality, namely, the presence of PWSCC flaws in Row 2 SG tubes in the small-radius, low-row U-bend apex area. In particular, Con Ed did not adequately account for conditions which adversely affected the detectability of, and increased the susceptability to, tube flaws. The team found that the identification of the first PWSCC defect in a Row 2 tube in 1997 was observed by Con Ed concurrent with the first occurrence of restrictions of eddy current testing (ECT) probe movement through the tube due to denting. The team concluded that these observations by Con Ed signified the potential for other similar cracks in the low-row tubes, but Con Ed did not adequately evaluate the susceptibility of low-row tubes to PWSCC, the extent to which this degradation existed, and the increased probability of such a defect to rupture during operation.

Further, the Special Inspection Team found that Con Ed did not adequately evaluate the potential for hour-glassing based on the indications of the low-row tube denting and the identified apex PWSCC defect. The team also found that Con Ed did not establish procedures and practices to determine if significant hour-glassing in the upper TSP flow slot was occurring.

The team found that significant ECT signal interference was encountered in the data obtained during the actual ECT of several low-row U-bend tubes, and this significant noise level reduced the probability of identifying existing PWSCC defects. However, the 1997 SG inspection program was not adjusted to compensate for the negative effects of the noise in detecting flaws, particularly when conditions that increased susceptibility to PWSCC existed. The program did not contain specific criteria for plugging tubes based on noise and/or provisions for enhancing the analysis of existing data.

The team found that tubes with PWSCC flaws in their small radius U-bends were left in service following the 1997 SG inspection, which resulted in a significant reduction in safety margin based on the increased risk of a SG tube rupture during Operating Cycle 14. Based on Con Ed's failure to identify and adjust or modify the inspection methods and analysis to account for significant conditions that affected the quality of the 1997 SG inspection, the team concluded

"E": Comment on P. 79 Second paragraph

This paragraph says that the special inspection team found a red finding, a green finding, and a no-color finding. The remainder of the paragraph does nothing to explain this further. What should the outside reader take away from this - that the SDP gives no clear answer??, that the special inspection team provided no clear results??

"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."

Although the SG life prediction model used for IP2 under-predicted the number of PWSCC indications that were actually be found in the 2000 SG examination, the Task Group learned that this type of prediction would be fairly consistent with operating experience at other plants similar in age to IP2. The Task Group reviewed a summary of SG examination findings in the Row 1 and 2 U-bends for a plant of a similar age, and found that the examinations revealed one PWSCC indication in low row U-bends for each of the SG tube examinations performed in 1991, 1994, and 1997, for a total of 3 indications found after 19.6 effective full power years (EFPY). In another case, SG examinations similarly revealed one PWSCC indication in low row U-bends for each of the SG tube examinations performed in 1997 and 2000, for a total of 2 indications after 21.6 EFPY. The measured depth of all of the indications exceeded 60% through-wall, up to approximately 96% through-wall. The Task Group observed that these SG examination findings in plants other than IP2 may indicate that the detection threshold may be much greater than 40% through-wall for other plants of a similar vintage.

This is probably driven more by the relative ineffectiveness of EC to detect cracks in the Ubend (without use of special procedures) not to SCC phenomenology.

The Task Group concludes from the difference in PWSCC behavior noted in SGs of a similar age and material, that care must be taken in using predictive models to evaluate tube performance. Licensees should maintain a questioning attitude in areas that can be challenging to inspect. Licensees should aggressively seek to understand inspection findings that differ from predictions.

The Special Inspection Team report also discussed their re-analysis of four tubes from the 1997 data. The team noted that the review of the 1997 data discussed in the report was performed with the benefit of the data and defect locations from the 2000 examination. The NRC staff noted that Con Ed should have reanalyzed the data based on finding the indication at R2C67 and observing high levels of noise in the data. The Task Group discussed the failure of eddy current analysts in the 1997 SG examination to find the PWSCC indication in the tube that failed, R2C5, with eddy current experts that have looked at the 1997 data. There were different views on whether the flaw in tube R2C5 could have reasonably been detected in 1997, but the Task Group was told that it would have been a difficult call for an eddy current analyst to have made because the indication was located in an especially noisy area of the tube.

The Special Inspection Team report found, and the Task Group also concluded, that the 1997 SG inspection plan was not adjusted to compensate for the negative effects of the noise in detecting flaws. As noted in the Special Inspection Team report, Con Ed was not assisted in this process by the current revision (Revision 4) of the EPRI SG Examination Guidelines (Reference 7). The team stated that the guidelines provided no noise criteria recommendations. However, as noted in Section 6.1 of this report, industry is planning an update to the guidelines to establish data quality requirements. In addition to data quality requirements, the Task Group recommends that the guidelines also contain practices for establishing the source of the noise, and adjusting the inspection techniques to compensate for the sources of noise in the data.

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Lessons-Learned Task Group Observations (cont.)

This is probably driven more by the relative ineffectiveness of EC to detect cracks in the U-bend (without use of special procedures) not to SCC phenomenology.

The Task Group talked to NRC staff and contractors to identify whether any industry standards on noise in eddy current data were in place in 1997. The consensus was that explicit data quality standards were not in place, and it was up to the analysts to determine if they had noise levels that interfered with their ability to call indications. The opinions of the NRC staff were that IP2 had such high levels of noise in the U-bends and sludge pile region that data quality was very poor, and the analysts would have had difficulty making reasonable calls unless the flaws were very deep.

There was, however, some evidence that the industry was concerned about the impact of noise on the eddy current data. Another major provider of eddy current hardware, training, and analysis software is Zetec, Inc. According to NRC staff, Zetec starting incorporating the measurement of noise in their eddy current analysis software, Eddynet 2, in 1995, in response to NRC concerns. Improvements made to Zetec software didn't help IP2, because Westinghouse used their own software when they conducted the 1997 SG tube examinations. The NRC staff is not familiar with the Westinghouse software and does not know if Westinghouse software provides a measurement of noise for the analyst similar to the Zetec software. One of the NRC staff commented that he believed that approximately 65 to 70% of all eddy current testing in the SGs in commercial nuclear power plants is performed by Westinghouse. The Task Group made no attempt to verify this estimate, but if this is correct, Westinghouse's analysts should be in a position to compare noise levels from plant to plant, and compare strategies that licensees use to cope with difficulties in obtaining good eddy current data.

The Task Group reviewed both Revision 4 and Revision 5 of the PWR Steam Generator Examination Guidelines to see what guidance was provided to the licensees on noise problems in eddy current data. In both revisions, the only guidance that would have assisted the analysts in evaluating the noise is vague, as pointed out in the NRC Special Inspection Team Report. No guidance is provided to the analyst on how to determine if too much noise is present, no strategies are provided to isolate the cause of the noise, and no strategies to mitigate the effects of noise are offered.

In the August 31, 2000 Special Inspection Team report, the NRC staff concluded that Con Ed correctly stated that there was no quantitative noise criteria present in EPRI Steam Generator Examination Guidelines, Rev. 4, used in 1997. However, the Special Inspection Team noted that the adverse relationship of signal noise to flaw probability of detection was not new. There were discussions on the adverse relationship of signal noise to flaw probability of detection from Draft NUREG 1477, "Voltage-Based Interim Plugging Criteria for Steam Generator Tubes" (Reference 8), and NRC Information Notice 94-88, "Inservice Inspection Deficiencies Result in Severely Degraded Steam Generator Tubes" (Reference 9). The team further noted that draft NUREG 1477, dated June 1993, stated relative to ECT testing and analysis guidelines that "noise criteria should be incorporated that would require that a certain specified noise level not be exceeded, consistent with the objective of the inspection. Data failing to meet these criteria should be rejected and the tube should be reinspected. These criteria should be broken down into criteria for electrical noise, tube noise, and calibration standard noise." The Task Group noted that the more detailed instructions (i.e., to incorporate a noise criteria and reinspect tubes that fail to meet that criteria) are contained in NUREG-1477, a supporting document for a voltage-based interim alternate plugging criteria for ODSCC at tube support plate intersections. Given that IP2 has never applied for this alternate repair criteria, it is not clear to the Task Group to what extent that Con Ed's staff would have

Comments from J. Muscara p. 8~~5~~4

<u>Lessons-Learned Task Group Observations (cont.)</u>

(pp2) seams high

discussed the RES review with Con Ed personnel during a site visit on August 29, 2000, in order to obtain Con Ed's views on the RES memo.

Results of the RES Review

RES's initial review of the staff's safety evaluation (SE) of the IP2 SG tube inspection interval extension (Reference 3) did not find any obvious problems with the SE. However, RES looked further at the relevant supporting documentation and did identify concerns. These additional documents were:

1) Licensee's submittal on a proposed licensing amendment to the IP2 Technical Specifications on SG inspection interval (Reference 4);

2) Licensee's response to NRR's request for additional information (RAI) (Reference 5); and

3) Licensee's report on the IP2 SG tube inservice examination conducted during the 1997 refueling outage (Reference 6).

RES documented the results of its review and its concerns in a memorandum to NRR dated March 16, 2000 (Reference 2). RES concluded that IP2's technical basis for adequacy of the operating cycle based on previous inspection results was inadequate, especially for PWSCC at a row 2 U-bend and outer diameter SCC at the top of the tubesheet under the sludge pile.

RES acknowledged that NRR sent an appropriate RAI to the licensee related to the evaluation of SG tube structural and leakage integrity for the entire cycle 14. This RAI (Item 1 in Reference 7) stated:

> "For 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."

RES characterized the licensee's response to the RAI (Reference 5) as "weak and incomplete." RES also believed that NRR's SE (Reference 3) indicated that the licensee conducted more thorough operational assessments than were described in response to the RAI. In particular, RES concluded that the case presented by the licensee on crack growth rate was technically inaccurate. In the licensee's discussion about the first time a row 2 U-bend PWSCC indication was found (Reference 5), they stated "[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." This statement is inconsistent with the evolution of SCC and with other industry experience. RES felt that the presence of the row 2 U-bend indication should have raised a "red flag" because this meant that the long incubation (i.e., initiation) phase had passed, the crack growth rates would not be minimal, and more cracks would be likely to occur. There should have been a much closer look by Con Ed at other IP2 row 2 U-bend inspection data[8]. The number of cracks resulting from stress

[8]Section 6.1 of this report discusses issues related to the poor quality of IP2 SG inspection data and the likelihood of being able to identify other row 2 U-bend flaws from the 1997 inspection data.

The poor quality impeded detection during the "screening" phase. i.e. ev. of strip chart recording - Amplitude along tube length. A closer look at the data means [illegible] e lissajous patterns, phase angle behavior.

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Results of the RES Review

(Last pp) The poor quality impeded detection during the "screening" phase (i.e., evaluation ~~evidence~~ of strip- chart recording - amplitude along tube length. A closer look at this data means looking at ~~bypass region~~ patterns/phase/~~high~~ angle behavior. Along the U-bends. If this had been done a much higher likelihood of detection would have resulted.

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corrosion cracking and the crack growth rate both increase significantly after the initiation phase has passed. Therefore, the number and size of cracks identified during cycle 13 should not have been expected to be the same as at the end of cycle 14. The RES staff member said an option for IP2 would have been to preventively plug row 2 tubes.

RES also took issue with Con Ed's "bounding" growth rates for outside diameter stress corrosion cracking (ODSCC) in the sludge pile region above the top of tubesheet and provided reasons why they were not "bounding."

RES concurred with the SE statement that the licensee's lay-up procedures for the SG for the period of time when IP2 was shut down from October 1997 to August 1998 were appropriate. Also, the RES review (Reference 2) did not identify any issues in the staff's SE related the use of the F* repair criteria. Therefore, the Task Group determined that further review of the F* repair criteria was not necessary. RES concluded: "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."

NRR Actions/Response Related to the RES Review

Shortly after receiving the March 16, 2000, RES review, NRR issued a memorandum from S. Collins to F. Miraglia, Deputy EDO (Reference 8), in which NRR identified a number of activities the staff would take as a follow-up to the IP2 event. These included reviewing results of the licensee's current SG inspections, results from previous inspections, the licensee's root cause evaluation, and the licensee's corrective actions to determine if the IP2 SGs are safe to be put back into operation. The memorandum also stated that the NRC staff will perform an evaluation of lessons-learned from both technical and regulatory process perspectives. The memorandum went on to say, "the results of this lesson-learned assessment will be used to identify any generic technical or process elements that could be improved in the NRC's review of SG issues."

The IP2 SG Tube Failure Lessons-Learned Task Group Charter (Reference 9) specifically states that information from RES's review of the SEs should be considered, along with the licensee's results of the IP2 SG inspections and root cause evaluation, and the IP2 restart SE, to assess the lessons-learned for both industry and the NRC.

In discussions with various NRR staff, one of the questions the Task Group asked was for their views on RES's findings. There was general agreement among the NRR staff that the licensee's assessment of degradation found in the SGs was inadequate. In particular, NRR staff felt that Con Ed and its contractor, Westinghouse, missed the significance of the row 2 tube U-bend apex crack that was found for the first time in 1997. This finding warranted further examination or analysis by Con Ed.

With regard to NRR's review of information provided by the licensee in response to the RAI (i.e., the "minimal" expected growth rates of U-bend cracks), two of the NRR staff acknowledged that reviewers have different levels of expertise and experience, and the significance of some inspection findings may not be pursued by all reviewers.

Although the RES response has been perceived by some stakeholders outside the agency as meaning that NRR did an inadequate review, one NRR staff member pointed out that even if

IP2 had not shut down for the unscheduled maintenance outage (from October 1997 to August 1998), the tube that failed in February 2000 would likely have failed even without an extension of the inspection interval[9]. While the interactions between the licensee and the NRC in May 1999, relating to the amendment to the Technical Specifications to extend the SG tube inspection interval, provided an opportunity to uncover problems with IP2's SG operational assessment, the real problem stemmed back to the quality of the June 1997 inspection.

fact is that if NRC had recognized in May 99 that IP2 did a poor job of evaluating steam generator integrity for the operating cycle, and not granted the extension, that IP2 would have had to inspect in June 1999 and they could possibly have "caught" the tube that failed. NRC had opportunity and missed it.

In response to RES's comment that Con Ed's "bounding" growth rate for crack growth was not "bounding," two NRR staff felt that, because of large measurement uncertainty, it is very difficult to accurately evaluate crack growth rates. Therefore, one cannot accurately predict the size of a flaw at the end of an operating cycle. But did they take the steps to bound it as IP2 claimed?

Con Ed's Comments on the RES Review

Con Ed told the Task Group members that they would have preferred that RES talk to them before issuing the March 16, 2000, memorandum. Con Ed agreed that they had provided a rather perfunctory response to the staff's RAI about PWSCC degradation and growth rates. However, Con Ed stated that they had a technical basis for their conclusion (their contractor, Dominion Engineering, had looked at this issue), but the details were not included in their response to the RAI. Con Ed felt that this additional information would have been useful for the RES review.

The Task Group noted that the purpose of the RES review, as defined in NRR's request (Reference 1), 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." Therefore, RES conducted their review based on the information available to the staff. As discussed in Section 8.1 of this report, if the staff felt they needed additional information to approve the SG tube inspection interval extension, they could have requested it at the time of the amendment review.

7.3 Conclusions/Lessons-Learned

Based on the observations discussed above, the Task Group reached the following conclusions:

1) During Con Ed's preparation of the license amendment request to extend the SG tube inspection interval (submitted to NRC in December 1998), and during preparation of the related RAI response (submitted to NRC in May 1999), Con Ed was weak in assessing the significance of SG degradation mechanisms and the condition of their SG tubes. However, the real problem stemmed back to the quality of Con Ed's SG inspection in 1997.

[9] IP2 inspected their SGs in June 1997. Four months later, in October, the plant shut down for unscheduled maintenance and remained shut down for about 10 months. The plant restarted in August 1998. Excluding the 10 months that the plant was shut down, the cumulative time that plant had operated at power, from the June 1997 inspection until February 2000 when the SG tube failed, was less than the normal 24 month inspection interval. (According to IP2 Technical Specifications, SG inspections are to be conducted no more than 24 months after the previous inspection.) Therefore, the SG tube that failed would likely have failed even without an extension of the inspection interval.

Comments from J. Muscara p. 97

<u>NRR Actions/Response Related to the RES Review</u>

(After pp1 and before pp2)fact is that if NRC had recognized in May 99 that IP2 did a poor job of evaluating steam generator integrity for the full cycle 14 and not granted the extension, that IP2 would have had to inspect in June 1999 and they could probably have caught the tube that failed. NRC had another opportunity and missed it.

(After pp2) But did they take the steps to ~~f~~Bound it as IP2 claimed?

2) Con Ed and its contractor, Westinghouse, missed the significance of the row 2 tube U-bend apex crack that was found for the first time in 1997.

3) Even if the licensee had not requested an extension of the SG inspection interval, the SG tube (SG24, tube R2C5) likely would have failed before the end of the normal 24-month operating cycle. but they needed to inspect in 24 calendar months not 24 Effective full power months - they would have inspected in June 1999 before the tube failed

4) There were a number of opportunities for both Con Ed and the NRC to identify problems with the IP2 operational assessment (see also Sections 6.2, 8.1, and 8.2 of this report).

5) Con Ed and Westinghouse did not recognize the significance of an important new SG degradation mechanism that was identified during their 1997 SG inspection. The NRC staff did not recognize the significance of this degradation mechanism during its review ~~in 1999~~ of the amendment request to extend the SG tube inspection interval. Nor in July 1997 when the information was made available to NRC in the IP2's inspection report

6) Knowledgeable NRC staff is essential for adequate SG oversight by the NRC. If the staff does not have the necessary expertise and training, the significance of some inspection findings may be missed. SG expertise in the Materials and Chemical Engineering Branch (EMCB) resides primarily with a few staff plus outside contractor support. Maintaining SG expertise to support the objectives of NRC's licensing and inspection programs is important.

7) The technical review and coordination between NRR and RES enhanced the agency's ability to address challenging SG technical issues. However, based on discussions with the staff and Con Ed, it appears that the process can be improved.

7.4 Recommendations

Based on the conclusions/lessons-learned discussed above, the Task Group developed the following recommendations:

1) 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).

2) 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.

3) 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.

/ what does this mean/imply ?

Comments from J. Muscara p. 98

Conclusion/Lessons-Learned (cont.)

(3) But they needed to inspect in 24 calendar months not 24 effective full power months - they would have inspected in June 1999 before the tube failed.

(5) Nor in July 1997 when the information was made available to NRC in the IP2's inspection report.

7.4 **Recommendations**

(3) What does this mean/imply?

include the following key elements to ensure that it is complete and acceptable from a technical standpoint:

1) Description of the amendment, including discussions on the content of the current license condition or TS, the proposed change and why the change is being requested, how it relates to plant equipment and/or operating procedures, whether it is a temporary or permanent change, and the effect of the change on the purpose of the TS or license condition involved;

2) Licensee's safety analysis/justification for the proposed change. The application should specify the current licensing basis that is pertinent to the change (e.g., codes, standards, regulatory guides, or Standard Review Plan (SRP) sections. The safety analysis that supports the change requested should include technical information in sufficient detail to enable the NRC staff to make an independent assessment regarding the acceptability of the proposal in terms of regulatory requirements and the protection of public health and safety. It should contain a discussion of the analytical methods used, including the key input parameters used in support of the proposed change. The discussion also should state whether the methods are different from those previously used and whether the methods have been previously reviewed and approved by the staff);

3) No significant hazards consideration determination per 10 CFR 50.92; and

4) Appropriate TS pages.

The Task Group reviewed the licensee's application (Reference 9), the staff's RAI (Reference 7), and a supplement to the application that provided the RAI response (Reference 6), against the guidance in OL No. 803, Section 2.2. The Task Group did not identify any issues regarding completeness and acceptability of the application and supplement with respect to the key elements noted in OL No. 803.

Interviews were held with the NRR staff that were involved with the review associated with Amendment No. 201. The staff indicated that they believed that the licensee's application was complete and acceptable except for the information requested by the staff's RAI. The RAI response was considered adequate by the staff technical reviewer at the time the SE was being prepared. However, subsequent to the IP2 tube failure event on February 15, 2000, one NRR staff member reviewed the RAI response and stated that a licensee conclusion regarding growth rates was "ridiculous." Specifically, the RAI response includes a section that discusses that primary water stress corrosion cracking (PWSCC) was found at a row 2 U-bend for the first time (SG 24, tube R2C67). The RAI response also states that: "[a]s 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." The staff member stated that although this statement was "ridiculous," it wouldn't have affected the staff decision with respect to row 2 tube integrity because the reviewers believed that the results of the 1997 SG inspection by the licensee established appropriate safety margins. Don't see how this conclusion could be made - The licensee did not evaluate the implications of the new mechanism and took no steps to bound the problem especially in view of the fact that have experienced tube ruptures in the history.

With respect to the RAI response, Con Ed stated that Dominion Engineering performed a study for IP2 on SG degradation in 1995 that made PWSCC predictions, but didn't predict that a PWSCC flaw in the U-bends would occur until 1999. When Con Ed found the PWSCC flaw in the SG 24 tube R2C67 U-bend during the 1997 outage, they contacted Dominion

Comments from J. Muscara p. 102

Completeness and Acceptability of the Licensee's Application (cont.)

(Between last 2 pp) Don't see how this conclusion could be made - the licensee did not evaluate the implications of the new mechanism and took no steps to ~~find~~ BOUND the problem ~~specifically~~ ESPECIALLY in view of the fact ~~that~~ they have experienced tube ruptures in this location.

STET

Engineering after the outage to get them to update the report based on the inspection findings. The new projection for PWSCC indications was one additional indication per cycle, not an exponential increase in indications. 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). Con Ed understood that they gave a rather perfunctory response to the RAI 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 Condition Monitoring/Operation Assessment (CMOA) was not described in detail in the RAI response. Even if they predicted "only" one SCC @ U bend they still took no action when these flaws are known to be capable of bursting during normal operation

Another observation by the NRR staff (based on review of documentation subsequent to the tube failure event) is that the licensee's application and RAI response did not address that the indication found in the row 2 U-bend during the 1997 SG inspection was located at the tube apex. This would have been a concern to the staff since a crack at the apex could break before there was leakage indication. Also, due to the failure mechanism involved, this could indicate higher stress levels at low row U-bends and the possibility of additional indications that may have not been detected. The Task Group concludes that there was an opportunity for Con Ed during preparation of the amendment application and RAI response to recognize the significance of the apex location of the row 2 U-bend indication (SG 24, tube R2C67) and possibly uncover problems with the 1997 operational assessment.

Use of Precedent by the NRC Staff

Section 2.3 of OL No. 803 describes guidance to the NRC staff regarding use of precedent in performing licensing reviews. Precedent licensing actions are those with a similar proposed change and regulatory basis for the SE. Use of precedent increases staff efficiency, minimizes the need for RAI's, and helps to ensure consistency in SEs. The OL states that the search for a precedent should continue until the staff is satisfied that either one or more appropriate precedents have been identified or that no appropriate precedent exists.

The NRR staff technical reviewer for Amendment No. 201 used the NRC's NUDOCS bibliographic data system to search for precedent. Several SEs were found related to extending the SG inspection interval. The staff noted that since an inspection interval extension of approximately 2 months was considered insignificant, the same review considerations would have been taken into account regardless of whether the licensee had only requested an extension to cover the wet lay-up period (versus asking for an approximate 2 month extension in addition to the wet lay-up period). The wet lay-up period refers to the time period the plant was in a cold shutdown operating mode (i.e., reactor coolant temperature $\leq 200°$ F) with chemically treated water added to the SGs to minimize corrosion. The Task Group concludes that the NRR staff used precedent licensing actions in preparing the SE for Amendment No. 201 in accordance with the guidance in OL No. 803.

Scope and Depth of the Review

Section 2.4.1 of OL No. 803 describes guidance to the NRC staff regarding scope and depth of the review. The OL states that the appropriate SRP section and the licensee's Updated Final Safety Analysis Report (UFSAR) and other docketed correspondence that form the licensing basis for the facility, as well as the relative risk significance of the licensee's request, should be used as guidance in determining the appropriate scope and depth of the review.

Comments from J. Muscara p. 103

Completeness and Acceptability of the Licensee's Application (cont.)

(After pp1) Even if they predicted "only" ~~and~~ one SCC @ U-bend they still took no action when these flaws are known to be capable of bursting during normal operation.

The NRR staff had the following observations related to the scope and depth of the review that was performed for Amendment No. 201:

1) There is no SRP section to provide guidance in performing reviews related to SG inspection interval extensions.

2) The scope and depth of the NRC staff review for the inspection interval extension amendment was appropriate. There was nothing unusual in the licensee's application that should have prompted the staff to perform a deeper review. Licensee performance for SG inspection industry-wide as a whole has been good as evidenced by only one recent tube failure (i.e., IP2) out of thousands of tubes inspected.

3) The requested change was not considered complex or safety significant by the staff reviewers. The significance of the inspection interval extension was to recapture the time spent in an unscheduled outage by extending the date for the required inspection by the time lost during the outage. The SGs were in wet lay-up during the unscheduled outage, and there was precedent for approving this type of extension. The request to extend the interval an additional period of approximately 2 months was considered insignificant by the reviewers. If the plant had not shut down for the unscheduled maintenance outage, the tube that failed in February 2000 would likely have failed during the normal operating cycle (i.e., inspection interval extension did not contribute to the failure). The change would have been considered safety significant if it had reduced safety margins. The staff noted that the occurrence of tube failures every few years does not indicate that there is a significant safety or risk problem. See Section 5.0 of this report for further discussion on risk insights.

4) Based on the complexity and safety significance of the requested change, the experience level of the staff technical reviewer was appropriate.

5) The review was done with the assumption that the licensee's 1997 inspection of 100% of the SG tubes was done in an adequate manner and formed a baseline for the review. Therefore, the staff did not see a need to thoroughly review the licensee's 1997 SG inspection report dated July 29, 1997 (Reference 10) as part of the amendment review process. Although the licensee's report was used by the NRC staff in preparation of the SE, the report was used primarily to obtain information related to tube plugging and in-situ pressure testing. The apex location of the indication found in the row 2 U-bend during the 1997 inspection (SG 24, tube R2C67) is only noted in a table in the licensee's inspection report and is not discussed in the text of the report. The licensee's amendment application does not discuss the row 2 U-bend. The RAI response discusses that PWSCC was found at a row 2 U-bend, but it does not discuss that the indication was found at the tube apex. Therefore, the apex location of the indication was not in the perspective of the reviewer.

SCC in any location in the tube is significant. How both the failure from flaws at the Apex as well as flaws in the transition

The Task Group concludes that the scope and depth of the review was consistent with the guidance in OL No. 803 since the requested change was not considered complex or safety significant. The staff did not review the licensee's 1997 inspection report in detail; however, there was no SRP guidance to perform reviews related to SG inspection interval extensions. Therefore, there was no guidance to the reviewers on whether review of previous licensee SG inspection reports was necessary. In hindsight, this could have been an opportunity to find inadequacies in the licensee's operational assessment directly related to the eventual tube

Comments from J. Muscara p. 104

Scope and Depth of the Review

(Before last paragraph) SCC in any location in the U-bend is significant. Have had tube failures from flaw at the apex ~~point~~ as well as flaws in the transition.

Content of the NRC Safety Evaluation

Section 4.0 and Attachment 2 of OL No. 803 describe guidance to the NRC staff regarding the content of the SE. As described in the OL, the SE provides the technical, safety, and legal basis for the NRC's disposition of a license amendment request. The SE should provide sufficient information to explain the staff's rationale to someone unfamiliar with the licensee's request. The SE includes a brief description of the proposed changes, the regulatory requirements related to the issue, and an evaluation that explains the staff's disposition of the request. The evaluation should include an analysis of the proposed changes in terms of regulatory requirements, established staff positions, industry standards, or other relevant criteria. The evaluation should also contain the staff's specific conclusion regarding whether the proposed change is acceptable in terms of public health and safety.

The Task Group reviewed the SE for Amendment No. 201 against the guidance in Section 4.0 and Attachment 2 of OL No. 803. The SE provided an appropriate level of detail concerning the description of the proposed change and the TS requirements related to this issue. The SE stated that: "[t]he objective of the NRC staff's evaluation is to determine the impact of the proposed extended inspection interval on the structural and leakage integrity of the tubes considering the extended period the plant was shut down." This objective is consistent with a statement made by an NRR technical staff member, during an interview with the Task Group, that there is no SRP guidance to perform the reviews related to SG inspection interval extensions and that the reviews are basically done such that the safety arguments convince the staff that SG tube integrity will be maintained.

The SE evaluated the following technical considerations, which are discussed in detail below:

1) Inspection results and test methods used during the June 1997 SG inspection;

2) Chemistry assessment for the SG during the shutdown period and for the present operating cycle; and

3) SG leakage monitoring program.

The SE stated that the licensee performed an extensive eddy current inspection in June 1997 (end of cycle 13) and that the inspection included 100% examination of all inservice tubes. The SE described the reasons why tubes were plugged and states that prior to tube plugging the licensee performed in-situ pressure testing on selected tubes that exceeded the EPRI/Westinghouse tube selection screening criteria. The SE concluded that the in-situ pressure tests showed that the SG tubes have maintained adequate structural integrity in accordance with Regulatory Guide (RG) 1.121 and that on the basis of the licensee's assessment, the staff found that the structural and leakage integrity of the tubes during cycle 13 was acceptable.

The SE also evaluated the SG tube degradation projected for the remainder of cycle 14 based on a review of licensee's end of cycle (EOC) 13 inspection and testing results. The SE stated that the licensee projected the severity of degradation at the EOC 14 considering the beginning of cycle degradation status, degradation growth rates, and EOC allowable degradation. The SE discussed the different forms of degradation found, including PWSCC at row 2 U-bends. The SE stated that the licensee's evaluation determined that the forms of degradation did not present a challenge to the 3ΔP structural margin criteria for the expected

The SE states this, but there was no evidence or information provided by IP2 that this was done. In particular with respect to row 2 U-bend cracking.

Comments from J. Muscara p. 106

<u>Content of the NRC Safety Evaluation</u>

(Last pp) The SE states this, but there was no evidence or information provided by IP2 that this was done. In particular with respect to ~~new~~ Row 2 U-bend cracking.

operating cycle length of 21.4 effective full power months (EFPM). The SE concluded that, based on a review of the licensee's assessment, the staff expected the SG tubes to continue to satisfy structural and leakage integrity requirements under normal and accident conditions through the end of the current operating cycle (i.e., cycle 14). As discussed in the "Completeness and Acceptability of the Licensee's Application" section above, the licensee's RAI response regarding growth rates (associated with the PWSCC indication found in the row 2 U-bend in 1997) was not questioned by the NRR staff during the time the amendment review was being performed. In hindsight, had this issue been pursued further (i.e., clarification phone call with licensee or second RAI), this was an opportunity to find inadequacies in the licensee's operational assessment directly related to the eventual tube failure.

The SE discussed the chemistry controls that were in place during the plant shutdown. The SE stated that the licensee maintained the SG in wet lay-up conditions in accordance with EPRI guidelines in order to minimize the potential for corrosion. The SE concluded that reduced temperatures and chemistry conditions during shutdown should have prevented further SG tube degradation. The SE also discussed the chemistry controls in place during cycle 14 operation and stated that the SG chemistry had been maintained in accordance with EPRI guidelines. The SE concluded that the chemistry controls provided assurance that corrosion during the cycle 14 operating period had been minimized.

The SE discussed the SG leakage monitoring program and stated that the licensee maintained an administrative limit more conservative than the TS limit. The SE concluded that the licensee's leakage monitoring program provided assurance that, should a leak develop during the operating cycle, it would be quickly detected, allowing immediate mitigating actions to be taken before tube failure occurs. However, this conclusion is not supported by the actual circumstances associated with the IP2 tube failure event on February 15, 2000. As described in Section 4.5 of the NRC's Augmented Inspection Team (AIT) Report, dated April 28, 2000 (Reference 11), following plant startup in October 1999, the leak rate in SG 24 appeared to vary from 2 to 4 gallons per day (gpd) but returned to pre-shutdown levels of 1.5 to 2.0 gpd through December 1999. Starting in January 2000, the leak rate slowly increased to about 3-4 gpd just prior to the tube failure on February 15, 2000. The leak rates observed prior to the event were significantly below the limit at which any mitigating action would need to be taken in accordance with the IP2 TSs. Conclusions and recommendations regarding the adequacy of the TSs for SG leakage are discussed in Section 6.3 of this report.

As discussed above, there were two opportunities during the license review process for the NRC staff to find inadequacies in the licensee's operational assessment (i.e., during review of the RAI response and during review of the licensee's 1997 inspection report). However, it is not clear if further follow-up in either one of these cases would have yielded a different result (e.g., denial of the amendment request). The bases for this conclusion are as follows:

1) Had the NRC questioned Con Ed regarding this first time row 2 U-bend apex PWSCC indication that was found in 1997 (SG 24, tube R2C67), Con Ed could have stated that based on the report from Dominion Engineering, they only expected one indication per cycle and that tube had been plugged in 1997. But there are indications that can lead to rupture. proper analysis would have shown the need for a mid-cycle inspection

2) If the NRC did not accept the Dominion Engineering report conclusions, the staff may have asked Con Ed to review the 1997 eddy current data results. Since Con Ed did not find any indications in 1997 for the tube that failed in 2000, it is uncertain that the licensee's re-review of the data would have found any indications in the subject tube

Comments from J. Muscara p. 107

Content of the NRC Safety Evaluation (cont.)

(1)But these are indications that can lead to rupture, MAYBE ~~profile~~ an~~d~~ analysis would have shown the need for a mid-cycle inspection.

that were previously missed. Con Ed could have also noted that 100% of the tubes were inspected in 1997.

3) NRC Information Notice (IN) 97-26, "Degradation in Small-Radius U-bend Regions in Steam Generator Tubes," was issued in May 1997, just before Con Ed began the 1997 SG inspections at IP2. Due to the timing of the release of the IN, the IN may not have been received by the licensee's SG inspection group before the inspection began. However, even if it had been received, as with all information notices, this IN did not require any specific action or require a written response. The IN points out that: "[t]he susceptibility to cracking in small-radius U-bends and the findings of recent field inspections have emphasized the importance of inspection of this area of SGs with techniques capable of accurately detecting U-bend indications." Discussions between the Task Group and Con Ed indicated that the licensee believed that the row 2 U-bend that was found and plugged in 1997 (SG 24, tube R2C67) was an easy call and therefore that didn't think they missed any other indications. If Con Ed had provided this information to the NRC during the amendment review process, it is not clear that the NRC would have raised any questions regarding the accuracy of detecting U-bend indications in the small-radius U-bends.

4) At the time of the amendment review, the plant was operating. As such, no further SG inspection data (e.g., using different type of probes) could be gathered beyond the existing 1997 inspection data without shutting down the plant. which was required to do in June 1999 if denied the amendment request

5) The NRC's SE needs to conclude that there is "reasonable assurance" that health and safety of the public will not be endangered by operation in the proposed manner. Based on the above hypothetical situations, it isn't clear that any new information would have been provided to the NRC during the amendment review that would have changed the reasonable assurance conclusion.

In addition, the NRR staff noted that with respect to the SG tube that failed in February 2000, it is likely that the same tube would have still failed even without an amendment to extend the inspection interval if the plant had been in operation the entire cycle. This conclusion is based on the fact that the tube failure took place in less than the number of effective full power days that was allowed between SG inspections (see Appendix A timeline). The Task Group agrees with the staff's conclusion.

Based on the above, the Task Group concludes that, in hindsight, during the amendment review process, the issue regarding PWSCC degradation that was found in 1997 in the row 2 U-bend apex (SG 24, tube R2C67) could have been pursued further. However, the Task Group also concludes that is not clear if this would have changed the outcome of the license amendment request (i.e., NRC staff approval of amendment request).

<u>Interface between NRC Headquarters and NRC Regional Staff</u>

The only guidance provided in OL No. 803 regarding the interface between NRC Headquarters and NRC Regional staff is provided in Section 4.1.1 of the OL. This guidance states that the PM may provide input regarding the licensee's performance for use in the assessment of licensee performance. The OL states that the assessment should be documented in the amendment cover letter and should also be forwarded to the appropriate regional contact for possible entry into the plant issues matrix. In the last few years, typical PM input addressed

Comments from J. Muscara p. 108

<u>Content of the NRC Safety Evaluation (cont.)</u>

(4) Which was required to do in June 1999 if denied the amendment request.

issues such as the timeliness of the licensee's application and the adequacy of the application (e.g., required multiple RAI's, telecons, and meetings to resolve all the technical issues). In the past, this information was used as input to the Systematic Assessment of Licensee Performance (SALP) process. However, with the recent implementation of the revised reactor oversight process (ROP), the SALP process has been discontinued. At present, there is no process that captures the PM input as a means to assess the licensee's performance.

With respect to the process used for development of an SE for a license amendment, this effort is typically completed by NRC Headquarters personnel without any input from the Regional staff. During an interview with Regional staff members, questions were asked regarding the interface between Headquarters and the Region during SE development. The staff observed that there should be some link between the licensing and the inspection processes. For example, if the NRR SE relies heavily on a statement from the licensee on a risk-significant issue, the Region could perform an inspection to verify the statement.

The Task Group concludes that, in some cases, it may be advisable for ~~NRC Headquarters~~ NRR staff to interface with Regional staff to get input (e.g., via inspection) during development of an SE for a license amendment. However, for the specific review performed for IP2 Amendment No. 201, it does not appear to the Task Group that Regional involvement would have provided any benefit.

"F" (attached)

<u>Review of the TSs Associated with the SG Inspection Interval</u>

IP2 Amendment No. 201 revised TS 4.13A.2.a to allow a one-time extension of the SG inspection interval. This TS requires that the SG inspections be conducted not less than 12 calendar months nor later than 24 calendar months after the previous inspection. The amendment modified a footnote associated with TS 4.13A.2.a to allow the inspection to be conducted during the year 2000 refueling outage, commencing no later than June 3, 2000. The previous SG inspection was completed on June 13, 1997. Without the amendment, the next scheduled inspection would have been required by June 13, 1999. The amendment had the effect of recapturing the time the plant was in wet lay-up (approximately 10 months) and also justified SG operation for an additional period of approximately 2 months. It should be noted that the IP2 SG tube failure occurred on February 15, 2000, which was approximately 8 months after the originally scheduled inspection date (i.e., less than the duration justified by the recapture of the wet lay-up period). This is illustrated in the timeline shown in Appendix A of this report.

As discussed in the licensee's application (Reference 9), the SG inservice inspection program is based upon the guidance in RG 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1, dated July 1975. Regulatory Position C.6 of RG 1.83 provides guidance regarding inspection intervals. The RG states that the first SG inservice inspection should be performed after 6 EFPM but before 24 calendar months and that subsequent inservice inspections should be not less than 12 nor more than 24 calendar months after the previous inspection.

The 12 to 24 month inspection interval specified in IP2 TS 4.13A.2.a. is consistent with the interval specified in RG 1.83. Based on the comparison of the IP2 TSs to RG 1.83, the Task Group did not identify any issues associated with the TSs for the SG inspection interval. It should be noted that the Task Group did not pursue the technical basis for the allowable interval between SG inspections.

"F": Comment on P. 10~~8~~9   Interface between NRC Headquarters and NRC Regional Staff

This section, in effect, equates NRC headquarters staff with NRR staff. Given the discussion in Chapter 7, it begs the issue as to the role of RES staff in such activities.

6) OIG finding: OIG found nearly no involvement in the amendment request review by either the NRR Project Manager assigned to IP2 or the EMCB Branch Chief.

Task Group comments: As discussed in the "Resources Used in the Review" section above, the technical complexity of the review was such that the review would not normally be done by the NRR Project Manager (PM). The review was assigned to EMCB technical staff consistent with the guidance in NRR OL No. 803. Detailed review of an amendment request is normally conducted by the assigned technical reviewer. The Task Group believes that the PM involvement was consistent with the guidance in OL No. 803, given the technical complexity of the review. Consistent with normal practices, EMCB branch supervision provided oversight of the technical reviewer, review of the RAI questions, and review of the completed SE. Note, it is the Task Group's understanding that, in order to clarify NRR management expectations, the NRR staff intends to review and revise the amendment review process described in OL No. 803, as appropriate, to address concurrence responsibilities , supervisory oversight, as well as second round RAIs.

8.1.3 Conclusions/Lessons-Learned

Based on the observations discussed above, the Task Group reached the following conclusions:

1) Subsequent to the IP2 tube failure event on February 15, 2000, the NRR staff noted that it did not agree with the licensee's conclusions concerning growth rates based on PWSCC being found at a row 2 U-bend (SG 24, tube R2C67) for the first time, as discussed in the licensee's RAI response dated May 12, 1999. However, during the staff's amendment review, this issue was not recognized, and the SE accepted the licensee's conclusions on degradation growth rates. The NRR staff also noted (subsequent to the tube failure event) that this issue wouldn't have affected the staff's decision regarding row 2 integrity during the amendment review because the reviewers believed that the results of the 1997 inspection established appropriate safety margins. This highlights the importance of the staff's SE being very specific concerning what information was relied on to form the basis for it's conclusions.

Again, how can we say this? for example there was no adequate operational assessment, and the U-bend cracked tube was not in situ tested. If the tube had been tested would we have concluded that appropriate safety margins had been established? how did we conclude [illegible] that the tube would have met the 3ΔP criterion?

2) There was an opportunity for Con Ed during preparation of the amendment application and RAI response to recognize the significance of the apex location of the row 2 U-bend indication (SG 24, tube R2C67) and possibly uncover problems with the 1997 operational assessment.

3) The NRR staff used precedent licensing actions in preparing the SE for Amendment No. 201 in accordance with the guidance in OL No. 803.

4) The scope and depth of the NRR staff review for Amendment No. 201 was consistent with the guidance in OL No. 803 since the requested change was not considered complex or safety significant. The staff did not review the licensee's 1997 inspection report in detail; however, there was no SRP guidance to perform reviews related to SG inspection interval extensions. Therefore, there was no guidance to the reviewers on whether review of previous licensee SG inspection reports was necessary. In hindsight, this could have been an opportunity to find inadequacies in the licensee's operational assessment directly related to the eventual tube failure. Specifically, if the

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8.1.3 Conclusion/Lessons-Learned

(1) Again, how can we say this? For example, there was no adequate operational assessment; and the U-bend cracked tube was not insitu tested. If the tube had been tested would WE have concluded that APPROPRIATE ~~opportunity of~~ safety MARGINS ~~maximize~~ had been ESTABLISHED ~~stabilized~~? How did we convince ourselves that the tube would have met the 3ΔP criterion?

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