Indian Point 2 Steam Generator Tube Failure
Lessons-Learned Report
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EXECUTIVE SUMMARY

1.0 OBJECTIVE

The objectives of the Indian Point 2 (IP2) Steam Generator (SG) Tube Failure Lessons-Learned Task Group are defined in a memorandum from S. Collins to W. Traverse dated May 24, 2000. This memorandum describes the approach and charter for an inter-office task group to assess the lessons-learned from the Indian Point 2 steam generator tube failure. The objective of this effort is to conduct an evaluation of the staff's technical and regulatory processes related to assuring steam generator tube integrity to identify and recommend areas of improvements applicable to the NRC and/or the industry.

This lessons-learned evaluation is dependent, in part, on the findings of the plant restart safety evaluation developed by the staff. Therefore, the objectives also include a review of this safety evaluation prior to plant restart to identify conclusions or issues that should be further reviewed or resolved by the NRC.

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 considered the technical areas as well as the regulatory processes involved in assuring SG tube integrity. The task group's evaluation has considered the following information in an integrated manner: (1) the licensee's steam generator examination results and findings; (2) root cause evaluation for the February 15, 2000 tube failure event; (3) the review by the Office of Research presented in its memorandum of March 16, 2000; (4) observations and findings of the Augmented Inspection Team and its followup inspection; (5) IP-2 restart safety evaluation, and several licensing amendments related to the extension of the SG inspection period since 1995. The task group has 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 in the NRC's new oversight program and that existed prior to the implementation of the new oversight program in April 2000; (2) the SG inspection and assessment methods implemented at IP-2; (2) the licensing amendments process utilized for the licensee's applications related to IP-2 SG tube examinations. In addition, the task group reviewed the existing industry guidelines for assuring SG integrity, the implications of the IP-2 event related to the adequacy of the existing guideline and the regulatory framework.

The task group also reviewed the Strategic Plan Reactor arena goals and measures to assess the implications of the event and the associated findings.

The task group review did not include a review/assessment of the existing SG DPO or the 2.206 petition that had been filed by the UCS. The existing NRC processes developed for handling these issues are being used, and review of these issues/processes were considered out side the scope of the task group charter.

2.2 Assumptions and Constraints

3.0 DISCUSSION OF THE IP2 SG TUBE FAILURE EVENT

At 7:17 pm EST on February 15, 2000, with the unit at 99% power, the operators of the Indian Point 2 nuclear power plant (a 4-loop, Westinghouse, pressurized-water reactor) received a nitrogen-16 alarm which is indicative of a steam generator tube failure. The licensee, Consolidated Edison Co. (ConEd), subsequently declared an "Alert" in accordance with procedures. The operators manually tripped the reactor, isolated faulted steam generator (SG) 24, and proceeded to use the three intact steam generators to cool the reactor. The licensee terminated the "Alert" after reactor coolant system temperature was reduced to below 200 degrees F, and the reactor was placed in the cold shutdown condition.

After placing the unit in the cold shutdown condition, ConEd conducted an inspection of SG 24 and found that a tube had failed in row 2, column 5 (R2C5). This small-radius, low-row tube had cracked at the apex of the U-bend due to primary water stress corrosion cracking (PWSCC). ConEd conducted an eddy current test (ECT) examination of the SG tubes and conducted visual inspections of the secondary side of the other SGs. During these ECT inspections, ConEd found greater than 1% of the tubes in SGs 21 and 24 contained defects, placing the unit in a condition that required NRC approval before restarting the plant in accordance with the technical specifications (TSs).

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 a 100% examination of the low-row U-bends 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, ConEd identified the first instances of probe restrictions caused by denting at the upper tube support plate in low-row U-bend tubes. These tubes were also plugged because an examination could not be completed. ConEd returned Indian Point 2 to operation in early July 1997.

Primary-to-secondary leakage during the operating periods prior to the February 2000 tube failure 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.

4.0 REGULATORY FRAMEWORK

4.1 Introduction

There are two types of commercial nuclear power generating facilities in the United States, those whose nuclear steam supply system are based on boiling water reactors (BWRs) and those based on pressurized water reactors (PWRs). Boiling water reactors produce steam to drive turbines by directly boiling water in a reactor vessel. A pressurized water reactor operates at conditions under which the water passing through the reactor does not boil because the very high pressure in the reactor significantly raises the boiling point of the water, thereby permitting the water to be heated to high temperatures without boiling. The heated water from the reactor is transferred to a steam generator where it passes through many tubes surrounded by water from the turbine portion of the plant. This water is at a pressure much lower than that of the reactor water system. The steam generator tubes containing the pressurized, hot reactor water heat the surrounding water, creating the steam that turns the turbine. Because the steam generator tubes physically separate the reactor's radioactive water on the inside of the tubes from the non-radioactive water on the outside of the tubes, it is part of the "reactor coolant pressure boundary" as that concept is defined in 10 C.F.R. § 50.2.

The steam generator tubes have a number of important safety functions. In addition to transferring heat from the "primary" to the "secondary" system to create steam, as part of the reactor coolant pressure boundary, they are relied upon to isolate the radioactive fission products in the primary coolant from the secondary system and to prevent uncontrolled fission product release under conditions resulting from core damage severe accidents. Steam generator tube integrity can be impaired because the tubes are subject to a variety of corrosion and mechanically induced degradation mechanisms that are widespread throughout the industry. (Steam generator tube integrity means that the tubes are capable of performing their intended safety functions consistent with the licensing basis, including applicable requirement.)

In recent years, the NRC staff has examined the regulatory programs which comprise the framework for ensuring the integrity of steam generator 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 steam generator tube integrity. The rule would have required the development and implementation of a risk-informed, performance-based program to maintain steam generator tube integrity. Following a regulatory analysis, however, the staff concluded that existing regulations provided an adequate regulatory basis for dealing with steam generator issues but that steam generator tube surveillance technical specifications (TS's) should be upgraded. Therefore, in 1997, the staff informed the Commission that a steam generator rule was not necessary but that the staff would develop a generic letter containing model technical specifications for steam generator tube surveillance and maintenance and requesting licensees to address current TS problems and develop guidance to support model TS's or pursue alternate steam generator tube repair criteria based on an appropriate risk assessment. That same year, the Commission approved the staff's approach and the Nuclear Energy Institute voted to adopt NEI 97-06 as a formal industry initiative to provide a consistent industry approach for managing steam generator programs and for maintaining steam generator 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 steam generator tube integrity, consistent with the Commission's Direction-Setting Initiative 13 (DSI-13), "The Role of Indistry." 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 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 tube failure on February 15, 2000, the staff's plans to develop an appropriate regulatory framework to assure steam generator 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 Indian Point tube failure, as well as other recent steam generator tune integrity issues at other facilities, whether this trend remains appropriate is an overarching issue which deserves careful consideration.

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 PWRs 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). Pursuant to 10 C.F.R §§ 50.56 and 50.57, upon substantial completion of construction of the nuclear facility in conformity with the construction permit and the application, and a finding that the facility will operate in conformity with the application and the Commission's regulations, and that there is reasonable assurance that the activities authorized by the license can be conducted without endangering the health and safety of the public and will be conducted in accordance with applicable regulations, and upon reaching other required findings, the NRC may issue an operating license for the facility.

Once authorized to operate, nuclear facilities must implement a quality assurance program as described in the facilities Final Safety Analysis Report (FSAR) which meets the criteria of Appendix B to Part 50, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants. Those criteria particularly relevant to maintaining steam generator tube integrity are Criterion IX, Control of Special Processes, Criterion XI, Test Control, and Criterion XVI, Corrective Actions.

Licensed operating facilities also must meet the inservice inspection requirements of 10 C.F.R. § 50.55a(g)(4) for components which are classified as ASME Code Class 1, Class 2, and Class 3. Among many other applicable requirements, nuclear power facilities must comply with the "maintenance rule" in 10 C.F.R. § 50.65 and the reporting requirements of 10 C.F.R. §§ 50.72 and 50.73.

4.3 License Technical Specifications

The proposed generic technical specifications require licensee to establish and implement a program to ensure that NRC-approved steam generator tube integrity performance criteria are maintained. The performance criteria would be defined in a license-controlled document subject to 10 C.F.R. § 50.59 and would include structural, accident-induced leakage, and operational leakage criteria.

4.4 NRC Guidance and Generic Communications

Draft Regulatory Guide DG-1074 describes a method acceptable to the NRC staff for monitoring and maintaining the integrity of the steam generator tubes at operating PWR's. It also provides guidance on evaluating the radiological consequences of design basis accidents involving leaking steam generator tubes in order to demonstrate that the requirements of 10 C.F.R. Part 100, "Reactor Site Criteria," regarding offsite doses, and GDC 19 regarding control room operator doses, can be met. The staff is evaluating whether to revise DG-1074 to incorporate comments received and to conform it to the new regulatory framework. This determination will be based on the staff's assessment of the EPRI guidelines and experience with the implementation of the NEI 97-06 initiative.

Information Notice 97-26

4.5 Industry Initiatives and Guidance

NEI 97-06 commits pressurized water rector licensees to a programmatic approach conceptually similar to that of DG-1074. NEI 97-06 references two types of lower tiered documents for guidance on the implementation of individual programmatic features: Electric Power Research Institute (EPRI) mandatory guidelines that are directive in nature and non-directive, general guidance that licensees may use. Following further open interaction among the staff, NEI and the public, the staff will document the results of its review and issue a Regulatory Issue Summary (RIS) with an attached safety evaluation as the basis for NRC endorsement of a revised NEI 97-06 and of a framework for steam generator tube integrity. After issuance of the RIS, individual licensees would be expected to commit to the revised NEI 97-06 guidelines and to submit an accompanying TS change request adopting the new steam generator regulatory framework.

4.6 NRC Inspection and Oversight

Inspection the old-fashioned way

Inspection under RROP

PI's and SDP

3deltaP pressure test

eddy current testing

40% through wall criterion

leakage limits

tube plugging criteria and repairs

condition monitoring

operational assessments

5.0 TECHNICAL ISSUES

5.1 Inspection Methods/Practices

5.1.1 Background

The NRC fulfills its responsibility through a system of licensing and regulatory activities that support its mission to protect public health and safety. One very important activity is inspecting the licensed facilities and activities. Together with the review of license amendment applications, the inspection data provides insights on the licensee's management of their steam generators. The licensee's management of their steam generators is directly dependent on the quality of their inspection of the steam generator tubes and associated internals. Both the licensee's inspection of the steam generators and the NRC's oversight of their steam generator programs through inspection oversight contribute to NRC's finding of reasonable assurance of safety for steam generators in operating units.

The charter for the IP2 Steam Generator Tube Failure Lessons-Learned Task Group directs the group to identify any generic technical or process elements that may be improved in the NRC's review of steam generator issues. In that context, the group is directed to recommend areas for improvement in the NRC's internal processes for regulating steam generator tube integrity and leakage and areas for improvement in industry's activities and guidelines related to managing steam generator tube integrity.

In the area of inspection methods and practices, there has been substantial improvement and change in the industry since the last inspection prior the tube failure (1997). The changes in inspection methods and practices will be discussed in this section, and recommendations will be made for both industry practices and NRC process. Industry recommendations for changes in inspection methods and techniques through the EPRI guidelines associated with NEI 97-06 are anticipated as a result of heightened awareness of steam generator inspection issues following this tube failure.

When considering the inspections that the licensee conducts of their steam generators, the task group considered the following:

A. Prior knowledge of critical areas and other aspects for determining samples
B. Efforts to improve signal processing - electronics and physical improvements
C. Use of other inspection techniques
D. Compensating for problems such as copper and sludge deposits
E. Qualification of methods and personnel for the plant-specific situation
F. Integration and analysis of available inspection data

5.1.2 Observations

5.1.2.1 Inspection Plans

1997 Inspection

In 1997, the IP2 Technical Specifications 4.13.C.1 required that ConEd submit a proposed steam generator examination program for NRC staff review and concurrence prior to each scheduled examination. The 1997 full length examination program was intended to complete a full length examination cycle in a three examination period. The cycle consisted of the 1993, 1995, and 1997 examinations.

By letter dated February 7, 1997, ConEd submitted a proposed steam generator tube examination program for the 1997 refueling outage at IP2 to the NRC for staff review. On April 24, 1997, the ConEd provided additional information to the staff in a meeting held at the NRC headquarters in Rockville, Maryland. In a letter dated May 6, 1997, the licensee submitted additional information regarding the proposed tests to compare the performance of Cecco-5 probes with that of Plus Point probes. By letter dated May 29, 1997, ConEd was notified by the NRC staff that they had reviewed the proposed examination plan and found it acceptable based on the information submitted. The staff safety evaluation found the plan was acceptable "because it sufficiently covers the areas of the tube bundle that are susceptible to degradation. In addition, the scope of the inspection is more comprehensive than that of the tube inspection in 1995 and the number of tubes being examined exceeds the requirements of IP2 TS." This staff position was also supported in the NRC Inspection Report 97-07.

The NRC safety evaluation called for ConEd to examine, as a minimum:

- full length of 33 percent of the active tubes in steam generator 21, 47 percent of the active tubes in steam generator 22, 33 percent of the active tubes in steam generator 23, and 33 of the active tubes in steam generator 24
- all tubes from the end of the tube to the first support plate intersection on the cold leg side and the second support plate intersection on the hot leg side
- all U-bends in rows 2 and 3.
- all dents at the tube support intersection
- all rerolled tubes to verify F* distance
- 20 percent of the pit indications at the sludge pile.

The 700 mil diameter probe was used to perform the initial eddy current testing. Any tube that did not permit passage of the 700 mil diameter probe was tested with progressively smaller probes. Tubes that did not pas the 610 mil bobbin probe were plugged. Furthermore, tubes immediately adjacent to any tube that did not pass the 610 mil probe were also subjected to an eddy current examination. This plugging criteria was based on ovalization of the tubes and pre-existing hour-glassing of the upper support plate flow slots.

The original examination scope, submitted to the NRC on February 7, 1997, was subsequently expanded during the outage, to include full length examination of all steam generator tubes.

This change was primarily due to the indications discovered by Cecco probe at the hot leg and cold leg upper support plate locations. Additionally, all sludge pile pit indications were characterized by the +Point probe to determine if linear-like indications could be associated with the pits. Sludge pile pitting and AVB wear were dispositioned by the bobbin analysis in the absence of a +Point linear indication. All other indications were dispositioned based on the Cecco. The full discussion of the expansion of scope was contained in the 1997 steam generator inspection report submitted by ConEd to the NRC, dated July 29, 1997, and was discussed in the NRC Inspection Report 97-07, which stated that the sample expansion was satisfactory and according to EPRI Guidelines.

The examination was conducted from either the hot or cold leg side of the channel head. All tubes requiring full length inspection were examined from the mouth of the tube through the tubesheet, around the U-bend, to the mouth of the tube on the opposite side. The examination program was as follows:

- One hundred percent of the hot leg tubes were examined from the mouth of the tubesheet up through the first support plate in Steam Generators 21, 22, 23, and 24 with the Cecco-5/bobbin probe.

- One hundred percent of the U-bends of Rows 2 and 3 in Steam Generators 21, 22, 23, and 24 were examined to the extent possible with the Cecco5/bobbin probe. A Rotating Pancake Coil (RPC) probe was utilized to examine the bends if the narrow radii of the bends precluded passage of the Cecco-5/bobbin probe.

- A minimum of 33 percent of the active tubes in Steam Generators 21, 22, 23, and 24 were selected for eddy current examination for both dents and defects over their full length with the Cecco-5/bobbin probe. Full length tube data was collected by the bobbin coil probe and all tube support plate data was collected by the bobbin coil and Cecco-5 probes.

- The balance of the cold leg tube ends were examined from the mouth of the cold leg tubesheet up through the first support plate in Steam Generators 21, 22, 23, and 24 with the bobbin coil probe.

Tubes with indications evaluated at 40 percent or larger of the wall thickness, linear indications (axial or circumferential), Cecco-5 indications at tube support plate intersections (both characterized by +Point and not confirmed by the +Point probe), and tube roll transition cracks that were not rerolled, or did not meet F* were plugged. Other tubes were plugged due to passage restrictions of the 610 mil diameter probe (twenty tubes). 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 the Zetec +Point Dent Inspection Probe (gimbaled +Point probe); eighteen tubes were preventively plugged based upon an Indian Point 2 tube support plate study.

Staff review has concluded the inspection expansion strategy was satisfactory (i.e., according to EPRI guidelines) for the new indications in the sludge pile regions. There was no opportunity for sample expansion in the U-bend area, even though the licensee had an indication of a new form of degradation in that area, because the licensee had already performed a 100% Cecco-5/bobbin probe inspection in that region. The limitations of their inspection were due to limitations in data quality in that region, not due to inadequate sample scope.

In reviewing the 1997 steam generator inspection plan, it was observed that Con Ed did not discuss in the inspection plan how hour-glassing of the upper support plate flow slots would be evaluated. Inspection of the flow slots was a regular part of their inspection program as there was a TS requirement to evaluate the long term integrity of small radius U-bends based on significant hour-glassing.

Even though the inspection plan did not address how hourglassing would be evaluated, the inspection report discussed the flow slot and lower support plate examination process and results. Con Ed's report discusses how they were able to access the lower support plate flow slots by lower handholes in all four steam generators, but was limited to inspecting the uppermost support plates in only Steam Generators 22 and 23 because they were the only generators with "hillside ports" in the steam generator shells. It should be noted that hillside ports were installed in Steam Generators 21 and 24 during the outage in 2000, to improve their ability to make inspections for hourglassing.

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

In ConEd's June 16, 2000 response to question 3 of a NRC RAI dated April 28, 2000 on ConEd's root cause analysis, the licensee's interpretation of "significant" hourglassing is discussed. Their interpretation was readily visible hourglassing, such as was seen in Surry 2 and Turkey Point. Their criteria was any visually observable bowing of the edge of the flow slot on either the hot or cold leg side. This concept was first established in the November 18, 1976, Con Ed submittal to the NRC that discussed the inspection performed on the Indian Point 2 steam generators as a result of the Surry 2 tube failure.

2000 Inspection

By letter dated February 11, 2000, Con Ed submitted a proposed steam generator tube examination program for their 2000 Refueling Outage, planned for June, 2000. This inspection plan was prepared and submitted before the tube failure. They proposed using the Cecco-5/bobbin probe for the majority of the eddy current testing. They planned to resolve by Cecco-5 coils any locations with distorted bobbin coil signals. If further characterization was necessary, they planned to use rotating probe coil technology (RPC). For the narrow radii U bends, they planned to use the RPC if passage of the Cecco-5/bobbin probe is precluded. Their inspection scope was described only as meeting, at a minimum, the requirements of NEI 97-06 "Steam Generator Program Guidelines", but following the latest revision of the EPRI PWR Steam Generator Examination Guidelines.

In practice, the scope of the inspection increased dramatically based on the tube failure in February 2000, and the recommendations of the NRC staff. The scope of the 2000 inspection is presented comprehensively in the 2000 Refueling Outage Steam Generator Inspection Condition Monitoring and Operational Assessment Reports, submitted to the NRC by letter dated June 2, 2000. In particular, the scope of the inspections were expanded to include 100% mid-range frequency Plus Point inspections of the U-bends, high frequency Plus Point inspections of Rows 2 and 3 U-bends (and some Row 4 signals that were classified as bad data), and some ultrasonic testing (UT) in the sludge pile region.

Although it wasn't captured in the proposed steam generator tube examination program, Con Ed also inspected the steam generator tube flow slots for hourglassing. To improve their inspection capabilities for hourglassing, hillside ports were installed in Steam Generators 21 and 24 during the outage in 2000. In ConEd's June 16, 2000 response to question 3 of a NRC RAI dated April 28, 2000 on ConEd's root cause analysis, the licensee cited a maximum displacement of 0.47 inch of the row 1 U-bend tube legs adjacent to the sixth support plate was measured at the center of the flow slot. According to ConEd, this displacement was the result of hourglassing of the flow slot that was not visibly discernable. Further, although the measured hourglassing was too small to be visually observed, the analysis results indicate that this leg displacement could have contributed to the leak event in the row 2 tube in SG24.

5.1.2.2 Signal Processing - Noise Problems

Observations:

- Con Ed's root cause evaluation for the tube failure, dated April 14, 2000, stated that "[s]ignificant contributing factors for this leak were masking of the indication in the 1997 inspection by nosie related to deposits and tube geometry, and increased stress in row 2 due to TSP flowslot deformation because of denting."
- In the April 28, 2000 NRC Augmented Inspection Team Report, it states that after the tube failure, "[t]he licensee reviewed the Plus Point eddy current data taken at the flaw location during the 1997 outage inspection and questioned the quality of the eddy current data collected at this location. Specifically, geometric variations in the tube circumference caused an uneven rotation of the eddy current probe as it was pulled through the tight radius U-bend tubes. The uneven probe rotation resulted in anomalous eddy current signals and reduced the probability of detection for indications in the tight radius U-bends."
- As a result of NRC questions regarding the signal to noise levels at IP2, NEI undertook a U-bend noise study comparing the noise level in the U-bends with two similar plants

The problem in 1997, according to ConEd, is that they didn't realize how the noise affected their ability to see flaws. They saw a flaw that they sized at approximately 50% TW, so they assumed that everything was fine. Their analysts maintained that the level of noise in the U-bends was comparable to that at other plants. In the 2000 inspection, NRC recommended to Con Ed that they use a 800 kH probe to reduce the noise levels. Con Ed reported that experiments with lower frequencies did not produce measurable differences in their ability to see flaws. Based on the information submitted, we didn't observe any enhancements in the 2000 inspection to increase the potential to catch ODSCC in the U-bend region. Con Ed tried UT in the freespan sludge pile region to see if they could enhance the inspections in that region.

ConEd's viewpoint

In ConEd's June 16, 2000 response to question 8 of a NRC RAI dated April 28, 2000 on ConEd's root cause analysis, Con Ed discusses the acceptability of the noise levels during the 1997 outage. Con Ed states that "the level of noise in R2C5 was not considered to be excessive in comparison with noise levels encountered in SG tubing at other plants according to analysts who reviewed the data. In the absence of specific noise level requirements in Revision 4 of the EPRI Guidelines (or any other document), the disposition for the noise level observed on R2C5 was left to the discretion of the data analysts. Based on the information available at the time, there was no reason to suspect that the background noise levels encountered would have a significant effect on the level of detectability of the eddy current technique. Additionally, the technique used in 1997 did find a flaw in SG24 R2C67, which was plugged, suggesting that the capability to discern a flaw was adequate. ... In the absence of the high frequency probe, there were also no feasible alternatives available at that time to improve signal quality or reduce U-bend noise levels."

In ConEd's June 16, 2000 response to question 1 of a NRC RAI dated April 28, 2000 on ConEd's root cause analysis, Con Ed discussed the adequacy of noise and data quality criteria. In particular, Con Ed stated that "[i]n 1997, there was no specific industry criteria addressing noise or related data quality. At that time there was no reason to suspect that noise and data quality were significant issues, since the inspection programs that were being implemented throughout the industry during that time frame were qualified and had a successful track record in detecting deleterious indications at many plants. Moreover, the technique used in the 1997 IP2 inspection did find a PWSCC U-bend indication.

The data quality protocol in effect in the industry in 1997 relied largely on analyst judgement to determine whether noise was sufficiently extensive to mask a flaw. The response of the analysts to noise-influenced data at IP2 in 1997 was consistent with generally accepted analyst response throughout the industry at that time. In 1997, analysts generally accepted data that gave no indication of either electrical noise or signs of probe failure. For this reason there were few tubes designated as "bad data" category due to noise. This was in part attributable to the inherent limitations of eddy current techniques utilizing probes then available, which challenged the limits of flaw detectability in high noise environments. In contrast, during the 2000 IP2 inspection, sensitivity to R2C5 and newly established noise rejection criteria resulted in hundreds of tubes initially being placed in the bad data category when examined by the medium frequency +Point probe. The new criteria proved to be an effective measure given the availability of the high frequency probe.

The first formal industry requirement for data quality is expected to be addressed in Revision 6 of the EPRI guidelines, which are scheduled to be issued in March 2001."

From ConEd's root cause analysis, dated April 14, 2000, Con Ed stated that "[r]etrospective examination of the R2C5 data from the 1997 inspection showed an anomalous indication. Expert review of the data concurred that the flaw would not have been called by accepted EC practices in 1997, due to the background noise in the signal related to geometry effects and deposits including copper. Once identified, using current sizing practices, the 1997 R2C5 flaw signal was sized in the range of 63-71% average depth, and 92% maximum depth. Thus, the principal cause of the leakage was the inability to detect the indication in 1997 inspection due to noise in the signal; growth of the indication between 1997 and 2000 is moderate and is not the principal root cause for the leakage."

In ConEd's June 15, 2000 response to question 6 of a NRC RAI dated April 28, 2000 on ConEd's root cause analysis, Con Ed discussed the U-bend flaw that was found in the 1997 inspection, R2C67. According to ConEd's response, R2C67 had a measured length of 0.4 inches. The depth was estimated at about 50% or well below the screening criterion for in situ testing (depth of 75%).

Comparison to Other Older Plants

The other similar Westinghouse plants with noise issues are Kewanee and Prairie Island. Prairie Island never had copper deposits, while Kewanee originally had copper but removed it a while ago. IP2 appeared to be the outlier for noise impact. In 1997, the mid-range (300 - 400 KHz) plus point probe was in use, but not the high frequency (800 KHz) probes for noise issues. Tests conducted by NEI in 2000 showed that the mid-range plus point probe was site validated for Kewanee and Prairie Island, but not for IP2 (ref. NEI/EPRI 2000 Noise Study) during the 1997 examination. Before the IP2 event, most plants used the mid-range probes for low row u-bend examinations. The high frequency probes were not commonly used. There were no site validations for the high frequency plus point probes at that time. After the event, other plants have started using the HFPP similar to IP2.

Industry Standards for Noise

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 standards were not in place, but trained analysts would know if they had noise levels that interfered with their ability to call indications. The opinions of the staff were that IP-2 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 indications 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. The eddy current techniques, software, and hardware are not unique to the nuclear industry, and can be used in similarly sized tubes in other heat exchangers. According to NRC staff, Zetec starting incorporating the measurement of noise in their analysis software, Eddynet 2, in 1995, in response to NRC concerns. They also provided specific guidelines on noise in their training classes *(need to confirm this)*. This improvements made to Zetec software didn't help IP2, because Westinghouse used their own software when they conducted the 1997 SG inspections. The staff has noted that approximately 65 - 70% of all eddy current testing in the steam generators in commercial nuclear power plants is performed by Westinghouse. If this is correct, their analysts should be in a unique 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 SG examination guidelines from the Electric Power Research Institute were also reviewed for guidance on the effects of noise on data quality. The guidelines have been widely accepted by the commercial nuclear industry for many years, and are frequently cited in the utility inspection plans and reports. "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." [PWR Steam Generator Examination Guidelines] 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. The task group reviewed both Revision 4 and Revision 5 of the PWR Steam Generator Examination Guidelines to see what guidance it 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 in content. For example, in Revision 4, the reader is told,"[d]istortions to bobbin coil signals typically occur as the 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. In either case, the use of appropriate diagnostic methods may generally provide an improved signal-to-noise ratio for better appreciation of the significance of the indication(s) in question. If an indication cannot be properly resolved, the tube shall be subjected to a documented engineering disposition." In the instructions regarding the practical examination data set to be used to qualify the analyst, Revision 4 directs that "[E]xtraneous test variables (e.g., denting, deposits, tube geometry changes) shall be included for each damage mechanism category, where applicable, based on steam generator operating experience."

Further, under the section titled "Training and Laboratory Program Contents: Steam Generator Eddy Current Data Analysts", one of the items in the list under "Data Analysis Principles: Factors Affecting Frequency Selection" is signal-to-noise. In the section that describes "Qualification Requirements for Examination of Steam Generator Tubing", instructions for the qualification data set direct that "where applicable, the influence of extraneous test variables associated with each of the damage mechanisms (e.g., denting, deposits, tube geometry changes) shall be assessed." Although the guidelines are weak in suggesting how to deal with noisy data, it is clear that the phenomena was recognized as an issue at the time that Revision 4 was written, June 1996.

Further additions to the discussion about noise are found in Revision 5 of the examination guidelines. In discussions on establishing a qualification data set, given in supplement J2, the reader is told that "flaws should produce signals similar to those being observed in the field in terms of signal characteristics, signal amplitude, and signal to noise ratio." In addition, in the "Summary of Requirements" in Revision 5, it states that "data quality requirements shall be determined and documented prior to the beginning of the examination process." In the discussion on Site-Qualified Techniques under the Technique Performance Requirements section, a documented review of a qualified technique's tubing-essential-variables (e.g., denting, deposits, tube geometry changes, the signal characteristics) is suggested to "ensure the application is consistent with site-specific steam generator conditions. The review shall establish tubing essential variables of the flawed tubes in the data set are similar in voltage and signal-to-noise to expected in-generator signals. If the review does not show similarity of tubing essential variables, the technique is not considered site-qualified." In addition, the utilities are directed to perform a degradation assessment, taking into account the presence of tube supports, geometric discontinuities (e.g., U-bends, expansion transitions, dents) or deposits which may mask defect signals."

Looking ahead, NEI told the NRC staff at a July 26, 2000 public meeting at NRC headquarters that lessons from IP-2 would be factored into Revision 6 of the examination guidelines. The objectives of the revision is to develop generic guidance on data quality which applies to all EC probes, which would include quality parameters, acceptance criteria, frequency of testing, and location of test. Specifically, draft data quality reports for bobbin and Plus Point have been developed for inclusion in Revision 6. This revision is being reviewed by vendors who ultimately have to implement them in their acquisition software.

5.1.2.3 Available Inspection Techniques

The task group talked with NRC staff familiar with the history of the eddy current techniques in current use. In the early 80's, the industry used primarily one frequency in their eddy current analysis. During that time, research funded by the NRC and industry was indicating that improved analysis was possible by acquiring the data at more than one frequency. By that time, it was well known that increasing the frequency restricted the signal to less depth in the tube, i.e., at high frequencies the eddy current just "saw" the inner part of the radius of the tubes. By using a mix of frequencies, this allowed the analyst to screen out extraneous data such as the presence of secondary side deposits or support members. The probes were designed to acquire data at multiple frequencies, so the data could be acquired from a single pull of the probe through the tube.

The mainstay of the eddy current data acquisition has been the bobbin coil probe. The bobbin coil probe is commonly used because of its speed in acquiring data, around 24 to 48 in/sec. Although the bobbin coil probe is sensitive to indications perpendicular to the windings of the probe, it is relatively insensitive to circumferentially oriented degradation and poor at characterizing degradation. By [some date], rotating pancake coil probes (RPC) were in common use to detect circumferentially oriented degradation and characterize degradation. In actual practice, their use was limited to resolving bobbin coil indications because of the slow speeds of the probe (0.1 to 0.6 in/sec).

By 1995, some plants were using a mid-frequency (around 300 kHz) rotating pancake coil probe with the trade name + Point, developed by Zetec, Inc. The NRC staff mentioned that even though the submittals from Con Ed would seem to suggest that high-frequency probes had not been used previously for steam generator inspections, they had been used for top-of-the-tubesheet inspections at Maine Yankee in 1994 and sleeve weld indications at another plant.

In 1995, Con Ed proposed to use a Cecco-5 array probe on an exploratory basis to detect defects, including axial and circumferential flaws in the tubesheet and tube support plate regions from the hot leg
top support plate to the hot leg tube end [1995 Inspection Report from Con Ed, dated June 14, 1995]. However, the U-bend regions were examined with the Rotating Pancake Coil probe (RPC) because of the limited flexibility of the Cecco for small radius bends. The Cecco-5 array probe also contained a bobbin probe, to reduce overall inspection time. For the 1997 inspection [1997 Presentation from Con Ed on their inspection plan, April 24, 1997], Con Ed proposed to use the Cecco-5/bobbin coil probe for the primary method of detection. The mid-range +Point probe was used for sizing and at locations that restricted the use of the Cecco-5 probe. Based on the 1995 exploratory use of the Cecco-5 probe, Con Ed evaluated the probe as sensitive to axial, circumferential, and volumetric degradation. Con Ed's desire to use the Cecco-5 probe was based on the data acquisition speed, 10 inches per second for the Cecco versus 0.1 inches per second for the +Point.

In the 2000 inspection [Cycle 14 Condition Monitoring Assessment and Cycle 15 Operational Assessment (Westinghouse SG-00-05-010)], Con Ed discussed ultrasonic examinations performed in the freespan sludge pile region during the 2000 inspection. Con Ed states that "[u]ltrasonic inspection was selected because it is not affected by copper-bearing sludge." In the June 19, 2000 response from ConEd to the March 24, 2000 RAI question 16 from the NRC, Con Ed states that "[t]he reason UT testing was of significant assistance in confirming the reliability of the eddy current analysis in the sludge pile and deposit regions is that the principles

upon which UT operates are different than eddy current. UT assesses the condition of the tube by the time of flight of directed sound waves rather than by electromagnetic induction. Sound is directed in three different directions in order to detect and characterize axial, circumferential and volumetric indications. UT is not affected by conductive and magnetic variations due to deposits and can more easily separate out the deposits from the tube itself. Thus, the UT results provide an independent technique to confirm the accuracy of eddy current analysis." The response also stated that the UT probe was restricted from passage at the first support plate in one tube that was tested. For the same reasons that UT was chosen for characterized flaws in the presence of deposits and sludge, this may be a good choice for the U-bend region. The probe size would have to be reduced to enable passage through the tight radius U-bends.

Comparison of Cecco with Plus Point

Con Ed performed blind Cecco-5 probe to +Point probe comparison tests in 1997. The tests were performed with a primary/secondary and resolution process, with the analysis performed by different and independent crews. The first test consisted of thirty two tubes with 138 tube support plate intersections. The second test consisted of twenty tubesheet crevice locations and forty locations that included the top of the tubesheet and tube support plate intersections. Con Ed did not indicate that they did a comparison of the probes in the U-bends. The Cecco-5 probe detected more flaw indications than the +Point probe during the blind study, leading Con Ed to conclude that the Cecco-5 probe was a satisfactory substitute for the RPC in some cases. Based on the results of the tests, Con Ed decided to use the Cecco-5 probe as the probe-of-record, and the +Point to characterize indications, as needed. The 1997 inspection report stated that one hundred percent of the U-bends of Rows 2 and 3 in all four steam generators were examined to the extent possible with the Cecco-5/bobbin probe. A Rotating Pancake Coil (RPC) probe was utilized to examine the bends if the narrow radii of the bends precluded passage of the Cecco-5/bobbin probe.

For the 2000 inspection, Con Ed originally applied a combination Cecco-5/bobbin probe to inspect the sludge pile region and used a midrange +Point probe to characterize the Cecco-5/bobbin indications, similar to their 1997 inspection practice. They reported a limited number of axially-oriented ODSCC indications in the sludge pile region, consistent with their past inspection results. After NRC staff reviewed the data, their assessment was that the noise levels in the Cecco-5/bobbin data were so high that outside diameter stress corrosion cracking (ODSCC) would be difficult to detect. When Con Ed performed a post in-situ eddy current inspection of a defect found in the sludge pile exam, they found that an indication located in the crevice region of the tubesheet in the same tube had been missed by the Cecco-5/bobbin analysts. This tube was in-situ burst tested, and marginally failed the structural integrity criterion ($3\Delta P$). The failed burst test suggests that this indication was probably of significant size in 1997, and was missed by the Cecco-5/bobbin probe examination. When Con Ed began to reevaluate other crevice data, they found more missed crevice indications. After the NRC staff expressed its concerns about the Cecco-5/bobbin examination, Con Ed decided to enhance its inspection efforts by using a midrange freqency +Point probe over the entire sludge pile region. Use of this inspection technique is also consistent with general industry practice in this region of the steam generator.

5.1.2.4 EPRI Appendix H Qualification

The 1997 tube examination at IP2 was conducted by Westinghouse personnel (contractor) under purchase specification No. NPE - 72217, Eddy Current Examination of S/G Tubes (7/8 inch; 0.050 inch thick tubes), IP2, revision 0, dated 12/17/96. The specification (specs.) defined

the requirement for ECT of S/G tubes at IP2. Among others, it stated that examination techniques are in accordance with EPRI SG Exam Guidelines, Appendix H. It also specified the preferred bobbin coil probe frequencies as: 10, 100, 200, and 400 kHz. It also specified that specialized probes shall utilize frequencies consistent with their application under the EPRI qualification program. The probes shall be capable of identifying defects in the presence of sludge and/or copper deposits. Section 4.8 of the specs states that state of the art probes for supplemental examinations shall be used to detect or further characterize eddy current indications found by the initial examination, as required by the company (ConEd).

For the 1997 Examination, IP2 was committed to the EPRI PWR Steam Generator Examination Guidelines, Revision 4. Section 7.3, Qualified Techniques, discuses that probes and degradation methods for which industry peer review has been satisfied could be used for the qualification of the examination technique. It 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.

During the 1997 inspections, the ECT calibration setup at Indian Point 2 was in accordance with the EPRI guidelines and are specified in the EPRI Eddy Current Technique Specification Sheets (ETSS). For U-bend +Point inspections, ETSS-96511 specified that the phase angle of the 40% ID flaw be set to 10 degrees. The 1997 IP2 technique sheet Analyst Technique Sheet (ANTS) IP2-97-E, specified the probe motion and through wall signals as setup references. With this setup, the smallest ID flaw - 20% on the EPRI Guidelines, Rev. 4 calibration standard, measured about 0 degrees (°) or less. Looking back at the 1997 setup and using the same setup technique on a standard that had both the 20 and 40% ID notch, it was identified that the phase angle for the 40% ID flaw was set at 5 to 6 degrees instead of the ETSS required 10 degrees {Industry tolerance is ± 3 degrees). Nevertheless, the licensee maintains that the review of the 1997 data for the tube that failed (R2C5) using the mid-range probe and the 2000 setup (phase rotation set at 15 degrees) also did not show a flaw.

The results of NRC's 1997 inspection of the eddy current testing activities, documented in NRC Inspection Report 97-07 dated July 16, 1997, indicated that the steam generator examinations were conducted in accordance with EPRI S/G Tube Inspection Guidelines. The report also noted that ConEd expanded their examination to inspect <u>all</u> support plate intersections with CECCO-5 probe and full length of all tubes with Bobbin and that they also used Plus Point probe during the examination.

5.1.2.5 Structure/Qualification of IP2's Examiners and Analysts

<u>NRC Oversight of IP2 Steam Generator Program - Our Regional Inspection Findings from 1995 and 1997</u>

Inspection Report No. 50-247/95-07 - 1995 Steam Generator Inspection

The inspector had the following findings: 1) their steam generator tube examination program for the current refueling outage conformed to code and regulatory requirements regarding code

edition and administrative controls of the program; 2) the steam generator eddy current examination met the requirements of the NRC Regulatory Guide 1.83, Rev. 2; 3) the licensee's oversight of contractor's nondestructive examination activities was good and effective. In particular, we noted that the oversight of in-service inspection activities performed by contractors is routinely provided by the quality control unit through surveillance. We noted that the surveillance checklists used by the quality control inspectors are elaborate and extensive. ConEd's Nuclear Power Engineering was responsible for developing steam generator tube examination programs and providing necessary oversight of eddy current examination activities, including the data analysis, resolution of indications, and plugging of defective tubes.

Inspection Report No. 50-247/97-07 - 1997 Steam Generator Inspection

Based on the 1997 findings by the regional inspection specialist, the steam generator eddy current analysis procedure was found to be acceptable, approved by the EC vendor and licensee personnel, and in accordance with ASME Code and TS requirements. This procedure provided clear guidance to primary and secondary analysts on requirements for identification and recording of indications. The procedure also delineated clear criteria for the type of indications that require further inspection in order to be appropriately dispositioned. Examination data and documentation were also in accordance with the EC analysis procedure and ASME Code. The Con Edision Eddy Current level III inspector closely followed the activities of the contractor performing the steam generator ISI.

Con Edison's tube examination program was prepared in accordance with the Electric Power Research Institute (EPRI) steam generator tube inspection guidelines. As a result of early eddy current inspection findings, an expansion was made to inspect all support plate intersections with the Cecco-5 probe and the full lengths of all.the unplugged tubes with the bobbin coil probe.

EC data acquisition personnel followed appropriate procedures, controlled critical parameters, and performed calibration checks as required. The scope of the EC inspections with the bobbin coil, Cecco-5, and Plus-Point coil probes exceeded TS requirements. A Cecco-5 EC probe was used for screening indications of the tubing support plate intersections and 20 inches above followed by a characterization using Plus Point probes. The bobbin coil portion of the Cecco-5 probe was being used to examine the straight portions of the tube at elevations higher than 20 inches above the tubesheet. The tubesheet area and the lower 20 inches were being examined with the Cecco probe.

EC analyst (primary, secondary and resolution) appeared to be performing analysis in accordance with the EC analysis procedure. Con Edison had an independent **(?)** EC level III contractor reviewing EC data to ensure the proper identification and recording of indications.

The inspector reviewed records of the qualifications and certifications of the Westinghouse personnel involved in the performance of the steam generator tubing eddy current data acquisition and analysis activities. Based on this review, and interviews with eddy current personnel, the inspector determined that these individuals met the qualification and certification requirements stated in the pertinent supplement of SNT-TC-1A and ASME Code Section XI.

The inspector found the steam generator tube inspection program procedures and implementation acceptable. The personnel managing and implementing the program were knowledgeable and followed procedures. Con Edison appropriately expanded inspections based on inspection findings.

Based on the review of Con Edison's specification, qualification and certification records, interviews with EC personnel and direct observation of the EC activities in progress, the inspector concluded that Con Edison maintained good oversight of the qualification and certification of EC personnel.

5.1.2.6 Impact of calibration standards used by IP2 for the 1997 and 2000 inspections

1997 Examination

During the 1997 inspections, the ECT calibration setup was in accordance with industry requirements and are specified in the EPRI Eddy Current Technique Specs. Sheets (ETSS). For U-bend +Point inspections, ETSS-96511 specifies that the phase angle of the 40% ID flaw be set to 10 degrees (however, the EPRI PWR SG Exams Guideline - Rev. 4 in effect in 1997 did not have a 40% ID flaw). The 1997 IP2 technique sheet Analyst Technique Sheet (ANTS) IP2-97-E, specified the probe motion and through wall signals as setup references. With this setup, the smallest ID flaw - 20% on the EPRI Guidelines, Rev. 4 calibration standard, measured about 0 degrees (°) or less. The + Point U-Bend probe was first used at IP2 during the 1997 outage, It was qualified per Industry Guidelines that was in existence at that time (EPRI Guidelines, Revision 4). A site specific qualification was neither required by the EPRI Guidelines, Rev. 4, nor performed at IP2 in 1997.

(Possibly More from the special team's report)

2000 Examination

During the 2000 Examinations, the mid range and high frequency probes were EPRI Appendix H qualified for detection per ETSSs #99997.1 and .2. The high frequency + Point probe offered the best available probe for inspection of the U-bends in the presence of deposits including copper. A site specific validation was developed per rev. 5. of EPRI Guidelines. EPRI ETSS-99997.2 was prepared for the 800 KHz test frequency.

The EPRI guide has a 40% ID notch and was used in 2000 at IP2 as specified in ETSS-96511. The site specific technique sheet, ANTS IP2-00-E, specifies 15 degrees for the 40% notch, which is more conservative than the 10 degrees EPRI ETSS requirement.

(Need input from the NRC's 2000 Inspection - W. Schmidt and/or Stephanie C.)

5.1.3 Conclusions

Inadequate follow-up of U-bend apex flaw (R2C67) identified in 1997. Therefore, the noise issue was not properly followed up and resolved and the failed tube was not identified in 1997.

Although not specifically required in 1997, IP2 did not have a site specific validation for the mid-range frequency probe used in 1997 for the copper deposit induced signal distortion they had in their steam generators. Therefore, there was a missed identification in 1997 of the flaw in the tube that failed in 2000.

5.1.4 Recommendations

1) The limitations of their U-bend inspection were due to limitations in data quality in that region, not due to inadequate sample scope.

2) There is a problem with lack of specificity in TS with respect to inspecting for "hourglassing" as a degradation process. The TS directs Con Ed to report significant hourglassing. The licensee and NRC staff should agree on a measurable definition of "significant" for hourglassing.

3) The EPRI guidelines should provide data quality measures. The licensees should be given explicit direction in the guidelines in how to identify excessive noise in the data, how to identify the source of the noise, and what to do about the problem after the source is identified.

4) There is a fundamental inconsistency in using the eddy current data for assessing structural integrity of the SG tubes. The staff has repeatedly said that none of the techniques used - bobbin, Plus Point, or Cecco-5 are currently qualified for sizing axial or circumferential flaws. Yet, 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 leads to a problem noted by a NRC staff member in a public meeting - the licensees believe in the reliability of the results of their eddy current to a much higher degree than they should. To address this problem, current techniques must be improved to enable the industry to use techniques that can be reliably qualified for sizing.

5) In their Blind Comparison Study of the Cecco-5/Bobbin probe versus the +Point probe, Con Ed should have also compared data from more areas of the steam generator, especially the U-bend area.

6) Because ODSCC at the U-bends has been observed for CE plants, eddy current techniques for SG tube with noisy signals in the U-bends should have a strategy for enhancing the examination of the outside of the tube. Perhaps UT could be used in this context.

7) In the noise study that compared the noise levels in the eddy current data from two other older plants, NEI produced noise data for the qualification standard that is much higher than the two plants compared with IP-2. Most of the tubes contained in the standard are new tubes. Unless there is something unique about these new tubes that would not be found in the general population of steam generators in the field, this finding should be assessed generically. Based on this finding, we cannot rule out noise in U-

bends based on just age of the steam generators or deposits on the outside of the tubes. If new tubes can contain this level of noise, the flaw detection capabilities in the U-bend region in newer plants should be assessed.

8) During the SG inspections, noise levels should be evaluated by the licensee and this information should be provided with the inspection reports. One way to do this would be to have the licensee provide a disk with sample data for review by a NRC consultant.

9) In addition to using two human analysts for the primary and secondary analysts, the industry should consider using computers to screen the test data.

10) The licensee's should ensure that they have sufficient in-house expertise even if they contract out the inspection function.

11) Plants could benefit from site-specific demonstration programs before getting into the examinations.

5.2 Condition Monitoring/Operational Assessment

5.2.1 Background

The charter for the IP2 Steam Generator Tube Failure Lessons-Learned Task Group directs the group to identify any generic technical or process elements that may be improved in the NRC's review of steam generator issues. In that context, the group is directed to recommend areas for improvement in the NRC's internal processes for regulating steam generator tube integrity and leakage and areas for improvement in industry's activities and guidelines related to managing steam generator tube integrity.

Condition monitoring and operational assessment reports have become a vital part of the steam generator integrity assessment process, for both the licensee and the NRC. The condition monitoring process is "backward looking, in that its purpose is to confirm that adequate steam generator tube integrity has been maintained during the previous operating period." The operational assessment process is forward looking, in that its "purpose is to demonstrate that the tube integrity performance criteria will be met throughout the next operating period until the ensuing scheduled tube inspection." (EPRI Steam Generator Integrity Assessment Guidelines)

Condition monitoring is performed while a plant is in outage. This involves inspecting the tubes according to the sampling requirements in their TS and the current revision of the EPRI Steam Generator Examination Guidelines, and performing structural and leakage integrity assessments based on the results of the inspections. The indications found during the inspection are evaluated against the performance criteria for structural and leakage integrity. "Structural and leakage integrity assessments of the inspected tubes are performed and results compared to their respective performance criteria. If a plant is operating under the requirements of its Technical Specification's repair limit, the bounding assumptions supporting this limit (e.g., growth, NDE uncertainty) need to be verified. Tubes need to be repaired according to the most limiting of the plant's technical specifications or the results of the integrity assessment. Condition monitoring also involves comparison of any operational leakage, occurring within the steam generators, with the performance criterion." (EPRI Steam Generator Integrity Assessment Guidelines)

"Structural integrity performance criterion is: Steam 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." (EPRI Steam Generator Integrity Assessment Guidelines)

"The accident induced leakage performance criterion is: The primary to secondary accident induced leakage rate for the limiting design basis accident, other than a steam generator tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all steam generators and leakage rate for an individual steam generator. Leakage is not to exceed [1 gpm per steam generator, except for specific types of degradation at specific locations where the tubes are confined, as approved by the NRC and enumerated in conjunction with the list of approved repair criteria in the Technical Requirements Manual]". (EPRI Steam Generator Integrity Assessment Guidelines)

"The operational leakage performance criterion is: The RCS operational primary-to-secondary leakage through any one steam generator shall be limited to the more conservative of the values given in the plant's Technical Specifications or the PWR Primary-To-Secondary Leak Guidelines."

The operational assessment evaluates the inspection findings against performance criteria at the end of the next operating period. 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. Factors that are important to this analysis are probability of detection (POD), growth rate, and NDE sizing. "A preliminary operational assessment is performed before startup by factoring the degradation growth rate into integrity and leakage analysis. The purpose of this assessment is to determine whether integrity performance criteria will be met or whether additional tests, repairs, inspections, or other actions may be necessary. All active degradation mechanisms must be considered appropriately in the analysis.

Based on the results of the condition monitoring and operational assessments, steam generator tube integrity can be measured against performance criteria. If the performance criteria is not met, actions can be taken by the licensee to either repair the tubes or modify the run time or operational parameters to satisfy the performance criteria." (EPRI Steam Generator Integrity Assessment Guidelines)

At the time of the last inspection at IP-2 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, but rather their reporting was based on requirements in their TS. Although the conceptual framework for condition monitoring and operational assessments was established in draft Regulatory Guide 1.121, issued for comment in August 1976, the terms for the reports and their content 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. The EPRI guidelines for the NEI 97-06 steam generator framework have provided consistent industry standards for performing these assessments within the EPRI document "Steam Generator Integrity Assessment Guidelines: Rev. 0".

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 areas that were considered are as follows:

A. Evaluation of new types of degradation
B. Basis and uncertainties for detection of degradation
C. Basis and uncertainties for degradation growth rates
D. Use of in-situ pressure tests
E. Assessment methodology and decision criteria

5.2.2 Observations

1997 Inspection

The task group reviewed the following documents from Con Ed:

- 1997 inspection report

- December 7, 1998 Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency

- May 12, 1999 response to request for additional information for proposed amendment

This review was to evaluate and compare the condition monitoring and operational assessments performed and how this information was documented in their 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. In 1997, the guidance for these types of assessments wasn't provided in an EPRI guidance document as in 2000.

The 1997 inspection report discussed the actual (as compared to planned) inspection scope and inspection 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:

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

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

- results of a blind comparison study with the Cecco-5 probe and the +Point probe

- 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. 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 hourglassing of the flow slots was reported.

The 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 a tube in Row 2 and Column 67, even though it was the first time they had found PWSCC in the U-bend region of the tubes. This review also indicated that the tube with the U-bend flaw 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 inspection report notes that a condition monitoring report was performed for the just completed Cycle 13 and no mention was made of completing a 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 steam generator 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.

The December 7, 1998 Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency based their technical argument on the comprehensive inspection that had been performed. The request further stated that the steam generators 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 steam generator 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 the apex of the U-bend for a tube in Row 2 and Column 67, and how that was assessed.

Con Ed sent a May 12, 1999 response 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 IP-2 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 also requested additional information on their 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 that Con Ed first discussed the significance of the indication found in the apex of the U-bend for a tube in Row 2 and Column 67. In this RAI is the first discussion and results of the operational assessment. Their 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.

- For the indications in the sludge pile region thought to be due to pitting attack, their conclusion was that because the maximum pitting depth in 1997 was evaluated at 45% by bobbin, tube integrity would not be challenged from this mechanism. The bobbin coil signal from the combination Cecco-5/bobbin probe was used for pit sizing in 1997.

- For ODSCC in the sludge pile region above the top of the tube sheet, the response noted that it was detected for the first time in 1997, with a possible precursor signal from the 1995 eddy current data. The response concluded that based on the sludge pile flaw eddy current characteristics at IP-2 and in-situ testing results from more limiting flaws at similar plants, this corrosion mechanism would not represent a burst or steam line break potential at end of cycle 14.

- For ODSCC in the tubesheet crevice, the response concluded that this mechanism would not challenge structural integrity during the cycle because these indications are restrained from burst due to the presence of the tubesheet, the in-situ burst tests showed margin without leakage, and the operating criteria for Cycle 14 was not essentially different from Cycle 13.

- For the Roll Transition PWSCC, the response concluded that structural integrity would not be challenged during the cycle on the basis of in-situ burst testing for an indication in this region.

- For the PWSCC at Dented Tube Support Plat Intersections, the response discusses the difference in detection in this region between the Cecco-5 and +Plus Point probes. It notes that the PWSCC indications at these locations were plugged primarily on the Cecco-5 response. The lack of a +Point response in this region strongly suggested to the licensee that these intersections would not represent a leakage potential during a postulated steam line break. They also suggested that a lack of a +Point response may have been due to some other causal mechanism, such as OD tube deposits.

- For the ODSCC at Dented Tube Support Plate Intersections, +Point verified 3 indications that had been identified by the Cecco-5 probe. Since none of the indications at dented tube support plates extended out of the plates, the response concluded that the tubes would be precluded from bursting in that location.

- For the PWSCC indication, the response noted that a Row 2 U-bend PWSCC was found for the first time in the 1997 outage. The response noted that the row 1 tubes were preventively plugged and the dimension of the indication by +Point characterization was below the in-situ screening criteria. The response concluded that growth rates associated with this indication would be considered minimal, since this was the first indication in 23 years.

<u>Basis and Uncertainties for Detection of Degradation</u>

As noted above, the 1997 inspection did not provide a discussion for the basis and uncertainties for detection of various types of degradation. The inspection report was used to discuss the actual inspection scope during the outage, provide a list of tubes repaired, report on hourglassing as required by their TS, 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. The December 7, 1998 Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency did not discuss the basis and uncertainties for detection in much more detail than the inspection report. In fact, the proposed amendment request repeated much of the information in the inspection result 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, the May 12, 1999 response to a April 19, 1999 request for additional information (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. Con Ed preferred this probe due to the faster data acquisition time when compared to other RPC technology such as +Point. Con Ed also reported that the Cecco-5 reported more indications than the +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 use of the +Point probe was reserved for situations where the Cecco-5 probe was limited in travel due to tube restrictions. Their 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 . Even in locations where the blind study had been performed, there were concerns about the confirmation of Cecco-5 indications with +Point. In the RAI response, there was a concern with a lack of +Point confirmation of Cecco-5 calls that indicated PWSCC at Dented Tube Support Plat Intersections, which they attributed to some mechanism such as interference from outer tube deposits. The handout from the April 24, 1997 Con Ed presentation on their 1997 Steam Generator Tube Inspection Plan discusses the Cecco probe,

and points out that the "potential was there - shortcomings needed addressed." Examples given for the shortcomings included "asymmetric dent samples needed" and "C-scan capability needed". Based on this finding, it would seem prudent to develop a blind study protocol that includes all areas of the steam generator 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.

Basis and Uncertainties for Degradation Growth Rates

The review of the inspection report revealed that growth rate data was not provided.

The December 7, 1998 Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency provide conclusions on growth rates during 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 steam generator 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 discussion indicated that this nominal increase or decrease was 3 - 4%, which was stated as within the accuracy of the eddy current measurements. This statement about the accuracy of the eddy current measurements was somewhat optimistic, as a figure of around 10% *(check this)* is more representative of industry experience. The amendment request also concluded that since the steam generators were maintained in cold shutdown temperature conditions, the environment for corrosion was reduced to an inconsequential level. No appreciable steam generator 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 response to request for additional information for proposed amendment provide limited information on the degradation growth rates resulting from the period of plant operation. As requested in the RAI, the growth rates were considered for each type of degradation:

- 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.

- ODSCC Above the Top of the Tubesheet (Sludge Pile): The response stated that 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 +Point. Therefore, assuming the +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 +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. (This is interesting, considering that the U-bend flaw was not in-situ tested because it did not meet the screening criteria – was the measurement uncertainty allowance added for PWSCC U-bend flaws, also?)

- ODSCC in Tubesheet Crevices: No growth rate information was given.

- Roll Transition PWSCC: No growth rate information was given.

- PWSCC at Dented Tube Support Plate Intersections: No growth rate information was given.

- ODSCC at Dented Tube Support Plate Intersections: No growth rate information was given

- 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 RES of this amendment request, dated March 16, 2000, discussed the adequacy of the information provided by Con Ed in the RAI response. The RES review found this response to the staff's question about their results of their 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. NRR staff agreed that the contention was ridiculous, but did not based their technical conclusions on that premise but on the basis that the results from the 1997 inspections established appropriate safety margins.

<u>Use of In-Situ Pressure Tests</u>

According to the May 12, 1999 RAI response, the selection process for the in-situ pressure tests was according to Westinghouse screening criteria, which evaluated all the degradation mechanisms listed in the above section with the exception of sludge pile pitting (pitting above the top of the tubesheet). The burst screening procedures were based on 1) crack voltage, critical or threshold, 2) maximum depth, and 3) depth profiling.

- Pitting Above the Top of the Tubesheet: The pit indications were not assessed because the criteria for pits wasn't included in the Westinghouse screening criteria. In spite of this, pit indications were screened based of a maximum bobbin coil depth of 50% and voltage of 3 volts. No indications met this criteria.

- ODSCC Above the Top of the Tubesheet (Sludge Pile): One indication measured at 48% maximum depth and a 0.54 inch length met the screening criteria and was pressure tested to 5075 psi without burst or leakage. Other ODSCC sludge pile indications were detected but did not meet more than one of the screening parameters, although a 20% measurement allowance was provided in the in-situ screening parameters.

- ODSCC in Tubesheet Crevices: The indication with the largest +Point indication was in-situ pressure tested, as well as the three others that exceeded the screening parameters. The four tested tubes showed no evidence of leakage when tested to a nominal cold pressure of 2900 psi (which is equivalent to approximately 2636 psi at operating temperature.) This pressure corresponds to the steam line break pressure. Testing to three times normal

operating pressure, 3ΔP structural requirement, was not performed. Although the reason for just using the lower pressure is not discussed explicitly, it may be that the lower pressure was chosen because the axial ODSCC indications within the crevice were considered to be restrained from burst by the presence of the tubesheet.

- Roll Transition PWSCC: An approximately one-half inch long indication in the original hard roll region was in-situ tested. The indication was pressure tested without leakage to show that indications that are reroll repaired did not typically represent a leakage potential. Again the indication in the tube was tested to a nominal cold pressure of 2900 psi. Another tube that was in-situ tested had both an axial ODSCC in the tubesheet crevice as well as a circumferential indication. This tube was also in-situ tested without evidence of leakage.

- PWSCC at Dented Tube Support Plate Intersections: Based on their analysis that indications remaining within the tube support plate regions would not represent a burst potential, they postulated axial PWSCC flaw sizes for parts of flaws that extend out of the TSP. Their analysis showed that a 0.42 inch long, 100% through-wall over the entire length flaw would be expected to provide integrity consistent with the 3ΔP structural requirement. No indications of this type were in-situ tested.

- ODSCC at Dented Tube Support Plate Intersections: Same technical argument as PWSCC. No indications of this type were in-situ tested.

- PWSCC at the Row 2 U-Bend: Con Ed believed that the dimension of the indication by +Point characterization was below the in-situ screening threshold for Row 2 U-bend flaws. The NRC staff believed that similar to their 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.

In summary, the 1997 inspection report from Con Ed contained a table summarizing the in-situ tests performed. Six tubes were tested, four from the tubesheet crevice region, one from the freespan above the top of the tubesheet, and one that was typical for the roll transition cracking region. All were successfully tested to pressures of at least 2900 psi without leakage or burst, although just one (the freespan above the top of the tubesheet) was tested to 5075 psi, three times normal operating pressure or 3ΔP structural requirement. Since the in-situ testing is used to assess the reliability of the NDE, it can only be conjectured whether the remaining 5 tubes would have met the 3ΔP structural requirement.

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 in some cases not consistent with other industry experience. As mentioned previously, NRC based their 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 text.

2000 Inspection

For the 2000 inspection, three reports were submitted. The reports consisted of a specific report concerning Primary Water Stress Corrosion Cracking in the U-Bend, a report discussing the remaining degradation mechanisms, and a report that compares the corrosion performance

of the IP2 steam generators to industry experience with Model 44 and Model 51 steam generators. Unlike for the 1997 inspection, Con Ed and Westinghouse could use the EPRI Steam Generator Integrity Assessment Guidelines, Rev. 0 , released in December 1999, 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 in their steam generator outage in 1997.

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, the results are given for the different types of analyses, along with the inputs.

Basis and Uncertainties for Detection of Degradation

The original inspection plans after the plant shut down due to the tube failure had Con Ed using the same inspection methodology as with the 1997 SG outage, using the combined Cecco-5/bobbin probe and the mid-frequency +Point probe. Based on staff recommendations based on noise levels in the data, the inspection plans expanded to using a 800 kHz high frequency probe. Even with the improvement in the inspection data from using the higher frequency probe, the staff had concerns regarding the NDE uncertainty arising from their inspections. These concerns arose primarily for the indications found in the sludge pile region and U-bends, and were based on Con Ed's reliance on on-site technique 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 technique validation had been performed in another region of the steam generator. Evaluating the uncertainties properly was especially important, because uncertainties of 5 – 10% could lead to a large difference in the burst pressures that would be calculated from the data. This increased the concerns by the staff in how structural integrity in the U-bends could be assured for the operating cycle.

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, 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 Electric Power Research Institute (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.

Basis and Uncertainties for Degradation Growth Rates

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 that the high frequency probe was not used in 1997 (had to compare the data at 400 kHz). 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.

Assessment Methodology and Decision Criteria

The assessment methodology and decision criteria submitted to the staff 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 C-scans and profiles provided to provide 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. Based on these inputs, there can only be a certain level of assurance of structural and leakage integrity based on the ability to accurately quantify these inputs.

5.2.3 Conclusions

Limitations exist to the extent that condition monitoring and operational assessments can capture the true integrity of the steam generator tubes. Even with the increased amount of information provided for the 2000 inspection condition monitoring and operational assessments, the outcomes are still dependent on uncertainties and difficulties in detection.

5.2.4 Recommendations

1) Even with these limitations, site validation of techniques can provide additional confidence in the capabilities to detect the degradation, especially in the regions of the generators that present the most challenge to inspect.

2) Licensees must be cautious not to rely too heavily on integrity assessments that are based on sizing techniques that are not qualified.

3) Licensees must also consider the effect of the threshold of detection on the growth rate assumptions.

4) The licensees should be careful to not rely on probability of detection values that are not representative of their inspection capability.

5) To enhance the reliability of the program, the licensees could consider evaluation programs that provide a "checks and balances" to the detection process, such as the Judas Tube Evaluation. This would consist of collecting tubes from the test and current inspection that had defects in them. They 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) If a blind study is performed between probes, the test should include areas of the generator that present the most challenges for detection.

5.3 Risk Insights

5.3.1 Background

Steam generator tube failures can occur spontaneously, that is the tube fails under normal operating conditions as a result of tube material degradation. A spontaneous tube failure occurred at Indian Point Unit 2 (IP2) on February 15, 2000. Tubes can also fail as a result of abnormal conditions associated with an accident or transient. Such failures are termed induced failures, and can result from a higher-than-normal differential pressure across the tubes that could result from main steam line rupture, or from combined effects of excessive pressure and temperature resulting from certain severe accident scenarios.

Both spontaneous and induced SG tube failures may be risk significant because radionuclides could bypass the reactor containment during these events. Containment bypass events result in a disproportionate amount of radionuclides being released to the environment, in comparison to other possible accident scenarios.

The criteria for a tube rupture, as analyzed in safety analyses and plant risk assessments is based on the level of primary-to-secondary leakage reached during the event. Regulatory Guide 1.121, provides a definition for tube rupture as "any perforation of the tube pressure boundary accompanied by a flow of fluid either from the primary to the secondary side of the tubes or vice versa, depending on the differential pressure condition prevailing during normal plant operation or developed in the event of postulated pipe break accidents within either the primary reactor coolant pressure boundary of the steam system pressure boundary." Typically, SG tube failures are categorized as tube ruptures if the leak rate from the failed tube reaches a level that exceeds the plant's normal makeup capacity. This is consistent with NUREG-0844 (p. 3-2) which states that SGTR events are defined by the NRC to be primary-to-secondary leak in excess of the normal charging capacity of the reactor coolant system. There is also a metallurgical definition for SG tube rupture that is unrelated to makeup capacity and not typically considered in risk assessments.

Obviously, the tube rupture criterion will vary among plants depending on plant conditions, plant-specific makeup capability, and the character of the tube failure (size, location, propagation). Tube ruptures are associated with leak rates in the range of several hundreds of gallons per minute. It is important to note that the tube failure at IP2 did not reach the level of leakage to catagorize it as a rupture, therefore, it will be referred to as a tube failure in this report.

The task group examined risk insights associated with the SGTR on both a plant-specific basis for IP2 and in a generic sense. In particular, the areas considered were:

- General risk insights on SGTR events derived from the IP2 event.

- Use of risk information in granting the IP2 SG inspection interval extension and in considering restart of the unit following repair of the tube failure.

1.04 Implications of the IP2 event on risk perspectives for SGTR.

Material relied upon by the task group included documented risk information and analyses of risk contributions from SGTR at IP2 before the event, as well as recent analyses using information derived from the event. The task group also sought the views of a number of key

agency staff familiar with risk assessment methods and with policies concerning the use of risk information for safety assessments.

5.3.2 Observations

5.3.2.1 General Risk Insights on SGTR Events Derived from IP2 Event

a. IP2 Event in Context of Previous SG Tube Failures

The Task Group reviewed information related to previous SG tube failures in order to put the IP2 event in context of other similar events. Table 1 provides a list of previous SGTR events at US PWRs based on information in Reference 1.

Reivew of the information in Table 1 shows that one spontaneous tube rupture has occurred about every **2 years at US PWRs during the past 20 years.** The frequency of spontaneous tube rupture was estimated in Reference 1 to be about **2.5E-2** per reactor year of operation. NUREG/CR-5770 Draft (Reference) states that the mean frequency of SGTR is 5.2E-3 **per critical year**, and that there is no statistical basis to show a decreasing trend in SGTRs experienced at US PWRs. The 5th percentile and 95th percentile values for frequency of SGTR given in NUREG/CR-5770 are 1.6E-3 and 1.1E-2 per critical year, respectively. The frequency of SGTR used in the IP2 IPE of **1.3E-2/ry** is close to the 95th percentile or conservative part of the range from the NUREG.

The classification of tube failure events as tube ruptures introduces some uncertainty in the estimated frequency of spontaneous tube ruptures. There have been a significant number of instances where tubes leaked, and the leakage was in a range where some studies considered the tube ruptured, but others did not. The NRC criteria for SGTR is a break causing a primary-to-secondary system leak in excess of the normal charging flow capacity (NUREG-0844). Therefore, classification of a particular event as a tube rupture is a function of a number of factors, such as plant conditions, break size, and the charging system flow capacity. As mentioned earlier, the event at IP2 did not result in high enough leakage to be considered a tube rupture.

The SGTR previous to the IP2 event occurred in 1993 at Palo Verde. The IP2 event does not indicate that the trend in occurrence of SGTRs is changing.

Examine rate/causes of "near-SGTRs"

Of interest to the Task Group was the similarity of the IP2 tube failure to the SGTR that happened at Surry in 1976. The similarity lies in the size and location of the failure at the u-bend apex in a low-row tube. The type of degradation, and hour glassing were other obvious similarities. The leak rate for the Surry SGTR is greater than the IP2 event leakage. The Surry and IP2 events are the only u-bend apex failures attributed to PWSCC. **Knowledge gained/lessons learned from Surry? Applicability to IP2???**

TABLE 1: SUMMARY OF TUBE FAILURES AT US PWRs

Plant/SG Model	Date	Leak Rate (gpm)	Size	Location	Degradation Mechanism	Contributing Factors
Point Beach - 1 W-44	2/26/75	125	2 adjacent ruptured bulges, each 20mm in length and width	Slightly above tube sheet, outer row hot leg	Wastage	Sludge pile
Surry-2 W-51	9/15/76	330[1]	114 mm long axial crack	U-bend apex, Row 1, Col. 7	PWSCC	Hour glassing
Prairie Island-1 W-51	10/2/79	336[1]	38 mm long axial fishmouth crack	76 mm above tube sheet, hot leg, Row 4, Col. 1	Loose parts wear	Sludge lancing equipment left in SG
Ginna W-44	1/25/82	760[1]	100 mm long axial fishmouth crack	127 mm above tube sheet, hot leg, Row 42, Col. 55 (3rd row from bundle periphery)	Loose parts wear, fretting	Baffle plate debris left in SG
Fort Calhoun CE	5/16/84	112	32 mm long axial fishmouth crack	Top of horiz. run, between batwing supports, hot leg, Row 84, Col. 29	ODSCC	Tube deformation from corrosion of vertical batwing supports, secondary side impurities
North Anna-1 W-51	7/15/87	637	360° circumferential crack	Top of 7th tube support plate, cold leg, Row 9, Col. 51	High-cycle fatigue	Lack of AVB support, denting
McGuire-1 W-D2	3/7/89	500	95 mm long axial crack, 9.5 mm maximum width	At the lower tube support plate, cold leg, Row 18, Col. 25	ODSCC	long shallow groove, possible contaminant
PaloVerde-2 CE-80	3/14/93	240	65 mm long axial fishmouth opening in an 250 mm long axial crack	Freespan between upper tube supports, hot leg, Row 117, Col.144	ODSCC	tube-to-tube deposit formation, caustic secondary water chemistry
Indian Point-2 W-44	2/15/00	146	**2.2 - 2.4 inch axial crack convert to mm**	U-bend apex, Row 2, Col.5	PWSCC	hour glassing

Notes: 1 - NRC estimate

b. SGTR Risk at IP2 Compared to Other PWRs

(See NUREG/CR 6365, Chap. 6). Consider both timeline (frequency) and consequences approaches.

In order to understand the generic risk impact attributable to the SGTR at IP2, it is important to put the IP2 event in the context of the risk of SGTR at other plants. NUREG/CR-6365, "Steam Generator Tube Failures" (Reference 1) provides a convenient 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 steam generator tube ruptures. Information from Table 18 in the NUREG is reproduced below.

Table 2: IPE Results for Selected US PWRs

Plant Name	Total CDF from Internal Events	Percent of total CDF from spontaneous SG tube ruptures	Percent of containment bypass fraction from spontaneous SG tube ruptures
Arkansas 1	5×10^{-5}	0.4%	26%
Callaway	4×10^{-5}	2%	10%
Comanche Peak	4×10^{-5}	6%	7%
Cook	6×10^{-5}	11%	11%
Diablo Canyon	9×10^{-5}	22%	11%
Farley	1×10^{-4}	0.04%	9%
Kewaunee	7×10^{-5}	8%	99%
Indian Point 2	3×10^{-5}	7%	**20% ????????**
Indian Point 3	4×10^{-5}	5%	79%
McGuire	4×10^{-5}	0.02%	2%
Seabrook	7×10^{-7}	1%	Not Available
Sequoyah	2×10^{-4}	4%	75%
Surry	2×10^{-4}	5%	Not Available
South Texas	4×10^{-5}	5%	22%
Trojan	6×10^{-5}	2%	Not Available
Vogtle	5×10^{-5}	4%	12%
Watts Bar	3×10^{-4}	3%	6%

Table 2 shows that based on the IPE information, IP2 is generally in the range of other plants for the total core damage frequency, the fraction of CDF attributed to spontaneous SGTR, and the containment bypass fraction attributed to spontaneous SGTR.

The contribution of the spontaneous SGTR to total CDF is not the measure used to determine the risk significance of various steam generator degraded conditions. This is because SGTRs generally result in containment bypass, and therefore, the offsite risk profile is much more strongly influenced by this event than is the CDF. Since containments reduce or eliminate the offsite consequences from most other core damage accidents, the risk contribution from SGTR gains increased significance.

Disproportionate risk considerations based on off site consequences from SGTR (Holahan comment). See transcripts from early 1980s. Any other information sources?????????

Induced SGTRs risk impacts resulting from combinations of high primary-to-secondary differential pressure or high primary system temperature were not explicitly considered in this report. As will be discussed, the staff risk assessment for IP2 based on the SG tube condition during Cycle 14 did consider induced SGTR contributions, as does the IP2 IPE. However, the relatively small contribution to SGTR risk at IP2 in this situation and the technical complexities involved with such considerations convinced the Task Group that for purposes of assembling lessons for the IP2 event, the risk considerations should be limited to spontaneous SGTR considerations.

5.3.2.2 Use of Risk Information in Granting the IP2 Inspection Interval Extension in 1999 and Making a Restart Decision in 2000

The 1999 safety evaluation granting the SG tube inspection interval extension (Reference) did not explicitly consider the risk impact of the inspection interval extension. The guidance in SRP 19, "Use of Probabilistic Risk Assessment in Plant-Specific, Risk-Informed Decisionmaking: General Guidance," (Reference) does not require that the staff consider risk information for the type of license amendment request that Con Ed submitted to the staff.

Section III.A of SRP 19.0 states:

> "Where the licensee's proposed change goes beyond currently approved staff positions, reviewers should consider both information derived through traditional engineering analysis as well as information derived from risk insights. ....If the licensee chooses not to provide the risk information, reviewers will evaluate the proposed application using traditional engineering analysis and determine whether the licensee has provided sufficient information to support the requested change."

The staff SER was based on information provided by the licensee that did not include a risk assessment. Based on their understanding of the condition of the SGs at that time, the staff judged that sufficient information was provided to support the request. **The Task Group judged that staff did not have reason to request risk information for this review and any such information probably would not have led to a different conclusion than was reached in the SER. This judgement is based on the risk information available in 1997, that would have used the IPE conclusions as a basis and not factored-in the potential failure from tube defects that were not called at that time.**

What role did risk information play in the restart SE?

5.3.2.3 The Impact of the IP2 Event on Risk Perspectives for SGTR

a. IPE Results

The understanding of the risk from SGTR before the IP2 tube failure is provided by the Individual Plant Examination (IPE) conducted by the licensee in response to Generic Letter 88-20 (Reference). The NRC reviewed the IP2 IPE submittal and issued a draft safety evaluation report in 1996 (Reference). The IPE gives an initiating event frequency for SGTR as 1.3E-2 per reactor-year (ry). The core damage frequency (CDF) for internal events has a mean of 3.1E-5/ry. Approximately 5 percent **(7% in NUREG table)** of that value is contributed by SGTR, or about 1.4E-6/ry.

The IPE considered core damage scenarios following tube rupture as well as an induced SGTR following a core damage event where primary system pressure remains high. The core-damage induced failure has an estimated frequency of 2.5E-7/ry.

Containment bypass is the primary concern for SGTR, because from a risk perspective the IPE results show that the largest fraction of containment bypass is associated with SGTR. Of the internal CDF of 3E-5/ry, about 6 percent is associated with containment bypass. Of the bypass fraction, about 86 percent is connected with SGTR-initiated events and about 13 percent from induced SGTR events. **Therefore, virtually all of the containment bypass sequences are associated with SGTR. BUT THE NUREG TABLE SHOWS 20% FROM SSGTR**

Consideration of operator actions was a key aspect in review of the risk impact of the IP2 event. The Task Group compared the AIT description of the event (Reference) to the assumptions used in the IPE to judge if the IPE estimate of SGTR risk applied to the event.

An important operator action for SGTR is isolation of the affected SG before overfill. This requires the operators to diagnose the event, take positive steps to assure that the SG is isolated, including terminating AFW flow to the affected SG. The operators must also cooldown and depressurize the RCS by opening steam dump valves, PORVs, and terminating safety injection. The IPE references MAAP analyses that indicate that overfill will occur approximately 30 minutes if the operators take no action. The IPE (Reference 10/31/95 RAI response, Q21) includes a detailed estimate of assumed operator time to perform certain actions. For example, specific times are estimated between isolating the SG and starting RCS cooldown, between completing cooldown and initiating RCS depressurization, and between completing depressurization and terminating safety injection.

The IPE human reliability analysis acknowledges that for SG tube failure scenarios where the symptoms of increasing radiation level and SG level are not as apparent as the case considered in the IPE analysis, the tube failure is less severe and more time would be available for response than credited in the IPE. The probability of manipulative error (the P_3 term in the IPE), or the chance that operators will not execute the proper steps in response to the event, is based on the estimated time available for key actions. The overall human error probability also includes that chance that operators mis-diagnose the event.

b. Comparison of IPE Assumptions to the Tube Failure Event

The NRC AIT report (Reference 4/28/2000) concluded that the tube failure event had moderate risk significance from the event response and mitigation perspective. The AIT was not charged with determining causal factors or assessing licensee performance that may have contributed to

the SG tube failure. The licensee performed the necessary actions to mitigate the event, and necessary mitigation systems functioned properly. No radioactivity was measured offsite in excess of normal background levels, and the event did not impact the health and safety of the public. The AIT identified performance problems in several areas that challenged operators, complicated event response, delayed achieving cold shutdown, and impacted the potential for radiological release. These problems were in areas including operator performance, procedure quality, equipment performance, and technical support.

The operator performance problems concerned initiation of an excessive RCS cooldown that exceeded procedural and technical specification limits. This action complicated the subsequent event response and delayed RCS cooldown. Operators were also slow to recognize system configuration problems that prevented successful operation of the auxiliary spray system, which was needed to lower RCS pressure, and lineup problems in the RHR system that complicated placing RHR in service.

Some procedural problems delayed RCS cooldown and depressurization.

Although a number of equipment problems were cited in the AIT report, none had a direct and significant impact on the response to the event. One equipment deficiency worth noting is that the strip chart recorder for the MS line radiation monitors had been out of service since April 1999. The strip chart recorder maintains a continuous record of primary-to-secondary leak rate for all the SGs. This condition limited the amount of pre-event leakage information available to the operators, but in this case, did not impact the ability of operators to detect the leak and identify the faulted SG.

The deficiencies noted in the AIT report did not raise any obvious questions related to the event response assumed in the IPE analysis. The AIT report noted that the leak rate at approximately 150 gpm is lower than the leak rate assumed in the IPE **(UFSAR: 104174lbm in 45 mins or approximately 300 gpm)**. This difference impacts the timing of the event and influences the time available for operator response and response options. It is possible that the deficiencies raised in the AIT regarding event response would have been exacerbated if the leak rate assumed in the IPE had been reached in the actual event. If the leak rate had been greater or had increased during the event, the combined effect of the operator response problems and the procedural deficiencies that delayed cooldown could have become more significant.

c. Staff Risk Assessment

NRR staff conducted a risk assessment of the condition of the SG tube during operating Cycle 14 (Reference 5/4 memo or special inspection report). The assessment was used in the NRC significance determination process (SDP) and had the objective of determining the degree to which NRC should engage the licensee concerning performance problems connected with the event. The assessment results were not necessarily considered to be indicators of the significance of risk to public health and safety. **(Quote manual chapter 0609 on SDP objectives).**

The staff assessment considered the degraded condition of the SG tubes as indicated by the occurrence of the event and used other information available from the plant's IPE to estimate the risk contribution from spontaneous SGTR and from induced SGTRs (both from over-pressurization and from core damage sequences). Based mostly on the contribution from spontaneous SGTR, the estimated risk contribution attributed to degraded SG tubes at IP2

during Cycle 14 is a probability of core damage with large early release of approximately 1E-4/yr.

The staff assessment assumed that the tube failure was equivalent to a tube rupture, although the leak rate during the event did not reach the magnitude of a rupture. The nature of the crack presented the potential for greater leakage if additional stresses had been placed on the tube or if existing stresses had been maintained. The results of the assessment indicated that the risk profile at IP2 was altered for operating Cycle 14. The inspection findings indicated that the contributing factors (i.e., SG maintenance deficiencies) allowed uncorrected degradation to exist, leading to the failure, and therefore, the degraded condition existed from some point following the 1997 tube inspection until the tube failure in February 2000. Therefore, the staff did not consider the event to be a random tube failure, and the risk profile for SGTR at IP2 during the entire operating cycle was assumed to be affected.

The staff assessment was a conservative evaluation of the impact of degraded SG tube conditions on SGTR risk, consistent with the SDP and led to a "potential red" significance finding. An SDP panel was held in which the preliminary red significance finding was upheld, with a final determination pending further review steps in the reactor oversight process. The Task Group did not have the benefit of subsequent steps in the SDP process that might refine the risk analysis and lead to a different finding. However, it appears that changes to risk assessment will probably not lead to a significantly different conclusion in the NRC evaluation.

Accident Sequence Precursor (ASP) Assessment: [Indications are that ASP analysis results will reflect NRR preliminary assessment, but will add this section when ASP analysis is available.]

d. Licensee Risk Assessment

The licensee provided an assessment of the risk impact of the event (Reference **docketed???)** 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 conditional 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 modification of the human error probabilities that were used in the IPE analysis that was conducted at the SGTR leak rate for a double-ended guillotine tube break.

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

2. The licensee used a modified HRA based on the longer time available for operators due to the lower-than assumed leak rate in the staff's analysis;
3. The licensee did not estimate a modified tube failure probability based on the degraded state during the operating cycle; and
4. The licensee did not consider MSLB or induced rupture contribution to risk.

The NRC assessment of the licensee analysis (Long email 7/20/00) made the following comments:

5. The licensee calculated conditional core damage probability (CCDP) rather the change in risk in terms of a change in CDF or LERF attributable to the degraded condition of the SG tubes.
6. The staff questioned the basis for the licensee changing 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.
7. The licensee assessment did not assess the risk contribution from tube ruptures other than spontaneous failures.

e. Effect of Cycle 14 SG Conditions on SGTR 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 p 5 of RG 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 time normal operating differential pressure). The causes for previous SGTRs are given in Table 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 with an expected frequency. 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 IP2 event was an instance where the failure resulted from degraded conditions that could have been avoided if reasonable, prudent engineering practices had been followed **(See Sections 4.4, 4.5? 4.6).** 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 was not random and could have been avoided. This leads to the judgment that conditions existed in the IP2 SGs before the tube failure that contributed to a higher level of SGTR risk for some period of time.

The NRR risk assessment takes the position that the IP2 SG conditions before the tube failure adversely affected SGTR 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 interceded before tube failure (Reference May 4, 2000 Barrett memo and Reference 1). In sum, the staff estimated that the probability of tube failure was larger than that generally accepted during previous operating history for IP2, and greater than the value used in the IPE.

Con Ed's assessment, discussed in Section 4.3.2.3, did not assume any effect on tube failure probability from deficiencies in the maintenance and inspection program, because in the view of the licensee, there were no such deficiencies.

As documented elsewhere in this report, The Task Group concluded that a number of programmatic failures contributed to the tube conditions that led to the tube failure event.

Provided that the contributing factors 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.

6. Potential Generic Implications

Explore connection between possible generic factors of contributors to IP2 degraded condition and SGTR risk for all or large number of PWRs. Generic factors include possible vendor deficiencies, shortcomings of industry guidelines, NRC process problems. Expect that only a qualitative assessment of overall risk implications would be made in the report, with a possible recommendation that staff pursue the issue and consider developing a more robust assessment of risk impacts.

5.3.3 Conclusions

5.3.3.1 IP2 Event Compared to NRC's Strategic/Performance Goals

NRC's Draft Strategic Plan (NUREG-1614, Feb. 2000) lists a number of strategic goals and performance goals in the Nuclear Reactor Safety arena. One of the strategic goals is to prevent radiation-related deaths and illnesses. One of the measures used to assess results in achieving this strategic goal is: "No reactor accidents[1]." The agency's performance goal of maintaining safety is directly related to achieving this strategic goal. One of the measures used to assess the agency's efforts to achieve this performance goal is: "No more that one event per year identified as a significant precursor of a nuclear accident[2]." Note that this measure is a lower threshold than the measure used for the strategic goal. The strategic plan further states that:

> Accidents that involve substantial core damage or a release of radionuclides can be minimized by maintaining a low frequency of events that have the potential to lead to a nuclear reactor accident or large early release.

As discussed in Section 4.3.2.1 of this Task Group report, the staff's risk assessment of the IP2 event to support the SDP is on the order of 1E-4 per year. Comparing this result, which is conservative, to the 1E-3 performance goal measure discussed above indicates that the IP2 event was at least an order of magnitude less that this performance measure.

In summary, the staff's "red" SDP preliminary finding indicates that the IP2 event is of high safety significance with a significant reduction in safety margin. If this finding is confirmed by the SDP process, the NRC will take appropriate actions. However, sufficient safety margin still existed such that the agency's safety and performance goals were not exceeded.

<u>Risk communication</u>: consideration should be given to using strategic plan principles as a basis for communication plans to address events that the public and/or NRC consider serious. The communication plans should present risk information in such a way as to put an individual event in the perspective of other plant risks and/or other societal risks. Efforts invested in this area may help to avoid unnecessary effort to deal with public mis-perceptions of event hazards and the nature of licensee and NRC response.

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[1] A "nuclear reactor accident" is defined as an accident which results in substantial damage to the reactor core, whether or not serious offsite consequences occur.

[2] Such events have a 1/1,000 (1E-3 per year) or greater probability of leading to a reactor accident.

Items to examine:
IN 2000-09 said that event was risk significant
AIT characterized event as having moderate risk significance
Special inspection Potential red not directly related to risk

what does IP2 web site say about risk
press release??
managers quoted in press

5.3.3.2 Risk Insights of Possible Corrective Actions

Lead-in using RG 1.174 principles??

In order to put the appropriate perspective on the range of possible corrective actions stemming from the IP2 event, the Task Group judged the possible benefits of anticipated corrective actions in terms of their qualitative impact on the SGTR risk at IP2. In general, corrective actions should focus on either prevention of tube failures or by mitigation of their consequences. Prevention activities would include steps to make improvements in the management of SG tube degradation through a combination of defense-in-depth measures, including in-service inspection, tube repair criteria, primary-to-secondary leakage monitoring, and water chemistry controls. Mitigation efforts would focus on emergency procedures, system performance and operator training.

Based on the preliminary staff risk assessment, there was a significant impact on the level of risk from SGTR at IP2 during the period of operation preceding the tube failure. In the case of IP2, operator actions to isolate the affected steam generator and effect cooldown have a large impact on the ability to effectively limit the consequences of the event. In the IPE, the difference in mitigation effectiveness changed the IPE results by________________. Therefore, the prevention of tube degradation and failure can be seen to have a more significant influence on SGTR risk than mitigation. However, it must be recognized that a balance between prevention and mitigation must be maintained, because completely deficient mitigation would lead to potential core damage and containment bypass.

Prevention/mitigation - three aspects of risk (see white paper) Tube integrity affects the consequences more than other ISI areas, so the perceived risk is greater.

Possible TG conclusion that it is appropriate to focus corrective actions on preventative measures.

5.3.3.3 Findings

1. The IP2 event did not significantly change our understanding of SGTR risk on an industry-wide basis. However, SG maintenance program deficiencies discussed elsewhere in the report could impact the SGTR risk at other plants, if not addressed.

> Lesson Learned: The event response appeared to indicate that appropriate emphasis is placed on measures aimed at mitigation of the design basis SGTR. Follow-up to the event demonstrates that further effort is needed to address measures that can prevent tube failures given the potential for containment bypass.

2. The IP2 event did not significantly change our understanding IP2 SGTR risk. However, there is confusion among the staff concerning the significance of a finding under the significance determination process and the safety significance of the finding.

> Lesson Learned: The degraded condition during IP2 Cycle 14 affected plant risk of SGTR for that operating cycle. However, there were a number of contributing factors leading to the degraded condition. Provided the contributing factors are corrected, the long-term risk of SGTR at IP2 should be unaffected,

> Lesson Learned: A potential misunderstanding exists among NRC staff concerning the relationship between SDP findings and safety significance.

3. SGTR is a design basis event, and IP2 shut down safely following the tube failure. SGTRs have occurred before and cannot be prevented in the future. Based on this, the response to the event (by the public, media, local and national officials, Con Edison, NRC) could be considered inconsistent with its risk significance.

> Lesson Learned: The public confidence issue should receive increased attention before events occur. This approach is consistent with efforts to establish communications plans.

5.3.4 Recommendations

- IP2 oversight - Over the long-term, NRC should ensure that the oversight process corrects the deficiencies that led to the degraded SG condition during IP2 cycle 14. Otherwise, the long-term risk of SGTR at IP2 could be affected. Maintains safety,

- Generic oversight - The oversight effort should extend to explore potential programmatic deficiencies at other plants based on the possible generic character of some of the deficiencies found. Maintains safety

- Risk communication - Due to the nature of SGTR and the technical complexities involved, a communications plan specific to tube failures should be established and should be followed when events occur. Public confidence and effectiveness and efficiency are addressed by this recommendation.

- New Oversight Process - Guidance/training should be provided to the staff to increase understanding of the distinction between an SDP color code, other risk-informed programs (see Gary's table), and safety significance of events/findings, in general.

5.3.5 References

1 U.S. Nuclear Regulatory Commission, NUREG/CR-6365, "Steam Generator Tube Failures," April 1996.

Regulatory Guide 1.121, "Basis for Plugging Degraded PWR Steam Generator Tubes," August 1976

5.4 IP2 Programs and Activities

5.4.1 Background

The Task Group reviewed the licensing and design bases of the steam generators (SGs) and the effectiveness of Consolidated Edison (Con Ed) Steam Generator (SG) tube integrity program implementation at Indian Point Unit 2 (IP2). The Task Group reviewed the related requirements in the plant technical specifications and the design description in the Updated Final Safety Analysis Report (UFSAR).

The Task Group reviewed the implementation of Con Ed's examination program to determine if the scope and frequency of the program met the regulatory requirements and license commitments. The Task Group also examined the oversight of the program by the licensee and contractors; the methods by which Con Ed (and/or its contractor) conducts steam generator examinations and disposes examination results; recent examination results (1995, 1997 and 2000) and the technical specifications primary to secondary leakage limits that existed before and after those examinations.

In reviewing the licensing basis, the Task Group considered NRC granted exemption and extensions to the technical specifications steam generator examination program as part of the licensing basis. The Task Group reviewed two applications for amendment to operating license submitted by Con Edison in 1997and 1998. These applications requested one time extension of the SG tube inspection interval beyond the 24 month limit of the plant TS. The Task Group also reviewed the program that existed for managing the steam generator primary-to-secondary leakage.

5.4.2 Observations

5.4.2.1 Licensing, design basis and Steam Generator Inspection Program

Licensing and Design Basis

Code of Federal Regulations, Part 50

The Task Group identified several sections of the Code of Federal Regulation (CFR) Part 50 that directly or indirectly applied to Con Ed's operation and maintenance of the steam generators. Those sections and the reasons why they applied are discussed below.

> 10 CFR 50 Appendix A, General Design Criteria (GDC) 1, Quality Standards and Records; 14, Reactor Coolant Pressure Boundary (RCPB); 15, Reactor Coolant System (RCS) Design; 30, Quality of RCPB; 31, Fracture Prevention of RCPB; 32, Inspection of RCPB define the requirements for the reactor coolant pressure boundary. The tubes of the steam generators are part of the RCS pressure boundary and as such, these criteria apply. The UFSAR, Sections 4.1.2. and 4.1.3 describe how IP2 meet the intent of these criteria.
>
> 10 CFR50, Appendix B, Criteria IX, "Control of Special Processes," XI, "Test Control" and XVI, "Corrective Actions," directly apply to the steam generator tube integrity program. These criteria were deemed applicable because the steam generator tube examinations involve special processes and testing on safety related component.

10 CFR 50.55a(g), ISI Requirements, (4) requires that components classified as ASME Code Class 1 must meet the requirements as set forth in Section XI of the edition of the ASME Boiler and Pressure Vessel Code and Addenda incorporated by reference. Con Ed was committed to the 1989 Edition of the ASME Section XI code. Some portions of the code that are worth noting are:

> ASME Section XI, 1989 Edition, Section IWB-2413, Inspection Program for Steam Generator Tubing, states: "The examinations shall be governed by the plant Technical Specifications."
>
> IWB 2430, Additional Examinations, (d) states: For steam generator tubing, additional examinations shall be governed by plant Technical Specifications.
>
> Appendix IV of ASME Section XI, Eddy Current Examination of Non-ferromagnetic Steam Generator Heat Exchanger Tubing, Section IV-6300, Recording of Results, states that flaws producing a response equal to or greater than 20% wall penetration shall be identified and the depth noted.

10 CFR 50.65, Maintenance Rule applies. This section was applicable since the steam generator tubes are safety related.

10 CFR 50.72 and 73, Reporting Requirements.

Technical Specifications

Technical Specifications (TS), Sections 3.1.F.2a, Primary to Secondary Leakage contains the operational leakage limits for the steam generator tubes. It establishes a limit of 0.3 gpm (432 gpd) in any steam generator which does not contain tube sleeves, or 150 gpd for any SG that contains sleeves. The TS also requires that if this limit is exceeded or if leakage from two or more steam generators in a any 20-day period is observed, the reactor shall be brought to the cold shutdown within 24 hours. 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 failed.

TS 4.13, Steam Generator Tube Inservice Surveillance provide the examination requirements for the steam generators. The IP2 TS requires SG examination at a 12 to 24 month interval The scheduled examination consisted of all four SGs. A random sample (20%) of the tubes containing sleeves needs to be inspected. IP2 did not employ sleeving of the degraded tubes as a repair technique, hence the TS requirements for inspection of the sleeved tubes do not apply. 12% of the tubes in each SG are required to be subjected to hot leg inspection, with 25% of these tubes also subjected to cold leg examination. If more than 5% (but less than 10%) of the tubes examined in a SG are degraded <u>and</u> one or more (but less than 1%) of tubes inspected are defective (requiring plugging or repair), then the examination needs to be expanded to another sampling of (6%) tubes in the affected SGs. Increased identification of defective or degraded tubes would expand the sample, ultimately to 100% of the tubes in all SGs based on the results of the sample examinations. TS defines "degraded tube" as a tube with imperfections large enough to be detected by eddy current inspection. This is considered to be 20% degradation. Tubes are considered acceptable for continued service if depth of degradation is less than 40% of the tube thickness, or 23% of the sleeve wall thickness.

Selection of tubes for examination shall include tubes in the area of the tube bundle in which degradation has been reported either at IP2 or at other utilities with similar SGs. Additionally all F* tubes need to be inspected in the pertinent tube-sheet region. The TS also specified the examination technique which were further revised to incorporate the probe size for eddy current examination in April 2000. SG Tubes are considered acceptable if depth of degradation 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). Additional examination is also required for degradation caused by denting. The basis section of the TS 4.13 concludes that the licensee's program for SG ISI exceeds the RG 1.83, Rev. 1, July 1975 requirements.

The TS further requires the licensee to submit the proposed SG examination program for NRC review 60 days prior to the scheduled exams, and results to be reported to NRC within 45 days of completion of the exam. Significant increases in the rate of denting and significant changes in SG conditions to be reported immediately. The TS also requires a 60 day report to the NRC with evaluation of the long term integrity of the small radius U-bend (beyond row 1) upon finding of significant hour-glassing of upper support plate flow slots. NRC reporting and prior NRC approval for restart is required if inspection needed to be expanded to 100% of the tubes in all SGs (result C-3 of TS Table 4.13-1) or if tubes in two or more SGs leaked, or leaks are attributable to two or more SGs due to denting. Whenever the reactor is shutdown to investigate SG tube leakage or repair a leaking tube, the NRC shall be informed before the repair is done and before the SG is returned to service.

The requirements of NRC approval of restart upon inspection results meeting C-3 of the TS Table 4.13-1 was incorporated in a TS amendment during the 1970s time frame. This requirement exceeds the RG 1.83, Rev 1 that requires NRC reporting per facility license and NRC approval of the proposed remedial actions. Most PWR licensees (e.g. ANO-2) TS contains the NRC reporting requirement but not the NRC approval of plant restart. {Further comparism of IP2 SG TS with the standard Westinghouse TS will be provided later}.

The IP2 TS does not reflect the current knowledge regarding the degradation mechanism and experience found at the plant or in the industry. It does not prescribe the types of information that should be included in the examination results 45 day report. Although there is a requirement to report significant changes in SG condition immediately, this requirement is open to interpretation and it could be missed.

Updated Final Safety Analysis Report

Indian Point 2 is a four-loop pressurized water reactor with one steam generator per loop, that transfer heat from the reactor coolant system (RCS) to the secondary water. The four SGs are identified as SG 21 through SG 24. The steam generators are vertical shell and U-tube model 44 Westinghouse steam generators supplied by Westinghouse, designed and manufactured to the ASME III requirements. The generators were put into commercial operation in August 1974, operating with a Reactor Coolant hot leg temperature (T_{hot}) of 574 degrees until 1990 when the temperature was raised to 589 as a result of a power up rate.

Each SG holds 3,260 tubes. Reactor coolant flows inside these tubes, with the secondary water/steam on the outside. The tubes are made of mill-annealed Inconel Alloy 600 and are arranged in an inverted U fashion, with increasing distances and heights from the inner-most row (row 1) outward. The tubing has an outside diameter (OD) of 0.875 inches and a wall thickness of 0.050 inches average. Each tube is identified by its row number, counting from the center out, and its column number, counting from one side of the SG. The "low-row" tubes (rows 1 - 4) each have 92 tubes. The row 1 tubes were removed from service, by plugging, prior to initial operation.

The tubes are supported vertically by the thick tube sheet at the bottom of the SG and horizontally as they pass through drilled-holes in the six evenly spaced carbon steel tube support plates (TSPs). In each TSP, there are holes cut to allow water/steam flow around the tubes. Also, there are six evenly spaced flow slots that run across the diameter, between the two legs of the adjacent row 1 tubes. The flow slot openings are about 15 inches long (spanning about twelve tubes) and about 3 inches wide. The U-bend area is located above the upper TSP.

The tube support plates consist of carbon steel plates with drilled holes for passage of the tubes. At the time of the tube failure, 10.2 % of tubes in the SGs were plugged with 25% being the plugging limit based on acceptable accident analysis results. UFSAR 4.2.5 states that the IP2 SG tubes are made of inconel, and have excellent resistence to general and pitting type corrosion when considered for the stress corrosion cracking experienced in SS tubes. The SG tube rupture is an analyzed accident under section 14.2, "Standard Safety Feature Analysis." The FSAR states that situations could conceivably involve uncontrolled release of radioactive material into the environment. With concurrent blackout, the analyzed site boundary dose is in the order of 0.75 rem whole body and 2.7 rem thyroid, thus a very small fraction of the 10 CFR Part 100 limits of 25 rem whole body and 300 rem to the thyroid. With the availability of AC power, the resulting dose is calculated to be 1.1% of the above value. The main steam line break with a preexisting tube leak is also an analyzed event that results in a similarly small site boundary dose of 0.8 rem to thyroid.

During operation, the RCS is pressurized to approximately 2,235 psig. Normal SG pressure varies with plant load between approximately 100 psig at no load to approximately 700 psig at 100-percent power. The pressure difference between the RCS and the SGs can cause leakage from radioactive RCS water to the secondary side of the SG. This is referred to as primary-to-secondary leakage.

Consolidated Edison Steam Generator Examination Program

The 1997 tube examination was conducted by Westinghouse personnel (contractor) under purchase specification No. NPE - 72217, Eddy Current Examination of Nuclear Steam Generator Tubes Revision 10, dated 12/17/96. The specification defined the requirement for eddy current examination of SG tubes at IP2. Among others, it stated that examination techniques are in accordance with EPRI SG Exam Guidelines, Appendix H. It specified the preferred bobbin coil probe frequencies as: 10, 100, 200, and 400 kHz. It also specified that specialized probes shall utilize frequencies consistent with their application under the EPRI qualification program. The probes were to be capable of identifying defects in the presence of sludge and/or copper deposits. Section 4.8 of the specification stated that state of the art probes for supplemental examinations were to be used to detect or further characterize eddy current indications found by the initial examination, as required by the company (Con Ed). The data analysis guidelines used by the contractor was required to be reviewed and approved by Con Ed prior to the examinations.

The specification required that a daily report be provided to Con Ed addressing some specified issues among which was " Summary of axial and circumferential indications and their locations."

SAO-180, Administrative Steam Generator Program Plan, implemented the SG Program. It identified the requirements and organization responsibilities necessary for the implementation of the Steam Generator Program. It was developed to meet the commitment to NEI 97-06, Steam Generator Program Guidelines. The Chief Nuclear Officer had the corporate responsibility for the SG program. The VP, Nuclear Engineering had the overall responsibility for the technical development and administration of the SG program. The SG Program Manager developed and updated the SG strategic plan and provided the Condition Monitoring and Operational Assessment (CMOA). The department manager, Nuclear Quality Assurance and Oversight reviewed the implementation of the SG Program.

(What Rev of SAO-180 was used in 1997? What revision exists now? - **at IP2**)

5.4.2.2 Con Ed's personnel qualifications and certification levels

According to the information in NRC Inspection Report 97-07, the examination personnel met the qualification and certification requirements stated in the pertinent supplement of SNT-TC-1A and ASME Code Section XI. This was in accordance with the industry guidelines .

The NRC reviewed the training provided to the 2000 examination data analysts in accordance with the criteria contained in the EPRI Guidelines, Section 6.2, Site-Specific Performance Demonstration. Con Ed provided additional information to supplement test scores that had been previously provided. The received information consisted of: (a) a copy of a handwritten log for May 4-10, 1997, describing on-site activities; (b) a one-page training introduction outline, (c) set up instructions for the combined Cecco-5 and bobbin probe, and (d) information regarding the contents of the practice data sets. No information was received regarding the contents of the written and practical tests. The practice data sets for the Plus Point probe (Reels 12 and 20) were noted to contain ID flaws at free span locations. Due to the lack of identification at Indian Point 2 of PWSCC in low radius U-bends prior to 1997, data from other SGs was used for the Plus Point practice data sets.

5.4.2.3 Oversight of Contractor's SG Examination Activities

During the NRC's 1997 and 1995 inspections at IP2, it was identified that the Con Ed maintained adequate control over the ISI Non Destructive Examination (NDE). Con Ed personnel determined the scope of work to be performed and reviewed and approved the NDE procedures used by the contractors against check lists developed from the ASME code. The oversight of ISI activities was also routinely provided by the Quality Control unit through surveillance. Overall, the licensee's oversight of contractor's activities was assessed to be good.

(See Region Special Team Findings)

5.4.2.4 Con Ed's Examination Results

<u>2000 Examination</u>

The 2000 examination plan was submitted on February 11,2000. It discussed plans to use the Cecco-5/bobbin probe (C-5) primarily. The probe was qualified to EPRI Appendix H. The Cecco-5 probe is a multiple element transmit-receive probes. It is sensitive to axial, circumferential, and volumetric degradation, and it does not discriminate orientation. Narrow radii U bend signals were to be resolved with an RPC probe if passage of the Cecco-5/bobbin probe is precluded. Plus Point will be used for sizing and C-5 restrictions. The plus point probes would be used to examine all row 2 and 3 U-bends.

Prior to the examination, on February 15, 2000, SG 24, tube R2C5 failed. The maximum leakage calculated from the failed tube was $\simeq$ 146 gpm. The design basis leakage (Tube Rupture) is 600 gpm. The licensee calculated a CCDP of $7.7E^{-5}$ for the event while the NRC calculated a CCDP of 1.0 $7E^{-4}$ (ref: NRC Inspection Report 2000-003).

Initial examination results showed three additional row 2 indications (C4, C71 and C74) in SG 24. The examination resulted in a Technical Specification 4.13 classification of C-3 for two steam generators which meant an inspection of all the tubes and a need for a NRC approval prior to restart. (Ref: LER 2000-003)

Portions of the licensee SG tube examination activities were observed by the NRC Resident Inspectors per IP 61725 and documented in NRC Inspection Report 2000-003 (May 16, 2000). The report provided a summary of licensee's findings and plans in support of NRR's reviews.

<u>1997 Examination</u>

In a letter dated 2/7/97, the licensee submitted their proposed SG tube examination program to the NRC. In the plan, SG 24 tubes R2C67 and R2C5 were among those initially selected for a full length examination. In a letter dated 5/29/97 NRC approved the licensee's program subject to additional clarification provided by the licensee in a 5/6/97 letter regarding a blind comparison of Cecco-5 and Plus Point eddy current probes. The staff had previously approved a three-week extension (April 14 to May 2, 1997) for the 1997 examination via letter dated April 9, 1997. TS 4.13.C.3 requires an evaluation be submitted of significant hour-glassing of the upper support plate flow slots.

The SG inspection plan included a 100-percent Plus Point probe examination of the low-row U-bends. The mid-range Plus Point probe used during the 1997 examination is a multifrequency probe, operating at 10, 100, 300, and 400 kHz.

The 1997 refueling outage SG inspection planned exceeded the TS requirement. The plann was to examine in all SGs, a minimum of 33% of the active tubes full length, all tubes from the end of the tube to the first support plate intersection on the cold leg and the first support plate intersection on the hot leg side, and all U-bends of rows 2 and 3. In addition all dents at the tube support intersections, all rerolled tubes to verify F* distance, and 20% of pit indications at sludge piles were to be inspected. Cecco-5, bobbin probe, plus point or Rotating Pancake Coil (RPC) probes were used. The licensee further committed to do a test comparison of the performance of Cecco-5 and plus point probes in detecting SG tube flaws.

The examination, completed in June 1997, identified the first low-row U-bend PWSCC indication (at the apex of R2C67 in SG24). This tube was plugged prior to restart; no insitu pressure test was performed. Also during this examination, Con Edison identified the first instances of probe restrictions caused by denting at the upper TSP in low-row U-bend tubes. These tubes were plugged because an examination could not be completed.

Con Ed's 1997 examination results were submitted to the NRC according to the plant Technical Specifications. Because of the tube examination results, the licensee expanded the scope of the examination to full length of all tubes. The reports contained a general description of the tube examination including the tubes plugged; trending of the number of tubes plugged/ tubes rerolled to maintain F* distance; examination of the existing plugs, flow slots, lower support plate and secondary side foreign object search examination results; and results of insitu leakage testing. The report identified the location of indication/restriction for plugged tubes, but did not contain flaw sizing information. Although, the level of detail provided in these reports were not sufficient to flag the technical and implementation problems identified elsewhere in this report (signal to noise ration etc.), the 1997 inspection results report identified a single axial indication at the apex of U-bend in a row 2 tube on SG 24 that was plugged. This first time identification of a row 2 U-bend apex PWSCC was not flagged for further evaluation in the report nor was it reported immediately to the NRC as the TS would require for significant change in SG condition. **[Did IP2 report follow any industry guideline?]**

The report indicated that video examination of the flow slots in the lower support plates and where possible, the upper support plates, were performed. The licensee reported that similar ro previous exam finding, the video tapes of the lower support plate flow slots showed essentially no change in "hour-glassing" of the flow slots and cracks in the tube support plates at some flow slots. However, the video showed some small cracks at upper support plates previously not observed. **[The licensee stated "the video quality was able to show small cracks...", but could the cracks be indication of start of islanding? Did we look at the size/extent of the cracks to get a feeling of the phenomenon that gives rise to hour-glassing, denting and islanding?]** One flow slot at the second support plate that showed closure was evaluated to be acceptable. A visual exam of the uppermost support plates showed no significant "hour-glassing," and the wedges were found intact upon sampling.

The Task Group reviewed some of the records of the 1997 NRC/Con Ed outage telephone calls. There was no indication that the crack discovered in the apex of the u-bend of a row 2 tube (R2C67 of S/G 24) was discussed. This information was also not discussed during the post NRC inspection telephone call between the NRC and the Licensee that was held on June 26, 1997. The timing of the phone calls relative to when the flaw was identified was not clear. In NRC Inspection Report 97-07, there was no indication that the flaw was discussed either. In Con Ed's result submittal dated July 29, 1997, the flaw was reported.

In 2000, the NRC reviewed the 1997 ECT data and the actions taken upon discovery of a PWSCC flaw at the apex of tube R2C67 in SG 24 using the Plus Point technique to conduct the U-bend examination.

While the flaw was identified and the tube plugged, neither Con Edison nor its ECT contractor recognized the discovery of the low-row U-bend apex indication as a significant condition adverse to quality and did not enter the issue into its corrective action program. 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 Indian Point 2. There was no specific review as to the significance of this flaw or the possible extent of the condition.

Con Ed conducted in-situ tests on 6 tubes (4 in SG 22 and 2 in SG 24) in rows 35, 32, 23, 24, and 27. Maximum pressures attained ranged from 2900 to 5075 psi. One row 2 (R2C67) apex of U-bend crack was identified and plugged in Steam Generator 24. At the end of 1997, 9.6% of SG 21, 12.4% of SG 22, 9.2 % of SG 23 and 9.4% of SG 24 had been plugged. (Reference: NRC Report 97-07)

(1997 Appendix H qualification? Probes used for rows 2 and 3 U-bends? RPC only?)

<u>1995 Examination</u>

Con Ed submitted the 1995 Examination Plan on December 16, 1994. 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, 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 Guidelines, Revision 3 to detect axial and circumferential cracks at dented support plates and tube roll transitions.

Con Ed submitted the 1995 results on June 14, 1995. During that SG inspection no PWSCC defects were identified in the U-bend region; however, PWSCC cracks were identified at the roll transition in the tube sheet. Examinations revealed a dent and an axial indication at the bottom edge of the third support plate. This indication was believed to be present during the previous examination but was not detected due to lack of proper techniques in identifying and characterizing flaws in the vicinity of the dent. The licensee revised the current data analysis guidelines to state "view the entire tube for indications, copper deposits, dents, dings and distorted signals, check all signals not mixed out in mix 1 vertical, review any flaw-like signals in free span and possible indications at the edges of the dented support plates." Subsequently, the licensee reviewed and evaluated the 1991 and 1993 bobbin examinations on 11,969 tubes using the current data analysis guidelines and did not find any additional defective tube. They also expanded their scope of examination using the Cecco-5 probe. (Reference: NRC Inspection Report 95-07)

5.4.2.5 Exemption/extension requests from Con Ed involving the SG since 1995

In an application, submitted on 2/14/97, the licensee asked for an extension of the 24 month maximum interval of SG tube examination by approximately three weeks, form 4/14 to 5/2/97. This short term extension of the TS required surveillance interval was granted by the NRC in a letter dated 4/9/97. The technical basis rested on the fact that although the previous outage was completed on 4/14/97, the unit did not restart before 5/2/97. In addition the unit was shutdown for a 49 day maintenance outage in early 1997, thus subjecting the reactor coolant system to a reduced temperature, a condition not conducive to SG degradation.

In a letter dated 12/7/98, Con Edison again asked for an extension of the 24 month SG examination interval beyond 6/13/99, the date an inspection would be due according to the TS requirement. The licensee indicated that although the SG examination was completed on 6/13/97 during the 1997 refueling outage, the unit was not heated up above 200 degrees before 6/30/97. Additionally, the plant was in cold shutdown for a cumulative duration of 304 days between the startup from the 1997 refueling outage and 8/5/98. During this period, the SGs were maintained in a wet lay-up condition with appropriate control. The licensee further planned a short 15 day outage in November 1999 to perform some required tests resulting in another 5 days in cold shutdown. The licensee indicated that this "non-operating" SG time of 309 days would extend the required inspection to 4/16/00. The licensee requested an additional 48 days postponement of the inspection until the commencement of the refueling outage scheduled to begin on 6/3/00. As a justification for this extension, the licensee submitted information on reduced temperature water chemistry control, non-appreciable wear growth of indications observed between the 1993 and 1995 outages, and essential halting of degradation during the wet lay-up period. The submittal also provided a broad analysis of the 1997 inspection results.

In response to the amendment request, the NRC requested the licensee to provide additional information including SG tube integrity operational assessment methodology for each degradation mechanism and the results of the condition monitoring assessment for the most recent examination results. In its response the licensee assessed eight forms of degradation and the associated 1997 examination results to conclude SG tube integrity for an extended period until next inspection. As pointed out later in the RES' independent review dated 3/16/00, there were some inherent flaws in the logic the licensee used in crack growth rate determination for sludge pile ODSCC and row 2 U-bend PWSCC indications. These weaknesses in the licensee's logic were not identified in the subsequent NRC safety evaluation that approved the license amendment for the requested extension of the inspection interval.

The NRR reviewer who reviewed the 1998 extension request from the licensee was a junior member of the SG technical review group, and had used GL 91-04. This GL provides guidance on a generic basis regarding items that should be considered when licensees plan to modify surveillance interval to be compatible with the 24 month fuel cycle. It contains some specific considerations related to SG inservice examination. The reviewer had also used several prior safety evaluations related to inservice inspection interval extension as precedence. It appears that plant TS required licensee submittals on 1997 SG examination results did not get timely review by the NRC technical experts. The licensee had mentioned about the finding of the row 2 U-bend apex PWSCC indication and the sludge pile ODSCC indications in their 1997 SG examination report, and provided further discussion about these indications in the response to the staff RAI related to the extension request. Although row 2 U-bend apex PWSCC indication was observed for the first time and a substantial increase in the sludge pile ODSCC indication

were observed in the 1997 inspection, as pointed out in the RES 3/16/2000 review, the licensee's projections related to the crack growth rate were not questioned.

{Discuss the SG inspection Program with IP2's program director and lead non-destructive examination (NDE) at the site - to support specific tasks 1, 2 and 3 **- At the Site}**

5.4.3 Conclusions - Lessons Learned

5.4.3.1

Con Ed's steam generator examination program was maintained in accordance with the licensing and design bases. Although, there might have ben weaknesses associated with taking appropriate corrective actions (10 CFR 50, Appendix B, criterion XVI) following identification of a row 2 U-bend apex crack in 1997.

With the 1997 SG Examination, Con Ed failed to identify the need for more focus/review in the Row 2 U-bend area. There was ample industry information available that should have alerted them to this when they found an apex crack in a Row 2 tube.

Other plants have proactively plugged row 2? Even after the 1997 outage, issues in the Information Notice should have driven Westinghouse (Con Ed) to review row 2's data. Especially since a row 2 tube was plugged because of an apex crack.

5.4.3.2

The regulatory oversight provided by the TS was weak. As a result, although the licensee's 1997 inspections met or exceeded the plant TS requirements, potential problems went unnoticed and uncorrected. The technical details were not sufficient to identify any implementation problems, nor did the report sufficiently identify, characterize or analyze potentially new degradation mechanism as required by the TS.

5.4.3.3

Con Ed's actions taken during the 1995 examination to deal with flaws identified in the bottom edge of the third support plate were extensive. They believed the indication was present during the previous examination but was not detected due to lack of proper techniques in identifying and characterizing flaws in the vicinity of the dent.

5.4.3.4

The basis for the NRC safety evaluation that authorized extension of the SG tube inspection in 1999 did not identify or discuss the implications of the row 2 u-bend apex indication found for the first time. Also, timely NRC review of the SG examination report submitted by the licensee was not prioritized.

5.4.3.5

The plant TS limit on Primary to Secondary leakage is not adequate to provide proactive indication of upcoming tube failure. Additional measures are needed for trending/monitoring of SG tube condition.

5.4.3.6

Missed identification in 1997 due to masking from tube deposits and geometric effects. Lack of site specific validation for mid-range frequency probe used in 1997.

5.4.4 Recommendations

5.4.4.1

Prompt actions might be required of the NRC regarding the Tech. Specs. on Operational leakage limits that allows a Primary to Secondary Leakage that could place the plant in a "High Risk," or "Less Safe," condition.

Establish SG examination results reporting requirements that require identification of critical parameters (e.g., S/N ratio, data resolution etc.), and identification/analysis for new degradation mechanisms.

Regulatory Guide 1.83, Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes: Methods for implementing the GDC is outdated and is referenced in the basis section of TS 4.13. The Reg. Guide should be revised or revisited.

> (Basis: The **technical specifications** on Steam Generators do not really ensure integrity of the generators. Licensees can comply with the specifications on leakage and examinations and still not do a good enough job to ensure tube integrity. IP2's leakage before failure was $\simeq$ 5 gpd. Tech. Specs. allowable was 432 gpd (No sleeves) or 150 gpd (If sleeved).

5.4.4.2

The staff should assess the need to review the SG examination reports. The examination plans and results may or may not reflect significant issues. While licensees are required to submit these, they are not necessarily reviewed by the NRC. In Con Ed's case, the 1997 results report showed that a row 2 u-bend apex flaw was identified. This might have generated further queries by the NRC if the report had been reviewed.

5.4.4.3

Licensees should be required (by regulation or industry guidelines) to address their plant specific issues that might not be covered in the generic guidelines. While it appeared that Con Ed followed the **industry guidelines** as they existed during the 1997 examinations, they still failed to identify the tube that failed later in service.

5.4.4.4

The NRC should consider examining the Westinghouse aspects of the 1997 examination problems. The differences between the 1995 and 19997 Westinghouse crews that conducted the IP2 examinations should be assessed. When abnormal issues were encountered, the questioning attitude demonstrated by the 1995 crew was very good, while for the 1997 crew, it appeared to be poor. {10 CFR Part 21 issue?}.

5.5 RES Independent Technical Review of Safety Evaluation

5.5.1 Background

NRR had requested, at the end of February 2000, that RES perform an independent technical review of the staff's safety evaluation (SE) on the steam generator (SG) tube inspection interval for IP2 (Reference 1). NRR requested this independent review to determine if the conclusions in the staff's SE were technically sound and the data presented by the licensee provided "reasonable assurance that the delayed inspection would not result in an appreciably increased probability of tube failure prior to the next scheduled inspection." NRR does not typically ask RES to review staff SEs. However, in this case, NRR requested the review as a direct result of the February 15, 2000, SG tube failure at IP2.

At NRR's request, the review was limited to looking at the technical issues, and therefore, RES did not address regulatory process issues. However, both technical issues and regulatory process issues were specifically included in the IP2 Lessons Learned Task Group's charter. NRR also requested, in Reference 1, that RES perform an independent review of the safety evaluation allowing the F* repair criteria to be used at IP2. RES provided the results of their reviews of the tube inspection interval and F* repair criteria to NRR in March 2000 (Reference 2).

The charter for the IP2 Steam Generator Tube Failure Lessons Learned Task Group explicitly stated that information from RES's independent technical review should be evaluated to identify lessons learned and recommend areas for improvement for both the industry and the NRC. In carrying out this task, the Task Group reviewed relevant documents related to the RES review and interviewed RES and NRR staff who were involved with the review to gain additional insights on SG issues relevant to the RES review. We also had two presentations, one by RES staff on SG design, operating experience, degradation mechanisms, inspection techniques, and repair criteria. The second presentation, which was given by RES's contractor, Argonne National Laboratory (ANL), focused more on IP2 specific SG issues. This presentation covered: (1) SG failure (i.e., leakage vs. rupture) at normal and main steam line break conditions, (2) degradation mechanisms (in particular primary water stress corrosion cracking (PWSCC) in SG U-bend regions, and (3) detection of flaws with low signal-to-noise ratios showing actual data from the 1997 IP2 inspection.

The Task Group's evaluation, including RES's findings, lessons learned, and recommendations are presented below.

5.5.2 Observations

5.5.2.1 RES Review Results

RES's initial review of the staff's safety evaluation (SE) of the IP2 SG tube inspection interval (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:

- Licensee's submittal on proposed amendment to Technical Specifications on SG inspection interval (Reference 4)

- Licensee's response to NRR's request for additional information (RAI) (Reference 5)

- Licensee's report on their SG tube inservice examination conducted during the 1997 refueling outage (Reference 6)

The RES review did not address the adequacy of SG inspections or SG inspection techniques. RES documented the results of their review and their 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 felt 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[3]. The number of cracks resulting from stress 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

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[3]Section 4.1 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. Section 4.4 **(or 5.2?)** discusses ANL's analysis of IP2's 1997 eddy current test data.

of the F* repair criteria. Therefore, the Task Group determined that further review of the F* repair criteria was not necessary. RES concluded that "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."

5.5.2.2 NRR Response to RES Review

There was no formal written response from NRR to RES on the March 16, 2000, RES review, and none was required. However, in a March 20, 2000, memorandum (Reference 8) from S. Collins, NRR, to F. Miraglia, EDO, 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 and 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 that the licensee's assessment of degradation found in the SGs was inadequate. In particular, NRR staff felt that Con Ed and their 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.

With regard to NRR's review of information provide 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 be missed.

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[4]. The significance of this is that the real problem stemmed back to the quality of the June 1997 inspection. However, the interactions between the licensee and the NRC in May 1999, relating to the

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[4]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.

amendment to the Technical Specifications to extend the SG tube inspection interval, provided another opportunity to uncover problems with IP2's SG operational assessment.

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 can not accurately predict the size of a flaw at the end of an operating cycle.

5.5.2.3 Industry Response to RES Review

[discussion to be added following visit to IP2]

5.5.2.4 Missed Opportunities

[note: 1. "Missed opportunity" may have to be defined, or we may want to use different terminology.
2. This discussion on missed opportunities does not come directly from the RES review. Therefore, it may fit better in a different section of the report.]

It appears that there were several opportunities when it would have been possible to uncover problems with the IP2 SG operational assessment. These are listed below.

(1) 6/97 SG inspection (Con Ed)
(2) phone calls with the licensee during and immediately following 6/97 SG inspection (Con Ed)[5]
(3) regional inservice inspection during 1997 outage (NRC)
(4) 12/98 proposal to amend Technical Specifications to extend SG tube inspection interval (Con Ed)
(5) 5/99 Con Ed response to RAI (Con Ed)
(6) 5/99 staff review of Con Ed response to RAI and staff SE on tube inspection interval (NRC)

The Task Group observed that the NRC issued Information Notice (IN) 97-26, "Degradation in Small Radius U-Bend Regions of Steam Generator Tubes," (Reference 10) in May 1997. This notice provided current information, at the time, about degradation affecting small radius (rows 1 and 2) U-bend regions of SG tubes in order to alert utilities to potential problems in this area. As with all information notices, this IN did not require any specific action or written response from licensees. However, it did point out U-bend PWSCC degradation problems in mill-annealed alloy 600 SG tubes, the same material as IP2's SG tubes. The IN stated that "The 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 degradation."

[5]During these phone calls, Con Edison did not point out that they had found an axial crack in a row 2 U-bend.

Due to the timing of the release of the IN with respect to the beginning of the SG outage at IP2 in June 1997, the IN may not have been received by the licensee's SG inspection group before the inspection began. This may have been more of a missed opportunity for the NRC staff.

5.5.3 Conclusions

Based on the Task Group's review, the Task Group made the following general conclusions. The licensee was weak in assessing the condition of their SG tubes. The real problem stemmed back to the quality of the June 1997 inspection. Con Ed and their contractor, Westinghouse, missed the significance of the row 2 tube U-bend apex crack that was found for the first time in 1997. Even if the licensee had not requested an extension of the SG inspection interval, the SG tube likely would have failed before the end of the normal 24-month operating cycle. There were a number of missed opportunities by both Con Ed and the NRC to identify problems with the IP2 operational assessment. The lessons learned that the Task Group has identified for industry and the NRC are discussed below.

5.5.3.1 Lessons Learned for Industry

1) Licensees (and the staff) must recognize the significance of new types of SG degradation when they first occur. Licensees must also understand the importance of having good quality data when making decisions on SG tube performance.

2) Licensees should use robust techniques to look for other problems that may exist. Too much focus or attention only on problems that occurred in the past may lead to ignoring other problems (e.g., tube degradation mechanisms) that could occur in the future. **[note: Unsupported in this section]**

3) Generic industry SG guidelines may not apply to all plant-specific situations. The conditions/assumptions that were used as the basis for the guidelines may differ from the actual conditions at the plant. For example, although IP2 used EPRI guidelines to conduct their 1997 SG inspection, the IP2 SGs had significant copper deposits on the OD of the SG tubes. EPRI guidelines may not have covered this condition. Use of different probes/inspection techniques would have resulted in less noise and greater likelihood of finding flaws.

5.5.3.2 Lessons Learned for NRC

1) Knowledgeable NRC staff is essential. If reviewers do not have an adequate level of expertise, the significance of some inspection findings may be missed. SG expertise in EMCB resides primarily a few staff plus outside contractor support. If they were to leave the NRC, this would leave a large void. Maintaining SG expertise in the agency is important.

2) Phone calls with licensees can play an important role in identifying issues that come up during the licensee's SG inspection and can lead to the licensee performing a better inspection and operational assessment. **[add discussion of timing of phone call (e.g., before, during and/or shortly after the SG inspection). These calls can have a different "value added" depending on when the call is made.]**

3) The RES response has been perceived by some stakeholders outside the agency is that NRR did an inadequate review. NRR's request to RES to perform an independent

technical review of the staff's SE was an unusual process within the agency. Timely technical reviews and coordination between different NRC offices can enhance the agency's efficiency and effectiveness.

4) The staff sometimes has an easier time defending their position to management when the results of their reviews are favorable than when the results of their reviews are negative. This can lead to a less "questioning" attitude by the staff.

5.5.4 Recommendations

Based on the lessons learned discussed above, the Task Group has developed the following proposed recommendations for industry and the NRC.

5.5.4.1 Recommendations for Industry

1) Licensees should pursue problems when a new type of SG tube degradation occurs for the first time to determine the ramifications on SG condition monitoring operational assessment (e.g., potential for the tube to rupture before leaking such as at the apex of the U-tube, risk significance).

2) Licensees must have an adequate corrective action program to address unexpected problems when arise.

3) Licensees should review generic industry guidelines carefully to ensure that the conditions/assumptions supporting the guidelines apply to their plant-specific situation.

4) NEI/EPRI guidelines should be improved to take into account the lessons learned from IP2 (e.g., the benefit of using high frequency probes, need for better quality data).

5.5.4.2 Recommendations for NRC

1) NRC should take steps to ensure that adequate SG expertise is maintained within the agency. This could be done through formal training and/or transferring knowledge from in-house SG experts to other staff through written guidance documents or even a mentoring program.

2) NRR should continue to have interactions (e.g., phone calls) with licensees during their SG inspections, at least on a selected basis. The staff should identify priorities to determine which licensees should be called (e.g., age of SG, tube material, problems with similar SGs at other plants). The following topics should be included in these calls:

   o Identify any new degradation mechanism that has not been seen before
   o Describe any data quality issues (e.g., low signal-to-noise ratio)
   o Describe inspection findings in freespan areas, U-bend region

   These topics should also be included in NRC SG inspection procedures.

3) NRR should provide a format (i.e., specifying type of information and level of detail) that licensees should use when they submit their SG inspection reports to the NRC. This would specify a uniform set of information that the staff will be able to review that would be more useful than the current reports that are submitted.

4) NRR should coordinate with RES to make effective and efficient use of the agency's technical resources. NRR should seek RES technical input in a timely manner. In the future, if 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.

5) NRC reviewers should be encouraged to ask questions during their reviews so that they will have a sufficient technical basis for the conclusions in their safety evaluations. SEs should be written consistent with the information that was provided by the licensee.

5.5.5 References

A. Memo from S. Collins, NRR, to A. Thadani, RES, "Request for Independent Reviews of May 26, 1999, Safety Evaluation Regarding Steam Generator Tube Inspection Interval and February 13, 1995, Safety Evaluation Regarding F* Repair Criteria for Indian Point Station Unit 2," Feb. 28, 2000.

B. Memo from A. Thadani, RES, to S. Collins, NRR, "Request for Independent Reviews of May 26, 1999, Safety Evaluation Regarding Steam Generator Tube Inspection Interval and February 13, 1995, Safety Evaluation Regarding F* Repair Criteria for Indian Point Station Unit 2," March 16, 2000.

C. Memo from E. Sullivan, EMCB, NRR, to S. Bajwa, DLPM, NRR, "Safety Evaluation Regarding Steam Generator Tube Inspection Interval for Indian Point Station Unit 2 (TAC No. MA4526)," May 26, 1999.

D. Letter from A. Blind, Con Edison, to NRC Document Control Desk, "Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency," Dec. 7, 1998.

E. Letter from Con Edison to NRC Document Control Desk, "Response to Request for Additional Information - Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency," May 12, 1999.

F. Letter from Con Edison to NRC Document Control Desk, "Steam Generator Tube Inservice Examination 1997 Refueling Outage," July 29, 1997

G. Letter from NRC to Con Edison, "Request for Additional Information - Regarding Indian Point Nuclear Generating Unit 2 Steam Generator Inspection Interval One-Time Extension (TAC No. MA4526)," May 5, 1999.

H. Memo from S. Collins, NRR, to F. Miraglia, EDO, "Lessons-Learned Evaluation from Indian Point Station Unit 2 Failure Event, March 20, 2000.

I. Memo from S. Collins, NRR, to W. Travers, EDO, "Indian Point Unit 2 Steam Generator Tube Failure Lessons Learned Task Group and Charter," May 24, 2000.

J. NRC Information Notice 97-26, "Degradation in Small Radius U-Bend Regions of Steam Generator Tubes," May 19, 1997

Note - Information from the following interviews was used for the discussion in Section 4.5. They will not be included as references in the final Task Group report.

K. Task Group Notes - Discussion with Joe Muscara, RES on June 20, 2000.

L. Task Group Notes - Discussion with Andrea Keim, NRR on June 27, 2000.

M. Task Group Notes - Discussion with Emmett Murphy, NRR on June 29, 2000.

N. Task Group Notes - Discussion with Jack Strosnider, NRR on July 5, 2000.

O. Task Group Notes - Discussion with Stephanie Coffin, NRR on July 19, 2000

P. Task Group Notes - Discussion with Mike Mayfield, RES, on Aug. 9, 2000

Q. Presentation to Task Group by William Shack, Argonne National Laboratory, June 28, 2000.

5.6 Root Cause Analysis/Restart Safety Evaluation

Later

6.0 REGULATORY PROCESS ISSUES

6.1 Licensing Review Process

6.1.1 Background

The licensing review process is one of the regulatory processes that support the NRC's Strategic Plan performance goal of maintaining reactor safety. The NRC issues license amendments for nuclear facilities only after safety and environmental regulations have been adequately addressed. Specifically, before an amendment is issued, the associated safety evaluation (SE) must conclude that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

License amendments involve changes to the operating license and/or the Technical Specifications (TSs). The review and approval or denial of license amendment applications is one of the primary mechanisms for regulating changes in operation of licensed nuclear facilities. The NRC's Office of Nuclear Reactor Regulation (NRR) Office Letter (OL) No. 803, "License Amendment Review Procedures" (Reference 44), provides guidance to the NRC staff to process license amendment applications.

Regulatory requirements related to the amendment of operating licenses (including the TSs), are contained in 10 CFR 50.36, "Technical specifications;" 10 CFR 50.90, "Application for amendment of license or construction permit;" 10 CFR 50.91, "Notice for public comment; State consultation;" and 10 CFR 50.92, "Issuance of amendment."

The Task Group evaluation of the licensing review process focused on the issuance of IP2 Amendment No. 201 (Reference 5) with respect to the process described in OL No. 803. This amendment, which was issued on June 9, 1999, revised the TSs to allow a one-time extension of the steam generator (SG) inspection interval. The Task Group review was focused on Amendment No. 201 due to concerns regarding the technical adequacy of the associated SE and the licensee's application as described in a review performed by the NRC's Office of Nuclear Reactor Research (RES). The RES review (Reference 3) also evaluated IP2 Amendment No. 180 (Reference 9) which revised the TSs to allow the repair of SG tubes via implementation of an F* criteria. The RES review did not identify any issues related to the staff's evaluation or the information submitted by the licensee for this amendment. Therefore, the Task Group determined that review of the F* criteria amendment was not necessary.

The purpose of the Task Group evaluation of the licensing review process was to determine if there are any generic regulatory process elements that could be improved relative to assuring steam generator tube integrity. The Task Group evaluation was performed using the latest revision of OL No. 803 (i.e., Revision 3) which was issued on December 30, 1999. During the time frame the NRC review for IP2 Amendment No. 201 was performed (December 1998 - June 1999), Revision 2 of OL No. 803 was in effect. However, the Task Group's judged that the licensing review process has not changed significantly from December 1998 to the present. Therefore, it was decided that it would be beneficial to evaluate potential improvements to the guidance that is currently in effect.

The major issues and areas that were considered by the Task Group in performing the evaluation of the licensing review process (with respect to the review associated with IP2 Amendment No. 201) included:

a) completeness and acceptability of licensee's application;

b) use of precedent by the staff;

c) scope and depth of the review;

d) resources used in the review;

e) adequacy of the safety evaluation;

f) interface between NRC Headquarters and NRC Regional Staff;

g) review of TSs associated with SG inspection interval;

h) future potential impact of the NRC's Work Planning Center; and

i) evaluation of guidance available to NRC staff reviewers.

6.1.2 Observations

The Task Group reviewed the correspondence related to IP2 Amendment No. 201 including the application from the licensee, NRC interoffice memorandums, a request for additional information (RAI) and an RAI response (References 5, 5A, 6, 7, 7A, and 8). The Task Group also conducted interviews of NRC staff from Headquarters and Region I to gain insights on steam generator tube integrity issues relevant to the IP2. These interviews included discussions regarding the specific licensing review process that was performed for IP2 Amendment No. 201. The observations based on the review of the above referenced correspondence as well as the information gathered during the interviews are described below.

<u>Completeness and Acceptability of the Licensee's Application</u>

Section 2.2 of OL No. 803 describes guidance to the NRC staff to perform an initial screening of the licensee's amendment application to determine if it is complete and acceptable. This review ensures that the application includes certain key elements, some of which are administrative in nature while others provide technical information. The application should 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 (10 CFR 50.92); and

4) Appropriate TS pages.

The Task Group reviewed the licensee's application (Reference 8), 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.

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 that reviewed it at the time the SE was being prepared. However, subsequent to the IP2 tube failure event on February 15, 2000, other staff members reviewed the RAI response and they 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. 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 stated that although this statement was "ridiculous" it didn't affect 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.

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 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. However, the 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). This Task Group agrees with the staff's conclusion.

<u>Use of Precedent by the NRC Staff</u>

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 maximizes 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 that performed the review 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 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 Task Group did not identify any issues regarding the use of precedent by the staff.

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.

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

1) 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 do a deeper review. Licensee performance for SG inspection industry-wide as a whole has been good as evidenced by only one tube failure recently out of thousands of tubes inspected.

2) The requested change was not considered complex or safety significant. 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 generators were in wet lay-up during the unscheduled outage, and there was precedent for granting this type of extension. The request to extend the interval an additional 2 months was insignificant. 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., issuance of Amendment No. 201 had no effect related to the tube failure). The change would have been considered safety significant if it had reduced safety margins. The fact that we have tube failures every few years does not indicate that we have a significant safety or risk problem. See Section 5.3 of this report for further discussion on risk insights.

3) Based on the complexity and safety significance of the requested change, the experience level of the staff that performed the review was appropriate.

4) 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 (Reference 26) 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

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 application does not discuss the row 2 U-bend at all. 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.

The Task Group agrees that the scope and depth of the review was appropriate since the requested change was not considered complex or safety significant. The Task Group also agrees that it was reasonable for the staff to assume that the licensee's 1997 inspection was done in an adequate manner and formed a baseline for the review. Therefore, the Task Group believes that the NRC staff should not have been expected to review the licensee's 1997 inspection report thoroughly during the license amendment review process. However, 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 1997 inspection report had been thoroughly reviewed during the amendment review process, the staff could have questioned the licensee's operational assessment given the apex location of the row 2 U-bend indication.

Resources used in the Review

Section 2.4.2 of OL No. 803 describes guidance to the NRC staff regarding the resources to be used in the review. The OL states that the number of hours to be expended should be based on the scope and depth of the review, the availability of precedent licensing actions, the technical complexity of the proposed changes, and the risk significance of the amendment request. The primary responsibility for preparation of a SE is assigned to a Project Manager (PM) or to technical staff. The PM would normally conduct the review and prepare the SE for those requests that are relatively low in technical complexity, relatively low in risk significance, and have relatively high similarity to precedent licensing actions. Technical staff would normally lead the review and evaluation preparation for those requests that are relatively high in technical complexity, relatively high in risk significance, and have relatively low similarity to precedent licensing actions. The assignment of responsibility for the remaining types of applications (e.g., medium technical complexity, medium similarity to precedent licensing actions) will typically result from discussions between the PM and technical staff. The PM should ensure that all relevant technical branches that may have some technical responsibility for the content of an amendment application be involved in the review. In some cases contractors are used to perform the review. The use of contractors is determined by the technical staff based on: (1) technical expertise required to perform the scope of review, (2) availability of technical staff to support the required review in a timely manner, and (3) availability of funds to support contractor review efforts.

As discussed above, the requested change associated with Amendment No. 201 was not considered complex or safety significant, and there was precedent licensing actions for changes related to extending the SG inspection interval. The SE for this Amendment was performed by the technical staff. In the judgement of the Task Group, and given the guidance in OL No. 803, the proposed change was such that review by technical staff was appropriate. The technical complexity could probably be considered in the medium range and as such would not normally be done by the PM. However, the review was not of sufficient technical complexity such that a senior reviewer or contractor would be required. Interviews with the NRR staff indicated that they believed that adequate resources were used in the review (i.e., enough time was spent, enough people were involved, and the appropriate people were involved).

Adequacy of the 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 that 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 during an interview with NRR technical staff 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 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 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).

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 25), 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 6.2 of this report.

As discussed in the "Scope and Depth of the Review" section above, the SE was prepared with the assumption that the 1997 inspection of 100% of the inservice tubes was done in an adequate manner and formed a baseline for the review. This assumption seems reasonable to the Task Group. Therefore, the Task Group believes that the NRC staff should not have been expected to review the licensee's 1997 inspection report thoroughly during the license amendment review process. Based on the above, it appears that the NRC's staff SE did an adequate evaluation of the technical considerations related to assuring that tube integrity would be maintained.

Interface between NRC Headquarters and NRC Regional Staff

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 issues such as the licensee's application was not submitted in a timely manner or the application was inadequate and 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 as required. For example, in some cases, it may make sense for the Region to perform an inspection to verify information relied on in the SE. 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.

Review of TSs associated with SG Inspection Interval

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 8), 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.

Future Potential Impact of NRC's Work Planning Center

In 1998, NRR initiated a top-down assessment of the program activities of the office with the goal of increasing organizational effectiveness and efficiency. NRR management and staff had identified a number of concerns regarding the way workload was planned and managed.

NRR management identified centralized work planning as a possible solution to the concerns and requested an outside consultant to conduct an efficiency review of workload management. The purpose of this review was intended to validate that management of workload was an area that required improvement. As part of the review, the consultant was to specifically consider centralized work planning as an option and identify other possible options for the improvement. The consultant conducted a study of NRR's licensing action process and workload management practices. As a result of this study, recommendations were made that NRR should take a proactive business planning approach, and establish a work planning center to prioritize and assign work. This recommendation confirmed the approach previously identified by NRR management, and the NRR Executive Team endorsed centralized work planning as a new initiative for development. A Work Planning Center (WPC) group was established and they are currently developing the process designed to improve the efficiency and effectiveness in managing the NRR workload.

The Task Group determined that it would be beneficial to investigate any future potential impact of that the WPC will have on the licensing review process as presently described in OL No. 803. Specifically, there was a concern that the WPC might be responsible for assigning specific reviewers for a license amendment depending on workload. This is a potential concern depending on the level of expertise needed for a specific review. Discussions with one of the members of the WPC indicated that the basis process as currently described in OL No. 803 will remain unchanged. The following steps relate to how a reviewer will be assigned for a license amendment application:

1) The licensee's application for amendment will still be routed initially to the PM.

2) The technical complexity, applicable precedent, and risk significance of the proposed change will still be used to determine if the review will be done by NRR technical staff or by the PM. This decision is still up to the PM.

3) If the technical staff is going to perform the review, the Section Chief in the applicable branch will still assign the reviewer.

Based on the discussions with the WPC, the Task Group does not have any concerns regarding the future potential impact of the WPC on the licensing review process.

Evaluation of Guidance Available to NRC Staff Reviewers

There is no SRP section that provides guidance for reviews associated with SG inspection interval extensions. Interviews with NRR technical staff indicated that some of the guidance used includes Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle" dated April 2, 1991, and Draft RG DG-1074, "Steam Generator Tube Integrity" dated December 1998. These documents provide some insight but do not provide explicit guidance with respect to the technical considerations that should be taken into account when evaluating a request to extend the SG inspection interval. The staff

noted that the reviews are done such that the safety arguments convince the reviewers that SG tube integrity will be maintained.

Although there is no explicit guidance, the NRR technical staff does not feel that a new SRP section is necessarily needed in this area since some (but not necessarily all) of the NRR technical staff have the knowledge and know the technical considerations that must be evaluated. Some less senior members of the technical staff indicated the need for some of the more senior reviewers to transfer their knowledge to rest of the technical staff.

The Task Group concludes that since no specific guidance is available for reviewers to perform license amendment reviews associated with SG inspection interval extensions, the knowledge of individual NRC technical staff members is relied on too heavily. Formal guidance needs to be developed to ensure that all reviewers are able to perform consistent and thorough safety evaluations.

6.1.3 Conclusions/Lessons Learned

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

1) The NRR staff noted that they did not agree with the licensee's RAI response conclusions concerning growth rates based on PWSCC being found at a row 2 U-bend for the first time. Although the staff disagreed with the licensee conclusions, this issue did not affect the staff's decision regarding row 2 integrity because the reviewers believed that the results of the 1997 inspection established appropriate safety margins. However, this issue was not discussed in the staff's SE which could be mis-interpreted to imply that the staff concurred with the licensee's conclusions regarding growth rates. See Section 5.5 of this report for further discussion on growth rates.

2) With the discontinuation of the SALP process, PM input regarding assessment of licensee performance (as documented on the amendment cover letter) is not captured by any process.

3) In some cases it may be advisable for NRC Headquarters staff to interface with Regional staff to get input (e.g., via inspection) during development of an SE for a license amendment.

4) Since no specific guidance is available for reviewers to perform license amendment reviews associated with SG inspection interval extensions, the knowledge of individual NRR technical staff members is relied on too heavily. Formal guidance needs to be developed to ensure that all reviewers are able to perform consistent and thorough safety evaluations.

5) Given that the licensee did not identify the apex location of the indication found in the row 2 U-bend during the 1997 inspection in the Amendment No. 201 application or RAI response, there does not appear to be anything that the NRC staff could have reasonably done with respect to the licensing review process to prevent the IP2 SG tube failure event from occurring. This conclusion is based on the following:

    a) the staff used applicable precedent licensing actions;

b) the scope and depth of the review was appropriate since the requested change was not considered complex or safety significant;

c) adequate resources were used in the review (i.e., enough time was spent, enough people were involved, and the appropriate people were involved);

d) the SE did an adequate evaluation of the technical considerations related to assuring that tube integrity would be maintained;

e) it was reasonable for the staff to assume that the 1997 inspection of 100% of the inservice tubes was done in an adequate manner and formed a baseline for the review; and

f) it is likely that the tube that failed in February 2000 would have still failed without an amendment to extend the inspection interval (if the plant was in operation the entire cycle) since the tube failure took place in less than the number of effective full power days that was allowed between SG inspections.

6) The scope and depth of the review for Amendment No. 201 was appropriate since the requested change was not considered complex or safety significant. In addition, it was reasonable for the staff to assume that the licensee's 1997 inspection was done in an adequate manner and formed a baseline for the review. The NRC staff should not have been expected to review the licensee's 1997 inspection report thoroughly during the license amendment review process. However, 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 1997 inspection report had been thoroughly reviewed during the amendment review process, the staff could have questioned the licensee's operational assessment given the apex location of the row 2 U-bend indication.

6.1.4 Recommendations

1) If the NRC staff is not in agreement with specific technical information provided by the licensee, this should be discussed in the staff's SE even if the information is not relied upon to form a conclusion. In addition, the SE should be specific as to what information was relied on to form the basis for the staff's conclusions (i.e., basis for granting the amendment). OL No. 803 should be revised accordingly.

2) The NRC staff should evaluate whether the PM input on licensee performance (as documented on the amendment cover letter) is of value given the discontinuation of the SALP process. Section 4.1.1 of OL No. 803 should be revised accordingly.

3) The NRC staff should revise OL No. 803 to add a discussion regarding interface between Headquarters and Regional staff during SE development. The discussion should state that in some cases it may be of value to get input from the Region (e.g., perform an inspection to verify information relied on in this SE).

4) The NRC staff should develop formal guidance/training materials for technical reviewers to utilize in performing license amendment reviews related to SG tube integrity. While developing this guidance, consideration should be given to direct the reviewer to thoroughly examine the results from the last SG inspection.

6.2 NRC Oversight Process and Inspection Program

6.2.1 Background

NRC Manual Chapter 2515, "Light Water Inspection Program - Operations Phase," describes the NRC's inspection policy for the light-water operating reactor inspection program. The key objective of the program is to obtain factual information providing objective evidence that power reactor facilities are operated safely and licensee activities do not pose an undue risk to public health and safety.

The baseline inspection element of this program is to be performed at all operating reactors. It requires inspections of licensee performance in the seven cornerstones of safety. The baseline inspections constitute an appropriate level of inspection at plants whose overall performance remains in the licensee response band. The inspections are performed by the resident and region-based inspectors. In the Barrier Integrity Cornerstone, Inspection procedure 71111.08, "Inservice Inspection Activities," is applicable for Steam Generator (SG) Tube examination. The procedure is required to be completed once every two years during a refueling outage at each facility.

Plants, whose performance is outside the licensee response band, will receive additional plant specific supplemental inspection based on their assessed performance in the cornerstones of safety. The supplemental inspections are only performed as a result of risk-significant performance issues that are identified by either performance indicators (PIs), baseline inspections, or event analysis. The depth and breadth of specific supplemental inspections chosen for implementation will depend upon the risk characterization of the issues.

The inspection program also provides for the agency's response to operational events. The guidance for determining the level of response to an event is contained in NRC Management Directive 8.3, "Incident Investigation Program."

Under the NRC's program that was in effect prior to April 2000, the equivalent of the baseline inspection was the Core inspection. In that program, Inspection Procedure 73753, Inservice Inspection, was required to be completed at each facility once each refueling outage.

The Task Group reviewed the scope and level of the NRC's Inspection activities in the area of Inservice Inspection that relate to Steam Generator Tube Examination Program. This area covered the old NRC's Oversight Process that was in effect until April 2000, as well as the New Reactor Oversight Process (ROP) that went into effect in April 2000. The group reviewed the guidance provided for NRC's inspection activities, the expectation relative to staff resources, and the requirements for the level of specific technical expertise of NRC inspectors.

6.2.2 Observations

6.2.2.1 Scope and planning of regional inspections of SG examinations

The baseline inspection procedure, IP 71111.08, Inservice Inspection Activities, does not require that the SGs be looked at. Even if SG examination is selected, the review could be minimal. The same option was in inspection procedure 73753 of the old program that was applicable during the 1997 inspection at IP2. At that time also, the regional diversion of efforts into Licensing and Design basis in the mid nineties following Millstone, diluted the efforts being

put on SGs. Nevertheless, ISI inspections were scheduled at every facility in accordance with the Core inspection program. The scope of the inspector's review was based on the current significant issues and also as directed by the inspector's supervisor. The planning did not usually involve 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, Generic Letters, etc) did not 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 a week and was not necessarily limited to SG activities, but 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 steam generator tube eddy current inspections. These conference calls involved regional participation on occasions and were to discuss the results of the licensee generator inspections and repair plans. NRR has a prepared outline of important discussion areas to cover with the licensee and documents the results of the conference call internally. However, this effort has not been part of the inspection program, and the results are not documented in inspection reports.

6.2.2.2 NRC Inspection Procedures for Inservice Inspection (ISI) that existed prior to the New Oversight Process

In the old program, the required Core inspections of ISI activities at the plants were accomplished in accordance with NRC Inspection Procedure (IP) 73753, Inservice Inspection, dated 05/04/95 The procedure contained the guidance for the onsite one week inspection activities each outage. It contains guidance to review licensee's examination plans, personnel qualification and certification. It also has a general guidance for observing NDE activities, including eddy current inspection. It directs checking the procedure, personnel, and results. It further says, If possible, review comparism of ISI adverse findings with previous examination results to determine changes in flaw size, etc. Inspector may request NRC contractor review of eddy current testing results. The procedure made reference to a guidance document that was being developed that could be used to help determine the acceptability of the Volumetric examination using eddy current testing technique.

There were additional non-core (Regional Initiatives/Reactives) inspection procedures for various aspects of the ISI process. IP 73755, ISI Data Review and Evaluation; IP 73051, ISI - Review of Program; and IP 73052, ISI - Review of Procedures. All are 1986 documents and are silent on eddy current testing. There was also procedure Part 9900, Technical Guidance, "Mechanical - Steam Generator Plug and Sleeving Repair. The procedure contained technical guidance on plugging and sleeving of tube activities. It was unrelated to SG examination activities.

However, there was NRC Inspection Procedure (IP) 50002, Steam Generators, dated 12/31/96 that provided detailed information on inspecting the history and material condition of SG tubing. It also provides guidance on assessing the effectiveness of licensee programs for SG tube examination. The procedure was not required to be used at any site since it was not a "CORE" procedure but was considered an "Initiative" type procedure. If this had been used at IP2 in 1997 (plus Information Notice 97-06), the NRC possibly could have questioned IP2 about the depth of analysis of the row 2 tubes, especially since a row 2 U-bend apex crack was found and plugged.

The NRC inspected IP2's 1995 SG tube examination using IP 73753. The results were documented in NRC Inspection Report 95-07 (April 28, 1995). The findings were basically that: (1) Examination met the requirements of Regulatory Guide 1.83, Rev. 2; (2) Primary to Secondary Leakage was experienced in previous cycle and through hydrostatic testing, leaks were found in SG 22 (through mechanical plug in R4C92) and SG 24; (3) The licensee identified issues including copper deposits, distorted signals, etc. They re-evaluated the data of 1991 and 1993 and found no issues and (4) They used Cecco-5 probe.

The NRC inspected IP2's 1997 SG Examination using IP 73753. The results were documented in NRC Inspection Report 97-07 (July 16, 1997). The findings focused on what IP2 was doing and their data collection and not on the analysis of the results of their examinations. For example the report contained assessments such as good management oversight; and examinations conducted in accordance with EPRI S/G Tube Inspection Guidelines. The report also noted that Con Ed expanded their examination to inspect all support plate intersections with CECCO-5 probe and full length of all tubes with Bobbin and that they also used Plus Point probe during the examination.

During the 1997 inspection, the NRC inspector looked at the scope of IP2's inspections and focused on data collection. He spent about 25% of his time on other issues that were not related to Eddy Current Examination. IP2 had a third party, independent level III NDE person who was not a direct employee of Westinghouse or Con Ed. The NRC's onsite inspection lasted only for four days. At the end of the on site inspection week, the licensee's tube examination was still ongoing. Later, on June 29, 1999, there was a phone call involving Con Ed, NRR and the Region I office to discuss the licensee's examination results. Among the topics discussed were IP2's use of the Cecco-5 probe, and the identification of outside diameter initiated stress corrosion cracking (ODSCC). Con Ed participated in several telephone calls with NRR to discuss their inspection activities and findings. The last phone call was conducted on June 29, 1997. None of the phone call records indicate that a row 2 u-bend apex crack was discussed.

6.2.2.3 Qualification and training requirements for regional and resident inspectors

Manual Chapter 1245, "Inspector Qualification Program for the Office of Nuclear Reactor Regulation Inspection Program," defines the training and qualification requirements for staff performing inspections in the NRR inspection program.

There are no specific requirements that an ISI inspector must be a specialist or an expert. While ISI inspectors are not required to be ISI experts, the region feels that inspector should be qualified in ISI techniques. The inspector should be a specialist and should posses project engineering expertise. To have been able to identify the issue in 1997, the regional inspector needed training in analysis and also close interaction with NRR reviewers. As part of the training program, prior to conducting individual inspections, inspectors assist other inspectors on NRC's NDE inspections at other reactor sites. Nevertheless, the regional inspector training drastically lags the industry experience and training. While some regions have added the eddy current course in the inspector training process, it is not a required course.

6.2.2.4 NRC AIT, AIT Follow-up, Special Team and SG ECT inspection reports related to Steam Generators since 1995

(Add 4.4, item 5)
(Add special team's conclusions)

6.2.2.5 RC's inspection focus and known Primary to Secondary leakage at IP2

The specific requirements for SGs examinations are left to the licensees and their guidelines. There are no stringent requirements on SGs other than the Technical Specifications. In general, there is a weak regulatory structure for Steam Generators. What the NRC expects licensees to do differs from their technical specifications (i.e. NRC staff expects licensees to do more than meet minimal requirements).

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, 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. Following the failure, the leaking tube was identified as R2C5 in SG 24. (Reference: NRC Report 2000-001).

Con Ed procedure AOI 1.2, "Steam Generator Tube Leak," provides operators direction to identify and quantify Steam Generator Primary to Secondary leaks and implement contingency actions to mitigate adverse consequences. Increase activity in one of six leakage monitoring processes (N-16, R-45 Condenser Off gas, R-46 SG Blowdown, Sample analysis, XX, YY) gives the condition for entering into AOI 1.2. Each main steam line has Nitrogen 16 (N-16) monitors that have indication in the control room via a common alarm on the Accident Assessment Panel. AOI 1.2 defines the specific response actions. Various actions such as increased monitoring are required at various leakage numbers but ultimately, a leakage greater than 30 gpd would require a plant shutdown. Air ejector discharge is continuously monitored by radiation monitor R45, and also sampled by chemistry. If R-45 High alarm set point (#?) Is reached, then condenser off gas diverts to containment, and the steam flow to the hoggers is closed. The set point for the R45 alarm is based on equations in the Off Site Dose Calculation Manual and not on Primary to Secondary leakage.

Procedure IPC-A-110, "Primary to Secondary Leak Rate," provides a method for the determination of Primary to Secondary coolant leak rate for projecting the leak rate trend.

Con Ed planned to reduce the administrative limits from 150 to 30 gpd. (EPRI Guidelines, effective Feb., 2000, has 75 gpd).

(Ref; Con Ed's Response to RAI - June 20, 2000)

The NRC staff did pretty well in responding to the Primary to Secondary leakage prior to the event. (Reference: Region I interviews) It was brought up, discussed by regional management, and well followed by the resident inspectors. Although, the resident interest and coverage were not specifically called for in NRC Inspection Procedures, it took a skilled inspector to quickly recognize the significance and follow up on it. The residents brought up the leakage issue and it was well followed by DRS with support from NRR. The feedback was that the leakage was not up to the concern level yet and to keep an eye on it. DRS and NRR probably consulted the EPRI guidance on Primary-to-Secondary leakage. Given the same leakage amount, would something be done different now? - No, the leakage was not indicative of an imminent failure. If they had shut down at the low leakage, they might have had difficulty in identifying where the leakage was coming from. Before the tube failed, leakage was less than the first level of EPRI's monitoring level. In light of this, should focus be based on leakage numbers or rates?

6.2.2.6 NRC's review of Licensee's Inspection results

There were some unofficial records of NRC/Licensee phone calls during the 1997 examinations. On June 2, 1997, the licensee informed the NRC of the latest inspection results. 110 defective tubes were to be plugged. They also talked about the tubes selected for In-situ pressure tests. No indication that the row 2, u-bend apex crack indication that was plugged was talked about. On June 3, 1997, another telephone conference was held with Con Ed. There was also no indication that the row 2 tube plugged was talked about. The author of Information Notice 97-26 (on small radius u-bend apex cracks) was on both phone calls. The telephone records do not show any sensitivity, on both sides, to the apex crack issues. Maybe the crack at IP2 had not been determined at the time of the phone calls. There is no indication that the NRC reviewed the 1997 examination results submitted by Con Ed in accordance with their TS.

6.2.2.7 Activities and implications of "defunct" NRC Mobile Laboratory

The NRC mobile laboratory (lab), also known as the Van, was not involved in Eddy Current Examination. There was a drive to obtain and use an eddy current analysis machine that did not materialize. Nevertheless, the lab would not have helped at IP2. The van was useful during the construction of the facilities. The region had tried steering the mobile lab program towards Eddy Current Examination. A request was made for a Steam Generator Mockup to be added to the NDE mobile lab as part of the NRC's inspection process. The NRC did not approve the use of the mock-up. Eventually, the mobile lab was terminated.

6.2.2.8 New Reactor Oversight Process (ROP) ISI Inspection procedure, 71111.08, Inservice Inspection Activities

The new baseline inspection procedure for Inservice Inspection, IP 71111.08, contains significantly less guidance for conduct of the inspection than the previous core inspection procedure, IP 73753. For example, IP 73753, section 2.06, "Effectiveness of Licensee Controls", stated that the inspector should evaluate the effectiveness of licensee's controls of ISI contractors. *As noted in NRC inspection report 50-247/2000-10, poor licensee performance in this area during the 1997 steam generator inspections was a contributing cause to the February 2000 tube failure.* ***(Need to confirm)*** This inspection program guidance was not carried forward into the new baseline inspection procedure, IP 71111.08. The new program could allow us to not look at SGs. The baseline inspection procedure (IP 71111.08) does not require that the SGs be looked at. Even if selected, the review could be minimal. The new inspection procedure (71111.08) needs to be tested to see what it really takes to get a good insight at the sites.

IP 50002 was available under the old inspection program to be conducted as a regional initiative to perform a more focused inspection on steam generator condition and to assess the effectiveness of the licensee steam generator inspection program. This inspection procedure was retained for use in the revised reactor oversight process in the supplemental inspection program as documented in IMC 2515, Appendix B.

The process for ensuring relevant information generated by staff technical offices, that may affect the quality of regional inspections, is not being consistently implemented to ensure that this information is considered for inclusion in the inspection program. ***(Need 1-2 examples to support this point, or delete it.)***

6.2.2.9 Performance Indicators (PIs) for SG tube leakage

Primary to secondary leakage is captured by the Reactor Coolant System Leakage Performance Indicator (PI). This PI tracks identified reactor coolant system (RCS) leakage, which is generally on the order of gallons per minute. Steam generator tube leakage is generally on the order of gallons per day, and therefore adverse trends in primary to secondary leakage would not be readily apparent in this PI.

The industry guidance for reporting the Reactor Coolant System Leakage PI, as contained in NEI 99-02, states that normal steam generator tube leakage is included if required by the plant's Technical Specification (TS) definition of RCS identified leakage. The guidance also states that all calculations of RCS leakage that are computed in accordance with the calculational requirements of TS are counted in this indicator. *(This guidance may not ensure that primary to secondary leakage is reported in all instances by all licensees).*

6.2.2.10 ROP event response procedures (IP 71153, Revised MD 8.3, Special Inspection Team IP 93812)

Event response procedures provided adequate guidance to the regional staff and management to respond appropriately to the steam generator tube failure.

6.2.2.11 Significance determination process (SDP)

There were no issues identified with the significance determination process (SDP) or the assessment process related to the inspection findings and PIs that resulted from the steam generator tube failure. ??

(See special team's outcome)

6.2.2.12 Assessment for SG related inspection findings or PIs.

(???)

6.2.3 Conclusions - Lessons Learned

6.2.3.1

The regional inspectors are not as knowledgeable as the NRR technical experts, and the regional inspector training is not geared towards high technical capability. Therefore, the inspection process could not be reasonably relied upon to preclude a situation such as IP2 from occurring. Headquarters (NRR) outage phone calls with the licensees are useful, but are not on any regulatory or inspection basis.

6.2.3.2

There was a weakness in communication of important potential generic information (Information Notice 97-26) to the region such that it could be factored into the inspection process. NRC Information Notice 97-26, Degradation in Small-Radius U-Bend Regions of Steam Generator Tubes, dated May 19, 1997 deals directly with issues such as the apex axial crack. The notice was out during the 1997 examination and should have been high priority. NRC inspection should have also considered this issue.

If there had been good communication between the region and NRR, during the 1997 inspection preparation and during the inspection, the issue might have surfaced in 1997. IP2 would have been questioned and the fact that a tube with the subject flaw was identified and plugged would have raised additional concerns.

6.2.3.3

The regional and Headquarters staff review of the results of the steam generator inspections by the licensee is an important agency effort to assure the adequacy of condition monitoring and operational assessment. However, this effort has not been formalized in the inspection program to ensure that it is consistently conducted, with the results formally documented to allow the follow-up and resolution of significant findings that may result from the review.

6.2.3.4

As SG examinations, the NRC needs to worry more about data analysis than data collection. For example, in 2000, we were still able to find what happened from the reviews of the 1997 examination.

6.2.3.5

The NRC's baseline inspection program does not require much in the scope and depth of NRC's inspection of steam generator ISI examinations. Inspection Procedure (IP) 71111.08, Inservice Inspection Activities, contains less requirement or guidance for SG inspections. In the old oversight process, the required steam generator examination inspection (73753) was not of sufficient scope and depth to identify any issue the licensee might be missing or not addressing properly. However, IP 50002, which was retained in the new process, appeared to contain sufficient information and guidance that could have provided additional oversight. 50002 was not required nor was it hardly ever used by the inspectors.

> NRC Inspection procedures are inadequate except maybe IP 50002 Steam Generators, dated 12/31/96. However, IP 50002 is not normally used nor is it required to be used.
>
> The NRC might have identified the potential problem during inspection activities in 1997 if IP 50002, Steam Generators, in conjunction with the information in Information Notice 97-26, had been used.

6.2.3.6

The combination of PIs and baseline inspection ensure that the key attributes of the Barrier Integrity cornerstone of safety are met. Therefore either the baseline inspection program or performance indicators should provide the indication of any adverse trends in primary to secondary leakage is monitored.

Based on the industry guidance contained in NEI 99-02 for reporting the Reactor Coolant System Leakage PI, some licensees may not be required to report primary to secondary leakage resulting from a faulted steam generator. ***Need to confirm***

6.2.4 Recommendations

6.2.4.1

The Technical Specifications on Steam Generators do not really ensure integrity of the generators. Licensees can comply with the specs on leakage and inspections and still not do well enough to ensure tube integrity.

(A) TS 3.1.F.2a on Operational leakage limits allows a Primary to Secondary Leakage that could place the plant in a "High Risk," or "Less Safe" condition.

Basis: IP2's leakage before failure was $\simeq$ 5 gpd. Tech. Specs. allowable was 432 gpd (No sleeves) or 150 gpd (If sleeved).

(B) TS 4.13.A.1.d defines degraded tube as a 20% through wall and detectably by eddy current inspection. ASME Code Section XI (1989 Edition), Appendix IV requires that flaws with 20% wall penetration shall be identified and the depth noted. IP2 could not detect well below 40% (like the rest of the industry). Therefore IP2 is (was) not technically in compliance with the Code?

6.2.4.2

The reporting requirement for SG examination results should be reviewed to require information that will be useful in assessing and understanding the condition of steam generators. For example, new flaw characteristics or locations, etc..

The staff should determine whether the review of licensee steam generator inspection results is an important agency activity to assess the adequacy of steam generator condition monitoring and operational assessment determinations by the licensee. If important, the staff should incorporate appropriate guidance into the inspection program to ensure the review is consistently conducted, and that significant findings are formally documented and followed up to resolution.

NRC review of the results should be conducted to some level (if report is meaningful and tailored properly) with a docketed response or acknowledgment provided.

Basis: The report is not usually reviewed in a timely manner (if reviewed at all), and the depth of review does not appear to be significant. Con Ed's 1997 report had information on a Row 2 Tube (R2C67) being plugged because of a U-bend apex flaw. Based on industry experience, if this information was seen by the NRC, the issue could have been raised concerning adequacy of leaving Row 2 tubes in service.

6.2.4.3

Reactor Oversight Process - Inspections: Enhance inspection procedure (Regional or Plant Status Monitoring) to consider Primary to Secondary leakage rates and rate changes. The staff should ensure that either the baseline inspection program or PIs adequately identifies adverse trends in primary to secondary leakage which could indicate a degradation of the RCS barrier. If PIs are the primary means for this indication, then the staff should review the guidance to ensure that all licensees are required to report primary to secondary leakage for both normal and faulted conditions. If appropriate, a new PI should be pursued that more accurately reports adverse trends in primary to secondary leakage.

Basis: The current technical specifications and administrative numbers didn't appear to provide much insights/warning with the February 15 failure.

If appropriate, additional guidance could be included in IP 71111.20 "Refueling and Outage Activities" to focus inspection effort on licensee preparations for steam generator maintenance and testing.

Although the baseline inspection program routinely monitors primary to secondary leakage, the SDP can not be used to establish the safety significance of an adverse trend. The staff should consider developing a new PI which tracks primary to secondary leakage and has established thresholds (e.g., percent of technical specification limit) to ensure increased NRC involvement in response to adverse trends in steam generator tube leakage.

Although no specific issues were noted with the SDP and assessment process, these processes need to be reviewed to assess the impact of any changes or revisions made to the inspection program or PIs. For example, any new inspection requirements resulting from this event must include a review of the SDP to ensure that resulting inspection findings can be adequately assessed for safety significance by the process.

6.2.4.4

NRR/Regional Communication: The technical interaction between the licensees and NRR (**Outage Phone Calls**) during the examinations should be better coordinated with the regional offices and factored into the inspection program. The phone calls could be used as part of the inspection preparation and the inspection could be geared towards following up on NRR and Regional identified issues. The regions should be more involved with the NRR/Licensee phone calls. The technical benefit is not captured now.

> Basis: Region I inspected IP2's examination in 1995 and 1997. Headquarters interacted with the licensee in both years, yet no useful information is contained in inspection reports that would reflect the crucial issues discussed and resolved. NRC (HQ) had information (IN 97-06) on flaws in tight bend (like row 2) tubes that could have been crucial if brought up.

6.2.4.5

COMMUNICATION: Dissemination of information to the regional offices and others should be looked at. It appears to be rather slow and sometimes lacking. For example, good NUREG reports are available on SGs but the region is not aware of them. How is the screening of generic information such as Information Notices, addressed? Could the inspection guidance be subjected to periodic changes based on accumulated generic information? However, it should be noted that the regions should not be overwhelmed with information. As an example, the way the MOV Program oversight was handled could be viewed as a good communication model.

NRC should improve how generic information such as Generic Letters and Information Notices and Operating experience get factored into regional inspection guidance. The phone calls with NRR and Licensees, including the regions, should continue. There should be closer interactions and sharing information between Headquarters and the regions.

6.2.4.6

Regional inspection planning should involve technical staff to better focus the inspection effort. The technical staff covers the technical crust of examination issues that are not captured in a way that the regional inspectors can be helped with key issues. The licensee's previous

examination results as part of their submittal could be part of the inspection preparation. The review could include NRR.

Basis: Regional Inspectors do not have the technical expertise available in the NRR. Inspection procedures (except IP 50002) do not help find technical issues.

Internal procedures must be established and consistently implemented to ensure that pertinent technical information that may affect the quality of NRC inspection is available by the inspectors. ***Delete if there are no substantiated examples of a problem in this area.***

6.2.4.7

Inspector Training: The staff should review the requirements of the baseline inspection program and the guidance contained in each inspection procedure to determine the KSAs required for the average inspector to successfully complete the objectives of the inspection program. Based on the results, changes should be made as appropriate to the level of detail of the inspection procedures and the training provided to inspectors.

The level of guidance in the inspection procedures must be commensurate with the knowledge, skills, and abilities (KSAs) of the average inspector who will be performing the inspection. A specialist inspector specifically trained in the area of interest needs less guidance than a generalist, who may need more specific information to conduct the inspection.

The staff should develop, revise, and implement, as appropriate the processes to ensure that relevant technical information is reviewed and considered for inclusion in the inspection program to ensure that it is available for use by the inspectors. ***Delete if no examples of a problem in this area.***

6.2.4.8

The staff should ensure that onsite communications in the licensee emergency response facilities, including the control room, are adequate to ensure required communications with onsite inspectors can be maintained. Expectations for licensee management briefings of the NRC should be reinforced with both licensees and the NRC staff, to ensure that they do not impose an unnecessary burden on the licensee while responding to an event. (From resident inspectors - unsubstantiated in our report?)

{Note: * Other technical issues that fall out from the other sections should be considered in the inspection sense.}

7.0 INDUSTRY INTERFACE ISSUES

7.1 Industry Guidelines for Steam Generator Inspection and Assessment

7.1.1 Background

In recent years, PWR licensees have relied upon a number of industry guidelines and technical publications issued by Electric Power Research Institute (EPRI) and Nuclear Energy Institute (NEI) to form the basis of their steam generator inspection and maintenance programs. Originally, individual technical reports were issued to address specific degradation mechanisms or to provide guidance concerning inspection techniques as they were developed in the industry. More recently, under the auspices of NEI, the industry has mounted a concerted effort to assemble a framework for SG maintenance programs that could be applied throughout the population of PWRs.

In December 1997, the NEI forwarded to the NRC NEI 97-06, "Steam Generator Program Guidelines" (Reference). The document was intended to serve as a framework for steam generator management programs to be implemented by licensees. The objective of issuing the guideline was to introduce consistency in application of industry guidelines to licensee SG management programs. The guideline refers to EPRI technical reports for detailed development of program attributes.

The Task Group examined the applicability of NEI Guidelines and EPRI technical reports to Indian Point unit 2 (IP2) at the time of the tube failure event in February 2000. The Task Group also derived implications for the guidelines from the IP2 event in the overall approach they take to management of SG degradation problems. Also of interest to the task group were any activities that industry contemplated or had undertaken to incorporate lessons from the event into the generic SG management guidelines.

The task group expressly did not review the overall acceptability of technical or programmatic aspects of the guidance documents. Such a review will be conducted by the NRC as part of the effort to produce a safety evaluation as discussed in SECY 00-0078 (Reference). The Task Group also did not address the role of ASME standards in SG maintenance programs, because application of engineering standards has not been raised as a major issue in the aftermath of the tube failure and regulations exist governing the use of industry standards.

7.1.2 Observations

– **Industry Guidelines Applicable to IP2**

NEI informed the NRC in December 1997 (Reference) that it had formally adopted NEI 97-06, and that each licensee would meet the guideline no later than the first refueling outage starting after January 1999. NEI Issued a revision to the guidelines (Rev. 1B) in January 2000.

The December 1997 NEI letter stated that:

> "Each licensee will evaluate its existing steam generator program, and where necessary, revise and strengthen program attributes to *meet the intent of* the guidance provided in NEI 97-06." (Emphasis added)

Thus, the initiative is somewhat open to interpretation as to what guidelines apply to a specific plant and what criteria are used to gauge the intent of the guidelines.

The NRC letter (Reference Feb. 3, 1998) acknowledging the guidelines supports the industry initiative, but expresses reservations regarding NEI 97-06 performance criteria: "the two criteria [structural and leakage criteria], as stated in NEI 97-06, may not ensure compliance with current regulations." The NRC letter goes on to say that licensees should carefully assess the NEI 97-06 guidance and ensure that implementation is consistent with NRC regulations.

The guidelines stipulate that licensees will adopt performance criteria for tube structural integrity, operational leakage, and accident-induced leakage. Implementation of the guideline was to be accomplished through proposed technical specification amendments and associated documents (the technical requirements manual???). NEI 97-06 discusses NRC regulations pertinent to SG integrity, and mentions Regulatory Guide 1.174 for guidance in the event that a risk-based tube integrity assessment is needed.

In a number of licensing submittals and other documents concerning SG inspection and maintenance, Consolidated Edison (Con Ed or the licensee) referenced EPRI guidance documents as the basis for parts of their program:

- Eddy Current Examination of Steam Generator Tubes for Indian Point Unit 2, Specification No. NPE-72217, (December 17, 1996, Rev. 10) references the EPRI PWR SG Examination Guidelines.

- In its proposed SG tube examination program for the 1997 refueling outage (Reference Feb 7, 1997), Con Ed referenced the EPRI PWR Steam Generator Examination Guidelines and its Appendix H, "Performance Demonstration for Eddy Current Examination" as the basis for qualification of the eddy current probe to be used for the inspection.

- In its response to NRC Generic Letter 97-05, "Steam Generator Tube Inspection Techniques," (Reference March 17, 1998) the licensee referenced NEI 97-06, and Appendix H of the EPRI PWR Steam Generator Examination Guidelines.

- Con Ed submittal (Dec. 7, 1998) stated that ECT probe qualification based on EPRI PWR SG Program Guidelines, and water chemistry on EPRI guidelines.

- Con Ed RAI response (May 12, 1999) Referenced EPRI Appendix H criteria for probe qualification.

- Wet lay up conditions maintained in accordance with EPRI guidelines during extended shutdown (see Section 3.2, May 1999 SE).

- In its proposed examination program for the 2000 refueling outage, (Reference Feb 11, 2000), the licensee again references the EPRI PWR Steam Generator Examination Guidelines and its Appendix H. Further, the licensee committed that the program would meet the requirements of NEI 97-06, "Steam Generator Program Guidelines. The licensee explicitly stated that Revision 5 of the EPRI guidelines would be followed in addition to the requirements of Technical Specification 4.13.

- Con Ed (Reference June 2, 2000) conducted a condition monitoring and operational assessment of the SGs based on NEI and EPRI guidance. Con Ed referenced EPRI TR-107621, Rev. 0, Steam Generator Integrity Assessment Guidelines, Nov. 1999, EPRI ISI Guidelines TR-107569, App H as the basis for POD and NDE sizing uncertainties development., and EPRI TR-107620-R1 Steam Generator In-Situ Pressure Test Guidelines.

- In the June 20, 2000, RAI response, Con Ed references EPRI PWR Primary-to - Secondary Leakage Monitoring Guidelines, Revision 2, February 2000.

- Steam Generator Tube Leak AOI 1.2 Rev 21 dated June 21, 2000, lists EPRI TR 104788-R1, PWR Primary-to-Secondary Leak Guidelines (Revision 1).

- The Nuclear Power Indian Point Station, Station Administrative Order, Administrative Steam Generator Program Plan, SAO-180, Rev. 0, was, "developed to meet Con Ed's commitment to the requirements of a nuclear industry initiative described in the Nuclear Energy Institute (NEI) "Steam Generator Program Guidelines 97-06." The administrative order lists NEI 97-06 and a number of EPRI guidelines as references.

It is clear from this listing that Con Ed used EPRI guidelines and committed to the NEI 97-06 initiative before the February 2000 tube failure event.

The Task Group judged the adequacy of the industry guidelines for IP2 in certain areas as discussed in Sections 4.1, 4.2 and 4.4 of this report, and related contributions that shortcomings in the guidelines may have had to SG conditions leading to the event. Although the Task group did not conduct an extensive review of the guidelines or of the NEI initiative, it is apparent that implementation of the guidelines or in some instances the technical guidance may have been lacking for the situation encountered at IP2. **For instance, use of the 800kHz Plus Point probe is not linked to an industry guideline, but was an important point during the 2000 SG inspections. A footnote states that prior to its use, it was qualified in low row u-bends by tests at EPRI, W and Con Ed, but it was not part of the guidelines (CHECK w/Louise on this).**

Con Ed's root cause evaluation (Reference April 14, 2000) "expert review of the data concurred that the flaw would not have been called by accepted EC practices in 1997, due to background noise in the signal related to geometry effects and deposits including copper." Therefore, the licensee's position appears to be that, although the guidelines were in use during 1997, they did not provide adequate guidance to facilitate finding the flaw that led to the failed tube.

It is clear that the licensee applied the EPRI guidelines and committed to following the NEI initiative. However, implementation of the guidelines appears to have been inconsistent prior to 1999 because sometimes the guidelines are referenced and other times NRC Regulatory Guides are used. It was also not clear that those guidelines in use were being implemented effectively. An objective of the NEI 97-06 initiative was to bring consistency to SG maintenance programs in this regard, but the commitment to the initiative was not in effect during the 1997 SG inspection.

b. Implications of the IP2 Event on Industry Guidelines

As discussed in Sections 4.1 and 4.2, shortcomings in the EPRI SG inspection guidelines should be addressed as a result of the IP2 event. Issues such as data quality, inspection method flaw sizing qualification, and ECT noise levels were specific points raised in the

aftermath of IP2. Presumably, there could be other technical issues not raised in this report that could become important under other circumstances. The following section (6.2) discusses the need for NRC to review the industry proposal for SG degradation management. In the shorter term, the NRC should be cautious about relying too heavily on the EPRI guidelines as a substitute for NRC inspection and oversight of licensee SG maintenance practices. A thorough review of the NEI initiative could uncover other significant shortcomings that, when corrected, will lead to a reliable framework for regulation of SG maintenance programs.

A key component of the NEI initiative are the revised technical specifications for SG integrity. As currently conceived by NEI, SG technical specifications would be revised to use a tighter leak rate limit, and tube performance would be judged based on tube structural and leakage criteria. It is not clear that the technical specifications being proposed in conjunction with the NEI initiative would have averted the IP2 event. The structural and leakage performance criteria may not trigger licensee actions as early as the inspection criteria in current tech specs. The inspection results criteria in current tech specs drive licensee actions in response to as-found degradation. Inspection results are not used as performance criteria under the NEI-proposed tech specs, and the NRC review should determine precisely what role inspection results are intended to play under the proposed framework.

Other technical problems with the guidelines found as a result of the IP2 event include characterization of ECT noise, data quality SEE Chapter 4

Industry Lessons-Learned and Initiatives to Modify Guidelines Based on Event

7.1.3 Conclusions

1. SG program deficiencies existed at IP2 despite commitments to follow industry guidance.
   <u>Lesson Learned</u>: An effective oversight mechanism is needed, whether it is industry- or NRC-based, to provide added assurance that minimum standards for SG programs are being maintained.

3. Industry has not yet taken steps to incorporate lessons learned from the event into existing guidance documents.

   <u>Lesson Learned</u>: Industry should be pro-active in determining how their proposed initiative can be made more effective in light of the shortcomings that led to the IP2 event.

7.1.4 Recommendations

- NRC should ensure that an effective oversight program is incorporated as part of the NEI initiative. This would help maintain safety by providing assurance that appropriate steps are being implemented in licensee SG maintenance programs. It would also serve to bolster public confidence that licensees are properly implementing guidelines. Agency effectiveness and efficiency would be served because reviewers and inspectors would have added assurance that guidelines were implemented more consistently across the industry.

- NRC should be cautious in relying too heavily on the NEI 97-06 initiative until it is reviewed by NRC. In the interim, the agency should consider prioritizing portions of the initiative for review in order to appropriately allocate resources. For instance, the proposed technical specifications might be reviewed before detailed technical reports are considered for review. This would serve to maintain safety by addressing a basic problem with SG maintenance (i.e., deficient technical specifications), while other resources are brought to bear on other parts of the NEI 97-06 initiative review. Prioritization of the effort would focus on increasing efficiency and effectiveness of agency activities.

7.2 <u>NRC Endorsement of Industry Guidelines</u>

7.2.1 Background

For a number of years, the NRC has been engaged in efforts to modify the regulatory approach to steam generator integrity. The staff has acknowledged that the existing regulatory framework was considered to be prescriptive, out-of-date, and not fully effective at ensuring steam generator tube integrity (see SECY 00-0078 and SECY 95-131, Continuance of Proposed rulemaking on Steam Generator Maintenance and Surveillance," May 22, 1995). To remedy the situation, the staff has considered a range of options, including rulemaking, a generic letter and draft regulatory guide, and an industry initiative. The industry initiative has taken the form of guidance documents and detailed technical reports that licensees use as the basis for steam generator maintenance programs. The industry initiative culminated in the publication of NEI 97-06, "Steam Generator Program Guidelines," in an attempt t to provide consistency to industry guidance.

The industry guidelines have been a primary focus in the aftermath to the IP2 tube failure event. Although the industry in general, and IP2 specifically, have committed to follow the NEI 97-06 initiative, it does not constitute a regulatory requirement in itself. Although the NRC has acknowledged licensee's use of the guidelines, and has even encouraged their use, the NRC has not formally endorsed the industry initiative nor any of the specific guidance documents. The task group was interested in determining if the NRC position on the guidelines may have had an impact on the state of the SG management program at IP2.

The Task Group examined the NRC position on the industry SG guidelines as stated in NRC internal documents, generic communications to licensees, and in correspondence to the industry. The Task Group also considered the implications of the NRC position regarding the guidelines on conditions leading to the IP2 tube failure event.

7.2.2 Observations

a. NRC position on Industry Guidelines

The industry guidelines for SG inspection and maintenance are considered a significant industry initiative. The NRC position on industry initiatives has evolved in recent years based on Direction Setting Initiative 13 (SECY 00-0116) and the NRC position on the SG guidelines has adapted to those changes. SECY 98-248, "Proposed Generic Letter 98-XX, 'Steam Generator Tube Integrity'" explained that the staff focus on SG integrity regulatory issues was shifted to work with NEI to resolve concerns with NEI 97-06. The staff expressed its preference to endorse the industry initiative rather than issuing a generic letter, consistent with DSI-13.

The staff put forward its plans to incorporate industry initiatives into the regulatory process in SECY 00-0116, "Industry Initiatives in the Regulatory Process," (DATE). The SECY proposed guidelines that the staff should follow to incorporate industry initiatives and to use an expedited process if necessary. The SECY uses the NEI 97-06 initiative as an example of an industry initiative that is intended to complement regulatory actions for issues within existing regulatory requirements. The NEI-97-06 initiative has gone through many of the preliminary steps outlined in the SECY and its attachments that lead to establishing the industry initiative for the management of SG integrity issues. Therefore, the NEI 97-06 initiative appears to be a prime candidate to use the proposed process, once it is approved.

NRC Regulatory Guides regarding steam generator inspection and maintenance have not been revised in many years and do not address the NEI initiative nor the individual EPRI guidelines that predated the initiative. For instance, Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes" Rev. 1, was issued in 1975 and predates the EPRI guidelines. The Regulatory Position in RG 1.83 lists components that should be included in a SG ISI program, including SG inspector qualification based on a standard issued by the American Society for Nondestructive Testing. The EPRI guidance is not mentioned. RG 1.121, "Basis for Plugging Degraded PWR Steam Generator Tubes," August 1976 also predates EPRI guidance.

Recent efforts focused on revising the regulatory framework for SG integrity included the development of a draft regulatory guide DG-1074, "TITLE." DG-1074 directs licensees to consider EPRI leakage monitoring guidelines, and went beyond the EPRI guidance in some ways (e.g., monitoring leakage at low power conditions). The DG also **recommends (right word?)** that NDE techniques and NDE personnel be qualified in accordance with Appendices G and H of the EPRI PWR Steam Generator Examination Guidelines. There are common elements between the industry guidance and the DG that licensees are currently using in their SG management programs. DG-1074 was issued for public comment (See SECY 00-0078) and it received numerous comments. However, the range of comments generated indicates that further development of the DG and the NEI initiative is necessary before they can become **reliable ????** parts of SG regulatory framework. In SECY 00-078, the staff expressed its intent to review the NEI initiative and to prepare a safety evaluation documenting its findings. The staff plans to then issue a Regulatory Information Summary documenting NRC endorsement of the NEI initiative based on findings in the SE. However, recent interaction with the industry (July 26 meeting with NEI) indicated that the staff has put review of the NEI initiative on hold pending lessons learned from IP2 and other SG-related review activities.

The NRC has issued numerous generic communications concerning SG tube failure events and SG inspection and maintenance practices. Several of these documents refer to EPRI SG guides in general or specific ways. Some examples are:

- GL 95-05 (Reference) referenced EPRI guidelines in the discussion of EC voltage Measurement Uncertainty (EPRI TR-100407, Revision 1, Draft Report August 1993, "PWR Steam Generator Tube Repair Limits-Technical Support Document for Outside Diameter Stress Corrosion Cracking at the Tube Support Plates") and in the discussion of Burst Pressure Versus Bobbin Voltage (EPRI Draft Report, NP-7480-L, "Steam Generator Tubing Outside Diameter Stress Corrosion Cracking at Tube Support Plates - Data Base for Alternate Repair Limits," Volume 1, Revision 1, September 1993, "7/8 Inch Diameter Tubing," and Volume 2, October 1993, "3/4 Inch Diameter Tubing."

- IN 97-26, Degradation in Small-Radius U-Bend Regions of Steam Generator Tubes" discusses EPRI probe qualification in general terms.

- IN 97-88, "Experiences During Recent Steam Generator Inspections," mentioned EPRI recommendations regarding crack detection at dented locations.

NRC has referenced but not endorsed the EPRI guidelines, as indicated in the preceding examples. The signal that may have been sent to the industry by taking this stance is that the NRC considered the existing guides sufficient for managing SG maintenance and inspection activities. The NRC should use the SECY 00-0116 process, once approved, to expedite the review of the NEI 97-06 initiative.

b. **Implications of the NRC Role Regarding the Guidelines**

NRC acknowledged NEI 97-06 (Reference Feb 3, 1998) and supported the industry effort, but did not endorse the guidelines. Although the staff did not review NEI-97-06, the feb 3, 1998, letter did note differences between NEI 97-06 and the draft regulatory guide DG-1074, which the NRC has since published for public comment. The letter went on to state that the performance criteria for structural integrity and accident-induced leakage might not ensure regulatory compliance. In his letter, the EDO recommended that licensees "carefully assess the NEI 97-06 guidance and ensure that implementation ....be consistent with 10 CFR 50.59 to ensure that they continue to maintain and operate their facilities such as to comply with current regulations."

Although industry has adopted guidelines for SG management, without NRC review and endorsement, licensees do not always have a clear view of the suitability of contemplated maintenance and repair activities. NRC has found weaknesses in the guidelines on a case-by-case basis (the follow-up to the IP2 event being the most recent example) and licensees are forced to address the weaknesses within the licensing process. This approach leads to an inefficient and, what could be viewed as a less-than-optimally effective process.

In the case of IP2, Guidelines existed in 1997 that the licensee referenced for that inspection. The NRC position on the guidelines was ill-defined, and as a result, little to no direction existed for inspectors or for technical staff to rely upon when evaluating SG-related licensing actions of licensee SG programs. Taking steps to review and approve an acceptable industry program should help to alleviate this situation, and will contribute to maintaining plant safety and agency efficiency and effectiveness.

7.2.3 Conclusions

1. There has been a long-standing NRC position of generally accepting use of the industry SG guidelines without formally endorsing them. Also, steam generator-related regulatory guides have not been revised to present a regulatory position on the guidelines.

   Lesson Learned: This situation could have been a secondary factor in contributing to conditions that led to the IP2 failure because the licensee considered the guidelines as a sufficient basis for their SG inspection and maintenance program. Some NRC staff consider the guidelines as a minimum requirement, and others feel that there are significant shortcomings to the guidance. Further, the range of NRC staff opinions on the sufficiency of the guidelines and may have contributed to shortcomings in the NRC licensing process, in areas such as inspection and technical review guidance. NRC should increase emphasis toward efforts to review the industry guidelines and to promulgate a regulatory position on them.

7.2.4 Recommendations

1) Consider increasing the priority of NRC review and endorsement of guidelines. This will contribute to maintaining plant safety and agency efficiency and effectiveness.

8.0 FINDINGS AND CONCLUSIONS

9.0 RECOMMENDATIONS

9.1 Actions

9.2 Further NRC Action

10. REFERENCES

APPENDICES

Appendix A - Timeline of IP2's SG Inspection/Repair Activities

Appendix B - Timeline of NRC's Inspection/Licensing Activities