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

4) Vendors that conduct the actual examinations, including collection and analysis of the data, are important to the SG examination process. The industry initiative should address vendor oversight by licensees.

Other recommendations to improve the effectiveness of the guidance can be found in Section 6 of this report.

Industry Initiative and Framework

benefits of improving

The Task Group considered the implications on the industry initiative and framework, given the IP2 event and its lessons-learned, the need to ~~improve~~ the EPRI guidance, and the safety significance of the issues. The Task Group believes that the industry initiative remains the most effective means to continue to maintain safety in this area. However, the lessons-learned discussed above identify issues that should be incorporated into the framework in an integrated way. The Task Group concludes that the industry should be requested to evaluate and propose modifications to the framework that consider the lessons-learned from IP2. These should include as a minimum:

1) means to ensure plant-specific implementation of lessons-learned;

2) improvements to the EPRI guidelines, and to emphasize the need.

3) the objective, format, and content of the improved technical specifications relating to SG tube integrity focusing on operability, primary to secondary leakage limits, and reporting requirements (both content and schedule of reports).

As stated above, the Task Group believes these activities should receive a high priority based on the generic aspects of the issues and the risk significance of the SG tube conditions at IP2 prior to the tube failure. Therefore, in the interim, the Task Group believes that NRC should issue a generic communication in accordance with existing procedures and policies that discusses the issues identified by the Special Inspection Team and generic applicability of these issues.

NRC Regulatory Processes

Based on a review of the licensing, inspection and oversight processes associated with the IP2 event and SG tube integrity, the Task Group believes that there are areas that should be improved in these processes to make them more effective as discussed below.

Licensing

The license amendment process is used by the NRC to review facility operating license changes proposed by a licensee. Such a request was made by Con Ed in December 1998 to extend their SG examination from June 1999 to June 2000. In effect, because of an approximate 10 month period the plant was shut down, the licensee was actually requesting an extension of the

ITEM # ______

44

131

examination interval of approximately 2 months beyond the already authorized 24 months (June 1997 to June 1999). This is illustrated in the Appendix A timeline of this report. Because the licensee followed industry guidelines for maintaining water chemistry in the SGs to minimize corrosion of the SG tubes during the shutdown, any degradation that would have occurred during the shutdown period would have been negligible.

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

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

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

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

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

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

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

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

Inspection

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

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

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

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

The new ROP baseline inspection procedure for ISI does not require that licensee SG examinations be inspected by the NRC. The inspection procedure contains significantly less guidance for conduct of the inspection than the previous core inspection procedure. Available

supplemental procedures contain considerably more detail. Under the new ROP, risk-informed thresholds are to be applied to inspection findings to determine when a significant degraded condition has occurred that warrants additional NRC interaction and supplemental inspection above the baseline program. Such thresholds do not currently exist to identify when the number or types of SG tube defects have reached a level that warrants additional NRC action.

There are no specific requirements for ISI inspector training or expertise. Region staff interviewed indicated that as part of the training program, prior to conducting individual inspections, inspectors assist other inspectors on NRC's NDE inspections at other reactor sites. A number of inspectors have received detailed training in eddy current examination and have personal NDE experience.

The Task Group also carefully reviewed the licensee submittal to the NRC dated July 29, 1997, regarding the IP2 1997 SG examination. The level of detail provided in the 1997 examination report submitted by Con Ed was not sufficient to pinpoint the technical and implementation problems, such as the eddy current data quality and noise issues discussed above (and in Section 6.1 of this report). The Task Group noted that the tube that failed was not reflected in the report as a degraded tube, since it was not identified by the licensee as such during the 1997 examination. The NRC's OIG report dated August 29, 2000, concluded that had the NRC staff or contractor with technical expertise evaluated the results of the IP2 SG inspection, the NRC could have identified the flaw in the tube that failed by reviewing the licensee's inspection report. After careful review, the Task Group concluded that the NRC staff could not have identified the tube that failed from its review of the licensee's inspection report. That report did not indicate that there was a flaw in the tube or provide any information on the tube. Even if the staff should have been prompted by the report's identification of a new degradation mechanism (PWSCC) in a similar tube that was plugged, it would have required further discussion with the licensee, additional staff review of the 1997 raw eddy current data of the failed tube, and identification of the flaw from the data, which clearly was of poor quality due to noise and about which experts are not in agreement whether anyone could have reasonably been expected to identify that flaw. Licensee reports in general, and this report in particular, do not provide this information or related discussions or evaluation of eddy current data. For the NRC to have this information, an eddy current specialist would have to review the raw data independently. This is not typically included within the scope of NRC inspection or review.

The Task Group reviewed the scope and depth of the NRC SG inspection program relative to the root causes for the IP2 SG deficiencies. Details of this review are provided in Section 8.2 of the report. Overall, the Task Group believes that:

1) The NRC should develop SG inspection guidance for the baseline inspection program.

2) Inspector training should be provided to support the objectives of the SG inspection program.

3) Information needs and processes to support the objective of the SG inspection program should be determined. In this regard the Task Group believes that the telephone calls conducted with licensees during the outages are effective and should be formerly incorporated into the inspection program.

4) Risk-informed thresholds should be established to identify when increased NRC interaction is warranted in response to SG tube degradation

5) The baseline program and/or performance indicators should be modified to identify adverse trends in primary-to-secondary leakage. Risk-informed thresholds should be established to identify when increased NRC interaction is warranted in response to an adverse trend.

Conclusions and Recommendations

Sections 5.0 through 8.0 of this report include sub-sections that provide the conclusions /lessons-learned and recommendations for the respective section as indicated in the report Table of Contents. Section 9.0 provides a table (Table 9-1) that lists all the report recommendations with a reference back to the supporting section in the report. Table 9-1 also provides the Task Group's ranking of each recommendation based on its importance relative to each of the pillars in the NRC's Strategic Plan (i.e., maintain safety, increase public confidence, increase effectiveness and efficiency, and reduce unnecessary regulatory burden).

Overall, the Task Group believes that the lessons-learned from IP2 are important relative to assuring SG integrity and that the industry initiative should expeditiously incorporate the lessons-learned into the regulatory framework.

1.0 OBJECTIVES

The objectives of the Indian Point 2 (IP2) Steam Generator (SG) Tube Failure Lessons-Learned Task Group are defined in an internal NRC memorandum dated May 24, 2000, from Samuel J. Collins, Director, Office of Nuclear Reactor Regulation, to William D. Travers, Executive Director for Operations. This memorandum and its attachments describe the approach and charter for an inter-office task group to assess the lessons-learned from the IP2 SG tube failure that occurred on February 15, 2000. The objective of this effort was to conduct an evaluation of the technical and regulatory processes related to assuring SG tube integrity in order to identify and recommend areas of improvement applicable to the NRC and/or the industry.

2.0 SCOPE OF REVIEW

2.1 Scope

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

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

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

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

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

2.2 Assumptions and Constraints

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

effort. In addition to verifying the scope of Task Group effort mentioned in Section 2.1, the following were noted:

1) The Task Group originally focused on reviewing information pertaining to the restart of IP2 with their current SGs in accordance with the charter. The NRC staff's draft safety evaluation was to have been forwarded to the Task Group for review. The Task Group terminated this effort when Con Ed made a decision to replace the SGs prior to restarting IP2.

2) The Task Group Charter requires it to provide recommendations for improvements and the staff to take appropriate follow-up actions. The Charter states that the Task Group is not expected to identify the process for resolving areas of potential weakness. Hence, this report does not detail how the recommendations should be resolved and incorporated in NRC and/or industry processes.

3.0 EVENT SUMMARY AND BACKGROUND

3.1 Event Summary

On February 15, 2000, with the unit at 99% power, the operators of the Indian Point 2 (IP2) nuclear power plant received indication of a steam generator (SG) tube failure. The licensee, Consolidated Edison (Con Ed), declared an "Alert" in accordance with the site emergency plan, which is the second lowest of the four NRC event classifications. The operators manually tripped the reactor, isolated the SG with the tube failure, and proceeded to use the three other SGs 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. Although the event resulted in a minor radiological release to the environment, the release was well within regulatory requirements and no radioactivity was measured off-site above normal background levels.

After placing the unit in the cold shutdown condition, Con Ed inspected SG 24 and found that the row 2, column 5 (R2C5) tube had failed. This small-radius, low-row tube had cracked at the apex of the tube U-bend due to primary water stress corrosion cracking (PWSCC). A typical SG and a typical SG tube U-bend are shown in Figures 3-1 and 3-2. Con Ed's inspection included an eddy current test (ECT) examination of the SG tubes and visual examinations of the secondary side of the SGs. During these ECT inspections, Con Ed found that 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).

By letter dated June 2, 2000, Con Ed provided its Condition Monitoring and Operational Assessment (CMOA) report which documented the as-found condition of the tubes during the SG inspections conducted following the February 2000 tube failure. Additionally, the CMOA report provided Con Ed's technical justification for the continued operation with the current SGs until SG replacement at the end of 2000. However, on August 11, 2000, as the NRC continued its review of the CMOA and other information provided by the licensee for restart approval, Con Ed announced that it would replace all four SGs before returning the plant to power operation.

3.2 Background

IP2 is a four-loop pressurized water reactor, meaning that there are four SGs, one per loop, that transfer heat from the reactor coolant system (RCS) to the secondary water. This heat causes the secondary water to boil, and the resulting steam is used to turn the turbine, which turns the electrical generator. The four SGs are identified as SG 21 through SG 24, with this designation referring to unit 2, SGs 1 through 4.

Each SG has 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 an average wall thickness of 0.050 inches. 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.

During power operation, the reactor coolant inside the SG tubes is pressurized to approximately 2,235 psig. Normal SG pressure on the outside of the tubes varies with plant load between approximately 1000 psig at no load to approximately 700 psig at 100-percent power. The resulting pressure difference across the SG tube wall can cause leakage from radioactive RCS water to the secondary side of the SG. This is referred to as primary-to-secondary leakage. Small amounts of leakage are allowed and limits on the leakage, based on a safety analysis, are contained in the plant's TSs.

Regulatory Requirements

SG tubes have an important safety role because they constitute a barrier between the radioactive primary side and non-radioactive secondary side of the plant. During operation, SG tubes can degrade due to corrosion mechanisms and mechanical wear on the OD or the inside diameter (ID) of the tubes. The plant's TSs require that a representative sample of the SG tubes be examined using ECT, once every two years during a plant shutdown, to ensure identification of degraded tubes and the removal from service of tubes with defects. If degradation is found, the sample of tubes is expanded to ensure that the sample remains representative of the overall SG conditions. Per the plant TSs, tubes with degradation greater than 40-percent through-wall (TW) are considered defective and must be either repaired or removed from service. Tubes are normally removed from service by inserting a plug at both ends of the tube.

At IP2, the primary-to-secondary leakage rate at which the plant can continue to operate is limited by the plant TSs to 0.3 gallons per minute (gpm) for each SG. Primary-to-secondary leakage can result from several sources, including leaking tubes that are in-service and through leakage by plugs in tubes that have been removed from service. The primary-to-secondary leakage is monitored by radiological analysis (knowing the primary coolant activity and comparing it to the secondary water activity) and by continuous radiation monitors on the steam lines, SG blowdown lines, and condenser air ejector discharge (off-gas).

Eddy Current Testing

ECT is a method of inspecting SG tubes by passing a probe that generates an electromagnetic field through the tubes. The probe senses the disturbance of the field due to flaws in the tubing. An eddy current is an electrical current caused to flow in a conductor due to the variation of an electromagnetic field. In ECT, a varying electromagnetic field is generated when an alternating current is passed through the probe, which consists of a wire coil. The eddy current is directly affected by a flaw that is perpendicular to its direction of flow. When the probe is inside a tube, the ECT analyst looks for changes in the coil impedance due to a flaw that is obstructing the eddy current flow within a tube.

Noise in ECT is defined as any non-relevant signal that tends to interfere with the normal reception or processing of a desired flaw signal. Signal-to-noise ratio is a way of evaluating the magnitudes of a relevant signal (defect) to the non-relevant signal (noise). The higher the signal-to-noise ratio, the easier it is to detect a flaw. ECT signals may be affected by deposits that collect on the OD surface of the tubes. Different types of flaws within the tube wall, deposits outside the tube, and SG structures, such as tube support plates (TSPs) and the tube roll transitions, all have an effect on the ECT signal and have a characteristic signal.

Steam Generator Degradation Mechanisms

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

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

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

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

IP2 Steam Generator History

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

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

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

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

Figure 3-1: Typical Steam Generator

Figure 3-2: Typical Steam Generator Tube U-bend

Figure 3-3: Example of Flow Slot Hour-Glassing

Figure 3-4: Examples of SG Tube Degradation Mechanisms

4.0 REGULATORY FRAMEWORK

4.1 Introduction

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

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

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

4.2 NRC Regulations

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

boundary), and Criterion 32 (Inspection of reactor coolant pressure boundary). 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 each facility's 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 SG 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 Atomic Energy Act requires that each license for an operating nuclear power facility must contain TSs based on the specific characteristics of the facility which enable the NRC to find that operation of the facility will provide adequate protection of the public health and safety. Typical TSs require that a representative sample of the SG tubes be examined for defects (flaws, cracks, or "indications") using eddy current testing at a minimum frequency of once every two years during plant shutdown. Tubes that are identified as containing flaws of a specified depth, greater than 40% through-wall, are removed from service, typically by plugging both ends of the tubes.

Technical specifications also limit the primary-to-secondary leakage by specifying a maximum leak rate in gallons per minute, or gpm. Primary-to-secondary leakage can result from several sources, including leakage past the plugs inserted into defective tubes.

Some TSs, including those governing IP2, require the licensee to submit its proposed SG examination program to the NRC staff for review prior to the scheduled examination and also require that the results of the SG examination be submitted to the NRC after completion of the examination. The TSs also may require the reporting of significant examination findings of certain types (and extent) of degradation. Contrary to the TSs governing the IP2 facility, most TSs do not require NRC approval of restart after the SG tube examinations and resulting repairs (plugging), regardless of the number of defective tubes found or the extent of the identified flaws.

4.4 NRC Guidance and Generic Communications

There are numerous NRC staff documents that address SGs, problems identified with maintaining SG tube integrity, and guidance for detecting and removing defective tubes from service.

NRC Regulatory Guides describe methods acceptable to the NRC staff for complying with, or implementing, particular NRC requirements. Regulatory Guides are not requirements. There are several Regulatory Guides particularly relevant to SG tube integrity. Revision 1 of NRC Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," provides guidance concerning SG inspection scope and frequency and nondestructive examination (NDE) methodology. This Regulatory Guide provides a basis for reviewing inservice inspection criteria in licensees' technical specifications. Draft Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," provides guidelines for determining tube repair criteria and operational leakage limits specified in licensee TSs. Based on the Part 50 General Design Criteria and other applicable regulations, these two documents provide the foundation for most plant TSs.

Draft Regulatory Guide DG-1074, which incorporates risk considerations, describes a method which would be acceptable to the NRC staff for monitoring and maintaining the integrity of the SG tubes at operating PWR's. It also provides guidance on evaluating the radiological consequences of design basis accidents involving leaking SG 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 Electric Power Research Institute (EPRI) guidelines and experience with the implementation of the NEI 97-06 initiative.

Information Notices (INs) are one type of generic communication used by the NRC to provide information to its licensees. Information Notices impose no regulatory requirements and require no specific actions or written responses from licensees.

On May 19, 1997, the NRC issued IN 97-26, "Degradation in Small-Radius U-bend Regions of Steam Generator Tubes." This IN was issued to disseminate information about recent degradation affecting small-radius (rows 1 and 2) U-bend regions of tubes and to alert licensees about potential problems in ensuring the integrity of these tubes. The IN described how Westinghouse-designed SGs have "for many years" exhibited defects in the small radius U-bend tubes based on eddy current inspection results. The IN stated:

> "The susceptibility to cracking in small-radius U-bends and the findings of recent field inspections have emphasized the importance of inspection in this area of SGs with techniques capable of accurately detecting U-bend degradation."
>
> * * *
>
> "U-bend degradation can potentially impair tube integrity if not effectively managed. Concerns in this regard stem from limitations of eddy current testing to detect and size U-bend cracks, the potential for some U-bend

cracks to have relatively long lengths, and the potential for high growth rates for some of these cracks."

* * *

"[A]vailable inspection techniques are not capable of reliably sizing crack depths and, for this reason, it has been industry's practice to "plug on detection" U-bend indications that are found."

* * *

"[T]he depth of cracks may be in excess of 50-percent through wall when they are first detected."

* * *

"[T]he integrity of the small-radius U-bend regions can be more fully ensured by efforts that include performing inspection of rows 1 and 2 U-bends using qualified eddy current techniques; performing in situ pressure testing, as necessary, to assess the condition of defective tubes; taking appropriate corrective actions, including plugging defective tubes; and assessing the appropriate operating intervals until the next SG tube inspection."

During the past ten years, the NRC has issued other INs focusing on SG tube integrity, including the following:

1) IN 90-49, "Stress Corrosion Cracking in PWR Steam Generator Tubes," dated August 6, 1990;

2) IN 94-62, "Operating Experience on Steam Generator Tube Leaks and Tube Ruptures," dated August 30, 1994;

3) IN 95-40, "Supplemental Information to Generic Letter 95-03,'Circumferential Cracking of Steam Generator Tubes'," dated September 20, 1995;

4) IN 97-88, "Experiences During Recent Steam Generator Inspections," dated December 16, 1997; and

5) IN 98-27, "Steam Generator Tube End Cracking," dated July 24, 1998.

Generic Letters (GLs)are another type of communication from the NRC to licensees. Other than possibly requiring a written response, GLs do not impose requirements on licensees, though they may request licensees to take certain actions or explain why the requested actions will not be taken. Recent GLs focusing on SG tube integrity include:

1) GL 95-03, "Circumferential Cracking of Steam Generator Tube," dated April 28, 1995;

2) GL 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking," dated August 3, 1995;

3) GL 97-05, "Steam Generator Tube Inspection Techniques," dated December 17, 1997; and

4) GL 97-06, "Degradation of Steam Generator Internals," dated December 30, 1997.

4.5 Industry Initiatives and Guidance

NEI 97-06 commits pressurized water reactor 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: 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 SG tube integrity. After issuance of the RIS, individual licensees would be expected to commit to the revised NEI 97-06 guidelines (one example of an "industry initiative") and to submit an accompanying TS change request adopting the new SG regulatory framework. The TSs would require licensees to establish and implement a program to ensure that NRC-approved SG tube integrity performance criteria are maintained. The performance criteria would be defined in a licensee-controlled document subject to 10 C.F.R. § 50.59 and would include structural, accident-induced leakage, and operational leakage criteria.

4.6 Steam Generator Tube Integrity Assessment

The SG tube integrity assessment process is comprised of two complimentary evaluative processes. "Condition monitoring," performed when the nuclear plant is shut down during an outage, involves monitoring and assessing the "as found" condition of selected samples of the SG tubes relative to tube integrity performance criteria. Failure of one or more tubes to satisfy the performance criteria may indicate programmatic deficiencies in the licensee's program for monitoring and maintaining SG tube integrity. Such failures must be reported to the NRC pursuant to 10 C.F.R. § 50.72 and corrective actions must be taken pursuant to 10 C.F.R. Part 50, Appendix B, Criterion XVI. Condition monitoring is thus "backward looking" in that it is intended to determine if adequate tube integrity has been maintained during the previous operating cycle.

In contrast to the condition monitoring look back, "operational assessments" look forward to demonstrate that the tube integrity performance criteria will be satisfied throughout the next operating cycle and scheduled tube inspection. The purposes of the operational assessment are to demonstrate that all structurally significant tube degradation has been detected, unacceptably flawed tubes have been taken out of service by, for example, plugging, and that any undetected flaws will not grow to be structurally significant during the next operating cycle. In effect, the operational assessment determines the allowable operating time for the upcoming cycle. The success of the operational assessment is dependent on such things as the probability of detection (POD) of actual flaws by the eddy current testing, the growth rate determinations for the flaws, and the estimated sizing of the flaws.

A licensee's typical inservice inspection of its SG begins with eddy current testing (ECT) of SG tubes. Eddy current testing is a sophisticated, nondestructive examination (NDE) method of examining tubes for flaws by passing a probe through the tubes. All tubes found to be defective during the inservice inspection are required to be removed from service by plugging or repair prior to plant startup. Tubes are considered defective when they fail to satisfy applicable tube repair criteria for the particular type of defect. The technical specification tube repair criterion for defects is 40% of the nominal tube wall thickness, known as the "40% through-wall" criterion, subject to demonstrating by operational assessment that the performance criteria will continue

to be met through the next operating cycle. The 40% criterion is applicable to the maximum measured depth of the subject indication. All indications should be considered defective unless they have been sized by qualified NDE sizing techniques.

Eddy current testing is followed by "in situ" pressure testing ("burst tests") to provide reasonable assurance that SG tubes will not rupture during normal or postulated accident conditions. The pressure test is conducted on a selected sample of tubes found by ECT to have flaws. The sample is selected to ensure that the most limiting flaws are included. Based on structural integrity assessments for the full range of normal operating conditions (including design basis "transients") and design basis accidents, the pressure tests use pressures of three times that of normal steady state full power operation and 1.4 times that of the limiting design basis accident concurrent with a safe shutdown earthquake.

Another means of evaluating SG tube integrity is to monitor the primary-to-secondary operational leakage, which is limited by plant TSs. This may give plant operators information to enable them to take timely remedial actions to safely respond to conditions of tube integrity impairment and reduce the chance of a tube rupture or to mitigate a tube rupture event.

4.7 NRC Inspection and Oversight

Prior to April, 2000, the NRC staff's "core" inspection of the licensee's SG inservice inspection (ISI) activities was accomplished using Inspection Procedure 73753, "Inservice Inspection" (May 4, 1995), and was required to be completed at each facility once every two years during an outage. Because the inspection procedure covered components other than the SGs, and allowed inspection on a sample basis, inspection of SG tube examination may or may not have been performed. This inspection guidance provided for staff review of licensees' examination plans, personnel qualifications and certification, observation of the SG tube ECT, and review of the results of the testing. Additional optional inspection procedures covered various aspects of the ISI process. NRC Inspection Procedure (IP) 50002, "Steam Generators" (December 31, 1996), provided detailed guidance on inspecting the history and material condition of SG tubes and on assessing the effectiveness of licensees' programs for examining SG tubes. IP 50002 was not part of the NRC's core inspection program, however, so it was not required to be used by the staff during each plant outage.

In April, 2000, the NRC began industry-wide implementation of its revised reactor oversight process (ROP), which includes revised inspection, oversight, and enforcement programs. Two processes are used to generate information about licensees performance and the safety significance of plant operations: performance indicators and inspections. Performance indicator data are measured against established criteria to determine the potential safety significance of plant operations. Inspection findings are evaluated according to their potential safety significance using a Significance Determination Process, or SDP. The assessment process then integrates the performance indicator data and the inspection findings to reach objective conclusions regarding overall plant performance. The NRC then uses an Action Matrix to determine in a systematic, predictable manner the regulatory action to be taken based on a licensee's performance. The more degraded a licensee's performance is, the more significant the agency's prescribed action is. The NRC, licensees, and other stakeholders recognize that this new oversight process will continue to be refined based on actual experience with its implementation, especially during its first year of industry-wide application.

The baseline inspection procedure now in use for ISI in the ROP is IP 71111.08, "Inservice Inspection Activities." Like a "core" procedure, this baseline inspection procedure is required to be performed at all plants during refueling outages. It provides inspectors with less guidance than IP 73753 did and does not require the staff to inspect licensees' SG tube examination activities. Rather, it identifies SG tube examinations as one licensee activity which can be selected for staff inspection. IP 71111.08 allocates 32 hours of inspection time for all staff ISI inspections, whether or not SGs are included in staff's selected inspection areas.

5.0 RISK INSIGHTS

5.1 Background

Steam generator (SG) 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. This can happen because a flow path exists from the secondary side of the SGs to the SG safety valves and the steam system dump valves. These valves discharge to the environment. Containment bypass events result in more radionuclides being released to the environment, in comparison to other possible accident scenarios.

Typically, for the purpose of plant safety assessment, 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[1]. This is consistent with NUREG-0844, "NRC Integrated Program for the Resolution of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity" (Reference 1), which states that tube rupture events are defined by the NRC to be primary-to-secondary leakage in excess of the normal charging capacity of the reactor coolant system[2]. There is also a metallurgical definition for SG tube rupture that is unrelated to makeup capacity and not typically considered in risk assessments.

The tube rupture criterion can 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. The tube failure at IP2 did not reach the level of leakage to catagorize it as a rupture; therefore, it is referred to as a tube failure in this report.

As noted in the NRC Special Inspection Report (Reference 2), there were no actual radiological consequences of the February 15, 2000, event. No radioactivity was measured off-site above normal background levels and, consequently, the event did not impact the public health and safety. The licensee's staff acted to protect the health and safety of the public. Specifically, the operators appropriately took those actions in the emergency operating procedures to trip the reactor, isolate the affected SG, and depressurize the reactor coolant system. Additionally, the necessary event mitigation systems worked properly.

---

[1] A plant's normal makeup capacity refers to the ability of non-emergency fluid systems to deliver reactor coolant to the reactor coolant system to compensate for losses because of leakage.

[2] Regulatory Guide 1.121 defines tube rupture without reference to plant makeup capacity, but the NUREG-0844 definition is conventionally used.

However, the NRC characterized the Special Inspection findings as having high risk significance because of a significant reduction in safety margin based on the increased risk of SG tube rupture (SGTR) during Operating Cycle 14. The NRC conclusions are preliminary pending evaluation of any further risk information the licensee chooses to provide in accordance with the Reactor Safety Significance Determination Process.

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

1) The risk of SG tube failure at IP2 in the context of overall risk perspective for tube failure events;

2) Use of risk information in approving the IP2 SG inspection interval extension; and

3) Potential risk implications of the IP2 event.

Material relied upon by the Task Group included documented risk information and analyses of risk contributions from tube failure at IP2 before the event, as well as recent NRC and licensee 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. The Task Group drew upon sources of generic information concerning SG tube performance and repair history in order to form a perspective of SG tube problems faced by US PWRs.

5.2 Observations

The Risk of SG Tube Failure at IP2 in the Context of Overall Risk Perspective for Tube Failure Events

IP2 Event Compared to NRC's Strategic/Performance Goals

NRC's Draft Strategic Plan (Reference 3) 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.[3]" 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.[4]" 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."

---

[3] 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 (see Reference 3).

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

As discussed later in this section, the staff's risk assessment of the IP2 event to support the significance determination process (SDP) is a frequency of core damage with large early release on the order of 1E-4 per year. Comparing this result, which is conservative, to the 1E-3 per year performance goal measure, discussed above, indicates that the IP2 event was at least an order of magnitude less than this performance measure.

In summary, the staff's preliminary SDP finding associated with the IP2 event indicates that the degraded SG tube conditions at IP2 constituted a significant reduction in safety margin. If this finding is confirmed by the SDP process, the NRC will take appropriate actions in accordance with the reactor oversight process. Although there was a reduction in safety margin, overall risk to the public was not significantly impacted. This was evidenced, in part, by the absence of measurable radioactivity offsite above normal background levels following the event. Sufficient safety margin still existed such that the agency's safety and performance goals were not exceeded.

IP2 Event in Context of Previous SG Tube Failures

The Task Group reviewed information related to previous SG tube failures and assessments of tube failure risk in order to put the IP2 event in context of other similar events. Table 5-1 provides a list of previous tube failure events at US PWRs based on information in Reference 4[5].

Review of the information in Table 5-1 shows that one spontaneous tube failure has occurred about every 3 years at US PWRs during the past 25 years. The frequency of spontaneous SG tube rupture (SGTR) was estimated in Reference 4 to be about 2.5E-2 per reactor-year (ry) of operation. NUREG/CR-5750 (Reference 5) states that the mean frequency of SGTR is 5.3E-3/ry, 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-5750 are 1.7E-3/ry and 1.1E-2/ry, respectively. The frequency of SGTR used in the IP2 IPE of 1.3E-2/ry is close to the 95th percentile from the NUREG report.[6]

The Task Group noted that the IP2 event was similar to the event that took place 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 similarities. The leak rate for the Surry tube failure was greater than the IP2 event leakage. The Surry and IP2 events are the only U-bend apex failures attributed to PWSCC.

Table 5-1 shows that the SG tube failure previous to the IP2 event occurred in 1993 at Palo Verde. The IP2 event does not indicate that the trend in occurrence of tube failures in terms of SGTR frequency is changing.

As mentioned earlier, the criterion for tube rupture can vary based on plant-specific characteristics. Therefore, the classification of tube failure events as tube ruptures introduces some uncertainty in the estimated frequency of spontaneous tube ruptures. There have been a

---

[5]Except for the IP2 event, Table 5-1 was reproduced from a list of SGTRs in Reference 4. The IP2 event, although not considered a tube rupture, was included in this list for comparison.

[6]Frequency values given here in reactor-years were converted from values in Reference 5 (that are in critical years) using an average criticality factor from Reference 5 of 76 percent.

number of instances where tubes leaked, and the leakage was in a range where some studies considered the tube ruptured, but others did not. To address this uncertainty, the Task Group sought information about less serious tube failures (i.e., leaks) in order to gain a more complete perspective of historical SG tube performance. The tube leaks listed in Table 5-1 were situations where operators were forced to shut down the plant due to the leak rates involved. Table 5-2 lists forced outages because of tube leaks at US PWRs for the 9-year period ending in 1999 (see Reference 6). Except for the 1993 Palo Verde tube failure from Table 5-1, the events in Table 5-2 were instances when SG tube leakage did not reach the level to force plant shut downs, but operators elected to shut down to address the leakage. Notable features from the table are the large number of leaks over the 9-year span (total of 28) and the marked decline in the annual rate of leaks during the second half of the period. Of the 28 total, only 4 occurred from 1995 through 1999.

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

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

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

<u>SG Tube Failure Risk at IP2 Compared to Other PWRs</u>

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

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

---

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

The contribution of the spontaneous SGTR to total CDF is not the measure used to determine the risk significance of various SG degraded conditions. This is because tube failures present the potential for containment bypass, and therefore, the offsite risk profile is much more strongly influenced by this event than is the CDF. Since containments reduce or eliminate the offsite consequences from most other core damage accidents, the percent risk contribution from tube failure has greater significance than its contribution to CDF.

Table 5-4 shows that based on the IPE information, IP2 is generally in the range of other plants for the total core damage frequency, the percent of CDF attributed to spontaneous SGTR, and the containment bypass fraction attributed to spontaneous SGTR. From this, the Task Group concluded that the risk significance of the tube failure for IP2 is not unique when compared to other PWRs.

Use of Risk Information in Approving the IP2 SG Inspection Interval Extension

The 1999 safety evaluation (SE) approving the SG tube inspection interval extension (Reference 7) 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 8), 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's SE was based on information provided by the licensee that did not include a risk assessment. Based on its 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 the staff did not have reason to request risk information for its review and any such information probably would not have led to a different conclusion than was reached in the SE. 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 highlighted at that time.

Potential Risk Implications of the IP2 Event

<u>IP2 IPE Results</u>

The understanding of the overall plant risk and risk from tube failure before the IP2 event is provided by the Individual Plant Examination (IPE) conducted by the licensee in response to Generic Letter 88-20 (Reference 9). The staff reviewed the IP2 IPE submittal and issued a safety evaluation report in 1996 (Reference 10). The IPE estimates an initiating event frequency

for SGTR of 1.3E-2/ry. The total core damage frequency (CDF) for internal events at IP2 has a mean of 3.1E-5/ry. Approximately 5 percent 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 contribution from induced SGTR has an estimated frequency of 2.5E-7/ry, not a large contribution to SGTR risk at IP2 compared to the CDF quoted above.

Containment bypass is the primary concern about tube failure, because the containment function of SG tubes makes tube failure a more significant contributor to plant risk than a similarly sized failure of another part of the reactor coolant pressure boundary inside containment. The IPE results for IP2 show that the largest fraction of containment bypass is associated with SGTR.

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 11~~12~~) 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 tube failure is isolation of the affected SG before overfill. This requires the operators to diagnose the event and take positive steps to assure that the SG is isolated, including terminating auxiliary feedwater flow to the affected SG. The operators must also cool down and depressurize the reactor coolant system (RCS) by opening steam dump valves and power-operated relief valves and terminate safety injection. The IPE references computer model analyses that indicate that overfill will occur in approximately 30 minutes if the operators take no action. The IPE (Reference 12) 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 scenarios where the tube failure is less severe than the full tube rupture considered in the IPE analysis, the leak rate is lower and more time would be available for response than credited in the IPE. The probability of operator error is based on the estimated time available for key actions. The overall human error probability also includes the chance that operators mis-diagnose the event.

Comparison of IPE Assumptions to the Tube Failure Event

The NRC AIT report (Reference 11) 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 or SG tube conditions 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 discussed in the NRC AIT report also 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.

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 (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. However, the NRC AIT report did not consider any of the performance deficiencies to be serious. Therefore, the Task Group concluded that further consideration of this area was not warranted.

Staff Risk Assessment

Following the IP2 event, NRR staff conducted a risk assessment that considered the condition of the SG tubes during operating Cycle 14 (Reference 2). 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 the risk to public health and safety from the IP2 event.

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 primarily on the contribution from spontaneous tube failure, the estimated risk contribution attributed to degraded SG tubes at IP2 during Cycle 14 is a frequency of core damage with large early release of approximately 1E-4/yr.

The staff assessment estimated the likelihood of a tube rupture from the failed tube. The staff judged that 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 by not depressurizing the reactor coolant system. The results of the assessment indicated that the risk profile at IP2 was adversely affected for operating Cycle 14. The inspection findings indicated that the contributing factors (i.e., SG tube integrity program deficiencies) allowed uncorrected SG tube degradation to exist. The degraded condition worsened during the operating cycle, so that at some point, the SG tube did not satisfy tube structural criteria (i.e., 3 times normal

operating differential pressure). Because the degraded condition was a result of SG tube integrity program deficiencies, the staff did not consider the event to be a random tube failure, and the risk profile for tube failure at IP2 during the operating cycle was assumed to be affected.

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

Licensee Risk Assessment

not relevant.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Inspection Report, must be addressed to provide assurance that tube integrity is satisfactorily maintained in the new SGs.

Potential Generic Implications

Other sections of this report explore possible contributing factors of the degraded SG tube condition that led to the IP2 tube failure event. The Task Group noted that the nature of some contributing factors leads to potential generic implications in other PWR SG tube integrity programs. The shortcomings in generic industry guidelines (listed in detail in the conclusions to Sections 6.1 and 6.2 of this report), the deficiencies of the licensee's implementation of SG regulatory requirements (Sections 6.3 and 6.4), and shortcomings that exist in the NRC SG regulatory process (Sections 8.1, 8.2, and 8.3), strongly suggest that the problems associated with the SG tube integrity program at IP2 could exist elsewhere in the industry.

The Task Group examined the extent of tube degradation problems throughout the industry. As shown in Table 5-5, there are approximately 1.2 million SG tubes in service in 209 SGs at 69 PWRs in the US. About 5 percent of the total number of tubes have been repaired (by either plugging or sleeving) through 1998. These tubes are spread throughout 188 SGs in 62 PWRs. This shows that tube degradation is an issue for many licensees.

An observation that could be made by comparing this information to the number of tube failures is that, overall, tube integrity programs are effective. Large numbers of tubes are repaired, in the vast majority of cases, before significant failures occur. However, the Task Group examined the information more closely by considering data related only to original SGs. There are about 850,000 tubes in original SGs in US PWRs, of which about 6 percent have required repair. Every plant with original SGs has tubes that required repair. This underscores to the Task Group that significant licensee attention at a large number of plants is needed to continue to maintain tube integrity.

Another generic aspect of the IP2 event considered by the Task Group was the communication to the public of the event details and its safety significance. A formal pre-established communications plan was not used by the NRC to disseminate information concerning the event. The NRC established a web site to make information available to the public. The staff answered a number of formal inquiries concerning the event and its significance and these were available to the public on the web site. The Task Group noted that, other than the assessment supporting the SDP, a risk assessment or statement of the safety significance of the event or of the SG tube condition was not available on the web site. The Task Group also noted that, in some instances, media reports concerning the event did not accurately portray its safety significance by implying significant radiological consequences.

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

From these observations, the Task Group concluded that the public confidence issue associated with event response should receive attention. The goal should be to ensure that the public is informed about details of the event, including its safety significance, in easy-to-understand terms.

5.3 Conclusions/Lessons-Learned

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

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

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

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

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

5.4 Recommendations

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

1) Con Ed must correct the deficiencies in its SG tube integrity program that led to the degraded SG condition during IP2 cycle 14. Otherwise, the long-term risk of SGTR at IP2 could be affected.

2) Over the long-term, NRC and industry should improve the oversight of licensee SG tube integrity programs based on the generic character of some of the lessons learned from the IP2 experience.

3) NRC should incorporate experience gained from the IP2 event and the SDP process into planned initiatives on risk communication and outreach to the public.

5.5 References

The following References were used for Section 5.0:

1) NUREG-0844, "NRC Integrated Program for the Resolution of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity," dated September 1988.

2) Letter, W. Lanning (NRC) to A. Blind, (Con Ed), "NRC Special Inspection Report - Steam Generator Tube Failure - Report No. 05000247/2000-010," dated August 31, 2000.

3) NUREG-1614, "US NRC Strategic Plan - Fiscal Year 2000 - Fiscal Year 2005, Draft," dated February 2000.

4) NUREG/CR-6365, "Steam Generator Tube Failures," dated April 1996.

5) NUREG/CR-5750, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995," dated February 1999.

6) EPRI, "Steam Generator Progress Report," Revision 14, TE-106365-R14, dated April 1999.

7) Letter, J. Harold (NRC) to A. Blind (Con Ed), "Issuance of Amendment for Indian Point Nuclear Generating Unit No. 2 Allowing a One-Time Extension of the Steam Generator Inspection Interval (TAC No. MA4526)," dated June 9, 1999.

8) NUREG-0800, Standard Review Plan 19.0, "Use of Probabilistic Risk Assessment in Plant-Specific, Risk-Informed Decisionmaking: General Guidance," Rev. 0, dated July 1998.

9) NRC Generic Letter 88-20, Supplement No. 1, "Initiation of the Individual Plant Examination For Severe Accident Vulnerabilities -10 CFR 50.54(f)," dated August 29, 1989.

10) NRC Memorandum, M. Hodges to S. Varga, "Review of Indian Point 2 Individual Plant Examination (IPE) Submittal - Internal Events," dated August 6, 1996.

11) Letter, H. Miller (NRC) to A. Blind, (Con Ed), "NRC Augmented Inspection Team - Steam Generator Tube Failure - Report No. 05000247/2000-002," dated April 28, 2000.

12) Letter, S. Quinn (Con Ed) to Document Control Desk (NRC), Response to April 26, 1995 request for additional information, dated October 31, 1995.

Table 5-1: Summary of Tube Failures at US PWRs*

Plant/SG Model/ Tube Material	Date	Leak Rate (gpm)	Size	Location	Degradation Mechanism	Contributing Factors
Point Beach 1[1] W-44 600MA	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[1] W-51 600MA	9/15/76	330[3]	114 mm long axial crack	U-bend apex, Row 1, Col. 7	PWSCC	Hour-glassing
Prairie Island 1 W-51 600MA	10/2/79	336[3]	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 1 W-44 600MA	1/25/82	760[3]	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 600 MA	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[1] W-51 600MA	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[1] W-D2 600MA	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
Palo Verde 2 CE-80 600 MA	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[2] W-44 600 MA	2/15/00	146	56 - 61 mm long axial crack	U-bend apex, Row 2, Col.5	PWSCC	Hour-glassing

*Except for the IP2 event, this table was reproduced from a list of SGTRs in NUREG/CR-6365. The IP2 event, although not considered a tube rupture, was included in this list for comparison.

Notes: 1-SGs replaced since tube failure 2-SGs to be replaced 3-NRC estimate

Table 5-2: Tube Leak Forced Outages at US PWRs

Plant	Date	Leak Rate (gpd)	Cause
St. Lucie 1	Jan. 1990	3	Foreign Object
TMI 1	Mar. 1990	1440	Fatigue
Millstone 2	May 1990		Cracked Plug
North Anna 2	Aug 1990	40	Cracked Plug
Oconee 2	Nov. 1990	130	Fatigue
Shearon Harris	Nov. 1990	50	Loose Part
Maine Yankee	Dec. 1990	1440	PWSCC
San Onofre 1	Apr. 1991	150	Sleeve Joint
Millstone 2	Apr. 1991	70	U-bend SCC
Millstone 2	May 1991	70	Tube Sheet Circ. Crack
McGuire 1	Jan. 1992	250	Freespan Crack
ANO 2	Mar. 1992	360	Tube Sheet Circ. Crack
Prairie Island 1	Mar. 1992	144	Roll Trans. Zone Axial Crack
Trojan	Nov. 1992	200	Sleeve weld Circ. Crack
Palo Verde 2	Mar. 1993	240	Upper Bundle Freespan IGSCC
Kewaunee	Jun. 1993	100	Leaking Plug
McGuire 1	Aug. 1993	185	Sleeve Failure
Braidwood 1	Oct. 1993	300	Freespan Cracks
McGuire 1	Jan. 1994	100	Leaking sleeve
Oconee 3	Mar. 1994	144	Fatigue
S. Texas	Mar. 1994	160	Leaking Plug
Zion 2	Mar. 1994	1440	Tubesheet crevice IGA OD
Oconee 2	Jul. 1994	144	Fatigue
Maine Yankee	Jul. 1994	50	Circ. Crack PWSCC
Byron 2	Aug. 1996	120	Loose Part
ANO 2	Nov. 1996	65	Axial Crack
Oconee 1	Nov. 1997	400	2 Welded Plugs
Farley 1	Dec. 1998	90	2 Freespan Cracks

Information from EPRI TR-106365-R14

Table 5-3: Annual Number of SGs Replaced at US PWRs From 1980 - 1999

Year	No. of SGs Replaced	No. of SG Forced Outages (from Table 5-2)
1980	3	
1981	3	
1982	3	
1983	5	
1984	5	
1985	0	
1986	0	
1987	0	
1988	0	
1989	8	
1990	0	7
1991	2	3
1992	0	4
1993	0	4
1994	3	6
1995	3	0
1996	8	2
1997	12	1
1998	10	1
1999	0*	0*

Summarized from EPRI TR-106365
*1999 data from NRC information

Table 5-4: 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^{-6}	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%

Taken from NUREG/CR-6365

Table 5-5: Summary of SG Tube Repairs at US PWRs through 1998

	All SGs			Original SGs		
	No. Tubes	SGs	Plants	No. Tubes	SGs	Plants
Total Tubes	1,188,794	209	69	848,358	141	47
Tubes plugged	39274	188	62	38399	141	47
Tubes sleeved	15900	34	14	15900	34	14
Total Tubes Repaired	55174 (4.6 % of total)			54299 (6.4 % of total)		

Information summarized from EPRI TR-106365

6.0 STEAM GENERATOR TUBE INTEGRITY PROGRAMS

6.1 Con Ed's SG Tube Examination Methods/Practices

6.1.1 Background

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

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

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

6.1.2 Observations

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

1997 SG Examination

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

determining the critical areas for each nuclear steam supply system vendor (i.e., Westinghouse, Combustion Engineering, and Babcock and Wilcox).

In 1997, IP2 TS 4.13.C.1 required that Con Ed submit a proposed SG 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 within three separate examinations, consisting of the 1993, 1995, and 1997 examinations. By letter dated February 7, 1997 (Reference 3), Con Ed submitted the required proposed SG tube examination program for the 1997 refueling outage at IP2 to the NRC for staff review. On April 24, 1997 (Reference 4), Con Ed provided additional information to the staff in a meeting held at the NRC headquarters in Rockville, Maryland to supplement the proposed plan.

By letter dated May 29, 1997 (Reference 5), Con Ed 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 (SE) 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 examination is more comprehensive than that of the tube examination 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 (Reference 6), discussed in Section 8.2 of this report.

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

1) full length of 33 percent of the active tubes in SG 21, 47 percent of the active tubes in SG 22, 33 percent of the active tubes in SG 23, and 33 of the active tubes in SG 24;

2) 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;

3) all U-bends in rows 2 and 3;

4) all dents at the tube support intersection;

5) all re-rolled tubes to verify F* distance (the F* distance referred to an area of the tube contained within the tubesheet); and

6) 20 percent of the pit indications at the sludge pile (the sludge pile region is an area outside the tubes above the tubesheet, where corrosion products and other impurities from the water collect and form sludge).

In reviewing the 1997 SG examination plan, the Task Group observed that Con Ed did not discuss in the examination plan how hour-glassing of the upper support plate flow slots would be evaluated. Examination of the flow slots was a regular part of Con Ed's examination program as there was a TS requirement to provide the NRC with a report evaluating the long term integrity of small radius U-bends (beyond Row 1) upon any finding of significant hour-glassing to the upper support plate flow slots. The requirement was added because timely detection of significant hour-glassing, along with detection of restrictions to probe passage through the tube, could provide a licensee early warning about increased degradation in the SG, and the potential for primary water stress corrosion cracking (PWSCC).

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

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

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

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

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

had been observed for the first time during the 1997 examination. This RAI (Reference 9), was sent to Con Ed by the NRC to gain additional information to evaluate Con Ed's December 7, 1998 license amendment request seeking a one-time extension of Con Ed's SG examination frequency (Reference 10).

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

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

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

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

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

In Con Ed's June 16, 2000 response (Reference 11), to an NRC RAI dated April 28, 2000 (Reference 12), on Con Ed's root cause analysis, the licensee's interpretation of "significant" hour-glassing is discussed. Con Ed's interpretation was readily visible hour-glassing, such as was seen in Surry 2 and Turkey Point. Con Ed's 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 examination performed on the IP2 SGs as a result of the Surry 2 tube failure.

After the R2C5 tube failure in February 2000, the displacement of the row 1 U-bend tube legs adjacent to the sixth support plate in SG 24 was measured, and a maximum displacement of 0.47 inch was recorded (Reference 11). According to Con Ed, this displacement was the result of hour-glassing of the flow slot that was not visibly discernable. Further, although the measured hour-glassing was too small to be visually observed, the analysis results indicate that this leg displacement could have contributed to the failure in the row 2 tube in SG24 by adding additional stresses to the U-bend region of the tube. It appears to the Task Group that a more quantitative criterion for hour-glassing, rather than just relying on visual observations, would have assisted Con Ed in detecting changes in degradation that were possibly more subtle than the rapid and severe degradation that was experienced at Surry 2.

The Task Group also noted that 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 examination in that region. From a report that which provides the results of a NRC inspection during the 1997 SG examination (Reference 6), the inspector concluded that Con Ed appropriately expanded their SG examinations based on examination findings. However, there was an opportunity for additional use of Plus Point probe to characterize the bobbin coil indications, but due to the signal to noise difficulties, the use of the mid-range frequency Plus Point probe may have not substantially improved the detection capability. The signal to noise ratio was not discussed in the 1997 SG examination report, the December 7, 1998 license amendment request, or the May 12, 1999 RAI, but was observed by both Con Ed and the NRC to be a major limiting factor in Con Ed's ability to find flaws during the 1997 SG examination. The Task Group noted that the NRC staff was not aware of the data quality problems caused by noise in the signal until the NRC Special Inspection Team reviewed the eddy current data after the tube failure in February 2000. Because data quality information is not routinely, if ever, provided to the NRC staff in the examination reports, problems with the quality of the SG tube examinations may not be detected by the NRC staff. The observation of the Task Group is that the limitations of their SG examination were due to limitations in data quality in that region, not due to inadequate sample scope.

As noted previously, Con Ed found two new forms of degradation in their 1997 SG examination which were different from the presumed tube conditions before the examination had been performed. The NRC Special Inspection Team noted in their August 31, 2000 report (Reference 13), that Con Ed did not question the use of the generically qualified technique relative to the observable noise in the SGs. When conditions are found in the SGs that are not consistent with the generic technique qualification, this indicates that a site-specific qualification strategy should be used as directed in Revision 5 to the EPRI Steam Generator Examination Guidelines (Reference 14). Qualification standards should, to the extent possible, represent the actual flaw conditions.

Based on the above discussion, the Task Group concluded that Con Ed adequately expanded the scope of the SG examination based on their examination findings, but the quality of their SG examination was limited by data quality, which is discussed in Section 6.4 of this report. The Task Group also concluded that a site specific qualification of the technique, although not required by the EPRI guidelines, could have provided additional insight on the detection capability of the eddy current during the examination.

2000 SG examination

By letter dated February 11, 2000 (Reference 15), Con Ed submitted a proposed SG tube examination program for their 2000 Refueling Outage, planned for June 2000. This SG examination plan was prepared and submitted before the tube failure, and was similar in concept to the 1997 SG examination plan . Con Ed proposed using the Cecco-5/bobbin probe for the majority of the eddy current testing. They planned to use the Cecco-5 probe to resolve any locations with distorted bobbin coil signals. If further characterization was necessary, they planned to use rotating probe coil (RPC) technology, which is the Plus Point probe. For the narrow radii U-bends, they planned to use the RPC if passage of the Cecco-5/bobbin probe was precluded. Con Ed's SG examination scope was described 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 SG examination increased dramatically based on the tube failure in February 2000, and the recommendations of the NRC staff. The scope of the 2000 SG examination is presented comprehensively in the 2000 Refueling Outage Steam Generator Examination Condition Monitoring and Operational Assessment Reports, submitted to the NRC by Con Ed in a letter dated June 2, 2000 (Reference 16). In particular, the scope of the SG examinations were expanded to include 100% mid-range frequency Plus Point examinations of the U-bends, high frequency (800 kHz) Plus Point examinations 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.

Again, the Task Group found that that Con Ed adequately expanded the scope of the SG examination based on their examination findings, but the quality of their examination was limited by data quality which is discussed in Section 6.4 of this report.

Based on the information submitted by Con Ed, the Task Group concluded that the use of the 800 kHz did provide a large improvement in Con Ed's ability to detect PWSCC. However, the Task Group didn't observe any enhancements in the 2000 SG tube examination to increase the potential to detect ODSCC in the U-bend region. Because ODSCC at the U-bends has been observed at some plants, mainly due to deposits on the outside of the tubes, licensees should ensure that they have a strategy for enhancing the examination of the outside of the tube if data quality is poor in those regions.

Con Ed's Use of Other Available SG Examination Techniques

Con Ed used ultrasonic examinations as an alternative SG examination technique to eddy current in the freespan sludge pile region during the 2000 SG examination. Con Ed told the Task Group that they used this technique as an independent verification to confirm the accuracy

of the eddy current analysis. As discussed in Reference 16, Con Ed states that "[u]ltrasonic inspection was selected because it is not affected by copper-bearing sludge."

UT 2000

In ~~the June 19, 2000~~ response from ~~Con Ed~~ to the March 24, 2000 RAI question 16 from the NRC (Reference ~~17),~~ ~~Con Ed~~ stated that the UT probe was restricted from passage at the first support plate in one tube that was tested. Therefore, the probe was not used in the U-bends and the probe size would have had to been altered to enable passage through the tight radius U-bends. The Task Group was also told of additional barriers to use of UT in the U-bends due to difficulties in directing and detecting the sound waves in curved surfaces.

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

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

6.1.3 Conclusions/Lessons-Learned

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

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

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

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

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

6.1.4 Recommendations

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

1) The EPRI guidelines should provide data quality measures. Guidelines should explicitly discuss how to identify excessive noise in the data, how to identify the source of the noise, and what to do about the noise after the source is identified.

2) Licensees should review generic industry guidelines carefully to ensure that the conditions/assumptions supporting the guidelines apply to their plant-specific situation (for example, site-specific performance demonstrations for examination techniques).

3) Industry should update EPRI SG Examination Guidelines to incorporate guidance on how to evaluate flow slots for hour-glassing and the impact of hour-glassing on PWSCC in low row U-bends.

6.1.5 References

The following References were used for Section 6.1:

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

2) Electric Power Research Institute, "PWR Steam Generator Examination Guidelines: Revision 4," Report No. TR-106589-V1, June 1996.

3) Letter, S. Quinn (Con Ed) to Document Control Desk (NRC), "Proposed Steam Generator Tube Examination Program - 1997 Refueling Outage," dated February 7, 1997.

4) Consolidated Edison, Handout from April 24, 1997 public meeting titled "Indian Point 2: 1997 Steam Generator Tube Inspection Plan," dated April 24, 1997. Note, this handout was included in the NRC meeting summary dated May 12, 1997.

5) Letter, J. Harold (NRC) to S. Quinn (Con Ed), "Proposed Steam Generator Tube Examination Program for Indian Point Nuclear Generating Unit No. 2 (TAC No. M98068)," dated May 29, 1997.

6) Letter, J. Rogge (NRC) to S. Quinn (Con Ed), "NRC Integrated Inspection Report 50-247/97-07 and Notice of Violation," dated July 16, 1997.

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

8) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Response to Request for Additional Information - Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency," dated May 12, 1999.

9) Letter, J. Harold (NRC) to A. Blind (Con Ed), "Request for Additional Information - Regarding Indian Point Nuclear Generating Unit 2 Steam Generator Inspection Interval One-Time Extension (TAC No. MA4526)," dated May 5, 1999.

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

11) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Response to the Staff's Requests for Additional Information (RAI) Regarding the Steam Generator Tube Examinations Conducted During Spring of 2000 Outage, and the Root Cause Evaluation of the Steam Generator Tube Rupture Event of February 15, 2000 (TAC No. MA8219)," dated June 16, 2000.

12) Letter, J. Harold (NRC) to A. Blind (Con Ed), "Indian Point Nuclear Generating Unit No. 2 (IP2) - Topics of Discussion for the May 3, 2000, Meeting (TAC No. MA8219)," dated April 28, 2000.

13) Letter, W. Lanning (NRC) to A. Blind (Con Ed), "NRC Special Inspection Report - Indian Point Unit 2 Steam Generator Tube Failure - Report No. 05000247/2000-010," dated August 31, 2000.

14) Electric Power Research Institute, "PWR Steam Generator Examination Guidelines: Revision 5," Report No. TR-107569-V1R5, September 1997.

15) Letter, A. Blind (Con Ed) to Document Control Desk (NRC), "Proposed Steam Generator Tube Examination Program - 2000 Refueling Outage," dated February 11, 2000.

16) Letter, J. Groth (Con Ed) to Dr. Travers (NRC), "2000 Refueling Outage Steam Generator Inspection Condition Monitoring and Operational Assessment Reports," dated June 2, 2000.

17) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Response to the Staff's Requests for Additional Information (RAI) Regarding the Steam Generator Tube Examinations conducted during Spring of 2000 Outage, and the Root Cause Evaluation of the Steam Generator Tube Rupture Event of February 15, 2000 (TAC No. MA8219)," dated June 19, 2000.

6.2 Con Ed's Condition Monitoring/Operational Assessment

6.2.1 Background

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

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

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

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

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

1) Evaluation of new types of degradation;

2) Basis and uncertainties for detection of degradation;

3) Basis and uncertainties for degradation growth rates;

4) Use of in-situ pressure tests; and

5) Assessment methodology and decision criteria.

6.2.2 Observations

1997 Inspection

Evaluation of New Types of Degradation

The Task Group reviewed the following documents from Con Ed:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

also requested additional information on Con Ed's condition monitoring assessment, degradation mechanisms evaluated using the Westinghouse screening criteria, and an assessment of the water chemistry performance during the extended period of wet lay-up and during the current cycle of operation.

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

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

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

Basis and Uncertainties for Detection of Degradation

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

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

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

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

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

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

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

Basis and Uncertainties for Degradation Growth Rates

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

The amendment request noted that of the 21 indications identified in 1993 and 1995, seven indications showed no change, four disappeared, four decreased in depth, and six increased in depth. The Task Group noted that indication size measurements are always limited by measurement accuracy, which can account for the supposed "disappearance" of indications. The discussion indicated that this nominal increase or decrease was 3 - 4%, which was stated

as within the accuracy of the eddy current measurements. The amendment request also concluded that since the SGs were maintained in cold shutdown temperature conditions, the environment for corrosion was reduced to an inconsequential level. No appreciable SG tube wear or degradation was expected as a result of the inspection interval extension. The amendment request did not address growth rates outside of the wet lay-up period.

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

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

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

3) PWSCC at Row 2 U-bend: The response stated that this was the first time that a Row 2 U-bend PWSCC indication was found. The response concluded that as this represented the first detected U-bend indication after approximately 23 years of operation, any growth rates associated with this indication would be considered minimal.

The Task Group found that the independent review by the NRC's Office of Research (RES) of this amendment request, dated March 16, 2000 (Reference x9, discussed the adequacy of the information provided by Con Ed in the RAI response. The RES review found Con Ed's response to the staff's question about the results of Con Ed's operational assessment for each degradation mechanism weak and incomplete. The review pointed out that Con Ed did not apply growth rates or NDE uncertainty in their operational assessment for stress corrosion cracking at the row 2 U-bend. The RES review disagreed with the contention by Con Ed that growth rates associated with the U-bend flaw would be minimal because this was the first detected U-bend indication after approximately 23 years of operation. RES stated that this contention was inconsistent with the evolution of stress corrosion cracking and with other industry experience. In discussions with the Task Group, Con Ed considered that, in retrospect, that they had provided a rather perfunctory remark about the growth rates of flaws in the U-bends, but felt that they had a technical basis for this remark based on SG lifetime prediction studies performed by Dominion Engineering. NRR staff agreed that the contention was flawed, but did not base its technical conclusions on that premise, relying instead on the basis that the results from the 1997 inspections established appropriate safety margins. The RES review is discussed in more detail in Section 7.0 of this report, and the NRR review of the license

amendment is discussed in more detail in Section 8.1. Additional discussion on the Dominion Engineering lifetime prediction studies is given in Section 6.4.

Use of In-Situ Pressure Tests

Licensees are provided with additional information on tube integrity by performing in-situ pressure tests on degraded tubes. In-situ pressure tests were used by Con Ed in 1997 to show that tubes that had been found by inspection to contain flaws would provide structural and leakage integrity at pressures up to three times the normal operating pressure (the 3ΔP structural requirement), and at a lower pressures of 2900 psi. The pressure tests are used to provide additional assurance that the inspection program is capable of detecting flaws before they compromise the structural or leakage integrity of the tubes. By using a conservative selection strategy for selecting tubes for pressure testing that represent the active degradation processes in the SG, the licensee can ensure that their SG program can provide assurance of tube integrity.

According to Con Ed's May 12, 1999 RAI response, the selection process for the in-situ pressure tests was performed according to a screening criteria developed by Westinghouse, 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 crack depth, and (3) crack depth profiling.

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 where ODSCC had been observed for the first time during this outage, and one that was typical for the roll transition cracking region. Only the tubes from the tubesheet crevice region were required to be tested according to the screening criteria, and the other two were selected as typical for that type of degradation. 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. The May 12, 1999 RAI response provided information on the in-situ testing rationale for both of the two forms of degradation observed in the 1997 inspection, summarized below:

1) ODSCC Above the Top of the Tubesheet (Sludge Pile): One indication measured at 49% maximum depth and a 0.55 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. The response concluded that based on the sludge pile flaw eddy current characteristics at IP2 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.

2) PWSCC at the Row 2 U-bend: Con Ed believed that the dimension of the indication by Plus Point characterization was below the in-situ screening threshold for Row 2 U-bend flaws. According to a June 15, 2000 Con Ed response to an NRC RAI (Reference 10), the indication was sized at 0.4 inches in length and approximately 50% in depth. Therefore, an in-situ pressure test was not performed for the tube in Row 2 Column 67.

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

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

Assessment Methodology and Decision Criteria

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

2000 Inspection

Evaluation of New Types of Degradation

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

In comparison to what was submitted in 1997, Con Ed submitted a comprehensive collection of information about the degradation mechanisms, including sizing information and voltages of indications detected. Rather than just providing conclusions about the tubes that needed

repair, as given in Con Ed's 1997 SG examination report, Con Ed provided the results of the the different types of analyses, along with the inputs for the 2000 examination.

Basis and Uncertainties for Detection of Degradation

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

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

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

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

impaired. While it is certainly not conservative to assume that the flaw size from the last inspection is at the detection threshold, overly large growth rates can be predicted by assuming that the flaw grew from a zero depth because it could not be detected.

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

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

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

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

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

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

The Task Group observes that this example of a lack of a direct correlation crack sizing with in-situ pressure testing performance should encourage licensees to be conservative in their selection of candidate tubes for in-situ testing. This example should also encourage licensees

to consider new forms of degradation for in-situ pressure testing, even when the flaw is sized below the screening criteria for in-situ pressure testing.

Assessment Methodology and Decision Criteria

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

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

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

6.2.3 Conclusions/Lessons-Learned

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

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

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

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

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

6.2.4 Recommendations

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

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

2) Licensees should use a conservative approach to screening tubes for in-situ testing, and should include tubes with new forms of degradation even if the screening threshold is not met. Industry should modify guidelines on the screening criteria to include new forms of degradation.

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

4) Licensees should consider the effect of the threshold of detection on the growth rate assumptions.

5) Licensees should recognize the potential for new forms of degradation and use robust techniques to look for problems that may exist, and not focus solely on degradation that has been found in the past.

6.2.5 References

The following References were used for Section 6.2:

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

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

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

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

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

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

7) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Response to Request for Additional Information - Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency," dated May 12, 1999.

8) Letter, S. Quinn (Con Ed) to Document Control Desk (NRC), "Additional Scope for the Indian Point 2 1997 Steam Generator Tube Inspection," dated May 6, 1997.

9) NRC Memorandum, A. Thadani to S. Collins, "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," dated March 16, 2000.

10) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Response to the Staff's Questions Regarding the Root Cause Evaluation for Steam Generator Tube Rupture Event of February 15, 2000 (TAC No. MA8219)," dated June 15, 2000.

11) Letter, J. Harold (NRC) to A. Blind (Con Ed), "Indian Point Nuclear Generating Unit No. 2 (IP2) - Topics of Discussion for the May 3, 2000, Meeting (TAC No. MA8219)," dated April 28, 2000.

12) Letter, J. Harold (NRC) to A. Blind (Con Ed), "Indian Point Nuclear Generating Unit No. 2 (IP2) - Request for Additional Information RE: Proposed Steam Generator Tube Examination Program - Supplement One (TAC No. MA8219)," dated March 24, 2000.

13) Letter, J. Zwolinski (NRC) to A. Blind (Con Ed), "Staff Concerns and Request for Additional Information Regarding the Steam Generator Operational Assessment, Indian Point Nuclear Generating Unit No. 2 (TAC No. MA9288)," dated July 20, 2000.

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

6.3 Con Ed's Implementation of Steam Generator Regulatory Requirements

6.3.1 Background

The Indian Point 2 (IP2) technical specifications (TSs) require the licensee to implement a steam generator (SG) examination program to verify, on a periodic basis, the integrity of their SGs and the tubes. The Task Group's review in this section was focused on assessing how Consolidated Edison's (Con Ed's) SG tube examination program at IP2 met the regulatory requirements.

The Task Group reviewed the licensing and design bases of the SGs contained in the IP2 TSs and the Updated Final Safety Analysis Report (UFSAR). In reviewing the licensing basis, the Task Group also considered NRC approved extensions to the required TS interval between SG tube examinations. The Task Group reviewed the implementation of Con Ed's SG tube examination program, including the qualification and certification of personnel that conducted the activities. The Task Group also reviewed the licensee's oversight of contractors; the methods by which Con Ed (and/or its contractor) conducted SG examinations and assessed examination results; and Con Ed's implementation of the TS primary-to-secondary leakage limits and implementation of the TS requirements related to NRC reporting. The Task Group reviewed the following areas:

1) The regulatory basis for the SG tube examination program;

2) Con Ed's SG tube examination program; and

3) Con Ed's 1995 and 1997 SG tube examination results.

6.3.2 Observations

Regulatory Basis for the IP2 Steam Generator Tube Examination Program

Title 10, Part 50 of the Code of Federal Regulations (10 CFR Part 50)

Several sections of Title 10 of the Code of Federal Regulation (10 CFR), Part 50 directly or indirectly applied to Con Ed's operation and maintenance of the SGs. 10 CFR 50.55a(g), ISI Requirements, establishes the primary Code of Federal Regulation requirements for inservice examination of the tubes. It 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. The Task Group noted that Con Ed was committed to the 1989 Edition of the ASME Section XI Code. Some sections of that Code that are worth noting are: (1) IWB-2413, Inspection Program for Steam Generator Tubing, which states: "The examinations shall be governed by the plant Technical Specifications, " (2) IWB 2430, Additional Examinations, (d) which states: "For steam generator tubing, additional examinations shall be governed by plant Technical Specifications," and (3) Appendix IV Eddy Current Examination of Non-ferromagnetic Steam Generator Heat Exchanger Tubing, Section IV-6300, Recording of Results, which states: "flaws producing a response equal to or greater than 20% wall penetration shall be identified and the depth noted." This would infer that detection methods should have a detection threshold of greater than or equal to 20% through-wall.

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

Technical Specifications

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

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

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

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

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

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

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

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

The experience from the IP2 event where the SG leakage did not exceed the TS limit before a tube failed indicates that IP2 TS leakage limits, by themselves, are not always sufficient to prevent such a failure or provide meaningful indication of an impending failure. Additionally, the IP2 TS did not reflect the current knowledge regarding the degradation mechanism and

experience found at the plant or in the industry. It did not prescribe the types of information to be included in the examination results 45-day report. Although there was a requirement to report significant changes in SG condition immediately, there was no guidance on what constituted a significant change.

Updated Final Safety Analysis Report (UFSAR)

The IP2 UFSAR describes the design and operation of the SGs as discussed in Section 3.0 of this report. At the time of the tube failure event in February 2000, 10.2 % of tubes in the SGs were plugged with 25% being the plugging limit based on the plant's safety analysis. A SG tube rupture event is analyzed in UFSAR Section 14.2, "Standard Safety Feature Analysis." The UFSAR states that "[a}dequate provisions have been included in the design of the plant and its standby engineered safety features to limit potential exposure of the public to below the limits of 10 CFR 100 for situations that could conceivably involve uncontrolled releases of radioactive materials to the environment." With concurrent station blackout, the analyzed site boundary dose is in the order of 0.75 rem whole body and 2.7 rem thyroid, 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 analyzed 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.

Con Ed's SG Tube Examination Program

The Task Group reviewed Con Ed procedure SAO-180, "Administrative Steam Generator Program Plan," and identified the requirements and organization responsibilities necessary for the implementation of the licensee's Steam Generator Program. The program was developed to meet the commitment to NEI 97-06, Steam Generator Program Guidelines.

The 1997 tube examination was conducted by Westinghouse personnel (Con Ed contractor) under a purchase specification in which the requirements for eddy current examination of SG tubes at IP2 were defined. Among others, it stated that examination techniques were to be in accordance with EPRI SG Tube Examination Guidelines, Appendix H. Revision 4 of the EPRI guidelines was in effect at the time of the licensee's SG tube examination in 1997. 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. 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 were required to be reviewed and approved by Con Ed prior to the examinations.

Oversight of Contractor's SG Examination Activities

During the 1995 and 1997 NRC inspections at IP2, as documented in NRC Inspection Reports 50-247/95-07 (Reference 4), and 50-247/97-07 (Reference 5), the NRC observed that Con Ed maintained adequate control over the ISI Non Destructive Examination (NDE). The 1997 report indicated that 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 inspection report stated that the Con Ed Eddy Current level III inspector closely followed the activities of the contractor performing the SG examinations. The oversight of ISI activities was also routinely provided by the Quality Control unit through surveillance. Overall, the licensee's oversight of contractor activities was assessed to be good. However, as pointed out in the NRC Special Inspection Report (Reference 1), proper evaluation of the examination findings by the licensee and its contractors to determine the degradation mechanisms and their impact on SG integrity was significantly lacking. Specifically, the NRC team determined that during the 1997 examination, Con Ed should have taken additional actions in response to ECT noise levels and increased susceptibility to PWSCC reflected by tube denting and the apex flaw at a U-bend, to assure that the plant was not returned to service with SG tubes that contained detectable PWSCC indications in the low-row U-bend area. Multiple existing indications of PWSCC in the row 2 U-bend area were missed. The Task Group concluded that this raised reasonable doubt as to the adequacy of the performance of the contractor and Con Ed oversight of the 1997 SG examination activities.

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

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

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

Con Ed's Personnel Qualifications and Certification Levels

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

requirements stated in the pertinent supplement of SNT-TC-1A, the American Society of Non-Destructive Testing, Personnel Qualification and Certifications, and ASME Code Section XI. This was in accordance with the industry guidelines. However, during the NRC's inspection in 2000, the NRC special team identified instances where the 1997 examination did not meet certain portions of the EPRI guidelines. The team also identified weaknesses in the training and data analysis guidance provided to the data analysts in 1997. The issues are described in detail in the NRC Special Inspection Report.

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

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

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

Con Ed's SG Tube Examination Results

1997 Examination

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

The number of SG tubes examined by Con Ed during the 1997 refueling outage exceeded the TS requirements. Con Ed expanded their examination to inspect all support plate intersections with a Cecco-5 probe and the full length of all tubes with a bobbin coil probe. The examination, completed in June 1997, identified the first low-row U-bend PWSCC indication (at the apex of tube R2C67 in SG24). That tube was plugged in 1997. The tube that failed in February 2000, R2C5 in SG 24, had been examined over its full length, but the licensee failed to identify the existing indications. Also during the 1997 examination, Con Ed identified the first instances of probe restrictions caused by denting at the upper tube support plate in multiple low-row U-bend tubes. Those tubes were also plugged.

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

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

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

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

1995 Examination

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

In an NRC inspection report (Reference 4), the inspector documented that during that SG examination, 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 tubes. They also expanded their scope of examination using the Cecco-5 probe. Based on this, the Task Group believed that when abnormal issues were encountered, the questioning approach demonstrated by the 1995 crew was good. The Task Group did not note this type of approach in the review of the licensee's activities for the 1997 examinations.

6.3.3 Conclusions/Lessons-Learned

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

1) The IP2 TS on SG tube integrity does not reflect current knowledge regarding SG degradation and failure mechanisms (e.g., hour-glassing), and provides insufficient guidance regarding the type of information and level of detail to be reported to the NRC. For example, the licensee report containing the results of its SG examination does not provide any details regarding the data quality.

2) The TS directs Con Ed to report significant hour-glassing. However, there is a lack of specificity in the TS with respect to inspecting for "hour-glassing" as a degradation mechanism.

3) The IP2 TS requires Con Ed to submit the results of the SG examinations within 45 days, but the reports are not usually reviewed by the NRC. Unless reports provide information that supports the NRC's inspection and licensing processes, such reports should not be required. If reports are required from the licensees, the staff review process should be well defined. The revised reactor oversight process, including the SDP, and the telephone calls with the licensee during an outage, should be considered in addition to the reports.

4) The IP2 TS limit on primary-to-secondary leakage did not provide pro-active indication of upcoming tube failure. The experience from the IP2 event where the SG leakage did not exceed the TS limit before a tube failed indicates that IP2 TS leakage limits, by themselves, are not always sufficient to prevent such a failure or provide meaningful indication of an impending failure.

5) There were some significant differences between the actions taken by the licensee to address new degradation mechanisms considered to be significant in 1995 and in 1997. During the 1995 examination, actions taken to deal with flaws identified in the bottom edge of the third support plate were extensive. However, the actions taken during the

1997 examination to deal with the new flaw identified in the apex of the U-bend of a row 2 tube were not sufficient.

6.3.4 Recommendations

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

1) PWR TSs should be revised and strengthened to reflect the current knowledge of the SG degradation mechanisms, examination techniques, and methodology.

2) The licensee and NRC staff should agree on a measurable definition of "significant" for hour-glassing.

3) The staff should assess the need for, and the process for the staff review of, the TS required reports that document the results of licensee's SG tube examinations. If the staff determines that such reports should be required, then the staff should also determine the information to be included in such reports, and the timing for submittal of the reports to the NRC. The staff should also develop a well-defined process to review such reports, and the specific purposes and objectives of such reviews. The revised reactor oversight process, including the SDP and the telephone calls with the licensee during an outage, should be considered in the process.

4) The staff should assess the adequacy of the TS regarding operational leakage limits.

5) The licensees should ensure that contractors supporting the SG examinations perform in an acceptable manner. The industry initiative should provide reasonable assurance of contractor oversight by licensees.

6.3.5 References

The following References were used for Section 6.3:

1) Letter, W. Lanning (NRC) to A. Blind (Con Ed), "NRC Special Inspection Report - Indian Point 2 Steam Generator Tube Failure - Report No. 05000247/2000-010," dated August 31, 2000.

2) Letter, A. Blough (NRC) to A. Blind (Con Ed), "NRC Integrated Inspection Report No. 05000247/2000-001," dated April 13, 2000.

3) Letter, H. Miller (NRC) to A. Blind (Con Ed), "NRC Augmented Inspection Team - Steam Generator Tube Failure - Report No. 05000247/2000-002," dated April 28, 2000.

4) Letter, M. Modes (NRC) to S. Quinn (Con Ed), "Inspection Report No. 50-247/95-07," dated April 29, 1995.

5) Letter, J. Rogge (NRC) to S. Quinn (Con Ed), "NRC Integrated Inspection Report 50-247/97-07 and Notice of Violation," dated July 16, 1997.

6) Letter, S. Quinn (Con Ed) to Document Control Desk (NRC), "Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency," dated February 14, 1997.

7) Letter, J. Harold (NRC) to S. Quinn (Con Ed), "Issuance if Amendment for Indian Point Unit No. 2 (TAC NO. M97976)," dated April 9, 1997.

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

9) Letter, S. Quinn (Con Ed) to Document Control Desk (NRC), "Proposed Steam Generator Tube Examination Program - 1997 Refueling Outage," dated February 7, 1997.

10) Letter, J. Harold (NRC) to S. Quinn (Con Ed), "Proposed Steam Generator Tube Examination Program for Indian Point Nuclear Generating Unit No. 2 (TAC No. M98068)," dated May 29, 1997.

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

12) Letter, S. Quinn (Con Ed) to Document Control Desk (NRC), "Proposed Steam Generator Tube Examination Program - 1995 Refueling Outage," dated December 16, 1994.

13) Letter, S. Quinn (Con Ed) to Document Control Desk (NRC), "Steam Generator Tube Inservice Examination 1995 Refueling Outage," dated June 14, 1995.

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

6.4.1 Background

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

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

Con Ed's Root Cause Evaluation

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

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

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

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

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

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

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

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

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

NRC's Special Inspection Team Report Findings

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

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

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

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

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

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

significant conditions that affected the quality of the 1997 SG inspection, the team concluded that this failure was an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions.

6.4.2 Observations

Con Ed's Observations

Con Ed concluded in their root cause evaluation that a significant contributing factor for this leak was masking of the indication by noise related to deposits and tube geometry. The problem in 1997, according to Con Ed, is that they didn't realize how the noise affected their ability to detect flaws. In Con Ed's June 15, 2000 response (Reference 5), to an NRC RAI dated April 28, 2000 on Con Ed's root cause evaluation, Con Ed discussed the U-bend flaw that was found in the 1997 inspection, in tube R2C67. According to Con Ed's response, R2C67 had a measured length of 0.4 inches. The depth was estimated at about 50% through wall or well below the screening criterion for in-situ testing (which was a depth of approximately 75%).

In Con Ed's June 16, 2000 response (Reference 6)~~, to an NRC RAI dated April 28, 2000~~ on Con Ed's root cause analysis, Con Ed discusses ~~the~~ acceptability of the noise levels ~~during~~ the 1997 outage. Con Ed stated 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."

Con Ed concluded that the level of noise in the U-bends ~~was~~ comparable to that at other plants. Based on the noise levels observed by the NRC inspection team ~~during the 2000 SG~~ examinations, NRC staff recommended to Con Ed that they use a 800 kHz probe to reduce the noise levels. The Task Group learned from Con Ed that, in their view, ~~the only thing that made~~ a significant difference in the 2000 inspection was the use of the 800 ~~kHz probe~~. Further, Con Ed reported that experiments with lower frequencies did not produce measurable differences in their ability ~~to detect~~ flaws.

Con Ed also concluded that, according to eddy current experts, finding the flaw in tube R2C5 would have been ~~difficult in~~ 1997 because of the noise levels and accepted EC practices in ~~1997. Con Ed~~'s root cause analysis, dated April 14, 2000, 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."

Con Ed also discussed the adequacy of noise and data quality criteria available to them in 1997. In Con Ed's June 16, 2000 response (Reference 6), to an NRC RAI dated April 28, 2000 on Con Ed's root cause analysis, 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 Plus 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."

In summary, Con Ed concluded that improvements in detection capability and data quality guidelines provided a SG examination in 2000 that was much superior to that conducted in 1997. Con Ed concluded that the 1997 SG examination was consistent with the EC practices and guidance available in 1997.

Lessons-Learned Task Group Observations

The Task Group reviewed the Special Inspection Team report and many of the supporting documents. The Task Group's findings related to the report have also been discussed in some detail in other sections of this report.

The Task Group observed that Con Ed's root cause evaluation and the Special Inspection Team Report agreed on the nature of the technical deficiencies in Con Ed's 1997 SG examination. The technical deficiencies in the SG examination were due to problems in data quality. The

Task Group also observed that the Special Inspection Team report was critical of the programmatic deficiencies that kept Con Ed from thoroughly evaluating the significance of the PWSCC in the U-bends. The report noted that programmatic deficiencies were not discussed in the root cause evaluation, but were a major contributing factor to the tube failure. The Special Inspection Team found Con Ed's root cause analysis to be inadequate because it did not identify and address significant SG inspection program performance issues or identify or address deficiencies in the processes and practices during the 1997 inspection. The Task Group has made similar observations , and these deficiencies are discussed in detail in Sections 5.0, 6.1, 6.2, 6.3, 7.0, 8.1, and 8.2 of this report.

The Special Inspection Team reviewed the 1997 ECT data, and the actions taken upon discovery of a PWSCC flaw at the apex of tube R2C67 in SG 24. Specifically, the team reviewed the 1995 and 1997 IP2 SG Life Prediction reports, written by Dominion Engineering, with respect to U-bend PWSCC. The team noted that these reports used industry data to predict the number of SG tubes that would have to be plugged due to PWSCC during the life of the unit.

The first Dominion Engineering SG life prediction report was completed following the 1995 outage, and the report was updated following the completion of the 1997 outage. The Task Group learned from Con Ed that the 1995 report was updated in 1997 specifically to consider the first indication of PWSCC in the U-bends. As the Special Inspection Team report noted, the 1995 report predicted that, as a best case estimate, no PWSCC cracks would be found in the U-bend area throughout the entire licensed life of Indian Point 2. A pessimistic estimate predicted one PWSCC U-bend crack at the end of the last cycle of operation, Cycle 21. The PWSCC indication in the Row 2 U-bend was discovered at the beginning of Cycle 14. With the discovery of the PWSCC indication in the 1997 inspection, Con Ed told the Task Group that the updated predictions were now about one PWSCC indication per outage.

In discussions with Con Ed, the Task Group was told that utilities with only one unit often must rely on outside expertise for specialized technical areas such as SG integrity. As is common practice with other licensees, Con Ed relied on the expertise of outside contractors for their SG tube examinations and life prediction modeling. The Task Group did note that although the new indication of PWSCC in the U-bends did not encourage Con Ed to perform a closer review of the data, the Task Group recognizes that Con Ed's contractor considered the implications of the finding with respect to the life prediction model that had been performed in 1995. The 1997 update to the IP2 SG life prediction model predicted that about one PWSCC indication would be expected in the next outage, but did not accurately predict the seven indications found in the 2000 inspection, in addition to the tube R2C5 that failed during plant operation. Three of the indications were detected with the mid-frequency probe, and four were detected with the use of the high frequency probe. Con Ed attributed the inconsistency of the model predictions with actual indications found during the 2000 SG tube examination to the input being strictly from the mid-frequency probe, which had a poorer detection capability in the U-bends. The predictions are based on the results of the previous SG tube examination, so if inspection capabilities change, so do the model predictions.

The 2000 SG tube examination findings obtained with the improved inspection technology was more consistent with the statements made by RES about the behavior of stress corrosion cracks in the RES independent review (discussed in Section 7.0). In the review, RES stated that

"the behavior of stress corrosion cracks is expected to differ from one operating cycle to the next especially when the cracks first initiate or are detected. The appearance of a 'first' stress corrosion crack typically indicates that an incubation phase has passed and that more cracks are likely. Studies from service experience indicate that once stress corrosion cracks initiate, the number of future indications will initially increase exponentially with time."

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

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

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

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

October 2, 2000

Review of Draft Indian Point 2 Steam Generator Lessons Learned Report

EPRI guidance

1. Executive Summary

   a. Charter states that the Lessons Learned Task Group effort was to evaluate the NRC staff's regulatory processes in order to identify and recommend areas for improvements applicable to the NRC and/or the industry. ~~The Task Group was not chartered to assess~~ the Indian Point 2 performance issues.

   b. Note the statement: the report was not issued for comment outside the group.

   c. "The Task Group concluded that the weaknesses in the Con Ed program contributed to the poor condition of the failed SG tube have generic implications. The examination guidance in use is common throughout the pressurized water reactor (PWR) industry."

      This statements implies the weaknesses in the Con Edison program are associated with common industry examination guidance. In fact, the Con Edison performance issues to accounting for conditions affecting the detectability of, and susceptibility to, tube flaws.

   d. The section on steam generator tube integrity program regulatory framework should also mention 10 CFR, Appendix B.

   e. The Task Group concluded that weaknesses in {NEI} guidance contributed to inadequate {Indian Point 2} examinations {in 1997}.

      The NEI guidance did not contribute to the weaknesses ... improved NEI guidance can help prevent recurrence. NEI guidance is just one of the many tools available to licensees to ensure that the adequate inspections are conducted. For example, licensees need to consider industry experience and industry information, ensure that an adequate technical direction and oversight of steam generator inspection program, and ensure that there is an effective corrective action process.

   f. "The Task Group believes that the guidance in use during 1997 IP2 examinations are vague with respect to the quality of eddy current data and the significance of noise in the data. The need for increased licensee attention when "new" types of degradation are found is not emphasized."

      Again, NEI guidance is one source of information that may be enhanced. The regulations already require through Appendix B that increased licensee attention is needed when "new" types of degradation are found.

   g. "Licensees should review generic industry guidelines carefully to ensure that the conditions/assumptions supporting the guidelines apply to their site specific situation."

      This recommendation implies that licensees generally do not already do this, and that Con Edison is not an outlier.

[illegible] repetition of

h. "The Task Group believes that the real problem (with respect to the license amendment) relates back to the quality of Con Ed 1997 examination."

The "real problem" was Con Edison's performance in not recognizing conditions that affected detection and susceptibility, resolving these conditions and alerting the NRC to these condition during the license amendment process.

2. Event Summary and Background

a. The Regulatory Requirements do not include 10 CFR 50, Appendix B. Not only is Criterion XVI important, but Criterion IX is how the EPRI guidance are tied to requirements. However, this is discussed later in 4.0 Regulatory Framework.

3. Con Ed's SG Tube Examination Methods/Practices

a. The licensee's management of their steam generators (SGs) is directly dependent on the quality of their examination of the SG tubes and associate internals.

This implies that the a quality SG examination is the main, if not the only, issue that licensee's need to manage. It is silent on other inspection program attributes such as technical understanding of steam generator both existing and expected degradation mechanisms, ability to recognize, evaluated and address anomalous conditions, steam generator chemistry control, etc., which are very important activities in the management of steam generators.

The background section reads as if all you need are the EPRI guidelines. However, the EPRI guidelines are just one input into a sound steam generator inspection program. The guidelines are generic in nature and not prescriptive in many areas. We should put the EPRI guideline in the right perspective and do not treat the EPRI guidelines as the panacea for steam generators.

The background does not provide equal treatment to other requirements of a robust SG inspection program, even though the observations section discussed the failure to address anomalous conditions.

Much of the observation section are not observations but a litany of historical facts. These facts should be incorporated into the background and the original background section taken out. It does not tie very well to the observations.

b. The Task Group (page 52, third paragraph) implies incorrectly that there was not much else that the licensee could have done, because the data quality, which was the root cause, was poor. Also, the writeup implies that the licensee's performance was adequate since they could not "expanded the scope" beyond 100%. This is reflected in the first conclusion of this section as well.

This contrary to the views of many of the staff involved in the special inspection. If by data quality, we need noise, the staff believe that the licensee did not account for this anomalous condition, particularly when there were indications of increased susceptibility. A number of actions could have been taken by the licensee. The licensee could have

simply plugged tube with "bad" data. They could have more thoroughly interrogated the data, which was readily available, of most susceptibility tubes to determine the extent of condition. The could have looked for ways in which to minimize the noise, i.e., higher frequency probe.

c. Recommend revising the second conclusion as follows: Con Edison did not use data quality standards during the 1997 steam generator inspections.

4. <u>Con Ed's Condition Monitoring/Operational Assessment</u>

a. Page 57, first paragraph, and page 59, third paragraph, discusses that there were no regulatory requirements to perform or submit the results of a CMOA to the NRC. This implies that the licensee went above and beyond the requirements. We should strike these sentences because:

- While a CMOA is can be one method, licensee's are required to identify, correct, evaluate and prevent recurrence of significant conditions adverse to quality.

5. <u>Con Ed's Implementation of Steam Generator Regulatory Requirements</u>

a. Page 74 discusses the issue of data analyst performance. The special inspection team did not arrive at such a conclusion and did not find any data to support such an assertion.

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

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

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

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

to what extent that Con Ed's staff would have reviewed this document. In addition, the Task Group notes that NUREG 1477 does not contain staff regulatory positions.

Looking ahead, NEI told the NRC staff at a July 26, 2000 public meeting at NRC headquarters that lessons from IP2 would be factored into Revision 6 of the examination guidelines. Handouts from that meeting state that the objective 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. According to the NEI presentation, draft data quality reports for bobbin and Plus Point have been developed for inclusion in Revision 6. This revision is being reviewed by the licensees who ultimately have to implement them in their SG programs. The Task Group also recommends that the EPRI guidelines emphasize prudent measures to be taken when evaluating the first occurrence of a new type of degradation for that plant, such as increasing the level of review or more carefully examining existing data, as discussed in the Special Inspection Team.

The Special Inspection Team further concluded that techniques to minimize the effects of the noise on data quality were not used and/or criteria for rejecting data based on high noise was not provided to the analysts in 1997. The Task Group was told by Westinghouse ECT analysts as well as NRC staff that techniques to minimize noise are available as filtering algorithms in commercially available software. Combined with frequency selection and frequency mixes, filtering algorithms can help "pick out" flaws from noisy data. The Task Group was also told that these techniques must be used carefully, or real flaws could get eliminated from the data.

At a May 3, 2000 meeting that Con Ed held with the NRC to discuss Con Ed's root cause analysis, a Westinghouse employee stated that other Westinghouse plants had similar levels of noise in the U-bend region of their tubes. Another Westinghouse employee later informed the Task Group of the same issue. As a result, NRC asked NEI informally to evaluate the noise issue in a generic sense, and NEI undertook a U-bend noise study comparing the noise level in the U-bends at IP2 with two similar plants.

In the NEI noise study, U-bend data from two other similar Westinghouse plants were evaluated for noise in the eddy current signals. The average noise levels were evaluated with both the mid frequency and high frequency probes. One plant, designated as P, never had copper deposits, while the other plant, designated K, originally had copper but removed it years ago. IP2 appeared to have higher average noise levels in the U-bend signals compared to the two other plants. Since only 10 to 20 tubes (of the 90 some in each SG) in Row 2 of each plant were used for this study, the Task Group notes that the results represented averages, and some tubes may exhibit higher noise levels than others. The Task Group understands from discussion with eddy current analysts that noise differences from tube to tube are frequently present, and can be the result of geometry differences or permeability variations.

The Task Group was told by NRC staff and eddy current analysts that in 1997, the mid-range (300 - 400 KHz) Plus Point probe was commonly used, but not the high frequency (800 KHz) probes. The evaluation by NEI in 2000 showed that the mid-range Plus Point probe was site validated for both the K and P plants, but not for IP2 during the 1997 examination. IP2 used the EPRI validation, rather than a site validation. EPRI had to perform a Appendix H qualification for the high frequency probe used at IP2 in 2000, and there were no site validations for the use of high frequency Plus Point probes in U-bends at that time. From discussions with NRC staff, the Task Group learned that before the IP2 event, most plants used the mid-range probes for low

row U-bend examinations and the high frequency probes were not commonly used. The Task Group observed that after the tube failure event, a few other plants have started using the high frequency probe in a limited way in the low row U-bend tubes of their SGs.

The Task Group noted that this noise study produced noise data for the qualification standard that is much higher than the two plants compared with IP2. 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 SGs in the field, the Task Group believes that this finding should be assessed generically. Based on this finding, the Task Group believes that the industry cannot rule out noise in U-bends based on just age of the SGs 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 could be affected.

Based on the potential for poor signal-to-noise ratios from conditions other than deposits outside the tubes, the Task Group concludes that the industry should carefully assess the potential for conditions that are detrimental to detecting flaws at each plant. Qualification standards should, to the extent possible, represent the actual flaw conditions, so the licensee can have a reliable prediction of what range of voltages that the actual flaws should have (rather than just machined flaws).

The Task Group was told that the analyst's job is tedious and performed under severe time constraints, and thus prone to the possibility of missing indications. The Task Group understands that there are data screening computer programs that will enhance (not replace) the detection capability of the analysts in some situations. Based on the Task Group discussions with NRC staff and eddy current analysts, the Task Group recommends that in addition to using two human analysts for the primary and secondary analysts, the industry should consider and develop guidelines for using computers to screen the test data.

Based on the above discussion, the Task Group has also concluded that improvements to the SG guidelines should include criteria for data quality and recommendations for improving the signal-to-noise ratios. The guidelines should receive appropriate review and endorsement by the NRC staff.

6.4.3 Conclusions/Lessons-Learned

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

1) Based on Task Group discussions with NRR staff and outside expert contractors, there were different views on whether the flaw in R2C5 could have been detected during the 1997 inspection due to problems with the noise in the data.

2) Similarities in Con Ed's root cause evaluation and NRC's Special Inspection Team findings support a similar view of the technical deficiencies of Con Ed's 1997 SG inspection such as data quality and the improvement in the 2000 SG inspection due to using a high frequency (800 kHz) probe.

3) Differences in Con Ed's root cause evaluation and NRC's Special Inspection Team findings reflect the NRC's view that there were SG programmatic deficiencies that kept

the licensee from adequately evaluating the significance of the degradation in both the 1997 and 2000 SG examinations.

4) NEI performed a study of noise in eddy current data that compared the noise levels in the eddy current data from IP2 with data from two other older plants. In this study, the plant nosie data was compared with the noise from an EPRI qualification standard, which consists mainly of new tubes. The noise in the standard was higher than that of the two plants compared with IP2. This study implies that noise can be a problem in tubes in new SGs as well as in old SGs.

5) Techniques to minimize noise, such as filtering algorithms, are available in commercially available software. Combined with frequency selection and frequency mixes, filtering algorithms can help "pick out" flaws from noisy data.

6) The data analyst's job is tedious and performed under severe time constraints, and thus prone to the possibility of missing indications. There are data screening computer programs that will enhance (not replace) the detection capability of the analysts in some situations.

6.4.4 Recommendations

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

1) Industry should update EPRI SG Examination Guidelines to incorporate data quality criteria, and provide guidance to identify and reduce sources of noise in the data.

2) Industry should update EPRI SG Examination Guidelines to incorporate guidelines on prudent measures to be followed when evaluating the first occurrence of a new type of degradation for SG tubes.

3) Care should be taken in relying on predictive models for PWSCC, and licensees should maintain an aggressive approach in evaluating inconsistencies with predicted and observed SG degradation behavior

4) Industry should consider the issue of noise in newer tubes in the revision to the EPRI SG examination guidelines.

5) EPRI guidelines should address the use of noise minimization techniques such as filtering algorithms.

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

6.4.5 References

The following References were used for Section 6.4:

1) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Root Cause Evaluation for Steam Generator Tube Rupture Event of February 15, 2000," dated April 14, 2000.

2) Letter, J. Harold (NRC) to A. Blind (Con Ed), "Indian Point Nuclear Generating Unit No. 2 (IP2) - Topics of Discussion for the May 3, 2000, Meeting (TAC No. MA8219)," dated April 28, 2000.

3) Letter, W. Lanning (NRC) to A. Blind (Con Ed), "Preliminary Results of NRC Special Inspection 50-247/2000010 - Steam Generator Tube Failure," dated July 27, 2000.

4) Letter, W. Lanning (NRC) to A. Blind (Con Ed), "NRC Special Inspection Report - Indian Point Unit 2 Steam Generator Tube Failure - Report No. 05000247/2000-010," dated August 31, 2000.

5) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Response to the Staff's Questions Regarding the Root Cause Evaluation for Steam Generator Tube Rupture Event of February 15, 2000 (TAC No. MA8219)," dated June 15, 2000.

6) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Response to the Staff's Requests for Additional Information (RAI) Regarding the Steam Generator Tube Examinations Conducted During Spring of 2000 Outage, and the Root Cause Evaluation of the Steam Generator Tube Rupture Event of February 15, 2000 (TAC No. MA8219)," dated June 16, 2000.

7) Electric Power Research Institute, "PWR Steam Generator Examination Guidelines: Revision 4," Report No. TR-106589-V1, June 1996.

8) NRC Draft NUREG 1477, "Voltage-Based Interim Plugging Criteria for Steam Generator Tubes," dated June 1993.

9) NRC Information Notice 94-88, "Inservice Inspection Deficiencies Result in Severely Degraded Steam Generator Tubes," dated December 23, 1994.

6.5 Industry Guidelines for Steam Generator Inspection and Assessment

6.5.1 Background

In recent years, PWR licensees have relied upon a number of industry guidelines and technical publications issued by the Electric Power Research Institute (EPRI) and the Nuclear Energy Institute (NEI) to form the basis of their steam generator (SG) tube inspection and integrity 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 tube integrity 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 1). This document was intended to serve as a framework for SG tube integrity programs to be implemented by licensees. The objective of issuing the guidelines was to introduce consistency in application of industry guidelines to licensee SG management programs. The guidelines refer to EPRI technical reports for detailed development of program attributes.

The Task Group examined:

1) The applicability of NEI Guidelines and EPRI technical reports to Indian Point (IP2) at the time of the tube failure event in February 2000; and

2) Implications of the IP2 event on industry guidelines.

The Task Group did not review all of the 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 documenting the staff's review of NEI 97-06, as discussed in SECY-00-0078, "Status and Plans for Revising the Steam Generator Tube Integrity Regulatory Framework" (Reference 2).

6.5.2 Observations

Industry Guidelines Applicable to IP2

In December 1997, NEI informed the NRC (Reference 3) that it had formally adopted NEI 97-06, and that each licensee would meet the guidelines 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 SG program, and where necessary, revise and strengthen program attributes to meet the intent of the guidance provided in NEI 97-06."

Thus, the initiative allows 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 acknowledging the guidelines (Reference 4) 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 (TS) amendments and associated documents controlled by licensees. NEI 97-06 discusses NRC regulations pertinent to SG integrity, and mentions Regulatory Guide 1.174 (Reference 5) 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 tube integrity, Consolidated Edison (Con Ed) referenced EPRI guidance documents as one of the bases for their tube integrity program, as discussed below.

1) In its SG tube examination specification (Reference 6), Con Ed referenced the EPRI PWR SG Examination Guidelines.

2) In its proposed SG tube examination program for the 1997 refueling outage (Reference 7), 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.

3) In its response to NRC Generic Letter 97-05, "Steam Generator Tube Inspection Techniques" (Reference 8), Con Ed referenced NEI 97-06, and Appendix H of the EPRI PWR Steam Generator Examination Guidelines.

4) Con Ed license amendment request submittal for a SG inspection interval extension (Reference 9), stated that ECT probe qualification was based on EPRI PWR SG Program Guidelines, and that water chemistry was based on EPRI guidelines.

5) Con Ed request for additional information (RAI) response associated with the above referenced license amendment request (Reference 10), referenced EPRI Appendix H criteria for probe qualification.

6) Wet lay up conditions were maintained in accordance with EPRI guidelines during extended shutdown (Reference 11).

7) In its proposed examination program for the 2000 refueling outage (Reference 12), Con Ed again referenced 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. The licensee explicitly stated that Revision 5 of the EPRI guidelines would be followed in addition to the requirements of Technical Specification 4.13.

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.

Con Ed's root cause evaluation related to the February 2000 tube failure event (Reference 13), stated that "expert review of the data concurred that the flaw would not have been called by accepted eddy current practices in 1997, due to background noise in the signal related to geometry effects and deposits including copper." Therefore, the licensee's position is 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 (see Section 6.4 of this report).

As discussed in Sections 6.1, and 6.2 of this report, the Task Group considered the adequacy of the industry guidelines for IP2. 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 itself, was lacking for the situation encountered at IP2. Sections 6.1 and 6.2 of this report discuss specific shortcomings with the industry guidelines, such as techniques to minimize eddy current noise, evaluation of hour-glassing progression, and emphasis of steps required for site-specific qualification of flaw detection techniques.

It is clear that the licensee applied the EPRI guidelines for the 1997 tube examination and committed to following the NEI initiative. The NRC said in its 1997 inspection report addressing the 1997 tube examination that the licensee's program was prepared in accordance with EPRI guidelines. However, SG tube conditions deteriorated and the tube failure occurred. In the opinion of the Task Group, the IP2 experience demonstrated weaknesses in the EPRI guidelines and in their implementation because they did not focus on areas that contributed to the state of significant tube degradation that led to the IP2 tube failure.

<u>Implications of the IP2 Event on Industry Guidelines</u>

As discussed in Sections 6.1 and 6.2 of this report, shortcomings in the EPRI SG inspection guidelines should be addressed as a result of the IP2 event. Issues such as data quality, tube examination method flaw sizing qualification, and ECT noise levels were specific points raised by the IP2 event. Section 8.3 discusses the need for the NRC to continue the review of the industry proposal for SG degradation management. In the interim, the NRC should not solely rely on the EPRI guidelines as a substitute for NRC inspection and oversight of licensee SG tube integrity practices until lessons from IP2 have been incorporated into the framework.

The Task Group is aware that the industry is assembling lessons-learned based on the IP2 experience. Industry representatives from NEI have stated that such an effort is being pursued, but the results are not yet available. Industry has not indicated how lessons-learned from IP2 will be implemented by licensees in their SG tube integrity programs, but the Task Group determined that shortcomings in the industry guidelines highlighted by the IP2 experience have generic implications, and as discussed elsewhere in this report, warrant changes to the guidelines.

6.5.3 Conclusions/Lessons-Learned

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

1) Con Ed used EPRI guidelines and committed to the NEI 97-06 initiative before the February 2000 tube failure.

2) Although the Task Group did not conduct an extensive review of the industry guidelines or of the NEI initiative, it is apparent that implementation of the guidelines, or in some instances the technical guidance itself, was lacking for the situation encountered at IP2.

3) Industry has not yet taken steps to incorporate lessons-learned from the event into existing guidance documents. Industry representatives (i.e., NEI) have stated that such an effort is being undertaken, but the results are not yet available.

6.5.4 Recommendations

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

1) In the near term, industry should ensure that lessons-learned from the IP2 experience are being used to ensure that effective SG tube integrity programs are being implemented by licensees. NEI should provide feedback to the NRC on the status of licensee implementation of IP2 lessons-learned.

2) In the longer term, industry should also use lessons-learned from the IP2 experience to strengthen the NEI initiative. NEI should provide feedback to the NRC on the specific changes planned to the 97-06 initiative based on the IP2 experience, including a schedule for implementation of the changes.

3) The Task Group notes that its recommendations on eddy current testing and tube inspection guidelines were focused on a particular situation that existed at IP2 (i.e., a specific type of degradation and location within the SG). While incorporation of the IP2 lessons into industry guidelines is important, further development of industry guidelines should also address all SG tube degradation modes and degradation locations in order to be generally applicable.

6.5.5 References

The following References were used for Section 6.5:

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

2) SECY-00-0078, "Status and Plans for Revising the Steam Generator Tube Integrity Regulatory Framework," dated March 30, 2000.

3) Letter, Ralph E. Beedle (NEI) to L. Joseph Callan (NRC), transmitted NEI 97-06, dated December 16, 1997.

4) Letter, L. Joseph Callan (NRC) to Ralph E. Beedle (NEI), "Nuclear Energy Institute (NEI) 97-06, 'Steam Generator Program Guidelines'," dated February 3, 1998.

5) Regulatory Guide 1.174, "An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," dated July 1998.

6) "Eddy Current Examination of Steam Generator Tubes for Indian Point Unit 2," Specification No. NPE-72217, Rev. 10, dated December 17, 1996..

7) Letter, S. Quinn (Con Ed) to Document Control Desk (NRC), "Proposed Steam Generator Tube Examination Program - 1997 Refueling Outage," dated February 7, 1997.

8) Letter, P. Kinkel, (Con Ed) to Document Control Desk (NRC), "10 CFR 50.54(f) Response to NRC Generic Letter 97-05: 'Steam Generator Tube Inspection Techniques," dated March 17, 1998.

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

10) Letter, J. Baumstark, (Con Ed) to Document Control Desk (NRC), "Response to Request for Additional Information - Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency," dated May 12, 1999.

11) Letter, J. Harold (NRC) to A. Blind (Con Ed), "Issuance of Amendment for Indian Point Nuclear Generating Unit No. 2 Allowing a One-Time Extension of the Steam Generator Inspection Interval (TAC No. MA4526)," dated June 9, 1999.

12) Letter, A. Alan Blind, (Con Ed) to Document Control Desk (NRC), "Proposed Steam Generator Tube Examination Program - 2000 Refueling Outage," dated February 11, 2000.

13) Letter, James S. Baumstark, (Con Ed) to Document Control Desk (NRC), "Root Cause Evaluation for Steam Generator Tube Rupture Event of February 15, 2000," dated April 14, 2000.

7.0 RES INDEPENDENT TECHNICAL REVIEW OF SAFETY EVALUATION

7.1 Background

In a memorandum from S. Collins, Director, Office of Nuclear Reactor Regulation (NRR), to A. Thadani, Director, Office of Research (RES), dated February 28, 2000, NRR requested that RES perform an independent technical review of the staff's safety evaluation (SE) on the steam generator (SG) tube inspection interval extension 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; 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 extension and F* repair criteria to NRR on March 16, 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. The major areas that were considered by the Task Group included:

1) Results of the RES review;

2) NRR actions/response related to the RES review; and

3) Con Ed's comments on the RES review.

The Task Group's evaluation, including RES's findings, lessons-learned, and recommendations are presented in the following sections.

7.2 Observations

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. The Task Group 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 also discussed the RES

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

Results of the RES Review

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

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

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

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

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

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

> "For each degradation mechanism, please provide a general description of the operational assessment methodology used to ensure that SG tube integrity will be maintained for the entire fuel cycle (cycle 14). The description should include an explanation of the predictive methodology, flaw growth rates, and NDE uncertainty used to determine structural and accident leakage integrity."

RES characterized the licensee's response to the RAI (Reference 5) as "weak and incomplete." RES also believed that NRR's SE (Reference 3) indicated that the licensee conducted more thorough operational assessments than were described in response to the RAI. In particular, RES concluded that the case presented by the licensee on crack growth rate was technically inaccurate. In the licensee's discussion about the first time a row 2 U-bend PWSCC indication was found (Reference 5), they stated "[A]s this represented the first detected U-bend indication after approximately 23 years of operation, any growth rates associated with this indication would be considered minimal." This statement is inconsistent with the evolution of SCC and with other industry experience. RES felt that the presence of the row 2 U-bend indication should have raised a "red flag" because this meant that the long incubation (i.e., initiation) phase had passed, the crack growth rates would not be minimal, and more cracks would be likely to occur. There should have been a much closer look by Con Ed at other IP2 row 2 U-bend inspection data[8].

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

The 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 of the F* repair criteria. Therefore, the Task Group determined that further review of the F* repair criteria was not necessary. RES concluded: "The evaluation and the information submitted by the licensee do provide reasonable assurance that the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next inspection interval."

NRR Actions/Response Related to the RES Review

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

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

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

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

Although the RES response has been perceived by some stakeholders outside the agency as meaning that NRR did an inadequate review, one NRR staff member pointed out that even if IP2 had not shut down for the unscheduled maintenance outage (from October 1997 to August 1998), the tube that failed in February 2000 would likely have failed even without an extension of the inspection interval[9]. While the interactions between the licensee and the NRC in May 1999, relating to the amendment to the Technical Specifications to extend the SG tube inspection interval, provided an opportunity to uncover problems with IP2's SG operational assessment, the real problem stemmed back to the quality of the June 1997 inspection.

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

Con Ed's Comments on the RES Review

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

The Task Group noted that the purpose of the RES review, as defined in NRR's request (Reference 1), was "to determine if the staff's conclusions are technically sound and that the data presented by the licensee provided reasonable assurance that the delayed inspection and the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next scheduled inspection." Therefore, RES conducted their review based on the information available to the staff. As discussed in Section 8.1 of this report, if the staff felt they needed additional information to approve the SG tube inspection interval extension, they could have requested it at the time of the amendment review.

7.3 Conclusions/Lessons-Learned

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

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

---

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

However, the real problem stemmed back to the quality of Con Ed's SG inspection in 1997.

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

3) Even if the licensee had not requested an extension of the SG inspection interval, the SG tube (SG24, tube R2C5) likely would have failed before the end of the normal 24-month operating cycle.

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

5) Con Ed and Westinghouse did not recognize the significance of an important new SG degradation mechanism that was identified during their 1997 SG inspection. The NRC staff did not recognize the significance of this degradation mechanism during its review in 1999 of the amendment request to extend the SG tube inspection interval.

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

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

7.4 Recommendations

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

1) When a new type of SG tube degradation occurs for the first time, licensees should determine the implications on SG condition monitoring and operational assessment (e.g., potential for the tube to rupture before leaking, such as at the apex of a small radius U-bend).

2) NRC should take steps to ensure that SG expertise is available to support the objective of the NRC's licensing and inspection programs. This could be done through formal training and/or transferring knowledge from in-house SG experts to other staff through written guidance documents or a mentoring program.

3) When NRR requests that RES perform an independent technical review of a staff's SE, NRR and RES should develop a process for handling the request and response.

7.5 References

The following References were used for Section 7.0:

1) NRC Memorandum, S. Collins to A. Thadani, "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," dated February 28, 2000.

2) NRC Memorandum, A. Thadani to S. Collins, "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," dated March 16, 2000.

3) NRC Memorandum, E. Sullivan S. Bajwa, "Safety Evaluation Regarding Steam Generator Tube Inspection Interval for Indian Point Station Unit 2 (TAC No. MA4526)," dated May 26, 1999.

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

5) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Response to Request for Additional Information - Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency," dated May 12, 1999.

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

7) Letter, J. Harold (NRC) to A. Blind (Con Ed), "Request for Additional Information - Regarding Indian Point Nuclear Generating Unit 2 Steam Generator Inspection Interval One-Time Extension (TAC No. MA4526)," dated May 5, 1999.

8) NRC Memorandum, S. Collins to F. Miraglia, "Lessons-Learned Evaluation from Indian Point Station Unit 2 Failure Event, dated March 20, 2000.

9) NRC Memorandum, S. Collins to W. Travers, "Indian Point Unit 2 Steam Generator Tube Failure Lessons-Learned Task Group and Charter," dated May 24, 2000.

8.0 NRC REGULATORY PROCESS ISSUES

8.1 Licensing Review Process

8.1.1 Background

The licensing review process is one of the regulatory processes that supports 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 facility operating license. The Technical Specifications (TSs) are included as part of the license. The review and approval or denial of license amendment applications is one of the primary mechanisms for regulating changes in the operation of licensed nuclear facilities. The NRC's Office of Nuclear Reactor Regulation (NRR) Office Letter (OL) No. 803, "License Amendment Review Procedures" (Reference 1), provides guidance to the NRC staff to process license amendment applications.

Regulatory requirements related to the amendment of operating licenses 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 Indian Point 2 (IP2) Amendment No. 201 (Reference 2) 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 also 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 4) which revised the TSs to allow the repair of SG tubes via implementation of an F* (or F-star) criteria. This criteria allows tubes that are degraded in a location not affecting structural integrity of the tubes to remain in service as an alternative to removal from service through use of plugs. 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 SG 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 concluded 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:

1) completeness and acceptability of the licensee's application;

2) use of precedent by the NRC staff;

3) scope and depth of the review;

4) resources used in the review;

5) content of the NRC safety evaluation;

6) interface between NRC Headquarters and NRC Regional Staff;

7) review of the TSs associated with the SG inspection interval;

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

9) evaluation of guidance available to NRC staff reviewers; and

10) evaluation of the findings by the NRC's Office of the Inspector General (OIG) related to NRR's amendment review.

8.1.2 Observations

The Task Group reviewed the correspondence related to IP2 Amendment No. 201, including the application from the licensee, NRC interoffice memoranda, a request for additional information (RAI) and an RAI response (References 2, 5, 6, 7, 8, and 9). The Task Group also conducted interviews of NRC staff from Headquarters and Region I to gain insights on SG tube integrity issues relevant to IP2. These interviews included discussions regarding the specific licensing review process that was performed for IP2 Amendment No. 201. In addition, the Task Group held a discussion with staff from Consolidated Edison (Con Ed) and Westinghouse in order to get their views on lessons-learned and observations related to the IP2 SG tube failure event. The observations based on the review of the above referenced correspondence as well as the information gathered during the interviews/discussions 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 per 10 CFR 50.92; and

4) Appropriate TS pages.

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

Interviews were held with the NRR staff that were involved with the review associated with Amendment No. 201. The staff indicated that they believed that the licensee's application was complete and acceptable except for the information requested by the staff's RAI. The RAI response was considered adequate by the staff technical reviewer at the time the SE was being prepared. However, subsequent to the IP2 tube failure event on February 15, 2000, one NRR staff member reviewed the RAI response and stated that a licensee conclusion regarding growth rates was "ridiculous." Specifically, the RAI response includes a section that discusses that primary water stress corrosion cracking (PWSCC) was found at a row 2 U-bend for the first time (SG 24, tube R2C67). The RAI response also states that: "[a]s this represents the first detected U-bend indication after approximately 23 years of operation, any growth rates associated with this indication would be considered minimal." The staff member stated that although this statement was "ridiculous," it wouldn't have affected the staff decision with respect to row 2 tube integrity because the reviewers believed that the results of the 1997 SG inspection by the licensee established appropriate safety margins.

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

after the outage to get them to update the report based on the inspection findings. The new projection for PWSCC indications was one additional indication per cycle, not an exponential increase in indications. Since the projections were based on the midrange probe findings, the use of the high range probe would have led to a different result based on the increased number of indications found (i.e., not just one indication as was found with the midrange probe). Con Ed understood that they gave a rather perfunctory response to the RAI question about PWSCC degradation and growth rates. Since they had Dominion Engineering look at this issue, they believed that they had a technical basis for their conclusion, but this part of the Condition Monitoring/Operation Assessment (CMOA) was not described in detail in the RAI response.

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

Use of Precedent by the NRC Staff

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

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

Scope and Depth of the Review

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

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

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

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

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

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

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

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

inadequacies in the licensee's operational assessment directly related to the eventual tube failure. Specifically, if the licensee's 1997 inspection report had been thoroughly reviewed during the amendment review process, the staff might have questioned the licensee's operational assessment given the apex location of the row 2 U-bend indication (i.e., SG 24, tube R2C67).

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, or 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 are 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 by the NRR staff, and there were precedent licensing actions for changes related to extending the SG inspection interval. The RES review (Reference 3) associated with Amendment No. 201 supports the NRR staff assessment of the safety significance of the requested change. Specifically, RES concluded that, assuming the original inspection interval was justified, granting the requested approximate 2 month extension of the inspection interval "would not have appreciably increased the probability of tube failure." The SE for this Amendment was prepared 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. As described in OL No. 803, Section 2.4, medium complexity changes include changes such as extension of surveillance test intervals. Therefore, the technical complexity for the Amendment No. 201 review could 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). The Task Group concludes that the resources used in the review for Amendment No. 201 were appropriate given the complexity and safety significance of the proposed change.

Content of the NRC Safety Evaluation

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

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

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

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

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

3) SG leakage monitoring program.

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

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

a challenge to the 3ΔP structural margin criteria for the expected operating cycle length of 21.4 effective full power months (EFPM). The SE concluded that, based on a review of the licensee's assessment, the staff expected the SG tubes to continue to satisfy structural and leakage integrity requirements under normal and accident conditions through the end of the current operating cycle (i.e., cycle 14). As discussed in the "Completeness and Acceptability of the Licensee's Application" section above, the licensee's RAI response regarding growth rates (associated with the PWSCC indication found in the row 2 U-bend in 1997) was not questioned by the NRR staff during the time the amendment review was being performed. In hindsight, had this issue been pursued further (i.e., clarification phone call with licensee or second RAI), this was an opportunity to find inadequacies in the licensee's operational assessment directly related to the eventual tube failure.

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

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

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

1) Had the NRC questioned Con Ed regarding this first time row 2 U-bend apex PWSCC indication that was found in 1997 (SG 24, tube R2C67), Con Ed could have stated that based on the report from Dominion Engineering, they only expected one indication per cycle and that tube had been plugged in 1997.

2) If the NRC did not accept the Dominion Engineering report conclusions, the staff may have asked Con Ed to review the 1997 eddy current data results. Since Con Ed did not

find any indications in 1997 for the tube that failed in 2000, it is uncertain that the licensee's re-review of the data would have found any indications in the subject tube that were previously missed. Con Ed could have also noted that 100% of the tubes were inspected in 1997.

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

4) At the time of the amendment review, the plant was operating. As such, no further SG inspection data (e.g., using different type of probes) could be gathered beyond the existing 1997 inspection data without shutting down the plant.

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

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

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

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

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

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

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

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

Potential Future Impact of the 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 this group is 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 potential future impact that the WPC may have on the licensing review process as presently described in OL No. 803. Specifically, the Task Group raised 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 basic 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 potential future impact of the WPC on assignment of reviewers during 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 the 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 NRR senior technical staff members is relied on heavily. Formal guidance needs to be developed to ensure that all reviewers are able to efficiently and effectively prepare SEs.

Evaluation of the Findings by the NRC's OIG Related to NRR's Amendment Review

On August 29, 2000, the NRC's Office of the Inspector General (OIG) issued its event inquiry, "NRC's Response to the February 15, 2000, Steam Generator Tube Rupture at Indian Point Unit 2 Power Plant" (Reference 12). The OIG had initiated this inquiry because of concerns from Congress and the public about the IP2 event. OIG's findings related to NRR's review of IP2 Amendment No. 201, and the Task Group comments on these findings, are as follows:

1) OIG finding: NRR's review of the SG inspection interval amendment request was not adequate.

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

2) OIG finding: The amendment request asked for a 1 year extension and was approved by NRR based on an SE completed by a junior engineer with limited experience in SG inspection techniques.

   Task Group comments: 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. The SE technical considerations associated with justifying the recapture of the 10 month wet lay-up period involved assessing that chemistry conditions were maintained such that corrosion was minimized. No issues have been raised with respect to the validity of the SE conclusions regarding

chemistry conditions. In addition, the additional period of approximately 2 months was considered insignificant by the NRR staff. As discussed in the "Resources Used in the Review" section above, the review was not of sufficient technical complexity such that a senior reviewer or contractor would be required. 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). Therefore, the SG inspection interval extension of approximately 2 months, associated with the issuance of Amendment No. 201, did not contribute to the tube failure event in February 2000. 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).

3) OIG finding: During the amendment review process, the senior engineer did not review the source documents submitted by IP2 or the 1997 inspection report.

Task Group comments: Detailed review of the submittal and other source documents is normally conducted by the assigned technical reviewer (i.e., person that prepares the SE). There is no specific guidance provided in OL No. 803 as to the scope of review required by the staff providing concurrence on SEs (e.g., whether source documents are expected to be reviewed). The Task Group concluded that there were two opportunities during the license review process for the NRC staff to find inadequacies in the licensee's operational assessment (i.e., during review of the RAI response and during review of the licensee's 1997 inspection report). However, it is not clear if further follow-up in either one of these cases would have yielded a different result (e.g., denial of the amendment request). The basis for this conclusion is detailed in the "Content of the NRC Safety Evaluation" section above. Therefore, it is also not clear that senior engineer review of the Con Ed submittal (i.e., amendment application and RAI response) and the 1997 inspection report would have yielded a different result with respect to the license amendment.

4) OIG finding: Other technical expertise available to the NRR staff was not employed to review the 1997 inspection report or the amendment request.

Task Group comments: As discussed in the "Resources Used in the Review" section above, the Task Group believes that the resources used in the review were appropriate given the complexity and safety significance of the proposed change. The review was not of sufficient technical complexity that a senior reviewer or contractor would be required.

5) OIG finding: Although the junior engineer was not completely satisfied with the response to the RAI, no additional questions were asked by the NRC of IP2.

Task Group comments: Review and interaction with the licensee during the review process was consistent with NRR OL No. 803. To minimize unnecessary regulatory burden, a "goal" of the review process is to limit the RAIs to one round; however additional questions may be asked, if necessary. In discussions with the Task Group, the reviewer (i.e., "junior engineer") stated that the RAI response was considered "adequate" during the amendment review timeframe. As discussed in the "Content of the NRC Safety Evaluation" section above, the Task Group concluded that, in hindsight, had

the tube degradation issue been pursued further (i.e., clarification phone call with licensee or second RAI), this was an opportunity to find inadequacies in the licensee's operational assessment directly related to the eventual tube failure. However, it is not clear if further follow-up would have yielded a different result (e.g., denial of the amendment request). The basis for this conclusion is detailed in the "Content of the NRC Safety Evaluation" section above.

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

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

8.1.3 Conclusions/Lessons-Learned

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

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

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

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

4) The scope and depth of the NRR staff review for Amendment No. 201 was consistent with the guidance in OL No. 803 since the requested change was not considered complex or safety significant. The staff did not review the licensee's 1997 inspection report in detail; however, there was no SRP guidance to perform reviews related to SG inspection interval extensions. Therefore, there was no guidance to the reviewers on whether review of previous licensee SG inspection reports was necessary. In hindsight, this could have been an opportunity to find inadequacies in the licensee's operational assessment directly related to the eventual tube failure. Specifically, if the licensee's 1997 inspection report had been thoroughly reviewed during the amendment review process, the staff might have questioned the licensee's operational assessment, given the apex location of the row 2 U-bend indication (i.e., SG 24, tube R2C67).

5) The resources used by the NRR staff in the review for Amendment No. 201 were appropriate, given the complexity and safety significance of the proposed change.

6) The licensee's RAI response regarding growth rates (associated with the PWSCC indication found in the row 2 U-bend in 1997) was not questioned by the NRR staff during the time the amendment review was being performed. In hindsight, had this issue been pursued further (i.e., clarification phone call with licensee or second RAI), this was an opportunity to find inadequacies in the licensee's operational assessment directly related to the eventual tube failure). However, it is not clear if this would have changed the outcome of the license amendment request (i.e., NRC staff approval of amendment request).

7) 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. For example, if the NRR SE relies heavily on a statement from the licensee on a risk-significant issue, NRR should request that the Region perform an inspection to verify the statement.

8) Since no specific guidance is available for reviewers to perform license amendment reviews associated with SG inspection interval extensions, the knowledge of individual NRR senior technical staff members is relied on heavily. Formal guidance should be developed (e.g., SRP) to ensure that all reviewers are able to efficiently and effectively prepare SEs.

9) 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 10 month wet lay-up period). Therefore, the SG inspection interval extension of approximately 2 months, associated with the issuance of Amendment No. 201, did not contribute to the tube failure event in February 2000. 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.

8.1.4 Recommendations

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

1) The NRC staff SE's should be specific as to what information is relied on to form the basis for it's conclusions (i.e., basis for approving the amendment). In addition, if the NRC staff is aware of significant information in the licensee's application that is incorrect, these issues should be discussed in the staff's SE even if the information was not relied upon to form a staff conclusion. This will help to identify those issues not otherwise addressed in the SE that later could be misinterpreted to imply that the staff concurred with the licensee's analysis/conclusions. OL No. 803 should be revised accordingly.

2) 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., if the NRR SE relies heavily on a statement from the licensee on a risk-significant issue, NRR should request that the Region perform an inspection to verify the statement).

3) The NRC staff should develop formal written guidance for technical reviewers to utilize in performing license amendment reviews related to SG tube integrity. The guidance should provide specific criteria to identify when the staff should review previous licensee SG inspection reports.

8.1.5 References

The following References were used for Section 8.1:

1) NRR Office Letter No. 803, Revision 3, "License Amendment Review Procedures," dated December 30, 1999.

2) Letter, J. Harold (NRC) to A. Blind (Con Ed), "Issuance of Amendment for Indian Point Nuclear Generating Unit No. 2 Allowing a One-Time Extension of the Steam Generator Inspection Interval (TAC No. MA4526)," dated June 9, 1999.

3) NRC Memorandum, A. Thadani to S. Collins, "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," dated March 16, 2000.

4) Letter, F. Williams (NRC) to S. Quinn (Con Ed), "Issuance of Amendment for Indian Point Nuclear Generating Unit No. 2 (TAC No. M89373)," dated March 13, 1995.

5) NRC Memorandum, E. Sullivan to S. Bajwa, "Safety Evaluation Regarding Steam Generator Tube Inspection Interval for Indian Point Station Unit 2 (TAC No. MA4526)," dated May 26, 1999.

6) Letter, J. Baumstark (Con Ed) to Document Control Desk (NRC), "Response to Request for Additional Information - Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency," dated May 12, 1999.

7) Letter, J. Harold (NRC) to A. Blind (Con Ed), "Request for Additional Information - Regarding Indian Point Nuclear Generating Unit 2 Steam Generator Inspection Interval One-Time Extension (TAC No. MA4526)," dated May 5, 1999.

8) NRC Memorandum, E. Sullivan to S. Bajwa, "Request for Additional Information - Regarding Indian Point Nuclear Station Unit 2 Steam Generator Inspection Interval (TAC No. MA4526)," dated April 19, 1999.

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

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

11) Letter, H. Miller (NRC) to A. Blind (Con Ed), "NRC Augmented Inspection Team - Steam Generator Tube Failure - Report No. 05000247/2000-002," dated April 28, 2000.

12) NRC Memorandum, H. Bell to Chairman Meserve, "Event Inquiry - NRC's Handling of Issues Associated with the February 15, 2000, Steam Generator Tube Rupture at Indian Point Unit 2 Power Plant (Case No. 00-03S)," dated August 29, 2000.

8.2 NRC Oversight Process and Inspection Program

8.2.1 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 steam generator (SG) tube failure at Indian Point 2 (IP2) occurred at a time when the NRC was transitioning to a new regulatory oversight process. Effective April 2, 2000, the NRC implemented this new reactor oversight process (ROP) for all commercial nuclear power plants. Many aspects of the agency's oversight process, such as the inspection program, assessment process, and enforcement policy, were revised to make them more objective, predictable, and understandable. Additionally, several new oversight processes were developed, such as performance indicators (PIs) and a significance determination process (SDP) for inspection findings.

The new ROP uses a framework of seven cornerstones of safety as the structure and basis for all oversight activities. These cornerstones are Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Occupational Radiation Safety, Public Radiation Safety, and Physical Protection. For each of these cornerstones, the new oversight process applies risk-informed safety thresholds to performance indicators and a baseline inspection program to obtain indications of declining licensee performance. These safety thresholds establish the Green, White, Yellow, and Red performance bands for both PIs and inspection findings.

A set of 18 PIs, with risk-informed thresholds, were developed to provide objective indications of licensee performance. The data for these PIs are collected by licensees and reported quarterly to the NRC. PI reporting is conducted in accordance with guidance document NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," which was developed by the industry and reviewed and approved by the NRC. SG tube leakage is reported by the Reactor Coolant System Leakage PI under the Barrier Integrity Cornerstone.

The baseline inspection element of the ROP inspection program is to be performed at all operating reactors. The inspections are performed by the resident and region-based inspectors. In the Barrier Integrity Cornerstone, inspection procedure 71111.08, "Inservice Inspection Activities" (Reference 1), is applicable for SG tube examinations. The procedure is required to be completed once every two years during a refueling outage at each facility.

Plants whose performance falls below a certain level will receive additional plant-specific supplemental inspection. The supplemental inspections are only performed as a result of risk-significant licensee 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 depend upon the risk characterization of the issues.

The risk characterization of inspection findings is performed using the SDP. The SDP was developed as a new tool in the ROP to allow risk-informed thresholds to be applied to inspection

findings on a risk scale similar to PIs. This allows, for example, a White inspection finding to have the same safety significance as a White PI.

The assessment process takes the PIs and SDP results as inputs, and uses an Action Matrix to determine the appropriate level of NRC interaction required based on the indications of licensee performance problems. The breadth and depth of the supplemental inspections to be performed are determined by the Action Matrix, along with the need for any other regulatory actions such as confirmatory action letters and orders.

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 (MD) 8.3, "Incident Investigation Program." As part of developing the new oversight process, MD 8.3 was revised to risk-inform the decision criteria for agency response to events. Although not issued at the time of the IP2 SG tube failure, this draft revision was available for use by regional management.

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" (Reference 2), was applicable for SG tube examination and was 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 the SG tube examination program. The review covered the NRC's old oversight process that was in effect during the February 2000 SG tube failure at IP2, as well as the new reactor oversight process (ROP) that went into effect in April 2000. The Task Group reviewed the following:

1) The scope and planning of NRC oversight and inspections of licensee's SG tube integrity management activities;

2) NRC Inservice Inspection (ISI) related Inspection Procedures;

3) Qualification and training requirements for NRC ISI inspectors; and

4) Implementation of NRC's inspection activities at IP2.

The Task Group also reviewed how SG tube leakage during normal operation is covered by the baseline inspection program and PIs. Finally, to obtain assessment data for the new ROP, the Task Group reviewed how inspection findings resulting from the SG tube failure were processed by the SDP and how these findings and PIs were evaluated for additional NRC action through the assessment process and Action Matrix.

8.2.2 Observations

<u>NRC Oversight of Licensee's SG Tube Integrity Management</u>

Prior to April 2000, NRC ISI inspections were performed at each facility by regional inspectors in accordance with the core inspection program. The scope of the inspector's review was based on a judgement regarding current significant issues and also as directed by the inspector's

supervisor. The planning did not usually involve NRC headquarters personnel. It did not require that industry information be factored in, although it sometimes was. New industry and generic information, such as Information Notices and Generic Letters, did not always get to the regional inspectors in time to be factored into their inspection activities. The site inspection involved one inspector for a period of one week and was not necessarily limited to SG activities, but could also include non-destructive examination (NDE) activities on other components.

NRR has routinely held conference calls with each licensee during its refueling outage (outage phone calls) to assess the adequacy of the licensee's SG tube eddy current inspections. These telephone calls involved regional participation on occasion and included discussions on the results of the licensee's SG tube 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 a formal part of the inspection program, and the results are not documented in inspection reports. During the 1997 SG tube examination at IP2, NRR and Con Ed held telephone conference calls to discuss the licensee's examination activities and findings. The Task Group reviewed and discussed with NRC staff, records of the telephone calls that were held on June 2, 3, and 29, 1997. There was no indication that a row 2 tube U-bend crack, such as one that was found in tube R2C67 of SG 24, was discussed during the calls. Nevertheless, some staff members interviewed by the Task Group indicated that they had specifically asked during the phone calls if any U-bend degradation in small radius tubes had been identified. The Task Group noted that the timing of the phone calls relative to when the flaw was identified was not clear.

In the ROP, the important attributes of each cornerstone of safety are covered by the combination of PIs and inspection. One of the key attributes of the Barrier Integrity cornerstone is to monitor the condition of the SG tubes, which make up a large portion of the RCS pressure boundary. Under the baseline inspection program, SG tube leakage during plant operation would be routinely monitored by the inspectors by IMC 2515, Appendix D, "Plant Status." Although primary-to-secondary SG leakage is not specifically noted, this manual chapter does direct inspectors to periodically walkdown the control room to note any adverse plant parameter trends, and to review various logs such as the control room and chemistry logs. However, risk-informed thresholds have not been established in the ROP that define when an adverse trend in primary-to-secondary leakage has reached a point where increased NRC interaction is warranted.

Primary-to-secondary leakage is also captured by the Reactor Coolant System (RCS) leakage Performance Indicator (PI). This PI tracks identified 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 from SGs would not be readily apparent in this PI.

The industry guidance for reporting the RCS leakage PI, as contained in NEI 99-02, states that normal SG 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 the TSs are counted in this indicator. Due to the differences in TS requirements between plants, this guidance may not ensure that primary-to-secondary SG leakage is reported in all instances by all licensees.

Several PIs and inspection findings were generated as a result of the SG tube failure at IP2 in February 2000. A Yellow PI for Reactor Coolant System Leakage was reported by the licensee for the 1st Quarter of 2000. Additionally, the NRC augmented inspection team (AIT) follow-up inspection (Reference 3), identified seven green inspection findings. Three white inspection findings pertaining to emergency preparedness program deficiencies were documented in another NRC inspection report (Reference 4). Also one green finding and a finding preliminarily determined to have high safety significance (red), were documented in the NRC Special Inspection Report (Reference 5).

Based on a review of applicable documents and analysis, the Task Group believes that each of these findings was adequately assessed by regional and Headquarters staff using the SDP. The Task Group notes that the process was still ongoing for the preliminary red finding (at the completion of the Task Group review) with the next step being the opportunity for licensee comment on the SDP analysis.

NRC Inspection Procedures for Inservice Inspection (ISI)

Prior to April 2000, the required inspections of ISI activities at the plants were accomplished in accordance with NRC Inspection Procedure (IP) 73753, "Inservice Inspection." The procedure contained guidance to review licensees examination plans, personnel qualification and certification. It also included general guidance for observing NDE activities, including eddy current inspection. It directed checking the procedure, personnel, and results. Comparison of ISI adverse findings with previous examination results to determine changes in flaw size, was recommended. Inspectors could request NRC contractor review of the eddy current testing results.

There were additional non-core 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), but none addressed eddy current testing. NRC Inspection Procedure (IP) 50002, "Steam Generators" (Reference 6), provided detailed guidance on inspecting the history and material condition of SG tubing. It also provided guidance on assessing the effectiveness of licensee programs for SG tube examination. However, 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. The Task Group believes that if this procedure had been used at IP2 in 1997, coupled with the information provided in Information Notice 97-26, "Degradation in Small-Radius U-bend Regions of Steam Generator Tubes," the inspector might have questioned Con Ed about the depth of their analysis of the extent of the degradation involving a U-bend apex crack that was identified in a row 2 tube.

In the NRC's new ROP, the new baseline inspection procedure for inservice inspection, IP 71111.08, Inservice Inspection Activities, does not require that SG examinations be inspected. Even if inspected, the review could be minimal. The same was true under the old core program and IP 73753, and is not unique to the ROP and IP 71111.08. The inspection procedure contains significantly less guidance for conduct of the inspection than the previous core inspection procedure, IP 73753. IP 50002 was available under the old inspection program to be conducted as a regional initiative focused inspection on SG condition as well as to assess the effectiveness of the licensee's SG tube examination 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.

Under the new ROP, risk-informed thresholds are applied to inspection findings to determine when a significant degraded condition has occurred that warrants additional NRC interaction and supplemental inspection above the baseline program. Such thresholds do not currently exist to identify, based on the results of IP 71111.08, when the number or types of SG tube defects has reached a level that warrants additional NRC action.

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. The regional staff members interviewed by the Task Group indicated that as part of the training program, prior to conducting individual inspections, inspectors assist other inspectors on NRC's ISI inspections at other reactor sites. Nevertheless, they felt that the regional inspector training 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. While ISI inspectors are not required to be ISI experts, some regional management who were interviewed by the Task Group believed that the inspectors should be qualified in ISI techniques. The inspector should be a specialist and should posses project engineering expertise. They felt that a regional inspector trained in data analysis closely interacting with the NRC's NRR technical staff might have been able to identify the issue in 1997. It was not clear to the Task Group, however, that even a NRC specialist inspector would have identified the issue in 1997. That inspector might have conducted a more effective inspection that might have prompted the licensee to conduct further reviews and possibly identify the degradation in the tube that eventually failed in 2000.

NRC's Inspection Activities at IP2

The NRC inspected IP2's 1995 SG tube examination using IP 73753. The results were documented in NRC inspection report 50-247/95-07 (Reference 7). The findings were, basically, that: (1) examinations met the requirements of Regulatory Guide 1.83, Revision 1; (2) primary-to-secondary leakage was experienced in the previous cycles and through hydrostatic testing, leaks were found in SG 22 (through mechanical plug in R4C92) and SG 24; and (3) the licensee identified issues including copper deposits, distorted signals, etc.; the licensee then re-evaluated the data from 1991 and 1993 and found no issues. The licensee used the Cecco-5 probe for its examinations. The NRC inspector noted that the oversight of in-service inspection activities performed by contractors was routinely provided by the quality control unit through surveillance. The inspector also noted that the surveillance checklists used by the quality control inspectors were elaborate and extensive. Con Ed's Nuclear Power Engineering was responsible for developing SG tube examination programs and providing necessary oversight of eddy current examination activities, including the data analysis, resolution of indications, and plugging of defective tubes.

The NRC inspected IP2's 1997 SG Examination using IP 73753. The results were documented in NRC inspection report 50-247/97-07 (Reference 8). The Task Group discussed the 1997 inspection with the regional inspection specialist that performed the inspection. The inspector noted that he was not an eddy current specialist, but more of a general non-destructive examination inspector. Therefore, he was not skilled in evaluating eddy current data, especially

in determining data quality. He also noted that he did not receive IN 97-26, "Degradation in Small-Radius U-bend Regions of Steam Generator Tubes," issued May 19, 1997, before he performed the inspection. He noted that information that would assist the inspectors is often not disseminated in a timely way to prepare the regional inspectors for upcoming inspections. This is especially important for highly specialized areas like SG inspections. The inspector also noted that he used the NRC's general ISI inspection procedure (IP 73753), and not the little-used, more specialized SG inspection procedure (IP 50002).

The NRC's 1997 inspection of Con Ed's SG tube examinations focused on the licensee's management of the SG examinations and the data collection process, and not on the analysis of the results of their examinations. For example, the NRC inspection report contained assessments such as "good management oversight," and "examinations conducted in accordance with EPRI SG Tube Inspection Guidelines." In the report, it was 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 coil probes and that they also used plus point probes during the examination. During the inspection, the NRC inspector spent about 25% of his time on other issues that were not related to eddy current examination. The inspector noted that 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 for four days. At the end of the on site inspection week, the licensee's tube examination was still ongoing. Later, on June 29, 1997, the NRC inspector participated in a telephone 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 stress corrosion cracking (ODSCC). Following the examinations, the licensee submitted the required TS examination report. There is no indication that the NRC reviewed the 1997 examination results in detail.

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, just before Con Ed began their 1997 SG inspection. 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 "[t]he susceptibility to cracking in small radius U-bends and the findings of recent field inspections have emphasized the importance of inspection of this area of SGs with techniques capable of accurately detecting U-bend degradation." 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 Task Group determined that the IN may not have been received by the licensee's SG group before the SG tube examinations began.

The NRC staff had responded to the primary-to-secondary leakage at IP2 prior to the February 2000 SG tube failure event. While there were no specific NRC inspection procedures to address the leakage, the NRC resident inspectors brought up the leakage issue and it was followed up by both the regional and headquarters NRC staff. The staff felt that leakage was not up to the concern level but needed to be closely watched. The staff probably consulted the EPRI guidance on primary-to-secondary leakage. The leakage was considered not indicative of an imminent failure. Before the tube failed, the maximum leakage was only about 5 gpd. After the tube failed, the licensee estimated a leakage of about 48 gpm. Based on the leakage before failure, the Task Group considered that the staff's actions were appropriate. This, however,

indicates inadequacies associated with the reliance on Technical Specification and EPRI leakage limits for ensuring that the plant could be shut down to avert a tube failure.

8.2.3 Conclusions/Lessons-Learned

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

1) The NRC's baseline inspection program (specifically inspection procedure 71111.08, Inservice Inspection Activities) does not include guidance on the scope and depth of NRC's inspection of licensees SG tube examinations.

2) The regional inspector training is not designed to develop inspectors' technical expertise in the area of eddy current examination. Therefore, the inspection process may not be reasonably expected to preclude a situation such as the IP2 SG tube failure from occurring.

3) The NRC (NRR) telephone calls (outage phone calls) with the licensees during the licensees' SG tube examinations can be effective, but are not formally included in either the licensing or the inspection process.

4) Relevant technical information generated by staff technical offices, that may improve the effectiveness of NRC inspections, is not being consistently considered for inclusion in the inspection program. There were delays in communicating generic information (such as Information Notice 97-26, "Degradation in Small-Radius U-bend Regions of Steam Generator Tubes," dated May 19, 1997, and NUREG/CR-6365, "Steam Generator Tube Failures," dated April 1996) to the inspector to use in the inspection process.

5) Neither the baseline inspection program nor the performance indicators (PIs) provide adequate indication, during power operation, of adverse trends in primary-to-secondary leakage due to SG tube degradation. Also, 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 failed or ruptured SG tube.

6) Means have not been established in the Reactor Oversight Process (ROP), either through the PIs or the significance determination process (SDP), to apply risk-informed thresholds to the results of the periodic SG tube examinations to identify SG tube degradation that warrants increased NRC interaction.

7) Inspection findings generated during the NRC follow-up to the IP2 SG tube failure were adequately evaluated for safety significance by regional and headquarters staff using the SDP.

8.2.4 Recommendations

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

1) The staff should develop additional guidance on when and how much of its inspection of licensees' SG tube examination should be completed in the NRC baseline inspection program.

2) The staff should review the training requirements for NRC inspectors for the SG baseline inspection program. The review should include the guidance contained in the SG inspection procedure to determine the required training for NRC inspectors to successfully complete the objectives of the NRC inspection program.

3) The technical interaction between the licensees and NRR (outage phone calls) during the licensees' SG tube examinations can be effective and should be factored into the inspection program. The phone calls should involve the regional inspectors and should be used as part of the preparation for NRC inspections. This will afford NRR the opportunity to help focus the inspections on the appropriate issues.

4) The staff should develop, revise, and implement, as appropriate, the process for timely dissemination of technical information to the inspectors to ensure that relevant technical information is reviewed and considered for inclusion in the inspection program.

5) The staff should ensure that the baseline inspection program and/or performance indicators (PIs) adequately identify adverse trends in primary-to-secondary leakage during power operation, which could indicate a degradation of the SG tube integrity. Risk-informed thresholds should be established to identify when increased NRC interaction is warranted in response to an adverse trend. The staff should ensure that any PI reporting requirements for primary-to-secondary leakage take into account potential differences in license requirements to ensure that all licensees would be required to report primary-to-secondary leakage for both normal and failed SG conditions.

6) The staff should establish risk-informed thresholds, either through the PIs or the significance determination process (SDP), that can be applied to the results of the periodic SG inspections to identify SG tube degradation that warrants increased NRC attention.

7) Although no specific issues were noted with the SDP and assessment process, these processes should be reviewed periodically to assess the impact of any changes or revisions made to the inspection program or PIs. For example, any new inspection requirements resulting from the IP2 event must include a review of the SDP to ensure that resulting inspection findings can be adequately assessed for safety significance.

8.2.5 References

The following References were used for Section 8.2:

1) NRC Inspection Procedure 71111.08, "Inservice Inspection Activities," issued April 3, 2000.

2) NRC Inspection Procedure 73753, "Inservice Inspection," issued May 4, 1995.

3) NRC Augmented Inspection Team Follow-Up - Steam Generator Tube Failure - Report No. 05000247/2000-007, dated July 10, 2000.

4) NRC Inspection Report 05000247/2000-006, dated July 14, 2000.

5) NRC Special Inspection Report - Indian Point Unit 2 Steam Generator Tube Failure - Report No. 05000247/2000-010, dated August 31, 2000.

6) NRC Inspection Procedure 50002, "Steam Generators," issued December 31, 1996.

7) NRC Inspection Report No. 50-247/95-07, dated April 28, 1995.

8) NRC Integrated Inspection Report 50-247/7-07, dated July 16, 1997.

8.3 NRC Endorsement of Industry Guidelines

8.3.1 Background

For a number of years, the NRC has been engaged in efforts to modify the regulatory approach to steam generator (SG) integrity to address acknowledged shortcomings with the existing regulatory framework. The staff's efforts are outlined in Section 4.1 of this report. Among the range of options considered by the NRC is an industry initiative directed at SG tube integrity. The industry initiative has taken the form of guidance documents and detailed technical reports that licensees use as the basis for SG tube integrity programs. The industry effort culminated in the publication of NEI 97-06, "Steam Generator Program Guidelines."

Although the industry in general, and IP2 specifically, have committed to follow the NEI 97-06 initiative, it is not a regulatory requirement. The NRC has acknowledged licensees' use of the guidelines, and has even encouraged their use. However, the NRC has not formally endorsed the industry initiative nor any of the specific guidance documents. The Task Group examined whether the NRC position on the guidelines may have had an impact on the state of the SG tube integrity program at Indian Point 2 (IP2).

The Task Group examined:

1) The NRC's position on the industry SG guidelines as stated in NRC internal documents, generic communications to licensees, and in correspondence to the industry; and

2) Implications of the NRC position regarding the guidelines.

8.3.2 Observations

NRC Position on Industry Guidelines

The industry guidelines for SG tube inspection and maintenance are a significant industry initiative. The NRC position on industry initiatives has evolved in recent years based on Direction Setting Initiative 13 (DSI-13, see Reference 1, SECY-00-0116), and the NRC position on the SG guidelines has adapted to those changes. SECY-98-248 (Reference 2), explained that the staff focus on SG integrity regulatory issues had shifted to work with NEI to resolve staff 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. 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 in a favorable position to use the SECY-00-0116 process.

NRC Regulatory Guides (RG) related to SG inspection and maintenance have not been revised in many years and do not address the NEI initiative or the individual EPRI guidelines that

predated the initiative. For instance, RG 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes", Revision 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. RG 1.121, "Basis for Plugging Degraded PWR Steam Generator Tubes," August 1976, also predates EPRI guidance.

Recent staff efforts focused on revising the regulatory framework for SG integrity included the development of draft RG DG-1074 on SG tube integrity (Reference 3). DG-1074 directs licensees to consider EPRI leakage monitoring guidelines, and goes beyond the EPRI guidance in some ways (e.g., monitoring leakage at low power conditions). The DG also takes the position 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 tube integrity programs. DG-1074 was issued for public comment (See SECY-00-0078, Reference 4), and it received numerous comments. However, the range of comments indicates that further development of the DG and the NEI initiative is necessary. In SECY-00-0078, the staff expressed its intent to review the NEI initiative and to prepare a safety evaluation documenting its findings. The staff plans to 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, 2000, meeting with NEI) indicated that the staff has deferred its review of the NEI initiative 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 guidelines in general or specific ways. Some examples are:

1) GL 95-05 (Reference 5), referenced EPRI guidelines in the discussion of eddy current 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."

2) IN 97-26, "Degradation in Small-Radius U-bend Regions of Steam Generator Tubes" (Reference 6), discusses EPRI probe qualification in general terms.

3) IN 97-88, "Experiences During Recent Steam Generator Inspections," (Reference 7) mentioned EPRI recommendations regarding crack detection at dented locations.

The NRC has referenced, but has not endorsed, the EPRI guidelines, as indicated in the preceding examples.

<u>Implications of the NRC Position Regarding the Guidelines</u>

NRC acknowledged NEI 97-06 in a letter dated February 3, 1998 (Reference 8), and supported the industry effort, but did not endorse the guidelines. Although the staff did not review NEI 97-06 in detail, the February 3, 1998, letter did note differences between NEI 97-06 and the draft RG 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 the February 3, 1998, letter, NRC 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." The Task Group found that some NRC staff consider the guidelines as a minimum standard, and others feel that there are shortcomings to the guidance.

Although industry has adopted guidelines for SG tube integrity, without NRC review and endorsement, licensees may not have a clear view of the potential weaknesses in the guidance or in the regulatory role of the guidelines. NRC and industry have found weaknesses in the guidelines on a case-by-case basis (the IP2 event may prove to be the most recent example), and licensees may address the weaknesses within the licensing process. Although in the end this approach may maintain safety, it leads to an inefficient and less than effective process.

When industry adopted NEI 97-06, licensees committed to meeting the guidelines no later than the first refueling outage starting after January 1999. A central feature of the NEI initiative is the proposed Technical Specifications (TSs) for SG tube integrity. As proposed by NEI, the TSs would use a tighter operational primary-to-secondary leak rate limit, and tube performance would be judged against tube structural and accident-induced leakage criteria. As licensees adopt the NEI guidelines, they will propose changes to their SG tube TSs using the NEI framework, including the proposed tube performance criteria. NRC has stated its reservations with these performance criteria (Reference 8), but has not formally reviewed the proposal. The Task Group concluded that the NRC should assign a high priority to completing its review of the NEI SG initiative.

In the case of IP2, EPRI guidelines existed in 1997 that Con Ed referenced for their SG tube examination program. The NRC position on the guidelines was not finalized, and as a result, NRC guidance used by inspectors was not fully coordinated with industry guidelines. Taking steps to review and finalize an acceptable industry program should help to alleviate this situation, and will contribute to maintaining plant safety and agency efficiency and effectiveness.

8.3.3 Conclusions/Lessons-Learned

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

1) The Task Group concluded that, in general, the regulatory framework discussed in SECY-00-0078 remains sound. The IP 2 SG tube failure event, by itself, does not provide a reason to depart from this framework. The IP2 event, however, does serve to further emphasize the potential safety significance of, and public concerns about, SG tube failure events.

8.3.4 Recommendations

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

1) The NRC should assign a high priority to its review of the NEI SG initiative and the associated EPRI guidelines. The NRC should use the SECY 00-0116 process, once approved, to expedite the review of the NEI 97-06 initiative. This will contribute to maintaining plant safety and increasing agency efficiency and effectiveness.

2) In the interim, the NRC should issue a generic communication clearly delineating the current state of SG tube integrity program guidance, sources of guidance for licensee use, and what steps licensees need to take in addition to using guidelines, to provide reasonable assurance of SG tube integrity. Attention should be directed to use of appropriate tube performance measures, whether they are current TS limits or some other acceptable measures.

8.3.5 References

The following References were used for Section 8.3:

1) SECY-00-0016, "Industry Initiatives in the Regulatory Process," May 30, 2000.

2) SECY-98-248, "Proposed Generic Letter 98-XX, 'Steam Generator Tube Integrity'," October 28, 1998.

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

4) SECY-00-0078, "Status and Plans for Revising the Steam Generator Tube Integrity Regulatory Framework," March 30, 2000.

5) Generic Letter 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking," August 3, 1995.

6) IN 97-26, "Degradation in Small-Radius U-bend Regions of Steam Generator Tubes," May 19, 1997.

7) IN 97-88, "Experiences During Recent Steam Generator Inspections," December 16, 1997.

8) Letter, L. Joseph Callan (NRC) to Ralph E. Beedle (NEI), "Nuclear Energy Institute (NEI) 97-06, 'Steam Generator Program Guidelines'," February 3, 1998.

9.0 RECOMMENDATIONS

The Task Group recommendations listed previously in this report (i.e., in Sections 5.0 - 8.0) have been consolidated into Table 9-1. This Table provides the Task Group's ranking of each recommendation based on its importance relative to each of the pillars in the NRC's Strategic Plan (i.e., maintain safety, increase public confidence, increase effectiveness and efficiency, and reduce unnecessary regulatory burden). Table 9-1 also provides information regarding the organization that the recommendation applies to. The information in each of the Table columns is as follows:

No. — This column provides the recommendation number.

Recommendation — This column provides the Task Group recommendation.

Action For — This column indicates the organization the recommendation applies to.

Report Reference — This column provides the Task Group Report section and recommendation number that was the source for the Table 9-1 recommendation.

Ranking — This column provides the Task Group's ranking as to the relative importance of each recommendation. The rankings are broken-down by each of the pillars in the NRC's Strategic Plan using the table headings as follows:

MS = Maintain Safety
PC = Increase Public Confidence
EE = Increase Effectiveness and Efficiency
RB = Reduce Unnecessary Regulatory Burden

Each of the pillars for each recommendation was given a score of 1, 2, or 3, and the combined score is shown in the "Total" column. The score definitions are as follows:

1 = Not critical/negligible impact
2 = Contributes to reaching goal
3 = Critical to reaching goal

TABLE 9-1
TASK GROUP RECOMMENDATIONS

No.	Recommendation	Action For	Report Reference		Ranking				
			Section	No.	MS	PC	EE	RB	Total

10.0 ACRONYMNS

APPENDICES

Appendix A - IP2 SG Inspection Timeline

Commencement of RFO 13	5/1/97	
1st NRC/Con Ed outage phone call	6/2/97	
2nd NRC/Con Ed outage phone call	6/3/97	
RFO 13 SG Inspection Completed (SG Manways closed)	6/13/97	1st Wet Lay-Up Period (18 days)
3rd NRC/Con Ed outage phone call	6/29/97	
Unit Restart	6/30/97	
Con Ed issues 45 day SG inspection report	7/29/97	
Unit Shutdown for Unscheduled Maintenance Outage	10/25/97	2nd Wet Lay-Up Period (285 days)
Unit Restart	8/5/98	
Con Ed Amendment Request for SG Inspection Interval Extension	12/7/98	
NRC issues Amendment No. 201 approving SG Inspection Interval Extension	6/9/99	
Due Date for RFO 14 SG Inspection (as originally scheduled per TS 4.13A.2.a)	6/13/99	Extension Period Justified By 1st & 2nd Wet Lay-Up Periods (Approximately 10 months)
IP2 Tube Failure Event	2/15/00	
	4/10/00	Extension Period Approved Beyond 1st & 2nd Wet Lay-Up Periods (Approximately 2 months)
Due Date for RFO 14 SG Inspection (as approved by Amendment No. 201)	6/3/00	

Appendix B - Eddy Current Probes

Eddy Current Probes

The Task Group talked with NRC staff and contractors 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 the 1980's, 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 to 400 kHz) rotating pancake coil probe with the trade name Plus 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 (SG) inspections, they had been used for top-of-the-tubesheet inspections at Maine Yankee in 1994 and sleeve weld indications at another plant where noise from deposits outside the tube was a limiting factor for flaw detection.

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. 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. 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, Con Ed proposed to use the Cecco-5/bobbin coil probe for the primary method of detection. The mid-range Plus 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 Plus Point.

Comparison of Cecco with Plus Point

Con Ed performed blind Cecco-5 probe to Plus Point probe comparison tests in 1997. The tests were performed with analysis by both primary and secondary analysts as well as a resolution analyst, 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. In addition to the sludge pile region at the top of the tubesheet, the U-bends would have been a challenging test for the comparison of the probes.

The Cecco-5 probe detected more flaw indications than the Plus 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 Plus 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 SGs 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 Plus Point probe to characterize the Cecco-5/bobbin indications, similar to their 1997 inspection practice. Based on the accounts of the missed indications in the 1997 and 2000 SG examinations, the Task Group concluded that the issues with the detection capabilities of the Cecco-5/bobbin probe did not get resolved, which led to additional use of the Plus Point in the 2000 SG examination.