Indian Point 2 Steam Generator Tube Failure
Lessons-Learned Report
(TAC No. MA9163)

Draft 2
September 8, 2000

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EXECUTIVE SUMMARY

1.0 OBJECTIVE

The objectives of the Indian Point 2 (IP2) Steam Generator (SG) Tube Failure Lessons-Learned Task Group are defined in an internal NRC memorandum dated May 24, 2000 (Reference 1). This memorandum describes the approach and charter for an inter-office task group to assess the lessons-learned from the Indian Point 2 steam generator tube failure that occurred on February 15, 2000. The objective of this effort was to conduct an evaluation of the staff's technical and regulatory processes related to assuring steam generator 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 the technical areas as well as the regulatory processes involved in assuring SG tube integrity. The Task Group's evaluation has considered the following information in an integrated manner: (1) the licensee's steam generator examination results and findings; (2) root cause evaluation for the February 15, 2000 tube failure event; (3) the review by the Office of Research presented in its memorandum of March 16, 2000; (4) observations and findings of the Augmented Inspection Team and its follow-up inspection; and several licensing amendments related to the extension of the SG inspection period since 1995. The Task Group has also reviewed and assessed the regulatory process involved in assuring SG tube integrity. This included: (1) the NRC inspection program related to the SG tube integrity in the NRC's new oversight program and that existed prior to the implementation of the new oversight program in April 2000; (2) the SG examination and assessment methods implemented at IP-2; (2) the licensing amendments process utilized for the licensee's applications related to IP-2 SG tube examinations. In addition, the Task Group reviewed how the existing 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 technical review of the guidelines or determine adequacy. As indicated in SECY 00-0078, the review of the guidelines is a separate effort, and the NRC will issue a safety evaluation on the industry guidelines in future.

The Task Group has reviewed OIG report titled "NRC's Response to the February 15, 2000, Steam Generator Tube Rupture at Indian Point Unit 2 Power Plant," and considered the validated findings for lessons-learned.

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 a review/assessment of 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/processes were considered out side the scope of the Task Group charter.

2.2 Assumptions and Constraints

As indicated in the previous section, Task Group's review of the generic industry guideline addressed only the application of the guideline at IP2 and implication of the lessons-learned from the IP2 event on the guideline. Because of this limitation, this report should not be taken as the NRC's position regarding the acceptability of the guideline which will be addressed in a separate safety evaluation.

The Task Group charter requires it to provide recommendations for improvements and the staff to take appropriate follow-up action. 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 processes.

3.0 DISCUSSION OF THE IP2 SG TUBE FAILURE EVENT

3.1 Event Summary

At 7:17 pm EST on February 15, 2000, with the unit at 99% power, the operators of the Indian Point 2 nuclear power plant received indication of a steam generator tube failure. The licensee, Consolidated Edison Co. (ConEd), subsequently declared an "Alert," the second lowest of the four NRC event classifications. The operators manually tripped the reactor, isolated faulted steam generator (SG) 24, and proceeded to use the three intact steam generators to cool the reactor. The licensee terminated the "Alert" after reactor coolant system temperature was reduced to below 200 degrees F, and the reactor was placed in the cold shutdown condition.

After placing the unit in the cold shutdown condition, ConEd conducted an inspection of SG 24 and found that a tube had failed in row 2, column 5 (R2C5). This small-radius, low-row tube had cracked at the apex of the U-bend due to primary water stress corrosion cracking (PWSCC). ConEd conducted an eddy current test (ECT) examination of the SG tubes and conducted visual inspections of the secondary side of the other SGs. During these ECT inspections, ConEd found greater than 1% of the tubes in SGs 21 and 24 contained defects, placing the unit in a condition that required NRC approval before restarting the plant in accordance with the technical specifications. Subsequently, on August 10, 2000, ConEd announced that it would replace all four steam generators before returning the plant to power operation.

3.2 Background

Indian Point 2 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, steam generators 1 through 4..

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

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

<u>Regulatory Requirements</u>

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 tubing can degrade due to corrosion mechanisms and mechanical wear on the OD or the inside diameter (ID) of the tubing. The plant's Technical Specifications (TS) 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. Tubes with degradation greater than 40-percent through wall (TW) are considered defective and must be removed from service. Tubes are normally removed from service by inserting a plug at both ends of the tube.

The primary-to-secondary leakage rate is limited by the plant TS to 0.3 gallons per minute (gpm). 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 through mass balance (knowing how much water is added to and taken out of the primary system) and by radiological analysis (knowing the primary coolant activity and comparing it to the secondary water activity).

Eddy Current Test Examination Technique

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 defects in the tubing. The technique is based on the principle of electromagnetic impedance of a coil in an alternating current circuit. In such a circuit, the impedance of the coil causes the circuit voltage and current to be out of phase. Changes in the coil impedance are observed as variations in the voltage across the coil and by the degree that the voltage and current are out of phase (referred to as the phase angle).

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 defect 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 defect that is obstructing the eddy current flow within a tube. The defect can be detected by observing the amplitude and phase angle of the coil voltage.

The frequency of the alternating current sent to the probe and the size of the probe affect how deep the eddy current penetrates into the tube, the higher the frequency the lower the penetration. Probes have been designed that operate at several frequencies at one time. One probe may collect different frequency data during an examination.

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 defect. 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.

Applicable Steam Generator Degradation Mechanisms

Stress corrosion cracking (SCC) is caused by the simultaneous presence of a tensile stress, a specific corrosive medium, and a susceptible material. A SCC 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. When the SG is shut down and cool, there is a circumferential gap between the tube outer wall and the hole in the TSP through which it passes. The gap is there by design to allow for tube thermal expansion as the reactor coolant system temperature is increased prior to a reactor startup. However, while the SG is shut down, corrosion products can form, based on water chemistry, and harden in that gap. As the reactor coolant system and the tubes heat up, tube expansion at the TSP is prevented due to the hardened corrosion products. The forces generated cause several things to happen:

1. Since the tube cannot expand at the TSP, the tube, as it tries to expand during heat up, becomes permanently dented, circumferentially. The cooldown, corrosion, heatup, and denting cycle reoccur with each shutdown and restart, as influenced by SG water chemistry.
2. Eventually, the denting process can continue until the tube ID is so closed that an ECT probe will not pass through. This is a restricted tube.
3. The forces causing the denting may induce tensile stresses in the tube ID or OD near the dent leading to localized SCC.
4. 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. 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.

Steam Generator History

Throughout the plants operating history, the Indian Point 2 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, ODSCC and PWSCC and probe restrictions in dented areas, and U-bend ODSCC.

Due to the composition of some secondary system components at Indian Point 2, 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 an 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 a 100% examination of the low-row U-bends and identified the first indication of PWSCC in the apex of the U-bend of tube R2C67 in SG 24. This tube was plugged prior to restart. Also during this examination, ConEd identified the first instances of probe restrictions caused by denting at the upper tube support plate in low-row U-bend tubes. These tubes were also plugged because an examination could not be completed. ConEd returned Indian Point 2 to operation in early July 1997.

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

4.0 REGULATORY FRAMEWORK

4.1 Introduction

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

The steam generator tubes have a number of important safety functions. In addition to transferring heat from the "primary" to the "secondary" system to create steam, as part of the reactor coolant pressure boundary (usually more than half of the entire boundary), they are relied upon to isolate the radioactive fission products in the primary coolant from the secondary system and to prevent uncontrolled fission product release under conditions resulting from core damage severe accidents. Steam generator tube integrity can be impaired because the tubes are subject to a variety of corrosion and mechanically induced degradation mechanisms that are widespread throughout the industry. (Steam generator tube integrity means that the tubes are capable of performing their intended safety functions consistent with the licensing basis, including applicable requirement.) Steam generator tubes can fail spontaneously during normal operation due to material degradation and also can fail as a result of abnormal or accident conditions. This latter type of failure is called an "induced" failure. Both spontaneous and induced failures may be safety significant because radionuclides could bypass the reactor containment and be released into the environment during these events. Tube failures are categorized as "tube ruptures" if the tube is perforated such that the primary-to-secondary leakage rate exceeds the normal charging pump capacity of the primary coolant system.

There are several types of steam generator tube degradation mechanisms. Stress corrosion cracking (SCC) is caused by a specific corrosive medium operating on the susceptible tube material which is subject to a tensile stress. When this occurs on the inside, or primary side, of the tube, it is known as primary water stress corrosion cracking, or PWSCC. When it occurs on the outside of the tube, it is referred to as outside diameter stress corrosion cracking, or ODSCC. PWSSC is associated with areas of high stresses and thus is most commonly found in certain highly stressed regions of the tubes, such as, for example, the U-bend transitional regions and the apex regions of small radius (low row) U-bend tubes.

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

In 1998, the staff informed the Commission of its intent to delay issuance of the generic letter while the staff worked with industry to resolve staff concerns about the industry initiative and with the objective of avoiding duplication by endorsing the industry initiative as an acceptable approach for maintaining steam generator tube integrity, consistent with the Commission's Direction-Setting Initiative 13 (DSI-13), "The Role of 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 2000, the staff informed the Commission that, on the basis of progress with the NEI initiative, and assuming no new significant issues, it intended to cancel work on the generic letter. This also was approved by the Commission.

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

4.2 <u>NRC Regulations</u>

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 steam generators are Criterion 1 (Quality standards and records), Criterion 14 (Reactor coolant pressure boundary), Criterion 15 (Reactor coolant system design), Criterion 30 (Quality of reactor coolant system boundary), Criterion 31 (Fracture prevention of reactor coolant pressure boundary), and Criterion 32 (Inspection of reactor coolant pressure boundary). Pursuant to 10 C.F.R §§ 50.56 and 50.57, upon substantial completion of construction of the nuclear facility in conformity with the construction permit and the application, and a finding that the facility will operate in conformity with the application and the Commission's regulations, and that there is reasonable assurance that the activities authorized by the license can be conducted without endangering the health and safety of the public and will be conducted in accordance with applicable regulations, and upon reaching other required findings, the NRC may issue an operating license for the facility.

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

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

4.3 License Technical Specifications

The Atomic Energy Act requires that each license for an operating nuclear power facility must contain technical specifications 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 technical specifications require that a representative sample of the steam generator tubes be examined for defects (flaws, cracks, or "indications") using eddy current testing once every two years during plant shutdown. Eddy current testing (ECT) is a method of inspecting SG tubes by passing a probe that generates an electromagnetic field through the tubes. 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 defective or degraded tubes. If degraded tubes are found, the sample size is expanded to search for further degradation.

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.

Technical specifications require the licensee to submit its proposed SG examination program the NRC staff prior to the scheduled examination and also require that the results of the SG examination be submitted, usually 45 days after completion of the examination. The technical specifications also may require the reporting of significant deformation found in certain regions of the tubes. Contrary to the technical specifications governing the Indian Point 2 facility, most technical specifications 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 steam generators, problems identified with maintaining steam generator tube integrity, and guidance for detecting and removing from service defective tubes.

NRC Regulatory Guides describe methods acceptable to the NRC staff for complying with, or implementing, particular NRC requirements. Regulatory Guides are not requirements. Two Regulatory Guides relevant to steam generator tube integrity are Revision 1 of NRC Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," which 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. 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 technical specifications. ["These guidelines are superceded by this regulatory guide."–DG-1074???]

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

Information Notices 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 Information Notice 97-26 (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 steam generators 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.
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> 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 information notices focusing on steam generator tube integrity, including the following: IN 90-49, Stress Corrosion Cracking in PWR Steam Generator Tubes (August 6, 1990); IN 94-62, Operating Experience on Steam Generator Tube Leaks and Tube Ruptures (August 30, 1994); and IN 95-40, Supplemental Information to Generic Letter 95-03,'Circumferential Cracking of Steam Generator Tubes' (September 20, 1995); IN 97-88, Experiences During Recent Steam Generator Inspections (December 16, 1997); and IN 98-27, Steam Generator Tube End Cracking (July 24, 1998).

Generic letters are another type of communication from the NRC to licensees. Other than possibly requiring a written response, generic letters 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 generic letters focusing on steam generator tube integrity include GL 95-03, Circumferential Cracking of Steam Generator Tube (April 28, 1995), and GL 95-05, Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking (August 3, 1995);

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: Electric Power Research Institute (EPRI) mandatory guidelines that are directive in nature and non-directive, general guidance that licensees may use. Following further open interaction among the staff, NEI and the public, the staff will document the results of its review and issue a Regulatory Issue Summary (RIS) with an attached safety evaluation as the basis for NRC endorsement of a revised NEI 97-06 and of a framework for steam generator tube integrity. After issuance of the RIS, individual licensees would be expected to commit to the revised NEI 97-06 guidelines and to submit an accompanying technical specification change request adopting the new steam generator regulatory framework. The technical specifications would require licensees to establish and implement a program to ensure that NRC-approved steam generator tube integrity performance criteria are maintained. The performance criteria would be defined in a 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 steam generator tube integrity assessment process is comprised of two complimentary evaluative processes. "Condition monitoring," performed when the nuclear plant is in shut down in an outage, involves monitoring and assessing the "as found" condition of selected samples of the steam generator 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 attempt to demonstrate that the tube integrity performance criteria will be satisfied throughout the next operating cycle and scheduled tube inspection. The purpose of the operational assessment is 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 steam generator begins with eddy current testing (ECT) of steam generator tubes. Eddy current testing is a sophisticated, nondestructive examination (NDE) method of inspecting tubes for flaws by passing a probe through the tubes. The probe generates an electromagnetic field which is disturbed by defects in the surface of the tube material. The defects cause spikes in the signal produced by the probe which can be used to characterize the size and depth of the defect. Theoretically a tube which is perfectly uniform and smooth except for one distinct defect would produce a uniform signal with a spike representing the defect. Such a signal would be the relevant signal for the defect. In reality, however, there are numerous sources of non-relevant signals that do not represent actual defects, and these non-relevant signals can interfere with, or mask, the relevant signals. These non-relevant signals are known as "noise." The degree of noise can be represented by the "signal-to-noise" ratio, which is simply the magnitude of the relevant signals divided by the magnitude of the non-relevant signals. The higher the signal-to-noise ratio, the easier it is to identify true defects in the tubes.

All tubes found to be defective during the inservice inspection are required to be removed from service by plugging or repair prior tom plant startup. Tubes are considered defective when they fail to satisfy applicable tube repair criteria for the particular type of defect. The 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 steam generator tubes will not burst during normal or postulated accident conditions. The pressure test is conducted on a selected sample of tubes found by eddy current testing 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 steam generator tube integrity is to monitor the primary-to-secondary operational leakage, which is limited by plant technical specifications. This gives plant operators information which enables them to take timely remedial actions to safely respond to conditions of tube integrity impairment to prevent 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 program included Inspection Procedure 73753, Inservice Inspection (May 4, 1995), and was required to be completed at each facility during each outage. This inspection guidance provided for staff review of licensees' examination plans, personnel qualifications and certification, observation of the steam generator tube eddy current testing, and review of the results of the testing. Additional non-core 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 steam generator tubes and on assessing the effectiveness of licensees' programs for examining steam generator 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 (RROP), 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 baseline inspection procedure now in use for inservice inspections is IP 71111.08, Inservice Inspection Activities. It provides inspectors with substantially less guidance than IP 50002 did and does not even require the staff to inspect licensees' steam generator tube examination activities. Rather, identifies steam generator 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 steam generators are included in staff's selected inspection areas.

5.0 INDUSTRY STEAM GENERATOR TUBE INTEGRITY PROGRAM

5.1 Con Edison's Inspection Methods/Practices

5.1.1 Background

As noted in following discussion from the August 31, 2000 NRC Special Inspection Report (05000247/2000-010), the steam generator tubes have an important safety role because they constitute a barrier between the radioactive primary side and non-radioactive secondary side of the plant. The plant's TS require that a representative sample of the SG tubes be examined using eddy current technology (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. Tubes with degradation greater than 40-percent through wall (TW) are considered defective and must be removed from service. Tubes are normally removed from service by inserting a plug at both ends of the tube.

Eddy Current Technology

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 caused by defects in the tubing. The technique is based on the principle of electromagnetic impedance of a coil in an alternating current circuit. In such a circuit, the impedance of the coil causes the circuit voltage and current to be out of phase. Changes in the coil impedance are observed as variations in the voltage across the coil and by the degree that the voltage and current are out of phase (referred to as the phase angle).

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 induced is opposite to the probe current. The eddy current is directly affected by a defect 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 defect that is obstructing the eddy current flow within a tube. The defect can be detected by observing the amplitude and phase angle of the coil voltage.

Single coil probes will induce the eddy current in only one direction, which is a compressed mirror image of the current in the coils. If the defect is not in the direction which interrupts the eddy current flow (parallel to the defect direction rather than perpendicular to the current flow), then that particular coil will not detect the defect. Specially designed ECT probes can classify defects as axial cracks, circumferential cracks or both.

The frequency of the alternating current sent to the probe and the size of the probe affect how deep the eddy current penetrates into the tube, the higher the frequency the lower the penetration. Probes have been designed that operate at several frequencies at one time. One probe may collect different frequency data during an examination.

The Plus Point probe consists of two coils wound at 90 degrees to each other. The coils are mounted on a shoe that rotates as it passes through the tube to allow a complete examination.

The turns of the two coils are interleaved so that both are effectively the same distance from the surface of the conductor. The coils are connected in a bridge circuit, as shown in Figure 4, and the voltage difference between the two signals is amplified. The two coils allow the scanning for both axial and circumferential defects. The mid-range Plus Point probe used during the 1997 examination is a multifrequency probe, operating at 10, 100, 300, and 400 kHz.

The Cecco-5 probe is an array probe that has multiple element transmit and receive probes. The Cecco-5 probe also contains a traditional bobbin coil which provides the primary method of detection. The Cecco-5 probe was designed for fast screening, and although sensitive to axial, circumferential, and volumetric degradation, it does not discriminate orientation.

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 defect.

The Electric Power Research Institute (EPRI) qualifies the ECT techniques for use during SG inspections. This qualification includes the verification that the technique can identify known defects with a probability of detection (POD) of greater than 80-percent, with a 90-percent confidence. The POD of flaws is calculated based on the detectability in a sample of tubes with known flaws (defects). These defects may be actual flaws in tubes removed from SGs across the industry or man made notches in tubes using laser-machining or a process called electro-discharge machining (EDM). The number of samples containing flaws and the number of samples that contain no flaws are statistically significant. The significance is based on the confidence and probability originally established as an acceptable level of performance.

The ECT techniques are calibrated, as with any measurement instrument, to known calibration standards during their use. These calibration standards include notches of known depth and length against which the analyst calibrates the instrument.

ECT information may be displayed in numerous forms. During an ECT examination, the data and the analyses conducted are electronically stored and maintained as part of the plant inspection record. The c-scan plot is a topographical picture, as if the tube was split and laid out flat, of the changes in probe impedance. The signal shows a voltage reading that has been adjusted for phase angle (referred to as the vertical component). The strip chart is a look at the high and low values shown on the c-scan, as if the c-scan was viewed from the side. The lissajous is a graphical view of the voltage and phase angle effects at a specific point in the tube.

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 TSPs and the tube roll transitions, all have an effect on the ECT signal and have a characteristic lissajous signal.

Through extensive training and qualification, the ECT analyst becomes familiar with the different effects and is able to detect a flaw. Through different techniques and data analysis, the analyst can make an estimate of the size (depth and length) of a defect.

<u>Inspection Reports</u>

The inspection data provide insights on the licensee's management of their steam generators, and the results of each steam generator examination for IP2 are required to be submitted to the NRC within 45 days after the completion of the examination according to IP2 TS Section 4.13. In addition, an evaluation which addresses the long term integrity of small radius U-bends beyond row 1 shall be submitted within 60 days of any finding of significant hourglassing (closure)of the upper support plate flow slots. There is no discussion in the TS regarding the format or level of detail that needs to be included in the inspection report.

<u>Scope of This Review</u>

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

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

When reviewing the inspection methods and practices from the Con Ed SG examinations, the task group considered the following:

a) Prior knowledge of critical areas and other aspects for determining samples;

b) Efforts to improve signal processing - electronics and physical improvements;

c) Use of other available inspection techniques; and

d) Qualification of methods and personnel for the plant-specific situation.

5.1.2 Prior Knowledge of Critical Areas and Other Aspects for Determining Samples

<u>1997 Inspection</u>

For each scheduled SG examination, the plant TS specifies the minimum number of steam generators and the minimum number of tubes that need to be sampled. 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. On the basis of inspection results, engineering evaluation, and related experience, areas of steam generator tubing are defined as critical areas by the type of degradation, the cause of the degradation, and the boundary of the degradation. The minimum samples may also be expanded in consideration of the critical areas that have been designated in the SGs. The 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 addition, the EPRI SG examination guidelines stipulate that 100% of the tubing and 100% of each type of repair shall be inspected within a rolling 60 effective full power month time frame.

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

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

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

- full length of 33 percent of the active tubes in steam generator 21, 47 percent of the active tubes in steam generator 22, 33 percent of the active tubes in steam generator 23, and 33 of the active tubes in steam generator 24

- all tubes from the end of the tube to the first support plate intersection on the cold leg side and the second support plate intersection on the hot leg side

- all U-bends in rows 2 and 3.

- all dents at the tube support intersection

- all rerolled tubes to verify F* distance (the F* distance referred to an area of the tube contained within the tubesheet)

- 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).

Bobbin coil eddy current probes with various diameters were used in the examination. The 700 mil diameter probe was used to perform the initial eddy current testing. Any tube that did not permit passage of the 700 mil diameter probe was tested with progressively smaller probes. Tubes that did not pass the 610 mil bobbin probe were plugged. Furthermore, tubes immediately adjacent to any tube that did not pass the 610 mil probe were also subjected to an eddy current examination.

This plugging criteria based on the restriction of the passage of the probes was based on ovalization of the tubes and pre-existing hour-glassing of the upper support plate flow slots.

Ovalization describes the out of round appearance of the tubes due to the bending and forming operations required to make small radius U-bend tubes. Corrosion of the carbon steel tube support plates (TSP) produces corrosion products in the crevices between the support plates and the tubes. The corrosion product causes denting in the tubes, but also acts 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. 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.

The original examination scope was subsequently expanded during the outage to include full length examination of all steam generator tubes. This change was primarily due to the indications discovered by Cecco probe at the hot leg and cold leg upper support plate locations. Additionally, all sludge pile pit indications were characterized by the +Point probe to determine if linear-like indications could be associated with the pits. Repair of the tube by plugging for sludge pile pitting and Anti-Vibration Bar wear was determined by the bobbin analysis in the absence of a +Point linear indication. All other repairs by plugging for indications that were detected were based on the Cecco examination. The full discussion of the expansion of scope was contained in the 1997 steam generator inspection report submitted by Con Ed to the NRC, dated July 29, 1997, and was discussed in the NRC Inspection Report 97-07, which stated that the sample expansion was satisfactory and according to EPRI Guidelines.

The revised examination program was as follows:

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

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

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

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

- All tubes requiring full length inspection were examined from the mouth of the tube through the tubesheet, around the U-bend, to the mouth of the tube on the opposite side.

Tubes with indications evaluated at 40 percent or larger of the wall thickness, linear indications (axial or circumferential), Cecco-5 indications at tube support plate intersections (both characterized by +Point and not confirmed by the +Point probe), and tube roll transition cracks that were not rerolled, or did not meet F* were plugged. Other tubes were plugged due to passage restrictions of the 610 mil diameter probe (twenty tubes). There were seventeen tubes administratively plugged because the restrictions permitted passage of a 610 or 640 mil diameter bobbin probe, but did not permit characterization of the restriction location by the Zetec +Point Dent Inspection Probe; eighteen tubes were preventively plugged based upon an Indian Point 2 tube support plate study.

NRC staff review concluded that the inspection expansion strategy was satisfactory (i.e., according to EPRI guidelines) for the new indications in the sludge pile regions. It is important to note 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 inspection in that region. There was an opportunity for additional use of +Point to characterize the bobbin coil indications, but due to the signal noise difficulties, it may have not substantially improved the detection capability. The observation of the TG is that the limitations of their inspection were due to limitations in data quality in that region, not due to inadequate sample scope.

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

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

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 in only Steam Generators 23 and 24, and video of the uppermost support plate in only Steam Generator 22. The examinations for hourglassing were made using fiber optics by either 35mm photography or video. According to Con Ed, this inspection has been performed fourteen times over approximately 25 years.

In Con Ed's June 16, 2000 response a NRC request for additional information dated April 28, 2000 on ConEd's root cause analysis, the licensee's interpretation of "significant" hourglassing is discussed. Con Ed's interpretation was readily visible hourglassing, 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 inspection performed on the Indian Point 2 steam generators as a result of the Surry 2 tube failure.

Based on the above discussion, the TG concluded that Con Ed adequately expanded the scope of the inspection based on their inspection findings, but the quality of their inspection was limited by data quality which will be discussed in a later section of this report.

<u>2000 Inspection</u>

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

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

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

Again, the TG found that that Con Ed adequately expanded the scope of the inspection based on their inspection findings, but the quality of their inspection was limited by data quality which will be discussed in a later section of this report.

5.1.3 Efforts to Improve Signal Processing - Electronics and Physical Improvements

As discussed in the background section, 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 defect.

Con Ed's root cause evaluation for the tube failure, dated April 14, 2000, stated that "[s]ignificant contributing factors for this leak were masking of the indication in the 1997 inspection by noise related to deposits and tube geometry, and increased stress in row 2 due to TSP flowslot deformation because of denting."

After the tube failure, an NRC Augmented Inspection Team (AIT) was formed. The AIT report, dated April 28, 2000, it states that after the tube failure, "[t]he licensee reviewed the Plus Point eddy current data taken at the flaw location during the 1997 outage inspection and questioned the quality of the eddy current data collected at this location. Specifically, geometric variations in the tube circumference caused an uneven rotation of the eddy current probe as it was pulled through the tight radius U-bend tubes. The uneven probe rotation resulted in anomalous eddy current signals and reduced the probability of detection for indications in the tight radius U-bends." The AIT report further noted that the NRC would be performing an independent analysis of the 1997 SG inspection data.

The AIT team reviewed the 1997 ECT data collected on eight tubes that Con Edison identified as possibly having detectable flaws in 1997 (including tube R2C5 in SG 24, the tube that failed on February 15, 2000). During this review, the team used the actual data collected in 1997 and assessed the detectability of these flaws and their potential size based on techniques used in 1997.

NRC's independent analysis of the 1997 SG inspection data also concluded that data quality was poor in the low row U-bends, and the signal to noise ratio was low. On the basis of this analysis, NRC staff recommended improvements to their 2000 inspection plan, namely, the use of a high frequency probe and analysis techniques to reduce the noise. In addition, there were no specific criteria to ensure the identification of defects "buried" in the noise. As a result of NRC questioning of the high noise, Con Edison and its contractor developed an additional training handout which provided more detail in how to interpret noise in the data stream.

The AIT determined that it was possible to compare the amplitude of the noise in the tubes being inspected to the size of a defect it could be masking. The ratio of the noise voltage to the defect voltage should be determined for the appropriate defects. In the documentation provided to the team on July 20, 2000, Con Edison compared the 1997 noise voltage in tube R2C5 to the voltage from the standard EDM notches and stated that the flaw depths would have been about 50-percent TW.

The AIT noted that Con Ed had relied on an EPRI qualification of the mid-range probe in 1997, rather than establishing a site specific qualification with the unique conditions at IP2. EPRI had determined the qualification of the mid-range Plus Point probe using a generic population of SG flaws with a sample set chosen to represent the spectrum of tube conditions consistent with a generic population. If the proportion of noisy tubes to non-noisy tubes is greater in a specific SG than in the qualification sample (as it was at Indian Point 2 in 1997) the POD could be affected. The AIT concluded that Con Edison should have questioned the use of the generically qualified technique relative to the observable noise. Con Edison could have qualified a technique separately for the noise levels and population encountered in the Indian Point 2 SGs.

The AIT 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 TG 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 TG was cautioned that these techniques must be used wisely, 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. As a result, NRC asked NEI 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.

ConEd's Viewpoint

The problem in 1997, according to ConEd, is that they didn't realize how the noise affected their ability to detect flaws. They detected a flaw that they sized at approximately 50% through wall (TW), so they assumed that their ability to detect similarly sized flaws was satisfactory. Westinghouse eddy current analysts maintained that the level of noise in the U-bends was comparable to that at other plants. In the 2000 inspection, NRC recommended to Con Ed that they use a 800 kHz probe to reduce the noise levels. The TG learned from Con Ed that, in their view, the only thing that made a big 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.

In ConEd's June 16, 2000 response to question 8 of a NRC RAI dated April 28, 2000 on ConEd's root cause analysis, Con Ed discusses the acceptability of the noise levels during the 1997 outage. Con Ed states that

> "the level of noise in R2C5 was not considered to be excessive in comparison with noise levels encountered in SG tubing at other plants according to analysts who reviewed the data. In the absence of specific noise level requirements in Revision 4 of the EPRI Guidelines (or any other document), the disposition for the noise level observed on R2C5 was left to the discretion of the data analysts. Based on the information available at the time, there was no reason to suspect that the background noise levels encountered would have a significant effect on the level of detectability of the eddy current technique. Additionally, the technique used in 1997 did find a flaw in SG24 R2C67, which was plugged, suggesting that the capability to discern a flaw was adequate. ... In the absence of the high frequency probe, there were also no feasible alternatives available at that time to improve signal quality or reduce U-bend noise levels."

In ConEd's June 16, 2000 response to question 1 of a NRC RAI dated April 28, 2000 on ConEd's root cause analysis, Con Ed discussed the adequacy of noise and data quality criteria. In particular, Con Ed stated that

> "[i]n 1997, there was no specific industry criteria addressing noise or related data quality. At that time there was no reason to suspect that noise and data quality were significant issues, since the inspection programs that were being implemented throughout the industry during that time frame were qualified and had a successful track record in detecting deleterious indications at many plants. Moreover, the technique used in the 1997 IP2 inspection did find a PWSCC U-bend indication.

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

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

From Con Ed's root cause analysis, dated April 14, 2000, Con Ed stated that

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

In Con Ed's June 15, 2000 response to a NRC RAI dated April 28, 2000 on Con Ed's root cause analysis, 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% or well below the screening criterion for in situ testing (depth of 75%).

Based on the information submitted, the TG concluded that the use of the 800 kHz did provide a large improvement in Con Ed's ability to detect PWSCC. However, the TG didn't observe any enhancements in the 2000 inspection to increase the potential to detect ODSCC in the U-bend region. Con Ed also tried ultrasonic testing (UT) in the freespan sludge pile region to see if they could enhance the inspections in that region, and concluded that UT confirmed the eddy current.

<u>Comparison to Other Older Plants</u>

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 TG notes that the results represented averages, and some tubes may exhibit higher noise levels than others. These differences from tube to tube can be the result of geometry differences or permeability variations. Although the high frequency probe used in the 2000 inspection reduced the signals from outside the tube, a magnetically biased probe would be needed to address permeability variations in the tubes. At this time, the analysts that the TG talked to were not aware of any magnetically biased high frequency probes. Another concern of the analysts was the potential for noise in the U-bends from permeability variations due to stress relief. A Westinghouse analyst noted that this issue would need more work.

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 high frequency plus point probes at that time. 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. After the 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 TG noted that this noise study produced noise data for the qualification standard that is much higher than the two plants compared with IP-2. Most of the tubes contained in the standard are new tubes. Unless there is something unique about these new tubes that would not be found in the general population of steam generators in the field, this finding should be assessed generically. Based on this finding, we cannot rule out noise in U-bends based on just age of the steam generators or deposits on the outside of the tubes. If new tubes can contain this level of noise, the flaw detection capabilities in the U-bend region in newer plants should be assessed.

Based on the potential for poor signal-to-noise ratios from conditions other than deposits outside the tubes, the TG 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 analyst should have a reliable prediction of what range of voltages that the actual flaws should have (rather than just machined flaws). Along with the other inspection information that is provided to the NRC in the inspection report, noise levels should be evaluated by the licensee and provided. One way to do this would be to have the licensee provide a disk with sample data to the NRC for review.

Industry Standards for Noise

The task group talked to NRC staff and contractors to identify whether any industry standards on noise in eddy current data were in place in 1997. The consensus was that explicit data quality standards were not in place, but trained analysts would know if they had noise levels that interfered with their ability to call indications. The opinions of the staff were that IP-2 had such high levels of noise in the U-bends and sludge pile region that data quality was very poor, and the analysts would have had difficulty making reasonable calls unless the indications were very deep.
There was, however, some evidence that the industry was concerned about the impact of noise on the eddy current data. Another major provider of eddy current hardware, training, and analysis software is Zetec, Inc. According to NRC staff, Zetec starting incorporating the measurement of noise in their analysis software, Eddynet 2, in 1995, in response to NRC concerns. They also discussed reducing noise issues in the data during their training classes. Improvements made to Zetec software didn't help IP2, because Westinghouse used their own software when they conducted the 1997 SG inspections. One of the staff commented that they believed that approximately 65 - 70% of all eddy current testing in the steam generators in commercial nuclear

power plants is performed by Westinghouse. If this is correct, their analysts should be in a unique position to compare noise levels from plant to plant, and compare strategies that licensees use to cope with difficulties in obtaining good eddy current data.

The SG examination guidelines from the Electric Power Research Institute were also reviewed for guidance on the effects of noise on data quality. The guidelines have been widely accepted by the commercial nuclear industry for many years, and are frequently cited in the utility inspection plans and reports. During the early 1980s, the Electric Power Research Institute and the Steam Generator Owners Group informally issued nondestructive evaluation (NDE) guidelines to provide reliable NDE strategies for the damage mechanisms known at that time. The guidelines were originally issued in 1981, and subsequently revised in 1984, 1988, 1992, 1996, and 1997. Another revision, Revision 6, is planned for the near future.

The guidelines were intended to standardize the NDE programs and provide guidance on developing robust SG NDE programs. The task group reviewed both Revision 4 and Revision 5 of the PWR Steam Generator Examination Guidelines to see what guidance it provided to the licensees on noise problems in eddy current data. In both revisions, the only guidance that would have assisted the analysts in evaluating the noise is vague. No guidance is provided to the analyst on how to determine if too much noise is present, and 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 AIT report, the NRC staff concludes that Con Edison correctly stated that there was no quantitative noise criteria present in EPRI Steam Generator Examination Guidelines, Rev. 4, used in 1997. However, the AIT team noted that the adverse relationship of signal noise to flaw probability of detection was not new. The AIT team further noted that draft NUREG 1477 "Voltage-Based Interim Plugging Criteria for Steam Generator Tubes", dated June 1993, section 3.5.3 states 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.*" It should be noted, however, that IP-2 does not used the voltage-based criteria for repairing their SG tubes, which is the focus of NUREG 1477.

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

Based on the above discussion, the TG has also concluded that improvements to the SG guidelines should include criteria for data quality and recommendations for improving the signal to noise ratios.

5.1.4 Use of Other Available Inspection Techniques

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

The mainstay of the eddy current data acquisition has been the bobbin coil probe. The bobbin coil probe is commonly used because of its speed in acquiring data, around 24 to 48 in/sec. Although the bobbin coil probe is sensitive to indications perpendicular to the windings of the probe, it is relatively insensitive to circumferentially oriented degradation and poor at characterizing degradation. By 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 kHz) rotating pancake coil probe with the trade name + Point, developed by Zetec, Inc. The NRC staff mentioned that even though the submittals from Con Ed would seem to suggest that high-frequency probes had not been used previously for steam generator inspections, they had been used for top-of-the-tubesheet inspections at Maine Yankee in 1994 and sleeve weld indications at another plant 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 +Point probe was used for sizing and at locations that restricted the use of the Cecco-5 probe. Based on the 1995 exploratory use of the Cecco-5 probe, Con Ed evaluated the probe as sensitive to axial, circumferential, and volumetric degradation. Con Ed's desire to use the Cecco-5 probe was based on the data acquisition speed, 10 inches per second for the Cecco versus 0.1 inches per second for the +Point.

In the 2000 inspection [Cycle 14 Condition Monitoring Assessment and Cycle 15 Operational Assessment (Westinghouse SG-00-05-010)], Con Ed discussed ultrasonic examinations performed in the freespan sludge pile region during the 2000 inspection. Con Ed states that "[u]ltrasonic inspection was selected because it is not affected by copper-bearing sludge." In the June 19, 2000 response from ConEd to the March 24, 2000 RAI question 16 from the NRC, Con Ed states that

> "[t]he reason UT testing was of significant assistance in confirming the reliability of the eddy current analysis in the sludge pile and deposit regions is that the principles upon which UT operates are different than eddy current. UT assesses the condition of the tube by the time

of flight of directed sound waves rather than by electromagnetic induction. Sound is directed in three different directions in order to detect and characterize axial, circumferential and volumetric indications. UT is not affected by conductive and magnetic variations due to deposits and can more easily separate out the deposits from the tube itself. Thus, the UT results provide an independent technique to confirm the accuracy of eddy current analysis."

The Con Ed response also stated that the UT probe was restricted from passage at the first support plate in one tube that was tested. Even though UT was chosen for characterizing flaws in the presence of deposits and sludge, this may not be a good choice for the U-bend region. Not only would the probe size would have to be reduced to enable passage through the tight radius U-bends, but the curve of the tube would present difficulties in directing and detecting the sound waves.

The TG was advised by Westinghouse of other potential hurdles to substituting UT for ECT in SGs. 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 data statistical significance available for performance demonstrations. As more utilities use UT, more data will be generated to fill this need.

<u>Comparison of Cecco with Plus Point</u>

Con Ed performed blind Cecco-5 probe to +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 +Point probe during the blind study, leading Con Ed to conclude that the Cecco-5 probe was a satisfactory substitute for the RPC in some cases. Based on the results of the tests, Con Ed decided to use the Cecco-5 probe as the probe-of-record, and the +Point to characterize indications, as needed. The 1997 inspection report stated that one hundred percent of the U-bends of Rows 2 and 3 in all four steam generators were examined to the extent possible with the Cecco-5/bobbin probe. A Rotating Pancake Coil (RPC) probe was utilized to examine the bends if the narrow radii of the bends precluded passage of the Cecco-5/bobbin probe.

For the 2000 inspection, Con Ed originally applied a combination Cecco-5/bobbin probe to inspect the sludge pile region and used a midrange +Point probe to characterize the Cecco-5/bobbin indications, similar to their 1997 inspection practice. They reported a limited number of axially-oriented ODSCC indications in the sludge pile region, consistent with their past inspection results. After NRC staff reviewed the data, the staff assessment was that the noise levels in the Cecco-5/bobbin data were so high that outside diameter stress corrosion cracking (ODSCC) would be difficult to detect.

When Con Ed performed a post in-situ eddy current inspection of a defect found in the sludge pile exam, they found that an indication located in the crevice region of the tubesheet in the same tube had been missed by the Cecco-5/bobbin analysts. This tube was in-situ burst tested, and marginally failed the structural integrity criterion (a burst pressure of three times the normal operating pressure). The failed burst test suggests that this indication was probably of significant size in 1997, and was missed by the Cecco-5/bobbin probe examination. When Con Ed began to reevaluate other crevice data, they found more missed crevice indications. After the NRC staff expressed its concerns about the Cecco-5/bobbin examination, Con Ed decided to enhance its inspection efforts by using a midrange frequency +Point probe over the entire sludge pile region with frequency mixes to subtract out the signals from the sludge pile. Use of this inspection technique is also consistent with general industry practice in this region of the steam generator.

Based on the accounts of the missed indications in the 1997 and 2000 SG examinations, the TG concluded that the Cecco-5/bobbin probe did not perform as satisfactorily as the +Point with adequate frequency mixes.

5.1.4 Qualification of Methods and Personnel for the Plant-Specific Situation

EPRI Appendix H Qualification

The 1997 tube examination at IP2 was conducted by Westinghouse personnel (contractor to Con Ed) under purchase specification No. NPE - 72217, Eddy Current Examination of S/G Tubes (7/8 inch; 0.050 inch thick tubes), IP2, revision 0, dated 12/17/96. The specification defined the requirement for ECT of S/G tubes at IP2. Among others, it stated that examination techniques are in accordance with EPRI SG Exam Guidelines, Appendix H. It also specified the preferred bobbin coil probe frequencies as: 10, 100, 200, and 400 kHz. It also specified that specialized probes shall utilize frequencies consistent with their application under the EPRI qualification program. The probes shall be capable of *identifying defects in the presence of sludge and/or copper deposits*. Section 4.8 of the specification states that state of the art probes for supplemental examinations shall be used to detect or further characterize eddy current indications found by the initial examination, as required by Con Ed.

For the 1997 Examination, IP2 was committed to the EPRI PWR Steam Generator Examination Guidelines, Revision 4. Section 7.3, Qualified Techniques, discusses that probes and degradation methods for which industry peer review has been satisfied could be used for the qualification of the examination technique. It further states that new probes and techniques should have been subjected to the performance measures. Performance measures should be verified for the application of new techniques and the intent of Appendix H demonstrated through a site specific program. Section 4.4.2 discusses the possible distortion that can occur to bobbin coil signals as a result of their proximity to tube diameter changes due to denting, roll expansions etc., or of the presence of secondary side deposits or support members. Supplement H2, Qualification Requirements for Examination of Steam Generator Tubing requires that the examination techniques and equipment used to detect and size flaws be qualified by performance demonstration.

During the 1997 inspections, the ECT calibration setup at Indian Point 2 was in accordance with the EPRI guidelines and are specified in the EPRI Eddy Current Technique Specification Sheets (ETSS). For U-bend +Point inspections, ETSS-96511 specified that the phase angle of the 40%

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

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

Structure/Qualification of IP2's Examiners and Analysts

NRC Oversight of IP2 Steam Generator Program - NRC Region I Inspection Findings from 1995 and 1997

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

The NRC inspector had the following findings: 1) Con Ed's steam generator tube examination program for the current refueling outage conformed to code and regulatory requirements regarding code edition and administrative controls of the program; 2) the steam generator eddy current examination met the requirements of the NRC Regulatory Guide 1.83, Rev. 2; 3) the licensee's oversight of contractor's nondestructive examination activities was good and effective. In particular, the inspector noted that the oversight of in-service inspection activities performed by contractors is routinely provided by the quality control unit through surveillance. The inspector noted that the surveillance checklists used by the quality control inspectors are elaborate and extensive. Con Ed's Nuclear Power Engineering was responsible for developing steam generator tube examination programs and providing necessary oversight of eddy current examination activities, including the data analysis, resolution of indications, and plugging of defective tubes.

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

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

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

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

The inspection specialist noted that the EC analysts (primary, secondary and resolution) appeared to be performing analysis in accordance with the EC analysis procedure. He noted that Con Edison had an independent EC level III contractor reviewing EC data to ensure the proper identification and recording of indications.

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

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

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

The TG discussed the 1997 inspection with the regional inspection specialist that performed the inspection. The inspection specialist noted that he was not an eddy current specialist, but more of a general non-destructive examination specialist. Therefore, he was not skilled in evaluating eddy current data, especially in determining data quality. He also noted that he had not received IN 97-26, "Degradation in Small-Radius U-Bend Regions of Steam Generator Tubes,", issued May 19, 1997, before he was scheduled to perform 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 specialist also noted that he used a general ISI inspection procedure, rather than using a little-used more specialized SG inspection procedure.

Concerns About the Analyst Performance in 1997

Upon re-review of the 1997 data, both Con Ed and the NRC found indications in the U-bends of the tubes in other than R2C5 that were not called during the 1997 inspection. In particular, the August 31, 2000 AIT report discussed the following tubes:

- R2C69 in SG 24 - The depth estimate based on 1997 data is 52.6-percent TW.
- R2C72 in SG 24 - The depth estimate based on 1997 data is 79.2-percent TW.
- R2C87 in SG 21 - this tube was identified as having several cracks - The depth estimate based on 1997 data is 63.7-percent TW.

The TG was unable to determine why these indications were missed in 1997. Suggestions have been made to the TG as to how analyst performance could be improved. One suggestion is for automated screening to be employed as an additional check. This would not help in the case of noisy data, but would reduce the chance of overlooking an indication due to analyst fatigue. Another suggestion is 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 should consider employing more than one Level III qualified data analyst (QDA) if there will be a lot 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 should also consider obtaining ambiguous data for site specific exams 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.

An enhancement that was made to the analysis of the IP2 data during the 2000 inspection was to use separate teams to look at the Cecco and bobbin data. In 1997, the same team looked at both. This may help because there are no guidelines currently to decide how much data is too much for the analyst to handle.

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

1997 Examination

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

The AIT determined that the U-bend mid-range Plus Point ECT probe, used for SG tube inspection, was not properly set up to the correct calibration standard. The AIT questioned Con Ed about the ECT Analysis Technique Specification Sheet # IP2-97-E (ANTS # IP2-97-E), Rev. 0, dated May 8, 1997, that was used during the 1997 outage. The AIT found that the probe had been set up incorrectly, not in accordance with the ERPI qualification of the probe Examination Technique Specification Sheet # 96511Pwscc_ubend.doc (ETTS # 96511), dated May 1996 (see Section 1R3.1). Con Edison and its contractor subsequently corrected this problem during the re-evaluation phase of stored 1997 data. This had little effect on the probability of detection of U-bend indications. The probe was not set up with the required calibration standard or with the phase rotation required by the Electric Power Research Institute-qualified technique sheet. The August 31, 2000 AIT report determined that this issue had very low risk significance, because it did not directly affect the ability to detect tube flaws and as such, did not affect the reactor coolant system integrity.

2000 Examination

Initially for the 2000 outage, the U-bend Plus Point phase set-up, ANTS # IP2-00-E, Rev. 1, dated February 27, 2000, was not properly set up, and had not changed from the erroneous set-up in 1997. In early March 2000, Con Edison issued ANTS # IP2-00-E, Rev. 2, dated March 4, 2000, to conform with ETTS # 96511. All the year 2000 U-bend examinations that had previously been completed were repeated using the corrected set-up.

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

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

The TG's conclusion was that although there appeared to be discrepancies in the calibration set-up for the probes in 1997 and 2000, it did not appear to be a major factor in the analysis of their data.

5.1.3 Conclusions/Lessons-Learned

Background

There is no discussion in the TS to guide the licensee regarding the format or level of detail that needs to be included in the inspection report.

Prior Knowledge of Critical Areas and Other Aspects for Determining Samples

The limitations of their 1997 inspection were due to limitations in data quality in that region, not due to inadequate sample scope.

In reviewing the 1997 steam generator inspection plan, the TG observed that Con Ed did not discuss in the inspection plan how hour-glassing of the upper support plate flow slots would be evaluated. Even though Con Ed's inspection plan did not address how hourglassing would be evaluated, the inspection report discussed the flow slot and lower support plate examination process and results.

In the 2000 inspection, Con Ed adequately expanded the scope of the inspection based on their inspection findings, but the quality of their inspection was again limited by data quality due to noise.

Efforts to Improve Signal Processing - Electronics and Physical Improvements

NRC's independent analysis of the 1997 SG inspection data concluded that data quality was poor in the low row U-bends, and the signal to noise ratio was low.

Con Edison could have qualified a technique separately for the noise levels and population encountered in the Indian Point 2 SGs.

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. These techniques must be used wisely, or real flaws could get eliminated from the data.

Use of the 800 kHz did provide a large improvement in Con Ed's ability to detect PWSCC.

No enhancements were observed in the 2000 inspection to increase the potential to detect ODSCC in the U-bend region.

Con Ed also tried ultrasonic testing (UT) in the freespan sludge pile region to see if they could enhance the inspections in that region, and concluded that UT confirmed the eddy current.

U-bend data from two other similar Westinghouse plants were evaluated for noise in the eddy current signals.

High levels of noise were observed in the qualification standard tubes. If new tubes can contain this level of noise, the flaw detection capabilities in the U-bend region in newer plants should be assessed.

Based on the potential for poor signal-to-noise ratios from conditions other than deposits outside the tubes, 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 analyst should have a reliable prediction of what range of voltages that the actual flaws should have (rather than just machined flaws).

Explicit data quality standards were not included in the EPRI steam generator inspection guidelines used in 1997, but trained analysts would know if they had noise levels that interfered with their ability to call indications.

Planned improvements to the EPRI SG examination guidelines should include criteria for data quality and recommendations for improving the signal to noise ratios.

Use of Other Available Inspection Techniques

Even though UT was chosen for characterizing flaws in the presence of deposits and sludge, this may not be a good choice for the U-bend region.

The Cecco-5/bobbin probe did not perform as satisfactorily as the +Point with adequate frequency mixes.

Qualification of Methods and Personnel for the Plant-Specific Situation

The results of NRC's 1997 inspection of the eddy current testing activities, documented in NRC Inspection Report 97-07 dated July 16, 1997, indicated that the steam generator examinations were conducted in accordance with EPRI S/G Tube Inspection Guidelines.

The NRC regional inspection specialist that performed the 1997 SG inspection was not an eddy current specialist, but more of a general non-destructive examination specialist.

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.

Upon re-review of the 1997 data, both Con Ed and the NRC found indications in the U-bends of the tubes in other than R2C5 that were not called during the 1997 inspection. The TG was unable to determine why these indications were missed in 1997. Suggestions have been made to the TG as to how analyst performance could be improved.

The AIT determined that the U-bend mid-range Plus Point ECT probe, used for SG tube inspection, was not properly set up to the correct calibration standard. Although there appeared to be discrepancies in the calibration set-up for the probes in 1997 and 2000, it did not appear to be a major factor in the analysis of their data.

5.1.4 Recommendations

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

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

3) [EPRI/NRC/Industry] There is a fundamental inconsistency in using the eddy current data for assessing structural integrity of the SG tubes. The staff has repeatedly said that none of the techniques used - bobbin, Plus Point, or Cecco-5 are currently qualified for sizing axial or circumferential flaws. Yet, parameters that are needed to assess structural integrity such as growth rates and probability of detection of a certain flaw size are based on unqualified sizing techniques. This leads to a problem noted by a NRC staff member in a public meeting - the licensees believe in the reliability of the results of their eddy current to a much higher degree than they should. To address this problem, current techniques must be improved to enable the industry to use techniques that can be reliably qualified for sizing. To independently verify that structurally challenging flaws are being left in service, choose tubes for in-situ testing conservatively. Utilities should consider more tubes (rather than less) for in-situ testing (i.e., expand scope to include tubes with lower % thru-wall indications). The lesson here is to be very conservative about screening out indications for in-situ testing in tight radius u-bends.

4) [Industry] When performing blind comparison studies for new probes or techniques, choose data from all challenging areas of the steam generator that the technique/probe will be used.

5) [Industry/EPRI] Because ODSCC at the U-bends has been observed for CE plants, there should be a strategy for enhancing the examination of the outside of the tube. Perhaps new techniques could be developed in this context.

6) [Industry/NEI/NRC] In the noise study that compared the noise levels in the eddy current data from two other older plants, NEI produced noise data for the qualification standard that is much higher than the two plants compared with IP-2. Most of the tubes contained in the standard are new tubes. Unless there is something unique about these new tubes that would not be found in the general population of steam generators in the field, this finding should be assessed generically. Based on this finding, we cannot rule out noise in U-bends based on just age of the steam generators or deposits on the outside of the tubes. If new tubes can contain this level of noise, the flaw detection capabilities in the U-bend region in newer plants should be assessed.

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

8) [Industry/EPRI Guidelines] In addition to using two human analysts for the primary and secondary analysts, the industry should consider using computers to screen the test data.

There should be guidelines for when this should be used, i.e., it shouldn't be used for high noise data.

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

10) [Industry/EPRI Guidelines] Plants could benefit from site-specific demonstration programs that reflect their specific degradation modes and inspection challenges.

11) [Industry/EPRI Guidelines] The industry should consider using filtering algorithms (commercially available software).

12) [Industry/EPRI Guidelines] More than one QDA would be prudent when you have lots of degradation to review, especially to make spot checks of primary and secondary analyst calls as well as review resolution calls.

13) [Industry/EPRI] There is no official vehicle for getting ambiguous data into next site specific QDA exam. It would be a good idea to put data containing missed flaws, different probes, etc. on the site specific exams. On the content of annual QDA training, supplemental training should focus on generic industry topics such as Row 2 tubes, egg crate flaws, and other challenging inspection areas. The NEI guidance should be more specific with respect to the content of the annual training.

14) [NRC] The NRC should revisit the probability of detection issues after the RES round-robin evaluation of inspection capabilities

15) [NRC] The NRC should revisit the flaw sizing issues after the RES round-robin evaluation of inspection capabilities

16) [Industry/EPRI Guidelines] Licensees should review generic industry guidelines carefully to ensure that the conditions/assumptions supporting the guidelines apply to their plant-specific situation.

5.2 Con Edison's Condition Monitoring/Operational Assessment

5.2.1 Background

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

One of the means for the licensees to communicate information on the present condition of the 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 integrity assessment process, for both the licensee and the NRC. However, at the time of the last inspection at IP-2 before the tube failure (1997), there was no regulatory requirement nor licensee commitment to perform or submit the results to the NRC from a condition monitoring or operational assessment. Instead, the limited information that was provided in the licensee's inspection report summaries was based on reporting requirements in their TS. As part of the licensee commitment to the NEI 97-06 Steam Generator Regulatory Framework, the licensees will be expected to adopt a generic set of steam generator technical specifications 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, 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. An EPRI guideline developed for the NEI 97-06 steam generator framework, "Steam Generator Integrity Assessment Guidelines: Rev. 0", now provides consistent industry standards for performing these assessments.

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

Condition monitoring is performed while a plant is in an outage. This involves inspecting the tubes according to the sampling requirements in the licensee's TS and the current revision of the EPRI Steam Generator Examination Guidelines, and performing structural and leakage integrity assessments based on the results of the inspections. The indications found during the inspection are evaluated against the performance criteria for structural and leakage integrity. The EPRI Steam Generator Integrity Assessment Guidelines state that:

"Structural and leakage integrity assessments of the inspected tubes are performed and results compared to their respective performance criteria. If a plant is operating under the requirements of its Technical Specification's repair limit, the bounding assumptions supporting this limit (e.g., growth, NDE uncertainty) need to be verified. Tubes need to be repaired according to the most limiting of the plant's technical specifications or the results of the integrity assessment. Condition monitoring also involves comparison of any operational leakage, occurring within the steam generators, with the performance criterion.

Structural integrity performance criterion is: Steam generator tubing shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cooldown and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a margin of 3.0 against burst under normal steady state full power operation and a margin of 1.4 against burst under the limiting design basis accident concurrent with a safe shutdown earthquake.

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

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

The operational assessment evaluates the inspection findings against performance criteria at the end of the next operating period. The assessment is to show that all structurally significant degradation has been detected and that which is undetected will not grow to be structurally significant during the next operating cycle. Factors that are important to this analysis are probability of detection (POD), growth rate, and NDE sizing. The EPRI Steam Generator Integrity Assessment Guidelines further states that:

"A preliminary operational assessment is performed before startup by factoring the degradation growth rate into integrity and leakage analysis. The purpose of this assessment is to determine whether integrity performance criteria will be met or whether additional tests, repairs, inspections, or other actions may be necessary. All active degradation mechanisms must be considered appropriately in the analysis.

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

Consistent with our 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 will be discussed separately. This areas that were considered are as follows:

a) Evaluation of new types of degradation;

b) Basis and uncertainties for detection of degradation;

c) Basis and uncertainties for degradation growth rates;

d) Use of in-situ pressure tests; and

e) Assessment methodology and decision criteria.

5.2.2 Observations

1997 Inspection

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

The task group reviewed the following documents from Con Ed:

- 1997 inspection report

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

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

This review was to evaluate and compare the condition monitoring and operational assessments performed and how this information was documented in their submittals to the NRC staff. A discussion of the documents is presented below in chronological order. The condition monitoring assessment was prepared for Con Ed by Westinghouse. The TG 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 requirement to submit these assessments, it was kept internally. Also, in 1997, the guidance for these types of assessments wasn't provided in an EPRI guidance document, but such guidance was provided in 2000.

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

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

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

- results of a blind comparison study with the Cecco-5 probe and the +Point probe
- the types and quantities of plugs in the tubes.

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

The TG 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 TG also noted that the tube with the U-bend flaw was not chosen for in-situ burst testing.

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

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

Con Ed sent a May 12, 1999 response to a April 19, 1999 request for additional information (RAI) for their proposed amendment request dated December 7, 1998. To better understand the condition of the IP-2 SG tubes, the staff had requested additional information on the operational assessment methodology for each degradation mechanism, including an explanation of predictive methodology, flaw growth rates, and NDE uncertainty. The staff had also requested additional information on 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 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. 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.

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

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

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

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

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

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

- For the PWSCC indication, the response noted that a Row 2 U-bend PWSCC was found for the first time in the 1997 outage. The response noted that the 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. In addition, the response noted that the indication that was found in the Row 2 U-bend was below the in-situ screening criteria, as determined by +Point eddy current measurements, so it was not in-situ tested. The response concluded that growth rates associated with this indication would be considered minimal, since this was the first indication in 23 years.

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

As noted above, the TG found that Con Ed's 1997 inspection report 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 hourglassing as required by their TS, report on foreign object inspection, present in-situ burst test results, discuss plug replacement, provide results from a blind study comparing probes, and list the amount of sludge removed.

Similarly, the December 7, 1998 Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency did not discuss the basis and uncertainties for detection in much more detail than the inspection report. 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, the May 12, 1999 response to a April 19, 1999 request for additional information (RAI) for their proposed amendment request provided the most complete discussion of the active degradation and how it was detected.

The three reports show a heavy reliance on an eddy current combination bobbin and array probe, called the Cecco-5 probe, for detection and characterization of indications. Con Ed preferred this probe due to the faster data acquisition time when compared to Rotating Probe Coil technology such as +Point. Con Ed also reported that the Cecco-5 reported more indications than the +Point probe in a blind study of the two probes, so they were confident in their ability to detect significant indications with this probe. The use of the +Point probe was reserved for situations where the Cecco-5 probe was limited in travel due to tube restrictions. 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 .

Even in locations where the blind study had been performed, there were concerns about the confirmation of Cecco-5 indications with +Point. In the RAI response, Con Ed and the NRR staff had concerns about +Point not confirming 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. The handout from the April 24, 1997 Con Ed presentation on their 1997 Steam Generator Tube Inspection Plan discusses the Cecco probe, and points out that the "potential was there - shortcomings needed addressed." Examples given for the shortcomings included "asymmetric dent samples needed" and "C-scan capability needed".

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

Basis and Uncertainties for Degradation Growth Rates

The TG review of Con Ed's 1997 inspection report revealed that growth rate data was not provided.

The December 7, 1998 Proposed Amendment to Technical Specifications Regarding Steam Generator Tube Inservice Inspection Frequency 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 steam generator eddy current wear data indicated no appreciable growth trend.

The amendment request noted that of the 21 indications identified in 1993 and 1995, seven indications showed no change, four disappeared, four decreased in depth, and six increased in depth. The TG 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 TG believes that this statement about the accuracy of the eddy current measurements was somewhat optimistic, as current figures are around 10% *(check this)* as this figure is more representative of industry experience. The amendment request also concluded that since the steam generators were maintained in cold shutdown temperature conditions, the environment for corrosion was reduced to an inconsequential level. No appreciable steam generator tube wear or degradation was expected as a result of the inspection interval extension. The amendment request did not address growth rates outside of the wet lay-up period.

The May 12, 1999, response to a request for additional information for the proposed amendment 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:

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

- ODSCC Above the Top of the Tubesheet (Sludge Pile): The response stated that that average depth detection thresholds for axial ODSCC are in the range of 20% to 30% through-wall with a probability of detection of about 0.2 to 0.5 for both the Cecco-5 and +Point. Therefore, assuming the +Point depth profile to be accurate, the growth in average depth for Cycle 13 is bounded by about 18% to 28% for sludge pile ODSCC indications. The response also notes that recent +Point depth sizing evaluations performed by Westinghouse for axial ODSCC indicate that flaw average depth standard deviation measurement error is about 10% through-wall. A 20% measurement uncertainty allowance is provided in the in-situ screening parameters. (This is interesting, considering that the U-bend flaw was not in-situ tested because it did not meet the screening criteria – was the measurement uncertainty allowance added for PWSCC U-bend flaws, also?)

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

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

- PWSCC at Dented Tube Support Plate Intersections: No growth rate information was given.
- ODSCC at Dented Tube Support Plate Intersections: No growth rate information was given
- PWSCC at Row 2 U-bend: The response stated that this was the first time that a Row 2 U-bend PWSCC indication was found. The response concluded that as this represented the first detected U-bend indication after approximately 23 years of operation, any growth rates associated with this indication would be considered minimal.

The task group found that the independent review by RES of this amendment request, dated March 16, 2000, discussed the adequacy of the information provided by Con Ed in the RAI response. The RES review found 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. 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. For additional discussion on the RES review, see Section 5.5 of this TG report.

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 steam generator 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 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.

- Pitting Above the Top of the Tubesheet: The pit indications were not assessed because the criteria for pits wasn't included in the Westinghouse screening criteria. In spite of this, pit indications were screened based of a maximum bobbin coil depth of 50% and voltage of 3 volts. No indications met this criteria.
- ODSCC Above the Top of the Tubesheet (Sludge Pile): One indication measured at 48% maximum depth and a 0.54 inch length met the screening criteria and was pressure tested to

5075 psi without burst or leakage. Other ODSCC sludge pile indications were detected but did not meet more than one of the screening parameters, although a 20% measurement allowance was provided in the in-situ screening parameters.

- ODSCC in Tubesheet Crevices: The indication with the largest +Point indication was in-situ pressure tested, as well as the three others that exceeded the screening parameters. The four tested tubes showed no evidence of leakage when tested to a nominal cold pressure of 2900 psi (which is equivalent to approximately 2636 psi at operating temperature.) This pressure corresponds to the steam line break pressure. Testing to three times normal operating pressure, $3\Delta P$ structural requirement, was not performed. Although the reason for just using the lower pressure is not discussed explicitly, it may be that the lower pressure was chosen because the axial ODSCC indications within the crevice were considered to be restrained from burst by the presence of the tubesheet.

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

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

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

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

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

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

Based on the above discussion, the assessment methodology and decision criteria presented in the response to the RAI was often limited, and in some cases not consistent with other industry experience. As mentioned previously, NRC based 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 Primary Water Stress Corrosion Cracking in the U-Bend, a report discussing the remaining degradation mechanisms, and a report that compares the corrosion performance of the IP2 steam generators to industry experience with Model 44 and Model 51 steam generators. Unlike the 1997 inspection, Con Ed and Westinghouse used the EPRI Steam Generator Integrity Assessment Guidelines, Rev. 0 , released in December 1999, to prepare the condition monitoring and operational assessments. Once again, the condition monitoring and operational assessments were performed by the same contractor that performed the inspections, Westinghouse, who provided the same services to Con Ed for the steam generator outage in 1997.

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

Basis and Uncertainties for Detection of Degradation

Con Ed's original inspection 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 +Point probe. Based on staff recommendations and concerns about noise levels in the data, the inspection plans expanded to use a 800 kHz high frequency probe. Even with the improvement in the inspection data from using the higher frequency probe, the staff had concerns regarding the NDE uncertainty arising from Con Ed's inspections. These concerns arose primarily for the indications found in the sludge pile region and U-bends, and were based on Con Ed's reliance on on-site technique validation in areas that didn't necessarily include the areas where the uncertainty would be applied. The largest uncertainty was expected from the results of the U-bend inspections, but the technique validation had been performed in the sludge pile region of the steam generator. Evaluating the uncertainties properly was especially important, because uncertainties of 5 – 10% could lead to a large difference in the burst pressures that would be calculated from the data. This increased the concerns by the staff in how structural integrity in the U-bends could be assured for the operating cycle.

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

Basis and Uncertainties for Degradation Growth Rates

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

Use of In-Situ Pressure Tests

The in-situ pressure tests provide another measure of leakage and structural integrity of the SG tubes. Although none of the tubes burst at pressures less than three times the normal operating pressure, an ODSCC indication in the sludge pile region and some PWSCC indications in the U-bends exhibited leakage.

Assessment Methodology and Decision Criteria

The assessment methodology and decision criteria submitted to the staff was far more complex than what was provided in 1997. The methodologies relied on Monte Carlo treatments to predict probabilities of burst and leakage for the next operating period. The analysis of the NDE was far more complex, with 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.

5.2.3 Conclusions/Lessons-Learned

The extent to which condition monitoring and operational assessments can capture the true integrity of the steam generator tubes is limited. Even with the increased amount of information provided for the 2000 inspection condition monitoring and operational assessments, the outcomes are still dependent on uncertainties and difficulties in detection. Despite these inherent limitations, licensees are provided with additional information on tube integrity by performing in-situ pressure tests on degraded tubes. The pressure tests provide additional assurance that the inspection program is detecting flaws before they compromise the structural or leakage integrity of the tubes.

A conservative selection of tubes representing the active degradation processes in the SG ensures that the steam generator program can provide assurance of tube integrity.

5.2.4 Recommendations

1) [Industry/EPRI Guidelines] Even with limitations due to measurement and detection uncertainties, site validation of techniques can provide additional confidence in the capabilities to detect the degradation, especially in the regions of the generators that present the most challenge to inspect. Site validation of techniques should be used for each detection technique, focusing on the most challenging areas of degradation.

2) [Industry/EPRI Guidelines] In-situ pressure tests provide additional assurance that the inspection program is detecting flaws before they compromise the structural or leakage integrity of the tubes. 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.

3) [Industry/EPRI Guidelines] Licensees must be cautious not to rely too heavily on integrity assessments that are based on sizing techniques that are not qualified.

4) [Industry/EPRI Guidelines] Licensees must also consider the effect of the threshold of detection on the growth rate assumptions.

5) [Industry/EPRI Guidelines] The licensees should be careful to not rely on probability of detection values that are not representative of their plant-specific inspection capability.

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

7) [Industry/EPRI Guidelines] If a blind study is performed between probes, the test should include areas of the generator that present the most challenges for detection.

8) [Industry/EPRI Guidelines] 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.

5.3 <u>Industry Guidelines for Steam Generator Inspection and Assessment</u>

5.3.1 Background

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

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

The Task Group examined:

- The applicability of NEI Guidelines and EPRI technical reports to Indian Point Unit 2 (IP2) at the time of the tube failure event in February 2000.

- Implications for the guidelines from the IP2 event in the overall approach they take in management of SG degradation problems.

Also of interest to the task group were any activities that industry contemplated or had undertaken to incorporate lessons from the event into the generic SG management guidelines.

The Task Group 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, Rev.1, as discussed in SECY 00-0078 (Reference).

Maitri - we may want to outline what efforts are underway?

5.3.2 Observations

5.3.2.1 Industry Guidelines Applicable to IP2

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

The December 1997 NEI letter stated that:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Con Ed's root cause evaluation (Reference April 14, 2000) 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 appears to be that, although the guidelines were in use during 1997, they did not provide adequate guidance to facilitate finding the flaw that led to the failed tube.

As discussed in Sections 5.1, 5.2 and **6??** of this report, the Task Group judged 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 may have been lacking for the situation encountered at IP2. **For instance, use of the 800kHz Plus Point probe is not linked to an industry guideline, but was an important issue during the 2000 SG inspections. A footnote (Reference?) states that prior to its use, it was qualified in low row u-bends by tests at EPRI, W and Con Ed, but it was not part of the guidelines (CHECK w/Louise on this).** The Task Group found a number of other specific areas where weaknesses in the guidelines may have contributed to SG conditions leading to the event.**(Check Sects 5.1, 5.2 for specifics.)**

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 is 1997 inspection report covering the 1997 tube examination that the licensee's program was prepared in accorance with EPRI guidelines. However, the tube failure occurred. **In the opinion of the Task Group, the IP2 event demonstrated clear weaknesses in the EPRI guidelines and in their implementation, because they did not prevent the state of significant tube degradation that led to the IP2 tube failure.**

5.3.2.2 Implications of the IP2 Event on Industry Guidelines

As discussed in Sections 5.1 and 5.2, shortcomings in the EPRI SG inspection guidelines should be addressed as a result of the IP2 event. Issues such as data quality, inspection method flaw sizing qualification, and ECT noise levels were specific points raised by the IP2 event. Presumably, there could be other technical issues not raised in this report that could become important under other circumstances. The following section (7.2) discusses the need for NRC to continue the review of the industry proposal for SG degradation management. In the shorter term, the NRC should not solely rely on the EPRI guidelines as a substitute for NRC inspection and oversight of licensee SG maintenance practices. A thorough review of the NEI initiative could uncover other significant shortcomings that, when corrected, will lead to a reliable framework for regulation of SG maintenance programs.

The task group found that the proposed technical specifications and relate tube performance criteria of the NEI initiative deserve close examination by the staff. A key component of the NEI initiative are the revised technical specifications for SG integrity. As currently conceived by NEI, SG technical specifications would be revised to use a tighter leak rate limit, and tube performance would be judged based on tube structural and leakage criteria. Tube inspection results are not used as performance criteria under the NEI-proposed tech specs. It is not clear that the NEI-proposed technical specification limits based on leakage would have averted the IP2 event. The licensee's tube inspection results criteria in current tech specs drive licensee actions in response to as-found degradation, **provided sufficient inspection techniques are applied.** The NEI-proposed structural and leakage performance criteria may not trigger licensee actions as early as the tube inspection criteria in existing technical specifications. In short, proposed tube performance criteria require close examination by the staff when the NEI initiative is reviewed.

May expand this TS discussion to include OA reporting requirement, reporting new degradation, and other issues the TG feels are important.

Other technical problems with the guidelines found as a result of the IP2 event include characterization of ECT noise, data quality SEE Chapter 5

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

5.3.3 Conclusions/Lessons-Learned

1) SG program deficiencies existed at IP2 despite commitments to follow industry guidance. Oversight of the licensee's implementation of industry guidance to provide assurance that minimum standards for SG programs were being maintained was not effective.

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

5.3.4 Recommendations

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

2) Industry should be cautious in relying too heavily on the NEI 97-06 initiative until it is reviewed by NRC. Industry should also use lessons learned from the IP2 experience to strengthen the NEI initiative. In the interim, the NRC should consider prioritizing portions of the initiative for review in order to address deficiencies highlighted by the IP2 program weaknesses and to ensure that similar deficiencies doe not exist elsewhere in the industry. For instance, the proposed technical specifications should be reviewed before detailed technical reports are considered for review. This would serve to continue to maintain safety by addressing a basic problem with SG maintenance (i.e., deficient technical specifications), while other resources are brought to bear on other parts of the NEI 97-06 initiative review. Prioritization of the effort would focus on increasing efficiency and effectiveness of agency activities.

6.0 CON EDISON'S STEAM GENERATOR TUBE INTEGRITY PROGRAM

6.1 Con Edison's Implementation of Steam Generator Regulatory Requirements

6.1.1 Background

The steam generators (SGs) play a vital role in maintaining the integrity of the reactor coolant pressure boundary (RCPB). They contain many thousand tubes that constitute more than 50% of the RCPB. A detailed description of the SGs, the tubes, and their functions is provided in section 3.0 of this report. The plant technical specifications (TS) require the licensees to implement a SG examination program to verify, on a periodic basis, the integrity of the SGs and the tubes. The Task Group's review in this section was focused on assessing how Con Ed's SG tube examination program matched with the regulatory requirements. The group reviewed the following areas: (1) The regulatory basis for the steam generator tube examination program, (2) Con Ed's steam generator tube examination program, and (3) Con Ed's 1995 and 1997 tube examination results.

The Task Group reviewed the licensing and design bases of the SGs contained in the Indian Point Unit 2 (IP2) TS and the Updated Final Safety Analysis Report (UFSAR). In reviewing the licensing basis, the Task Group considered NRC granted extensions to the technical specifications steam generator examination program as part of the licensing basis.

The Task Group reviewed the implementation of Con Ed's SG tube examination program, including the qualification and certification of personnel that conduct the activities. The Task Group also examined the licensee's oversight of contractors; the methods by which Con Ed (and/or its contractor) conducts steam generator examinations and disposes examination results; and Con Edison's implementation of the technical specifications primary to secondary leakage limits. The licensee's implementation of the TS requirements related to NRC reporting was also reviewed.

The Task Group reviewed the results of Con Ed's 1995 and 1997 tube examinations documented in NRC inspection reports and Con Ed's examination reports that were submitted to the NRC.

6.1.2 Observations

6.1.2.1 Regulatory Basis for the Steam Generator Tube Examination Program

Title 10, Part 50 of the Code of Federal Regulations (10 CFR50)

Several sections of the title 10 of the Code of Federal Regulation (10CFR), Part 50 directly or indirectly applied to Con Ed's operation and maintenance of the steam generators. 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."

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

Technical Specifications

IP2 Technical Specifications (TS), Section 3.1.F.2a, Primary to Secondary Leakage, contains the operational leakage limits for the steam generator tubes. It establishes a limit of 0.3 gpm (432 gpd) in any steam generator which does not contain tube sleeves, or 150 gpd for any SG that contains sleeves. The TS also requires that if the limit is exceeded or if leakage from two or more steam generators 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 TS, such measures are implemented to prevent larger leaks and possible gross pipe failure. Although the licensee experienced increased SG leakage prior to the February 2000 tube failure, the leakage did not exceed or come within the same order of magnitude to the TS limit until the tube failed.

TS Section 4.13, Steam Generator Tube Inservice Surveillance, provides the examination requirements for the steam generators. The IP2 TS requires examination of all four SGs at a 12 to 24 month interval. 12% of the tubes in each SG are required to be subjected to hot leg inspection, with 25% of these tubes also subjected to cold leg examination. If 5% or more of the tubes examined in a SG are degraded or one or more tubes inspected are defective (requiring plugging or repair), then the examination needs to be expanded. Increased identification of defective or degraded tubes would expand the sample, ultimately to 100% of the tubes in all SGs based on the results of the sample examinations. TS defines "degraded tube" as a tube with imperfections large enough to be reliably detected by eddy current inspection. This is considered to be 20% degradation.

The TS specifies the selection criteria for tubes to be examined. The TS also specified the examination technique which were further amended to incorporate the probe size for eddy current examination in April 2000 **[amendment 209-Maitri to verify]**. SG Tubes are considered acceptable if depth of degradation is less than 40% of the tube wall thickness and the tube permits the passage of a 0.610 inch diameter probe (or a 0.540 inch diameter probe with the tube wall strain less than a certain number). The acceptability of tubes with less than 40% degradation is explained in the basis section of the TS 4.13. It is 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. However, because of the limitations on detection threshold for stress corrosion cracking indications, as pointed out in NRC inspection report 2000-010, it has been a common industry practice to plug on detection. The basis section of the TS 4.13 states that the licensee's program for SG ISI exceeds the RG 1.83, Rev. 1, July 1975 requirements.

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

The requirements of NRC approval of restart upon inspection results meeting C-3 of the TS Table 4.13-1 was incorporated in a TS amendment during the 1970s time frame. This requirement exceeds the RG 1.83, Rev 1 that requires NRC reporting per facility license and NRC approval of the proposed remedial actions. The NRC approval of the restart requirement is somewhat unique for IP2 and its sister plant IP3, in that most PWR licensees' (e.g. ANO-2) TS contains 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 examination of the SG tubes and obtained information regarding the examination results via phone 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 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 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

The IP2 UFSAR describes the design and operation of the steam generators as discussed in Section 4.0 of this report. At the time of the tube failure in February 2000, 10.2 % of tubes in the SGs were plugged with 25% being the plugging limit based on safety analysis. The SG tube rupture is an analyzed accident under section 14.2, "Standard Safety Feature Analysis." The FSAR states that situations could conceivably involve uncontrolled release of radioactive material into the environment. With concurrent blackout, the analyzed site boundary dose is in the order of 0.75 rem whole body and 2.7 rem thyroid, thus a very small fraction of the 10 CFR Part 100 limits of 25 rem whole body and 300 rem to the thyroid. With the availability of AC power, the resulting dose is calculated to be 1.1% of the above calculated 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.

6.1.2.2 Consolidated Edison Steam Generator Examination Program

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

The 1997 tube examination was conducted by Westinghouse personnel (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 was required to be reviewed and approved by Con Ed prior to the examinations.

Although Con Ed committed in their program documents to the NEI and EPRI guidelines, the Task Group did not identify any formal commitment made to the NRC to use the guidelines. Moreover, there was no formal NRC endorsement of the guidelines.

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

Con Ed procedures requires operators to identify and quantify Steam Generator Primary to Secondary leaks and implement contingency actions to mitigate adverse consequences. Various actions such as increased monitoring are required at various leakage numbers but ultimately, a leakage greater than 150 gpd would require a plant shutdown. ConEd revised this leakage limit to 30 gpd following the February 2000 tube failure. EPRI Guidelines, 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 XXX and YYY.

Oversight of Contractor's SG Examination Activities

During the NRC's 1997 and 1995 inspections at IP2 documented in NRC inspection report 97-07 and 95-07, 1 the NRC observed that the Con Ed maintained adequate control over the ISI Non Destructive Examination (NDE). The reports 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 oversight of ISI activities was also routinely provided by the Quality Control unit through surveillance. Overall, the licensee's oversight of contractor's activities was assessed to be good. However, as pointed out in section XX of this report, and also in the NRC special inspection report 2000-010, proper evaluation of the examination findings by the licensee and its contractors to determine the degradation mechanisms and their impact on SG integrity was lacking. Specifically, the NRC team determined that during the 1997 examination, Con Ed should have taken additional actions tp assure that the plant was not returned to service with SG tubes that contained detectable Primary Water Stress Corrosion Crack (PWSCC) indications in the low-row U-bend area. Multiple existing indications of PWSCC in the row 2 U-bend area were missed.

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 97-07 and also in the NRC special team inspection report 2000-010. The Task Group found that, according to the information in NRC Inspection Report 97-07, the 1997 examination personnel met the qualification and certification requirements stated in the pertinent supplement of SNT-TC-1A and ASME Code Section XI. This was in accordance with the industry guidelines. 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 the data analysts in 1997. The issues are described in detail in NRC inspection report 2000-010. The Task Group determined that while the two NRC inspections were completed in accordance with the applicable inspection procedures, the discrepancy between the conclusions drawn by was indicative of the following: The 1997 inspection was conducted by one inspector and was primarily on a sampling manner. It was accomplished withing the requirements specified in the NRC inspection procedure. That Task Group felt that this discrepancy could be corrected with enhancement to the NRC inspection procedure and/or improvement in inspector training.

Extension requests from Con Ed involving the SG since 1995

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

In a letter dated 12/7/98, Con Edison again asked for an extension of the 24 month SG examination interval beyond 6/13/99, the date an inspection would be due according to the TS requirement. The licensee indicated that after the SG examination was completed during the 1997 refueling outage, there was a cumulative duration of 309 days of non-operating time. During most of this period, the SGs were maintained in a wet lay-up condition with appropriate control. The licensee requested an additional 48 days postponement of the inspection beyond the non-operating 309 days until the commencement of the refueling outage scheduled to begin on 6/3/00. As a justification for this extension, the licensee submitted information on reduced temperature water chemistry control, non-appreciable wear growth of indications observed between the 1993 and 1995 outages, and essential halting of degradation during the wet lay-up period. The submittal also provided a broad analysis of the 1997 inspection results.

Further details of the NRC review of the amendment request is contained in section 8.1 of this report. As pointed out later in the RES' independent review dated 3/16/00, there were some inherent flaws in the logic the licensee used in crack growth rate determination for sludge pile ODSCC and row 2 U-bend PWSCC indications. These weaknesses in the licensee's logic were not identified in the subsequent NRC safety evaluation that approved the license amendment for the requested extension of the inspection interval.

It also appears that plant TS required licensee Submittal on 1997 SG examination results did not get timely review by the NRC technical staff. The licensee had mentioned about the finding of the row 2 U-bend apex PWSCC indication and the sludge pile ODSCC indications in their 1997 SG examination report, and provided further discussion about these indications in the response to the staff RAI related to the extension request. Although row 2 U-bend apex PWSCC indication was observed for the first time and a substantial increase in the sludge pile ODSCC indication were observed in the 1997 inspection, as pointed out in the RES 3/16/2000 review, the licensee's projections related to the crack growth rate were not questioned. As a result, an opportunity for questioning the licensee's assessment of the new indication was missed.

6.1.2.3 Con Ed's Examination Results

<u>1997 Examination</u>

The task group review of the 1997 SG examination by the licensee and its contractor is contained in section 8.2 of this report. The NRC special inspection team report 200-010 also addressed this issue in detail. In general, the scope of the 1997 refueling outage SG tube examination performed by the licensee met or exceeded the TS requirement. The examination, completed in June 1997, identified the first low-row U-bend PWSCC indication (at the apex of R2C67 in SG24). The tube that failed in February 2000 (R2C5) was examined over the full length. The mid-range plus point probe was used to examine the U-bend area. Also during the 1997 examination, Con Edison identified the first instances of probe restrictions caused by denting at the upper TSP in multiple low-row U-bend tubes. Those tubes were plugged.

Con Ed's SG examination results were submitted to the NRC as required by the IP2 Technical Specifications. The licensee's report of the 1997 examination (letter dated 7/29/97) listed tubes with indications that were plugged. The locations of the indications were also provided. However, the report contained no analysis of the results as to a trend or degradation mechanisms involved. The report also 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. The response continued to say that the video quality was able to show small cracks at upper support plates previously not observed. One flow slot at the second support plate that showed closure was evaluated to be acceptable. As noted in NRC special inspection report 2000-010, 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 report was not sufficient to flag the technical and implementation problems, such as the signal to noise ratio, identified elsewhere in this report. As noted in this report, the licensee;'s report containing the 1997 examination results was not reviewed by the NRC. The Task Group noted that the tube that failed in February 2000 was not reflected in the report as a degraded tube, since it was not identified as such during the 1997 examination. While the NRC 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 steam generator inspection, the NRC could have identified the flaw in the U-bend of row 2, column 5, in steam generator 24 that was indicated in the licensee's inspection report, the

Task Group did not determine that it could have been possible to do so. The licensee's 1997 inspection report did not indicate that there was a flaw in the row 2, column 5 tube. It would have taken further discussion with the licensee, then the licensee conducting additional reviews of their 1997 examination data, and then possibly identifying that the tube examination data showed the presence of crack.

The Task Group also reviewed some of the records of the 1997 outage NRC/Con Ed outage telephone calls held on June 2, 3, and 26, 1997. There was no indication that the crack discovered in the apex of the u-bend of a row 2 tube (R2C67 of S/G 24) was discussed. Also, the timing of the phone calls relative to when the flaw was identified was not clear. While the flaw was identified and the tube plugged, the NRC staff felt that neither Con Edison nor its ECT contractor recognized the discovery of the low-row U-bend apex indication as a significant condition adverse to quality and did not enter the issue into its corrective action program. Identification of this flaw was significant, because it was the first observation of this type of degradation in the U-bend area in SG tubes at Indian Point 2. There was no specific review as to the significance of this flaw or the possible extent of the condition. Following the 1997 tube examination, Con Ed conducted in-situ tests on 6 tubes (4 in SG 22 and 2 in SG 24) in rows 35, 32, 23, 24, and 27. The maximum pressures attained ranged from 2900 to 5075 psi. One row 2 (R2C67) apex of U-bend crack was identified and plugged in Steam Generator 24. At the end of 1997, 9.6% of SG 21, 12.4% of SG 22, 9.2 % of SG 23 and 9.4% of SG 24 had been plugged.

<u>1995 Examination</u>

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

In NRC inspection report 95-07, 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 tube. They also expanded their scope of examination using the Cecco-5 probe. Based on this, the Task Group felt that when abnormal issues were encountered, the questioning attitude demonstrated by the 1995 crew was good. The Task Group did not note this type of attitude in the review of the licensee's activities for the 1997 examinations.

6.1.3 Conclusions/Lessons-Learned

1) The TS on SG tube integrity does not reflect the current knowledge regarding degradation and failure mechanism and provides insufficient guidance regarding the type of information to be reported to the NRC.

2) The basis for the technical specification requirement for Con Ed to submit the results of the steam generator tube examinations within 45 days (and the proposed examination 60 days prior to the schedule examination) is not defined in the regulatory process. Further more, the reports are not usually reviewed by the NRC.

3) The plant TS limit on Primary to Secondary leakage did not provide proactive 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 sufficient to prevent such a failure or provide meaningful indication of an impending failure.

4) The scope of Con Ed's 1997 SG tube inspections met and exceeded the requirements of the technical specifications in that it was broadened to cover 100% of the tubes. Nevertheless, potential problems regarding implementation of the SG program went unnoticed and uncorrected by the licensee.

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.

6.1.4 Recommendations

1) The staff should revise and strengthen the regulatory framework to address the identified implementation weaknesses, and specify SG performance assessment reporting to NRC.

2) The staff should address the TS SG examination results reporting requirements. The report should be tailored to certain information that would provide better indication of the SG tube conditions (e.g., new degradation mechanisms). Along with this, the staff should assess the need and the process for the staff to review the reports.

3) The staff should assess the adequacy of the TS regarding operational leakage limits. A rate of change limit should also be considered.

4) The staff should evaluate whether Con Ed's contractor (Westinghouse) performance during the 1997 steam generator tube examination conformed to regulatory requirements such as 10 CFR 21.

6.2 Root Cause Analysis/Special Inspection

Later

7.0 RES INDEPENDENT TECHNICAL REVIEW OF SAFETY EVALUATION

7.1 Background

In a memorandum from S. Collins, NRR, to A. Thadani, 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 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 are:

a) Results of the RES review;

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

c) Consolidated Edison Company'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. We also had two presentations, one by RES staff on SG design, operating experience, degradation mechanisms, inspection techniques, and repair criteria. The second presentation, which was given by RES's contractor, Argonne National Laboratory (ANL), focused more on IP2 specific SG issues. This presentation covered: (1) SG failure (i.e., leakage vs. rupture) at normal and main steam line break conditions, (2) degradation mechanisms (in particular primary water stress corrosion cracking (PWSCC) in SG U-bend regions, and (3) detection of flaws with low signal-to-noise ratios showing actual data from the 1997 IP2 inspection. The Task Group 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.

7.2.1 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:

- Licensee's submittal on proposed amendment to Technical Specifications on SG inspection interval (Reference 4)
- Licensee's response to NRR's request for additional information (RAI) (Reference 5)
- Licensee's report on their SG tube inservice examination conducted during the 1997 refueling outage (Reference 6)

The RES review did not address the adequacy of SG inspections or SG inspection techniques. RES documented the results of their review and their concerns in a memorandum to NRR dated March 16, 2000 (Reference 2). RES concluded that IP2's technical basis for adequacy of the operating cycle based on previous inspection results was inadequate, especially for PWSCC at a row 2 U-bend and outer diameter SCC at the top of the tubesheet under the sludge pile.

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

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

RES characterized the licensee's response to the RAI (Reference 5) as "weak and incomplete." RES also 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[1]. The number

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[1]Section **XXXX** of this report discusses issues related to the poor quality of IP2 SG inspection data and the likelihood of being able to identify other row 2 U-bend flaws from the 1997 inspection data. Section **XXXX** discusses ANL's analysis of IP2's 1997 eddy current test data.

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 that "The evaluation and the information submitted by the licensee do provide reasonable assurance that the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next inspection interval."

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

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

The RES response has been perceived by some stakeholders outside the agency is that NRR did an inadequate review. However, 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[2]. 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.

7.2.3 Consolidated Edison Company's Comments on RES Review

Con Ed 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 and did not need to obtain additional information that the licensee may have had but did not provide to the NRC. As discussed in Section **XXXX** of this report, if the staff felt they needed additional information to approve the SG tube inspection interval extension, they could have done so at the time of the amendment review.

7.3 Conclusions/Lessons-Learned

Based on the Task Group's review, the Task Group made the following general conclusions.

- The licensee was weak in assessing the condition of their SG tubes. The real problem stemmed back to the quality of the June 1997 inspection.

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[2] 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.

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

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

- There were a number of opportunities by both Con Ed and the NRC to identify problems with the IP2 operational assessment.

The lessons learned that the Task Group has identified for industry and the NRC are discussed below.

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

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

3) Timely technical reviews and coordination between NRR and RES can enhance the agency's ability to address challenging technical SG issues.

7.4 Recommendations

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

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

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

3) NRR should coordinate with RES to make effective and efficient use of the agency's technical resources. NRR should continue to seek RES technical input in a timely manner. In the future, if NRR requests that RES perform an independent technical review of a staff's SE, NRR and RES should develop a process for handling the request and response.

7.5 References

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

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

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

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

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

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

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

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

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

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

Note: Information from the following interviews was used for the discussion in Section 7. They will not be included as references in the final Task Group report.

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

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

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

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

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

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

17. Presentation to Task Group by William Shack, Argonne National Laboratory, June 28, 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 support the NRC's Strategic Plan performance goal of maintaining reactor safety. The NRC issues license amendments for nuclear facilities only after safety and environmental regulations have been adequately addressed. Specifically, before an amendment is issued, the associated safety evaluation (SE) must conclude that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

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

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

The Task Group evaluation of the licensing review process focused on the issuance of IP2 Amendment No. 201 (Reference 5) with respect to the process described in OL No. 803. This amendment, which was issued on June 9, 1999, revised the TSs to allow a one-time extension of the steam generator (SG) inspection interval. The Task Group review was focused on Amendment No. 201 due to concerns regarding the technical adequacy of the associated SE and the licensee's application as described in a review performed by the NRC's Office of Nuclear Reactor Research (RES).

The RES review (Reference 3) also evaluated IP2 Amendment No. 180 (Reference 9) which revised the TSs to allow the repair of SG tubes via implementation of an F* (or F-star) criteria. This criteria allows tubes that are degraded in a location not affecting structural integrity of the tube 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 steam generator tube integrity. The Task Group evaluation was performed using the latest revision of OL No. 803 (i.e., Revision 3) which was issued on December 30, 1999. During the time frame the NRC review for IP2 Amendment No. 201 was performed (December 1998 - June 1999), Revision

2 of OL No. 803 was in effect. However, the Task Group judged that the licensing review process has not changed significantly from December 1998 to the present. Therefore, it was decided that it would be beneficial to evaluate potential improvements to the guidance that is currently in effect.

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

a) completeness and acceptability of licensee's application;

b) use of precedent by the staff;

c) scope and depth of the review;

d) resources used in the review;

e) adequacy of the NRC safety evaluation;

f) interface between NRC Headquarters and NRC Regional Staff;

g) review of TSs associated with SG inspection interval;

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

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

j) 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 5, 5A, 6, 7, 7A, and 8). The Task Group also conducted interviews of NRC staff from Headquarters and Region I to gain insights on steam generator tube integrity issues relevant to 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 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.

Completeness and Acceptability of the Licensee's Application

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

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

With respect to the RAI response, Con Edison stated that Dominion Engineering did a study for them 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 U-bends during the 1997 outage, they contacted Dominion Engineering after the outage to get them to update the report based on inspection findings. The new projection for PWSCC indications was one additional indication per cycle, not exponential. Since the projections were based on the midrange probe findings, the use of the high range probe would have led to a different result based on the increased number of indications found (i.e., not just one indication as was found with the midrange probe). 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 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 maximizes staff efficiency, minimizes the need for RAI's and helps to ensure consistency in SEs. The OL states that the search for a precedent should continue until the staff is satisfied that either one or more appropriate precedents have been identified or that no appropriate precedent exists.

The NRR staff that performed the review for Amendment No. 201 used the NRC's NUDOCS bibliographic data system to search for precedent. Several SEs were found related to extending the SG inspection interval. The staff noted that since a 2 month inspection interval extension 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 steam generators to minimize corrosion. The Task Group did not identify any issues regarding the use of precedent by the staff.

Scope and Depth of the Review

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

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

1) The scope and depth of the NRC staff review for the inspection interval extension amendment was appropriate. There was nothing unusual in the licensee's application that should have prompted the staff to 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 out of thousands of tubes inspected.

2) 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 generators were in wet lay-up during the unscheduled outage, and there was precedent for granting this type of extension. The request to extend the interval an additional 2 months was 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., issuance of Amendment No. 201 had no effect related to the tube failure). The change would have been considered safety significant if it had reduced safety margins. The fact that we have tube failures every few years does not indicate that we have a significant safety or risk problem. See Section 9.0 of this report for further discussion on risk insights.

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

4) The review was done with the assumption that the licensee's 1997 inspection of 100% of the SG tubes was done in an adequate manner and formed a baseline for the review. Therefore, the staff did not see a need to thoroughly review the licensee's 1997 SG inspection report (Reference 26) as part of the amendment review process. Although the licensee's report was used by the NRC staff in preparation of the SE, the report was used primarily to obtain information related to tube plugging and in-situ pressure testing. The apex location of the indication found in the row 2 U-bend during the 1997 inspection is only noted in a table in the licensee's inspection report and is not discussed in the text of the report. The licensee's application does not discuss the row 2 U-bend at all. The RAI response discusses that PWSCC was found at a row 2 U-bend but it does not discuss that the indication was found at the tube apex. Therefore, the apex location of the indication was not in the perspective of the reviewer.

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

<u>Resources used in the Review</u>

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, and there was precedent licensing actions for changes related to extending the SG inspection interval. 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 believes that the resources used in the review for Amendment No. 201 was appropriate given the complexity and safety significance of the proposed change.

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

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 during an interview with NRR technical staff that there is no SRP guidance to perform the reviews related to SG inspection interval extensions and that the reviews are basically done such that the safety arguments convince the staff that SG tube integrity will be maintained.

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

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

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

3) SG leakage monitoring program.

The SE stated that the licensee performed an extensive eddy current inspection in June 1997 (end of cycle 13) and that the inspection included 100% examination of all inservice tubes. The SE described the reasons why tubes were plugged and states that prior to tube plugging the licensee performed in-situ pressure testing on selected tubes that exceeded the EPRI/Westinghouse 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 $3\Delta P$ 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 25), following plant startup in October 1999, the leak rate in SG 24 appeared to vary from 2 to 4 gallons per day (gpd) but returned to pre-shutdown levels of 1.5 to 2.0 gpd through December 1999. Starting in January 2000, the leak rate slowly increased to about 3-4 gpd just prior to the tube failure on February 15, 2000. The leak rates observed prior to the event were significantly below the limit at which any mitigating action would need to be taken in accordance with the IP2 TSs. Conclusions and recommendations regarding the adequacy of the TSs for SG leakage are discussed in Section 8.2 of this report.

As discussed in the "Scope and Depth of the Review" section above, the SE was prepared with the assumption that the 1997 inspection of 100% of the inservice tubes was done in an adequate manner and formed a baseline for the review. This assumption seems reasonable to the Task Group since the requested change was not considered complex or safety significant. This assumption is also supported by OL No. 803, Section 1.2, which states: "[t]he review of license amendment applications is one of the primary mechanisms for regulating **changes** [emphasis added] in the licensees' operation of the facility. During the time period the Amendment No. 201 review was performed (i.e., December 1998 - June 1999), the plant had already been operating in cycle 14. The licensing basis (prior to issuance of Amendment No. 201), as defined by a footnote to TS 4.13.A.2.a, allowed SG operation to continue until the next required inspection at the end of cycle 14, commencing no later than June 13, 2000 (see "Review of TSs associated with SG Inspection Interval" section below for further discussion). The licensee's 1997 inspection report was performed at the end of cycle 13. The Task Group believes that it was reasonable for the NRC staff to assume that the current licensing basis was valid and that only information pertinent to extending the interval beyond the current licensing basis needed to be reviewed. Therefore, the Task Group believes that the NRC staff should not have been expected to review the licensee's 1997 inspection report thoroughly during the license amendment review process. However, as noted in the "Scope and Depth of the Review" section above, in hindsight, the amendment review could have been an opportunity to find inadequacies in the licensee's operational assessment directly related to the eventual tube failure.

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, 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, one month before Con Ed began their 1997 SG inspections. 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 was an easy call and therefore that didn't think they missed any other indications. It is not clear that had Con Ed provided this information to the NRC if the accuracy of detecting U-bend indications would have been questioned.

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 only needs to conclude that there is "reasonable assurance" (not absolute 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 doesn't appear 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 the row 2 U-bend could have been pursued further. However, the Task Group also concludes that is not clear if this would have changed the outcome of the licensee's request (i.e., approval of the amendment). In addition, the issuance of Amendment No. 201 in no way contributed to the tube failure that occurred in February 2000.

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

The only guidance provided in OL No. 803 regarding the interface between NRC Headquarters and NRC Regional staff is provided in Section 4.1.1 of the OL. This guidance states that the PM may provide input regarding the licensee's performance for use in the assessment of licensee performance. The OL states that the assessment should be documented in the amendment cover letter and should also be forwarded to the appropriate regional contact for possible entry into the plant issues matrix. In the last few years, typical PM input addressed issues such as the licensee's application was not submitted in a timely manner or the application was inadequate and required multiple RAI's, telecons, and meetings to resolve all the technical issues. In the past, this information was used as input to the Systematic Assessment of Licensee Performance (SALP) process. However, with the recent implementation of the revised reactor oversight process (ROP), the SALP process has been discontinued. At present, there is no process that captures the PM input as a means to assess the licensee's performance.

With respect to the process used for development of an SE for a license amendment, this effort is typically completed by NRC Headquarters personnel without any input from the Regional staff. During an interview with Regional staff members, questions were asked regarding the interface between Headquarters and the Region during SE development. The staff observed that there should be some link between the licensing and the inspection processes as deemed necessary. For example, in some cases, it may make sense for the Region to perform an inspection to verify information relied on in the SE. However, for the specific review performed for IP2 Amendment No. 201, it does not appear to the Task Group that Regional involvement would have provided any benefit.

Review of TSs associated with SG Inspection Interval

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

As discussed in the licensee's application (Reference 8), the SG inservice inspection program is based upon the guidance in RG 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1, dated July 1975. Regulatory Position C.6 of RG 1.83 provides guidance regarding inspection intervals. The RG states that the first SG inservice inspection should be performed after 6 EFPM but before 24 calendar months and that subsequent inservice inspections should be not less than 12 nor more than 24 calendar months after the previous inspection.

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

Future Potential Impact of NRC's Work Planning Center

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

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

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

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

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

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

Based on the discussions with the WPC, the Task Group does not have any concerns regarding the future potential impact of the WPC on 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 rest of the technical staff.

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

<u>Evaluation of the Findings by the NRC's OIG Related to NRR's Amendment Review</u>

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." The OIG had initiated this inquiry (report) because of concerns from Congress and the public because of 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) <u>OIG finding:</u> NRR's review of the amendment request was not adequate.

   <u>Task Group comments:</u> As discussed in the "Adequacy 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 the row 2 U-bend could have been pursued further. However, the Task Group also concludes that is not clear if this would have changed the outcome of the licensee's request (i.e., approval of the amendment). In addition, the issuance of Amendment No. 201 in no way contributed to the tube failure that occurred in February 2000.

2) <u>OIG finding:</u> 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.

   <u>Task Group comments:</u> 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 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).

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). 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 "Adequacy of the NRC Safety Evaluation" section above.

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 was approriate given the complexity and safety significance of the proposed change.

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. As discussed in the "Adequacy 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 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 "Adequacy 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. The review was assigned to EMCB technical staff consistent with the guidance in NRR OL No. 803. Consistent with normal pracitces, EMCB branch supervision provided oversight of the junior engineer, review of the RAI questions, and review of the completed SE. Detailed review is normally conducted by the assigned technical reviewer.

8.1.3 Conclusions/Lessons-Learned

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

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

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 and possibly uncover problems with the 1997 operational assessment.

3) The NRR staff used applicable 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 review for Amendment No. 201 was appropriate since the requested change was not considered complex or safety significant. In addition, it was reasonable for the staff to assume that the licensee's 1997 inspection was done in an adequate manner and formed a baseline for the review. The NRC staff should not have been expected to review the licensee's 1997 inspection report thoroughly during the license amendment review process. However, in hindsight, this could have been an opportunity to find inadequacies in the licensee's operational assessment directly related to the eventual tube failure. Specifically, if the 1997 inspection report had been thoroughly reviewed during the amendment review process, the staff could have questioned the licensee's operational assessment given the apex location of the row 2 U-bend indication.

5) The resources used in the review for Amendment No. 201 was appropriate given the complexity and safety significance of the proposed change. Enough time was spent, enough people were involved, and the appropriate people were involved.

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 licensee's request (i.e., approval of the amendment).

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

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

9) 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 that Regional involvement would have provided any benefit.

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

8.1.4 Recommendations

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

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

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

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

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 SG tube failure at Indian Point 2 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 agencies 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," is applicable for Steam Generator (SG) Tube examination. The procedure is required to be completed once every two years during a refueling outage at each facility.

Plants, whose performance 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 will 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 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, 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 Steam Generator Tube Examination Program. The review covered the old NRC's 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 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

8.2.2.1 NRC oversight of licensee's SG tube integrity management

Prior to April 2000, NRC ISI inspections were performed at each facility 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 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 could also include Non-destructive Examination (NDE) activities on other components.

NRR has routinely held conference calls with each licensee during their refueling outage to assess the adequacy of the licensee steam generator tube eddy current inspections. These conference calls involved regional participation on occasion and were to discuss the results of the licensee generator inspections and repair plans. NRR has a prepared outline of important discussion areas to cover with the licensee and documents the results of the conference call internally. However, this effort has not been part of the inspection program, and the results are not documented in inspection reports. The Task Group also reviewed some of the records of the 1997 outage NRC/Con Ed outage telephone calls held on June 2, 3, and 26, 1997. There was no indication that the crack discovered in the apex of the u-bend of a row 2 tube (R2C67 of S/G 24) was discussed. Also, 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 Leakage Performance Indicator (PI). This PI tracks identified reactor coolant system (RCS) leakage, which is generally on the order of gallons per minute. Steam generator tube leakage is generally on the order of gallons per day, and therefore adverse trends in primary to secondary leakage would not be readily apparent in this PI.

The industry guidance for reporting the Reactor Coolant System Leakage PI, as contained in NEI 99-02, states that normal steam generator tube leakage is included if required by the plant's Technical Specification (TS) definition of RCS identified leakage. The guidance also states that all calculations of RCS leakage that are computed in accordance with the calculational requirements of TS are counted in this indicator. Due to the differences in TS requirements between plants, this guidance may not ensure that primary to secondary 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 augmented inspection team (AIT) follow up inspection identified seven green inspection findings as documented in NRC inspection report 50-247/2000-07. Three White inspection findings pertaining to emergency preparedness program deficiencies were documented in NRC inspection report 50-247/2000-06. And one green finding and a finding preliminarily determined to have high safety significance (Red), were documented in NRC inspection report 50-247/2000-10.

Each of these findings was adequately assessed by regional and Headquarters staff using the SDP. The assessment process and Action Matrix were used by the region to determine the appropriate agency response to these combination of PIs and inspection findings.

[FRYE TO FINISH CONFIRMING THIS]

8.2.2.2 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, dated 05/04/95 The procedure contained guidance to review licensee's examination plans, personnel qualification and certification. It also had a 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. Inspector may request NRC contractor review of the eddy current testing results. The procedure made reference to a guidance document that was being developed that could be used to help determine the acceptability of the Volumetric examination using eddy current testing technique.

There were additional non-core 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, dated 12/31/96 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. The procedure was, however, 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 97-06, the inspector could have questioned ConEd 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 Reactor Oversight Program (ROP), the new baseline inspection procedure for Inservice Inspection, IP 71111.08 does not require that SG examinations be looked at. 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 to perform a more focused inspection on steam generator condition and to assess the effectiveness of the licensee steam generator inspection program. This inspection procedure was retained for use in the revised reactor oversight process in the supplemental inspection program as documented in IMC 2515, Appendix B.

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 of SG tube defects has reached a level that warrants additional NRC action.

8.2.2.3 Qualification and training requirements for regional and resident inspectors

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

There are no specific requirements that an ISI inspector must be a specialist or an expert. While ISI inspectors are not required to be ISI experts, some region management interviewed believe that 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 anlysis closing 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.

The regional staff members 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. 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.

8.2.2.4 NRC's Inspection Activities at P2

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

The NRC inspected IP2's 1997 SG Examination using IP 73753. The results were documented in NRC Inspection Report 97-07 (July 16, 1997). The NRC inspection focused on ConEd'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 S/G 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 and that they also used Plus Point probe during the examination. During the inspection, the NRC inspector 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 initiated stress corrosion cracking (ODSCC). Prior to the June 29, 1997 telephone conference call, on June 2 and 3, 1997, Con Ed had participated in telephone calls with NRR to discuss their inspection activities and findings. None of the phone call records that the Task Group reviewed indicate that a row 2 u-bend apex crack was discussed. The licensee informed the NRC of the latest inspection results. 110 defective tubes were to be plugged. They also talked about the tubes selected for In-situ pressure tests. Following the examinations, the licensee submitted the required TS examination report. There is no indication that the NRC reviewed the 1997 examination results.

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, one month 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 "The susceptibility to cracking in small radius U-bends and the findings of recent field inspections have emphasized the importance of inspection of this area of SGs with techniques capable of accurately detecting U-bend degradation."

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

The NRC staff responded to the Primary to Secondary leakage prior to the event. While there were no specific NRC inspection procedures to address the leakage, it was brought up for discussion to the regional management, and well followed by the resident inspectors. The residents brought up the leakage issue and it was well followed 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 150 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 Technical Specification and EPRI leakage limits at ensuring that the plant could be shut down to avert a tube failure.

8.2.3 Conclusions/Lessons-Learned

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

2) Neither the baseline inspection program or the PIs provide adequate indication of adverse trends in primary to secondary leakage during power operation due to SG tube degradation.

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

4) Headquarters (NRR) outage phone calls with the licensees are effective, but are not included in any regulatory or inspection process in a structured way. The process for ensuring relevant information generated by staff technical offices, that may affect the quality of regional inspections, is not being consistently implemented to ensure that this information is considered for inclusion in the inspection program.

5) The regional inspector training is not geared towards high technical capability in the area of eddy current examination. Therefore, the inspection process could not be reasonably relied upon to preclude a situation such as IP2 from occurring.

6) There were delays in communication of generic information (such as Information Notice 97-26, Degradation in Small-Radius U-Bend Regions of Steam Generator Tubes, dated May 19, 1997) to the region such that it could be factored into the inspection process. An adequate means has not been established in the ROP, either through the PIs or the SDP, to apply risk-informed thresholds to the results of the periodic steam generator inspections to identify SG tube degradation that warrants increased NRC interaction.

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

8) All of the inspection findings generated during the NRC follow up to the SG tube failure were able to be adequately evaluated for safety significance by regional and Headquarters staff using the SDP. Regional staff was able to use the assessment process and Action Matrix to determine the appropriate agency response to these combination of PIs and inspection findings.

8.2.4 Recommendations

1) Regional inspection planning should involve technical staff to better focus the inspection effort.

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

3) The staff should review the following communication issues to identify areas where formal processes could be established or improvements made to existing processes:

   (i) The technical interaction between the licensees and NRR (Outage Phone Calls) during the examinations should be factored into the inspection program. The phone calls should involve the regional inspectors and could be used as part of the inspection preparation to afford NRR the opportunity to help focus the inspections on the appropriate issues.

   (ii) The dissemination of information to the regional offices and others should be looked at. It appears to be rather slow and sometimes lacking. For example, there was an Information Notice and a NUREG with useful information on SGs that the regional staff was not aware of prior to conduction the inspection at IP2.

4) The staff should review the reporting requirement for SG examination results for the appropriate detail and type of information that will be effective in assessing and understanding the condition of steam generators. (e.g. new flaw characteristics or locations).

5) The staff should consider the following improvements for the Reactor Oversight Process:

   (i) Establish risk-informed thresholds, either through the PIs or the SDP, that can be applied to the results of the periodic steam generator inspections to identify SG tube degradation that warrants increased NRC interaction.

   (ii) Ensure that either the baseline inspection program or PIs adequately identifies adverse trends in primary to secondary leakage during power operation which could indicate a degradation of the steam generator 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 faulted conditions.

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

6) The staff should determine whether the review of licensee steam generator inspection results is an important agency activity to assess the adequacy of steam generator condition monitoring and operational assessment determinations by the licensee.

7) The staff should develop, revise, and implement, as appropriate the processes to ensure that relevant technical information is reviewed and considered for inclusion in the inspection program to ensure that it is available for use by the inspectors.

8.3 NRC Endorsement of Industry Guidelines

8.3.1 Background Parts of this could be in Jack's framework section

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

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

The Task Group examined:

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

b) The implications of the NRC position regarding the guidelines on conditions leading to the IP2 tube failure event.

8.3.2 Observations

8.3.2.1 NRC position on Industry Guidelines

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

The staff put forward its plans to incorporate industry initiatives into the regulatory process in SECY 00-0116, "Industry Initiatives in the Regulatory Process," (DATE). The SECY proposed guidelines that the staff should follow to incorporate industry initiatives and to use an expedited process if necessary. The SECY uses the NEI 97-06 initiative as an example of an industry initiative that is intended to complement regulatory actions for issues **within (are we w/in existing requirements???)** 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 proposed process, once it is approved.

NRC Regulatory Guides regarding steam generator inspection and maintenance have not been revised in many years and do not address the NEI initiative or the individual EPRI guidelines that predated the initiative. For instance, Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes" Rev. 1, was issued in 1975 and predates the EPRI guidelines. The Regulatory Position in RG 1.83 lists components that should be included in a SG ISI program, including SG inspector qualification based on a standard issued by the American Society for Nondestructive Testing. RG 1.121, "Basis for Plugging Degraded PWR Steam Generator Tubes," August 1976 also predates EPRI guidance.

Recent efforts focused on revising the regulatory framework for SG integrity included the development of a draft regulatory guide DG-1074, "TITLE." DG-1074 directs licensees to consider EPRI leakage monitoring guidelines, and went beyond the EPRI guidance in some ways (e.g., monitoring leakage at low power conditions). The DG also 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 management programs. DG-1074 was issued for public comment (See SECY 00-0078) and it received numerous comments. However, the range of comments generated indicates that further development of the DG and the NEI initiative is necessary. In SECY 00-078, the staff expressed its intent to review the NEI initiative and to prepare a safety evaluation documenting its findings. The staff plans to then issue a Regulatory Information Summary documenting NRC endorsement of the NEI initiative based on findings in the SE. However, recent interaction with the industry (July 26 meeting with NEI) indicated that the staff has 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 guides in general or specific ways. Some examples are:

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

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

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

NRC has referenced but not endorsed the EPRI guidelines, as indicated in the preceding examples. The signal that may have been received by the industry by the agency taking this stance is that the NRC considered the existing guides sufficient for managing SG maintenance and inspection activities.

8.3.2.2 Implications of the NRC Position Regarding the Guidelines

NRC acknowledged NEI 97-06 (Reference February 3, 1998) and supported the industry effort, but did not endorse the guidelines. Although the staff did not review NEI-97-06, the February 3, 1998, letter did note differences between NEI 97-06 and the draft regulatory guide DG-1074, which the NRC has since published for public comment. The letter went on to state that the performance criteria for structural integrity and accident-induced leakage might not ensure regulatory compliance. In 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."

Some NRC staff consider the guidelines as a minimum requirement, and others feel that there are significant shortcomings to the guidance. Further, the range of NRC staff opinions on the sufficiency of the guidelines and may have contributed to shortcomings in the NRC licensing process, in areas such as inspection and technical review guidance.

Although industry has adopted guidelines for SG management, without NRC review and endorsement, licensees may not always have a clear view of the potential weaknesses in the guidance or in the regulatory acknowledgment of the guidelines. NRC and industry have found weaknesses in the guidelines on a case-by-case basis (the follow-up to the IP2 event being the most recent example) and licensees address the weaknesses within the licensing process. Although in the end this approach may maintain safety, it leads to an inefficient and what could be viewed as a less-than-optimally effective process by not providing a process for generic implementation.

In the case of IP2, Guidelines existed in 1997 that the licensee referenced for that inspection. The NRC position on the guidelines was not finalized, and as a result, little to no direction existed for inspectors or for technical staff to rely upon when evaluating SG-related licensing actions of licensee SG programs. Taking steps to review and approve an acceptable industry program should help to alleviate this situation, and will contribute to maintaining plant safety and agency efficiency and effectiveness.

8.3.3 Conclusions/Lessons-Learned

1) There has been a long-standing NRC position of generally accepting use of the industry SG guidelines without formally endorsing them. Also, steam generator-related regulatory guides have not been revised to present a regulatory position on the guidelines. This situation could have been a secondary factor in contributing to conditions that led to the IP2 failure because the licensee considered the guidelines as a sufficient basis for their SG inspection and maintenance program.

2) Inspection Report 97-07 may be an example where the inspector was satisfied that the licensee's tube examination plan was based an EPRI guidance and decided that there was no need for further review. The absence of a clear NRC position on EPRI guidelines and on the NEI initiative along with the absence of associated inspection guidance may have handicapped the 1997 NRC inspection of the IP2 SG tube examination program. **[SHOULD THIS GO TO THE NRC INSPECTION/OVERSIGHT SECTION???]**

8.3.4 Recommendations

1) Assign a high priority to the NRC review and endorsement 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 maintenance guidance, acceptable sources of guidance (if any) for licensee use or what steps licensees need to take in addition to using guidelines to provide 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.

3) Simultaneously, NRC should establish improved inspection guidance so that inspectors can make better judgements regarding licensee SG tube maintenance activities.

9.0 RISK INSIGHTS

9.1 Background

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

Both spontaneous and induced SG tube failures may be risk significant because radionuclides could bypass the reactor containment during these events. This can happen because a flow path exists from the secondary side of the steam generators through containment, to the steam generator safety valves. These safety valves discharge to the environment. Containment bypass events result in a disproportionate amount of radionuclides being released to the environment, in comparison to other possible accident scenarios.

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

Obviously, the tube rupture criterion 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. It is important to note that the tube failure at IP2 did not reach the level of leakage to catagorize it as a rupture, therefore, it is referred to as a tube failure in this report.

As noted in the NRC Special Inspection Report (reference), there were no actual 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.

However, the NRC characterized the inspection findings as having high risk significance because of a significant reduction in safety margin based on the increased risk of 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:

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

b) Use of risk information in granting the IP2 SG inspection interval extension; and

c) Implications of the IP2 event on risk perspectives for SG tube failure.

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 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.

9.2 Observations

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

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

NRC's Draft Strategic Plan (NUREG-1614, Feb. 2000) lists a number of strategic goals and performance goals in the Nuclear Reactor Safety arena. One of the strategic goals is to prevent radiation-related deaths and illnesses. One of the measures used to assess results in achieving this strategic goal is: "No reactor accidents[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]." Note that this measure is a lower threshold than the measure used for the strategic goal. The strategic plan further states that:

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

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

In summary, the staff's preliminary "red" 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. Although there was a reduction in safety margin, overall risk to the public was not significantly impacted. This was in part evidenced by the absence of measurable radioactivity offsite above normal background

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[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.

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

levels following the event. Sufficient safety margin still existed such that the agency's safety and performance goals were not exceeded.

9.2.1.2 IP2 Event in Context of Previous SG Tube Failures

The Task Group reviewed information related to previous SG tube failures and for previous assessments of tube failure risk in order to put the IP2 event in context of other similar events. Table 1 provides a list of previous tube failure events at US PWRs based on information in Reference 1. As noted in Table 1, the IP2 tube failure 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 obvious similarities. The leak rate for the Surry tube failure is greater than the IP2 event leakage. The Surry and IP2 events are the only u-bend apex failures attributed to PWSCC. **Knowledge gained/lessons learned from Surry? Applicability to IP2???**

Review of the information in Table 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 steam generator tube rupture (SGTR) was estimated in Reference 1 (published in 1996) to be about 2.5E-2 per reactor year of operation. NUREG/CR-5770 Draft (Reference) states that the mean frequency of SGTR is 5.2E-3 **per critical year**, and that there is no statistical basis to show a decreasing trend in SGTRs experienced at US PWRs. The 5th percentile and 95th percentile values for frequency of SGTR given in NUREG/CR-5770 are 1.6E-3 and 1.1E-2 per critical year, respectively. The frequency of SGTR used in the IP2 IPE of **1.3E-2**/ry is close to the 95th percentile or conservative part of the range from the NUREG.

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 number of instances where tubes leaked, and the leakage was in a range where some studies considered the tube ruptured, but others did not.

The SGTR 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.

The tube failures listed in table 1 were situations where operators were forced to shut down the plant due to the leak rates involved. As discussed earlier, some or all of these events could be considered tube ruptures for the purposes of risk assessment. Other tube failures involving controlled or planned plant shutdown to address the leaks were also considered by the task group in order to form a more complete perspective of the extent of SG tube performance problems. Table 1A lists forced outages because of tube leaks at US PWRs for the 9-year period ending in 1999. The table included failures from table 1 during the period. Notable features from the table are the large number of failures over the span (total of 28) and the marked decline in the annual rate of failures during the second half of the period. Of the 28 total, only 4 occurred from 1995 through 1999.

WHATS THE CONCLUSION FROM THIS? Use of guidelines worked? Threat of SG regulatory action motivated better SG programs?

The task group could draw only tentative conclusions from the information in table 1a. First, it appears that from long-term perspective, SG tube failures, in terms of 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 failures have become much rarer events, with about one occurring per year. Based on this, the event at IP2 is not out-of character in terms of overall SG tube performance at US PWRs.

TABLE 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* W-44	2/26/75	125	2 adjacent ruptured bulges, each 20mm in length and width	Slightly above tube sheet, outer row hot leg	Wastage	Sludge pile
Surry-2* W-51	9/15/76	330[1]	114 mm long axial crack	U-bend apex, Row 1, Col. 7	PWSCC	Hour glassing
Prairie Island-1 W-51 600MA	10/2/79	336[1]	38 mm long axial fishmouth crack	76 mm above tube sheet, hot leg, Row 4, Col. 1	Loose parts wear	Sludge lancing equipment left in SG
Ginna* W-44	1/25/82	760[1]	100 mm long axial fishmouth crack	127 mm above tube sheet, hot leg, Row 42, Col. 55 (3rd row from bundle periphery)	Loose parts wear, fretting	Baffle plate debris left in SG
Fort Calhoun CE 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* W-51	7/15/87	637	360° circumferential crack	Top of 7th tube support plate, cold leg, Row 9, Col. 51	High-cycle fatigue	Lack of AVB support, denting
McGuire-1* W-D2	3/7/89	500	95 mm long axial crack, 9.5 mm maximum width	At the lower tube support plate, cold leg, Row 18, Col. 25	ODSCC	long shallow groove, possible contaminant
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 W-44 600 MA	2/15/00	146	**2.2 - 2.4 inch axial crack convert to mm**	U-bend apex, Row 2, Col.5	PWSCC	hour glassing

Notes: 1 - NRC estimate *SGs replaced since tube failure

TABLE 1a: Tube Leak Forced Outages at US PWRs

Plant	Date	Leak Rate	Cause	
St. Lucie 1	Jan. 1990			
TMI 1	Mar. 1990			
Millstone 2	May 1990			
North Anna 2	Aug 1990			
Oconee 2	Nov. 1990			
Shearon Harris	Nov. 1990			
Maine Yankee	Dec. 1990			
San Onofre 1	Apr. 1991			
Millstone 2	Apr. 1991			
Millstone 2	May 1991			
McGuire 1	Nov. 1992			
ANO 2	Mar. 1992			
Prairie Island 1	Mar. 1992			
Trojan	Nov. 1992			
Palo Verde 2	Mar. 1993			
Kewaunee	Jun. 1993			
McGuire 1	Aug. 1993			
Braidwood 1	Oct. 1993			
McGuire 1	Jan. 1994			
Oconee 3	Mar. 1994			
S. Texas	Mar. 1994			
Zion 2	Mar. 1994			
Oconee 2	Jul. 1994			
Maine Yankee	Jul. 1994			
Byron 2	Aug. 1996			
ANO 2	Nov. 1996			
Oconee 1	Nov. 1997			
Farley 1	Dec. 1998			

Information from EPRI TR-106365-R14

9.2.1.3 SG Tube Failure Risk at IP2 Compared to Other PWRs

One way to understand the generic risk impact attributable to the tube failure at IP2, is to put the IP2 event in the context of the risk of tube failure at other plants. NUREG/CR-6365, "Steam Generator Tube Failures" (Reference 1) 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 steam generator tube ruptures. Information from Table 18 in the NUREG is reproduced below.

Table 2: IPE Results for Selected US PWRs

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

The values in Table 2 of the contribution to CDF from spontaneous tube ruptures range from 0.02 percent of CDF to 22 percent. The values of the percent of containment bypass fraction from spontaneous tube ruptures varies over a wider range, from 2 percent to 99 percent. The wide variation is due to the differences in risk profiles for various plants. The differences could be attributed to design differences. For instance, ice condenser containment plants might be expected to have a lower percentage risk contribution from SGTR because these plants have a lower containment design pressure than other plants. Therefore, early containment failure during certain other higher core damage frequency accidents is possible. Early containment failure would increase the contributions of the core damage accidents other than those involving SGTR. **NOT TRUE FOR SEQUOYAH**

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

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

Induced tube failure risk impact resulting from combinations of high primary-to-secondary differential pressure or high primary system temperature were not explicitly considered in this report. As will be discussed, the staff risk assessment for IP2 based on the SG tube condition during Cycle 14 did consider induced tube failure contributions, as does the IP2 IPE. However, because the risk significance at of the event IP2 appears to be limited to only part of the operating cycle preceding the event, the Task Group concluded that for its purposes of assembling lessons based on the IP2 event, the risk implications should be limited to spontaneous tube failure considerations.

9.2.2 Use of Risk Information in Granting the IP2 SG Inspection Interval Extension

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

Section III.A of SRP 19.0 states:

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

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

9.2.3 Implications of the IP2 Event on Risk Perspectives for SG Tube Failure

9.2.3.1 IPE Results

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). The NRC reviewed the IP2 IPE submittal and issued a draft [is there a final??] safety evaluation report in 1996 (Reference). The IPE estimates an initiating event frequency for SGTR as 1.3E-2 per reactor-year (ry). The core damage frequency (CDF) for internal events has a mean of 3.1E-5/ry. Approximately 5 percent **(7% in NUREG table)** of that value is contributed by SGTR, or about 1.4E-6/ry.

The IPE considered core damage scenarios following tube rupture as well as an induced SGTR following a core damage event where primary system pressure remains high. The core-damage contribution from induced SGTR has an estimated frequency of 2.5E-7/ry, not a large contribution to SGTR risk at IP2.

Containment bypass is the primary concern for 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 the reactor coolant pressure boundary. The IPE results for IP2 show that the largest fraction of containment bypass is associated with SGTR. Of the internal CDF of 3E-5/ry, about 6 percent is associated with containment bypass. Of the bypass fraction, about 86 percent is connected with SGTR-initiated events and about 13 percent from induced SGTR events. **Therefore, virtually all of the containment bypass sequences are associated with tube failure. BUT THE NUREG TABLE SHOWS 20% FROM Spon 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) 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, take positive steps to assure that the SG is isolated, including terminating AFW flow to the affected SG. The operators must also cooldown and depressurize the RCS by opening steam dump valves and PORVs, and terminate safety injection. The IPE references MAAP analyses that indicate that overfill will occur in approximately 30 minutes if the operators take no action. The IPE (Reference 10/31/95 RAI response, Q21) includes a detailed estimate of assumed operator time to perform certain actions. For example, specific times are estimated between isolating the SG and starting RCS cooldown, between completing cooldown and initiating RCS depressurization, and between completing depressurization and terminating safety injection.

The IPE human reliability analysis acknowledges that for SG tube failure scenarios where the tube failure is less severe than the full tube rupture considered in the IPE analysis, the leak rate is less 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.

9.2.3.2 Comparison of IPE Assumptions to the Tube Failure Event

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

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

The operator performance problems concerned initiation of an excessive RCS cooldown that exceeded procedural and technical specification limits. This action complicated the subsequent event response and delayed RCS cooldown. Operators were also slow to recognize system configuration problems that prevented successful operation of the auxiliary spray system, which was needed to lower RCS pressure, and lineup problems in the RHR system that complicated placing RHR in service. Some procedural problems 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. One equipment deficiency worth noting is that the strip chart recorder for the MS line radiation monitors had been out of service since April 1999. The strip chart recorder maintains a continuous record of primary-to-secondary leak rate for all the SGs. This condition limited the amount of pre-event leakage information available to the operators, but in this case, did not impact the ability of operators to detect the leak and identify the faulted SG.

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

9.2.3.3 Staff Risk Assessment

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

The staff assessment considered the degraded condition of the SG tubes as indicated by the occurrence of the event and used other information available from the plant's IPE to estimate the risk contribution from spontaneous SGTR and from induced SGTRs (both from over-pressurization and from core damage sequences). Based primarily on the contribution from spontaneous tube failure, the estimated risk contribution attributed to degraded SG tubes at IP2 during Cycle 14 is a probability of core damage with large early release of approximately 1E-4/yr.

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

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

9.2.3.4 Licensee Risk Assessment

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

The licensee argued that the tube failure event did not present a large early release potential because of the ample time available for evacuation of the local population. The licensee also used the low leak rate to justify a modification of the human error probabilities that were used in the IPE analysis that was conducted at the SGTR leak rate for a double-ended guillotine tube break.

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

1) The licensee used a modified HRA based on the longer time available for operators due to the lower-than assumed SGTR leak rate in the staff's analysis;

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

3) The licensee did not consider the MSLB or induced SG tube rupture risk contribution.

The NRC assessment of the licensee analysis (Long email 7/20/00) 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.

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

3) The licensee assessment did not assess the risk contribution from tube failures other than spontaneous failures.

9.2.3.5 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 p 5 of RG 1.121). The risk estimate for spontaneous SGTR in the IP2 IPE assumes that tube conditions meet some minimal expectation for leakage and burst integrity compatible with the margins associated with the traditional structural criteria (e.g. 3 time normal operating differential pressure). The causes for previous tube failures are given in Table 1, and are, in most cases, considered to be random events that could not have been predicted. Such events are never "anticipated events," but have occurred 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 (Reference May 4, 2000 Barrett memo and Reference 1). In sum, 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 agrees with the staff's conclusion that the IP2 tube failure event resulted from degraded conditions that could have been avoided if reasonable, prudent engineering practices had been followed **(See Sections 5.1, 5.2?, and Special Inspection findings)**. Further, the type of failure and contributing factors such as degradation type, failure location, and stress intensification from hour-glassing point to a failure at IP2 that was encountered in a previous failure (Surry 1976), was not random, and could have been avoided. This leads to the Task Group's judgment 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 in Section 5.3.2.3, did not assume any effect on tube failure probability from deficiencies in the maintenance and inspection program, because in the view of the licensee, there were no such deficiencies. The NRC Special Inspection report disagrees with the licensee position.

As documented elsewhere in this report, The Task Group concluded that a number of programmatic failures contributed to the tube conditions that led to the tube failure event. 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 effects of the programmatic deficiencies that led to the degraded SG tube condition, because the degradation itself is 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 the new steam generators are maintained in a satisfactory condition.

Risk significance of the IP2 degraded SG conditions during cycle 14 can be understood by relating the tube conditions found during the 2000 tube inspection with the design basis for the plant. As discussed in the NRC special inspection report (Reference), there were four tubes containing flaws that should have been detected in 1997. The structural margin for the tubes (i.e. 3 times the normal operating differential pressure) provides margin for the tubes to withstand accident and transient loads. It is clear that the tube that failed during operation in February did not have adequate structural integrity to withstand accident loads. Some of the other tubes had flaws that were of significant depth, more than the 40% through-wall, and may not have withstood an accident (IN-SITU RESULTS??). Therefore the potential existed for multiple tube failures during a MSLB or LOCA, accidents outside the design basis for the plant. SEE pg 158 of NUREG 6365)

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

9.2.3.6 Potential Generic Implications

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

Based on the preliminary staff risk assessment, there was a significant impact on the level of risk from SGTR at IP2 during the period of operation preceding the tube failure. In the case of IP2, operator actions to isolate the affected steam generator and effect cooldown have a large impact on the ability to effectively limit the consequences of the event. Therefore, the prevention of tube degradation and failure can be seen to have a more significant influence on SGTR risk than mitigation. However, it must be recognized that a balance between prevention and mitigation must be maintained, because completely deficient mitigation would lead to potential core damage and containment bypass. Such an approach would be contrary to the defense-in-depth philosophy that has helped to assure plant safety.

The staff examined the extent of tube degradation problems short of tube failures throughout the industry in order to assess the need for maintaining robust tube integrity programs. {from EPRI TR-106365} There are approximately 1.2 million SG tubes in service in 209 Sgs at 69 plants in the US. About 4.6 percent of the total number of tubes have been repaired (by either plugging or sleeving) through 1998. These tubes are spread throughout 190 steam generators in 62 plants. Therefore, it is clear that tube degradation is a widespread problem throughout the industry.

An observation that could be made by comparison of this information to the number of tube failures is that overall, tube integrity programs do well by repairing tubes before significant failures occur. However, the task group examined the information more closely by separating out the portion of the tube population associated with replacement Sgs.

The number of tubes in original Sgs is about 850,000, of which about 6.4 percent have required repair. Every non-replaced SG has tubes that required repair. From this, the Task Group concluded that, unsurprisingly, older generators have more problems than newer ones. But what is striking is that all older generators have had at least some tube repairs. This highlighted to the Task Group that in order for the industry to maintain sufficient safety margin from tube failures, significant licensee attention at a large number of plants is required to maintain tube integrity.

[Consider summarizing tube repair info in a table]

PUNCH LINE: Adequate integrity is important to maintaining safety on a generic basis.

Another generic aspect of the IP2 event considered by the Task Group was the effect of communication of the details of the event and its significance to the public. A formal communications plan was not used to disseminate information concerning the event. The NRC established a web site to make information available and to answer questions. The staff answered a number of formal inquiries concerning the event and its significance and these were avaiable for public review. **The task group noted that a risk assessment or statement of the safety significance of the event was not available on the web site until??? [check with jeff/pat/louise on this]**

The Task group concluded that the public confidence issue should receive increased attention before events occur. This approach is consistent with efforts to establish communications plans.

9.3 Conclusions/Lessons-Learned

The Task Group noted that serious degradation during IP2 operating Cycle 14 resulted in an increased risk of SG tube failure. Further, the Task Group found that the contributing factors to the situation at IP2 could have generic implications on SG maintenance practices at other PWRs, and therefore, on the overall risk of tube failure. The following lessons developed by the task group are drawn from the specific IP2 event and from the generic concerns encountered by the Task Group.

1) As discussed previously in Section 9.2., the staff's risk assessment based on the IP2 event resulted in a probability of core damage with large early release on the order of 1E-4 per year. Comparing this conservative result to the 1E-3 per year performance measure associated with the NRC strategic plan for reactor safety indicates that the IP2 event was well within the accepted performance measure.

   In it's risk assessment associated with the IP2 event, the staff determined 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. Although there was a reduction in safety margin, overall risk to the public was not significantly impacted. This was in part evidenced 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.

2) The degraded condition during IP2 Cycle 14 affected the plant's risk of tube failure for that operating cycle. However, there were a number of contributing factors leading to the degraded condition. Provided the contributing factors are corrected, the long-term risk of tube failure at IP2 should be unaffected.

3) The IP2 event did not significantly change our understanding of tube failure risk on an industry-wide basis. However, SG maintenance program deficiencies discussed elsewhere in the report could impact the tube failure risk at other plants, if not addressed. Further, the widespread nature of tube degradation problems suggests that SG tube integrity deserves continued attention by both NRC and industry.

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

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

9.4 Recommendations

1) IP2 oversight - Con Ed should ensure that it corrects the deficiencies that led to the degraded SG condition during IP2 cycle 14. Otherwise, the long-term risk of SGTR at IP2 could be affected. Maintains safety,

2) Generic oversight - Over the long-term, NRC should correct deficiencies in its oversight of licensee SG tube maintenance programs. The oversight effort should extend to explore potential programmatic deficiencies at other plants based on the possible generic character of some of the deficiencies found as a result of the IP2 event. Maintains safety

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

4) The public confidence issue should receive increased attention before events occur. This approach is consistent with efforts to establish communications plans. NRC should consider using NRC strategic plan principles as a basis for communication plans to address events that the public and/or NRC consider serious. The communication plans should present risk information in such a way as to put an individual event in the perspective of other plant risks and/or other societal risks. Efforts invested in this area will help to facilitate

timely communication with the public and may help to avoid unnecessary effort to deal with public mis-perceptions of event hazards and the nature of licensee and NRC actions.

References

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

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

10.0 FINDINGS AND CONCLUSIONS

11.0 RECOMMENDATIONS

11.1 Actions

11.2 Further NRC Action

12.0 REFERENCES

APPENDICES

Appendix A - Timeline of Indian Point 2 Steam Generator Inspection/Repair Activities

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