James S. Baumstark
Vice President
Nuclear Engineering

Consolidated Edison Company of New York, Inc.
Indian Point 2 Station
Broadway & Bleakley Avenue
Buchanan, New York 10511

Internet: baumstarkj@coned.com
Telephone: (914) 734-5354
Cellular: (914) 391-9005
Pager: (917) 457-9698
Fax: (914) 734-5718

January 19, 2001

Re: Indian Point Unit No. 2
Docket No. 50-247
NL-01-005

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop P1-137
Washington, DC 20555-0001

References:
1) NRC Inspection Report 05000247/2000-010 and NRC Letter to Mr. J. Groth from Mr. H. J. Miller, Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2 dated November 20, 2000

2) NRC Inspection Report 05000247/2000-012 and NRC Letter to Mr. A. Blind from Mr. W. Lanning dated December 4, 2000

3) NRC Letter to Mr. J. Groth from Mr. H. J. Miller dated December 20, 2000

Subject: Reply to a Notice of Violation – NRC Inspection Report 05000247/2000-010

Dear Sirs:

The purpose of this letter is to respond to the Notice of Violation enclosed with the NRC's letter of November 20, 2000. This violation is associated with the steam generator in-service inspections performed during the 1997 refueling outage at Indian Point Unit No. 2. We are also providing supplemental information regarding improvement initiatives in our Corrective Action Programs in response to continuing NRC interest in this important area as described in the NRC letter to Mr. J. Groth from Mr. H. J. Miller dated December 18, 2000 and NRC Inspection Report 05000247/2000-012. Following the February 15, 2000 steam generator event, we have made multiple significant steam generator program improvements within the site-wide corrective action program. While the details of certain

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of our steam generator program activities have previously been reported to the NRC, several of them have been implemented quite recently and are summarized here. Specific actions have been entered into our corrective action system.

<u>Steam Generator Program Improvements</u>

On March 22, 2000 a new Station Administrative Order (SAO)-180, "Administrative Steam Generator Program," was approved. This SAO implements Con Edison's commitment to the requirements of the nuclear industry initiative described in the Nuclear Energy Institute (NEI) "Steam Generator Program Guidelines 97-06." Major elements of this program include:

a) The establishment of a Steam Generator Management Committee (SGMC) chaired by the Vice President, Nuclear Engineering. The SGMC is a multi-discipline committee that provides recommendations and guidance to the Chief Nuclear Officer for improving steam generator reliability.

b) The appointment of a Steam Generator Program Manager who oversees the implementation of the program.

c) Criteria specified to ensure greater steam generator integrity relative to potential degradation mechanisms, inspection, tube integrity assessments, primary to secondary leakage monitoring, maintenance of secondary integrity, and reporting requirements.

d) Enhanced program requirements in the areas of Primary and Secondary Water Chemistry, Foreign Material Exclusion, and Self-Assessment of program health.

<u>Primary to Secondary Leakage Limits</u>

New primary to secondary leakage limits identified in the February 2000 revision of EPRI TR-104788, "PWR Primary to Secondary Leakage Guidelines" have been implemented. Applicable station procedures have been revised to identify reduced primary to secondary leakage administrative limits and actions. The administrative limit was reduced from 150 gpd to 75 gpd. Although this change could not have precluded the February 15, 2000, event, the new limit reduces the probability of occurrence of another steam generator tube rupture.

<u>Steam Generator Replacement Project</u>

During the Third and Fourth Quarter, 2000, a project to replace the original Westinghouse Model 44 steam generators with newer Westinghouse Model 44F steam generators was completed. The replacement steam generators incorporate several improved design features, including thermally treated Alloy 600 tubes, and 405 stainless steel tube support plates with broached quatrefoil tube holes in a square pitch array. These material improvements significantly minimize denting because of the higher corrosion

resistance of 405 stainless steel as compared to the original steam generator carbon steel tube support plates. The quatrefoil tube hole arrangement design is an enhancement of the flow slots in the upper support plate. This design eliminates the probability of flow slot hourglassing.

Further, the low-row steam generator tubes (ROWS 1-7) were stress relieved during manufacturing to reduce residual stresses from the bending process. This further reduces the potential of PWSCC in the U-bend area. The replacement steam generators have full depth hydraulically expanded tube to tube sheet joints. Although this would not reduce the probability of a tube leak in the U-bend area, it will reduce that potential within the tube sheet area.

Replacement Steam Generator Examinations

Pre-service inspections were performed on the primary and secondary sides of the replacement steam generators. The primary side inspection consisted of 100% full length Bobbin probe, 100% hot leg top of tube sheet inspection with Rotating Pancake Coil (RPC) probe, 100% Row 1 and 2 U-bend inspection with RPC probe, and inspection of 80 of the row 1, 2 and 3 U-bend tubes with the 800 kHz +Point Probe. No tubes were plugged based upon the results of these inspections.

Secondary side inspection and Foreign Object Search and Retrieval (FOSAR) activities were performed both when the generators were in storage horizontally and when installed vertically.

Secondary Side Copper Reduction

One of the major areas of concern identified in connection with prior steam generator eddy current inspections was the effect of interference or noise on the eddy current test signals obtained during the actual testing of several low-row U-bend tubes. One cause of noise is the presence of ferro-magnetic materials such as iron oxide and copper in the secondary side of the steam generators. During the 2000 outage a number of steps were taken to reduce the amount of ferro-magnetic materials that could accumulate on the secondary side of the generators.

The last remaining six low-pressure feedwater heat exchangers and the gland seal steam condenser, which had contained copper bearing tubes, were replaced. This minimizes the amount of copper that could eventually enter the steam generators. The copper removal program activities have been in progress since 1982, with the replacement of moisture separator reheaters and high-pressure feedwater heaters with stainless steel components. Nine other low-pressure feedwater heaters were replaced in 1987. Over three successive refueling outages (1991, 1993 and 1995) the three, admiralty brass condensers were replaced with titanium tube modular units. This completed the removal of copper bearing alloys in the principal components of the secondary side of the plant.

Long Loop Recirculation System

The Long Loop Recirculation System provides a flow path for the recirculation of water from the condensate and feedwater systems, to enable cleanup of impurities prior to plant startup. Using the existing condensate pumps to provide a motive force, impurities within the hotwell, condensate and feedwater system piping and equipment will be flushed to the hotwells through the condensate and feedwater systems, and then filtered by new particulate filters. A portion of the effluent of the filter can be polished using vendor supplied, trailer mounted demineralizers. All of the water is returned to the condenser. The system has been installed and has been used during the present start up. Use of this system will minimize the amount of copper and iron oxide material that is available for deposit on the secondary side of the replacement steam generators.

Removal of Residual Copper in the Feedwater System

To maximize the operational life of the steam generators, a flush to remove copper was performed on the feedwater system. This was accomplished concurrently with the Steam Generator replacement project by increasing the pH on the secondary side to greater than 10.0 with the addition of chemicals such as Hydrazine and Ammonia.

Further, the removal of residual copper from an additional portion of the feedwater system was accomplished with the recently installed Long Loop Recirculation System. The replacement steam generators were isolated from the feedwater system during this operation. The pH in the feedwater system was increased by the addition of Ammonium and Hydrazine to a maximum pH of 10.5. The Long Loop Recirculation System was then utilized to circulate the fluid with the purpose of putting the residual copper in the secondary side of the plant into a soluble state. This process was initiated on November 23 and completed on November 28. This copper was removed primarily through the draining and filling of the system. It is estimated that this process removed approximately 2,200 grams of copper.

Corrective Action Program Initiatives

At Indian Point 2 we are doing our utmost to improve issues identification and our Corrective Action Program (CAP). The initiatives described above pertaining to our steam generator program are but a part of a much broader station commitment to CAP improvements. Our attention to improving issue identification and corrective action programs at Indian Point 2 is continuing, and additional focus on these programs will occur in 2001, specifically addressing program performance and the issues noted in the referenced December 4, 2000 Inspection Report.

As a result of recent CAP improvements, responses to identified problems have become more comprehensive, effective, and timely. By the end of year 2000, the total number of outstanding CR evaluations and corrective actions have been reduced by over one-third to a much more manageable level of approximately 2800 CR's. The average age

of open evaluations dropped from 150 days at the beginning of the year to less than 30 days by year's end. CAP metrics demonstrate significant site-wide improvements in overall program quality during 2000. There are no IP2 departments that are currently below standard in any of the key quality measures, such as the quality of root/apparent cause evaluations, schedule adherence, and timeliness for completing evaluations and corrective actions.

Seven (7) structured human performance stand-downs were held in 2000 to provide reinforcement to our employees of the importance of recognizing and correcting human performance issues. Recent station and industry events were reviewed as part of the lessons-learned function at these stand-downs. This effort will continue into 2001. In January 2001, Human Performance Fundamentals Training was provided to site managers and supervisors. This training focused on providing human performance awareness to management and recognition of tools that are available to address human performance issues.

Our current multiple initiatives in the various areas of our corrective action program are discussed in Attachment A to this letter. The station's corrective action program, having previously been identified as a specific area of interest and focus, will continue to receive our sustained attention following the unit's return to full power operation.

NOV Pertaining to 10 CFR 50, Appendix B, Criterion XVI

Con Edison is committed to significant improvements in all aspects of Indian Point 2 operations. We firmly believe that this commitment will result in improved plant performance. As previously noted in the NRC's Inspection Report 05000247/2000-010, Con Edison believes that the Company's 1997 steam generator inspections were consistent with then-applicable NRC requirements, including 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions." Accordingly, pursuant to the provisions of 10 CFR 2.201, we deny the violation set forth in the referenced Inspection Report. We hope that this letter and its attachments and exhibits adequately explain the basis for this difference, but irrespective of this, we believe that Con Edison and the NRC share a common view of the steps that should be taken to improve plant performance and public confidence in plant operations.

Following receipt of the NRC's November 20, 2000 letter, Con Edison requested third-party experts to review the NRC's Inspection Report 05000247/2000-010, as well as related materials, including specifications, processes, practices, and eddy current data from the 1997 inspections, and to address the conclusions reached in the Inspection Report related to the adequacy and sufficiency of the 1997 steam generator inspections. The conclusions of these experts are set forth in affidavits which are included as exhibits to Attachment B. Attachment B and its exhibits accordingly form the basis for denial of the violation.

Commitments made by Con Edison contained in this letter are listed in Attachment C.

Should you or your staff have any questions regarding this submittal, please contact either the undersigned or Mr. John F. McCann, Manager, Nuclear Safety and Licensing.

Sincerely,

Attachments

ERSILIA A. AMANNA
Notary Public, State of New York
No. 01AM6033689
Qualified in Westchester County
Commission Expires March 20, 2002

cc: Director, Office of Enforcement
US Nuclear Regulatory Commission
Washington, DC 20555-0001

Mr. Hubert J. Miller
Regional Administrator-Region I
US Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Mr. Patrick D. Milano, Project Manager
Project Directorate I-1
Division of Reactor Projects I/II
US Nuclear Regulatory Commission
Mail Stop O-8-2C
Washington, DC 20555

Senior Resident Inspector
US Nuclear Regulatory Commission
PO Box 38
Buchanan, NY 10511

ATTACHMENT A TO NL 01-005

CORRECTIVE ACTION PROGRAM SUMMARY

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247
JANUARY 2001

INDIAN POINT 2 CORRECTIVE ACTION PROGRAM

NRC Inspection – Problem Identification and Resolution

On December 4, 2000, the NRC issued Inspection Report (IR) No. 50-247/00-012, documenting the results of the annual baseline inspection for the problem identification and resolution (PI &R) process at Indian Point 2 (IP2). The inspection examined activities conducted at Indian Point 2 as they relate to the identification and resolution of problems, and compliance with the Commission's rules and regulations and the conditions of the operating license. In the report, the NRC Staff recognized the progress made in reducing the backlog of open evaluations and corrective actions within the overall corrective action program (CAP). However, based on the sample selected for review, the NRC team identified CAP performance issues and findings that revealed some continuing weaknesses in the initiation of condition reports for identified issues, in the significance classification and prioritization of problem evaluations, and in the prioritization of corrective action tasks. The examples cited for the above weaknesses were identified as Green (very low risk significant) inspection findings, in accordance with the NRC's reactor oversight program significance determination process. Con Edison recognizes our current challenge to continue our improvement efforts, both in the corrective action program and addressing the recurring equipment challenges.

During 2000, the Corrective Action Group (CAG) commenced several initiatives to address issues similar to those raised in IR 00-012 that had been identified as part of our own internal self-assessments. Specific actions being taken to address the crosscutting issues described in the report are as follows:

- Effectiveness of Problem Identification

  The inspection report states that Con Edison has not identified some lower level issues and in some instances, personnel did not initiate condition reports for identified problems. As a result, the information was not captured in the corrective action program for tracking and trending purposes or to determine the need for additional evaluation to ensure effective resolution.

  Con Edison recognizes that documenting all levels of issues found in our condition reporting system is essential so that we can immediately address those issues and learn from them. As discussed in the inspection report, those specific issues should have had condition reports generated when they were first discovered. To address this challenge, we are continuing to reinforce the importance of initiating a condition report when a condition adverse to quality is discovered or introduced during their work activities. Also, in February 2000, CAG initiated refresher/new training for site personnel in the use of the electronic Condition Reporting System (CRS). This training emphasizes the importance of identifying and documenting any and all condition adverse to quality. The training

also stresses that if we don't recognize and understand the problem, we cannot fix it. This training effort, which is continuing, is producing the desired focus on CRs. During 2000 approximately 11,000 condition reports were initiated.

- Prioritization and Evaluation of Issues

The inspection report indicates that although most issues were appropriately classified, some weaknesses in the screening and escalation processes exist. Some examples of weaknesses in the quality of evaluations and use of cause codes for trending were identified. Although progress in reducing the backlog of open and overdue evaluations was recognized, the report confirmed our assessments that the number of overdue evaluations remains higher than desired.

In October 2000, CAG initiated a formal review of closed condition reports to independently assess the adequacy of the closure for condition reports that were closed between December 1, 1998 and June 30, 2000. This effort focused on determining whether: (1) proper classification was identified for the condition report (i.e., significance level), (2) description of condition reports provided a proper problem statement, (3) corrective action(s) identified for addressing problems were effective and, (4) implementation of the corrective action(s) and closure of the condition report was effective. The results of this assessment indicated reasonable confidence exists that appropriate corrective actions are being identified and completed for those conditions reported. However, several process and quality related issues were identified during the review. These issues related to closure of condition reports to another IP2 process (thus making the tracking of closure status difficult), overlooking assignment of corrective actions to address human performance errors, inconsistent quality of condition report responses, lack of documenting the problem resolution processes, lack of clarity for problem statements, lack of adequate focus on larger programmatic issues that could provide barriers for repetitive failures, and the correlation of repetitive equipment with CRs. Based on these results, condition reports were generated to document these issues, and interim actions were implemented to address process improvements.

Corrective Action Program (CAP) reports have been significantly enhanced during 2000 by the development of Accountability Based CAP metrics. These reports have been successful in improving CAP performance as the trends of all key CAP indicators are positive. Reductions in the backlog of long-standing and overdue evaluations have been made during 2000. For example, significant reductions in the average age of open CR evaluations and the number of overdue CR evaluations occurred. An especially powerful aspect of these metrics has been their influence in improving the quality of CR closures. These quality metrics have improved the ability to close out CR's and have resulted in improving the ability to fix the problem right the first time.

- Effectiveness of Corrective Actions

The report recognizes the progress made in reducing the backlog of open and overdue corrective actions, but identifies weaknesses in the process used to prioritize completion commensurate with the condition's risk.

Actions being taken in response to the formal review of closed Condition Reports discussed above will result in increased effectiveness of corrective actions. Additional program changes are in the process of being implemented to clarify condition report significance levels to ensure appropriate attention is placed on completion of corrective actions commensurate with the condition's potential risk significance. Improved metrics, management involvement, and increased oversight by the Corrective Action Review Board (CARB) will continue the progress in reducing the backlog of open and overdue corrective actions.

- Effectiveness of Licensee Audits and Assessments

The inspection report states that Con Edison QA department audits and line organization self-assessments indicated the ability to self-identify issues, many of which were similar to the NRC team's findings. However, a QA effectiveness review focused on verification of action completion, not on the effectiveness of actions taken.

In November 2000, the CAG initiated a corrective action effectiveness review of the August 1999 event to compliment the QA review. The objective of this review is to: (1) determine whether the Station documents, evaluates, understands, and allocates resources to resolve equipment problems on a consistent, risk informed basis and, (2) whether risk significant events do not evolve or escalate from lack of appropriate and adequate response to degrading plant conditions. The scope of this review is primary focused in the following areas:

- Equipment condition and performance causes that precipitated or aggravated the event and the associated plant response.
- Subsequent significant events that challenged the operators and the effectiveness of management support provided.

Some additional details of the Indian Point 2 Corrective Action Program and program improvements are provided below.

Program Overview

Problem identification and resolution at Indian Point 2 is performed in accordance with Station Administrative Order (SAO) – 112, "Corrective Action Program". This process is designed to identify and analyze nonconforming or anomalous conditions, and to initiate timely and effective corrective actions to resolve identified conditions and preclude

recurrence. A computer based Condition Reporting System (CRS) provides the mechanism to initiate conditions, track assignments and corrective action closure, and is widely available for use. Management ensures that employees are trained on using CRS, encourages employees at all levels to identify and report a broad range of problems, and reinforces their expectations that problem identification, reporting, and corrective action is a part of each employee's daily work activities. Identified problems are screened promptly for their effect on safety, reliability, operability, and reportability. The corrective action process applies Significance Levels (SL) to conditions based on the probability of an occurrence and the consequences of an event. Four levels of significance are defined with level 1 (SL-1) being the most significant and level 4 (SL-4) being the least significant. The Corrective Action Program requires a formal root cause analysis for SL-1 and SL-2 Condition Reports (CR). Individuals or teams trained in root cause analysis techniques evaluate significant problems using structured root cause methodology to identify root and contributing causes and corrective actions to prevent recurrence. SL-3 CR's require an apparent cause evaluation, focusing on correcting the immediate cause, and SL-4 CR's may have but do not require a response. The overall corrective action program is periodically monitored and assessed for effectiveness.

Employees are directed to originate a CR for any nonconforming or anomalous conditions that are discovered as soon as possible. This is usually no later than the end of the shift for shift personnel and within the next working day for non-shift personnel. The Originator of a CR determines, if possible, if the identified condition is potentially an Operability, Reportability, and/or Environmental concern, and, if so, is required to immediately report the condition to Operations shift management. All CR's are reviewed by shift management within 24 hours to ensure appropriate immediate actions have been taken. A Corrective Action Screening Committee meets daily to determine the significance level and assign a manager (Owner) to analyze the cause(s) and develop corrective actions. The process requires that every CR be evaluated by the responsible manager within 30 days. Corrective actions are discussed with the appropriate group/individual, due dates agreed on, and assignments made. It is expected that managers outside a particular organization support each other's priority for problem resolution. The CRS is used to track CR evaluations, assignments and corrective action closure. On-line reports and periodic status summaries developed by the Corrective Action Group are provided to assist managers in monitoring progress is evaluating and closing CR's.

A Corrective Action Review Board (CARB), chaired by the Plant Manager and the Corrective Action Program Manager, assist in managing the corrective action program. CARB includes the line managers from all major Indian Point 2 departments and meets at a regular basis to monitor the effectiveness of the corrective action program. The focus of CARB over the past year has been on obtaining line management ownership of the corrective action program and ensuring that improvements in the program continue. CARB is also chartered with the following:

- Reviewing, approving, and scoring for quality, all SL-1 and selected SL-2 Condition Reports.

- Reviewing and approving all effectiveness reviews performed for all SL-1 CR's.
- Reviewing Corrective Action Trend Reports and, when necessary, investigates adverse trends in station performance.
- Assessing department/section corrective action program implementation by reviewing quarterly assessments of program health.
- Approving all Corrective Action Program changes and, as necessary, recommends changes.
- Reviewing all requests for schedule extensions of investigations and corrective actions associated with SL-1 and SL-2 CR's.

Program Improvements

Indian Point 2 has made significant improvements to the corrective action program since the 1997 Steam Generator eddy current inspections. An electronic Commitment Identification Reporting System (CITRS) was developed in 1996. Prior to CITRS condition reporting was a "paper" system, with little capability to manage the process. Although some improvements were evident, an Independent Safety Assessment (ISA) Team in early 1998 concluded that the process was cumbersome and inefficient. While CITRS allowed problems to be identified in one central place, there were separate and distinct databases for tracking and resolving problems that inhibited effective integration for work management and cause trending purposes. Additionally, corrective action was seen to be partially owned by several organizations and there was little ownership for problem resolution. Actions could be assigned to almost anyone and then transferred to others indiscriminately. Searches of the database were difficult to conduct and meaningful reports and trending were not easily developed. Management standards and expectations for a corrective action program were not clearly established, communicated, nor reinforced.

In October 1998, a new station wide Corrective Action Program was implemented. This new program clearly defined reporting thresholds, emphasized strong individual and department accountability for closure of items, and established an appropriate process for determining CR priority and significance levels. Additional program enhancements included the following:

- Established and staffed a full-time, centralized Corrective Action Group.
- Identified and published appropriate performance indicators and trending methods to measure program effectiveness.
- Upgraded the process for conducting root cause and apparent cause analysis to include human error and equipment failure cause codes.
- Developed training requirements and provided baseline training for the revised process.
- Established a process to conduct periodic effectiveness reviews of completed corrective actions.
- Implemented the Corrective Action Review Board (CARB).

- Established an "Owner" concept and designated managers to take ownership of corrective action program actions. These individuals are responsible for successful close out of activities and can only assign actions to other owners.

In support of this new program, a more user friendly, reliable, and unified Condition Reporting System (CRS) was developed. CRS provides extensive CR reporting and monitoring capabilities. Stand alone web-based reports were developed to enable users to quickly locate and use data.

These program and system improvements, coupled with management's reinforcement of standards and expectations, have resulted in reporting material, process and program deficiencies at a low threshold. Since 1998 over 30,000 Condition Reports have been entered into CRS. The number of CR's being written each year continues to trend up. For example in 2000, approximately 13.5% more CRs were written than in the previous year. This increase in the identification of deficiencies is attributed to management's frequent reinforcement of their expectation to find problems through self-assessments of programs, processes and procedures, and to report these problems for evaluation in a timely manner.

Corrective Action Program (CAP) metrics have been significantly enhanced during 2000 by the development of Accountability Based CAP metrics. These metrics provide the management team a "report card" on each CAP owner's program health. Specifically, an owner's ability to close assignments in a timely manner, to be accountable to a schedule, and to provide high quality CR closures are measured.

These reports have been successful in improving CAP performance as the trends of all key CAP indicators are positive. For example, the average age of open CR evaluations has decreased from well over 100 days to approximately 30 days and the number of overdue CR evaluations has decreased from over 1,000 to less than 200 recently. An especially powerful aspect of these metrics has been their influence in improving the quality of CR closures.

In addition to increases in the number of CR's closed, the quality of both SL-2 (root cause) and SL-3 (apparent cause) have significantly increased over the past year. A score sheet rates an owner in the following areas:

- Identifying the root (or apparent) cause.
- Identification of appropriate corrective actions.
- Focus of the corrective actions.
- Identification of interim or compensatory actions, as appropriate.
- Assessment of the safety significance of the event/problem.

These quality metrics have improved the ability to close out CR's and have resulted in improving the ability to fix the problem right the first time.

Another successful new metric is the development of a site-wide "self-identification" rate. This metric determines the percent of a department's problems that are being identified internally, as opposed to other internal and external groups. The self-identification rate for the station was initially 22% and has increased to 40% over the past year, with several departments consistently self-identifying over 65% of their problems. This success supports management's expectation for rigorous self-assessment.

Additional corrective action program improvements accomplished during 2000 include the following:

- Revision to SAO-112, "Corrective Action Program", to remove several of the error traps that were associated with earlier revisions of this procedure.
- Developed over ten "conduct of business" procedures, including guidelines on how to perform effectiveness reviews.
- Initiated hands-on training for using the Condition Reporting System (CRS).
- Initiated a weekly Corrective Action Newsletter that provides information to site personnel on corrective action program performance.
- Provided root cause initial and refresher training.
- Developed a station "event-free clock" metric that measures the time between major human performance events, and provides trends in this area.
- Eight Corrective Action Group employees visited other nuclear stations to benchmark best practices.
- Received CAP assistance from the Institute of Nuclear Power Operations (INPO), Millstone, D. C. Cook, Beaver Valley, South Texas Project, Indian Point 3, and Calloway.
- Facilitated periodic site-wide human performance stand downs to discuss the meaning of "error-free" performance, how to achieve it, and most importantly how to recognize error rich environments.
- Expanded the Corrective Action Group's staffing from 8 to 12 individuals. Experienced managers from South Texas and Connecticut Yankee have been hired, with additional experienced professionals expected to join the group in early 2001.
- Initiated a Human Performance Daily Newsletter that identifies potential challenges to human performance successes. This newsletter also provides daily tips and information on the "event free clock".

As a result of recent CAP improvements, responses to identified problems have become more comprehensive, effective, and timely. By the end of year 2000, the total number of outstanding CR evaluations and corrective actions have been reduced by over one-third to a much more manageable level of approximately 2800 CR's. The average age of open evaluations dropped from 150 days at the beginning of the year to less than 30 days by year's end. CAP metrics demonstrate significant site-wide improvements in overall program quality during 2000. There are no IP2 departments that are currently below standard in any of the key quality measures, such as the quality of root/apparent cause evaluations, schedule adherence, and timeliness for completing evaluations and corrective actions.

Management recognizes that additional improvements in the corrective action program are required. Corrective Action Group plans for 2001 describe specific areas where the program is not fully effective, provide goals and expected results, and identify specific additional actions for program improvements. Objectives include, affirming and continuously reinforcing the ownership of the corrective action program by all employees and contractors through frequent communications, management interaction, and strong oversight by the Corrective Action Review Board, Station Nuclear Safety Committee, Quality Assurance and the Nuclear Facilities Safety Committee. Also, familiarizing the personnel with the corrective actions process changes, management expectations for condition reporting, and management support for effective problem resolution. We also recognize the need for continuing training of our people in the area of problem investigation (i.e., apparent cause/root cause investigation) and to establish a standard for quality and effectiveness reviews. We continue to use the performance indicators to monitor, measure and adjust our performance.

ATTACHMENT B TO NL 01-005
REPLY TO A NOTICE OF VIOLATION
INSPECTION REPORT NO. 05000247/2000-010

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247
JANUARY 2001

I. RESTATEMENT OF THE NOTICE OF VIOLATION

10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Contrary to the above, despite opportunities during the 1997 Indian Point 2 refueling outage, Con Edison did not fully identify and correct a significant condition adverse to quality involving the presence of primary water stress corrosion cracking (PWSCC) flaws in four Row 2 steam generator tubes, in the small radius low-row U-bend apex area. In conducting the 1997 steam generator inservice inspection, Con Edison did not adequately account for conditions that adversely affected the detectability of, and increased the susceptibility to, tube flaws. Specifically, while performing steam generator eddy current test (ECT) examination, during the 1997 outage:

- a PWSCC defect was identified for the first time, at the apex of one row 2 tube, signifying the potential for other similar cracks in the low-row tubes. However, Con Edison did not adequately evaluate the susceptibility of low-row tubes to PWSCC and the extent to which this degradation existed.

- indications of tube denting were identified for the first time in low-row tubes at the upper tube support plate (TSP) when restrictions were encountered as ECT probes were inserted into those tubes. Restrictions in 19 low-row tubes signified increased probability of deformed flow slots (hourglassing) at the upper TSP. Hourglassing of the upper TSP increases the stress at the U-bend apex of tubes. These stresses are a prime precursor for PWSCC. However, Con Edison did not adequately evaluate the potential for hourglassing based on the indications of the low-row tube denting.

- significant ECT signal interference (noise) was encountered in the data obtained during the actual ECT of several low-row U-bend tubes. This significant noise level reduced the probability of identifying an existing PWSCC tube defect. However, the 1997 SG inspection program was not adjusted to compensate for the adverse effects of the noise in detecting flaws, particularly when conditions that increased susceptibility to PWSCC existed.

As a result, a minimum of four tubes (with PWSCC flaws in their radius U-bends) were left in service following the 1997 inspection, until the failure of one of these tubes occurred on February 15, 2000 while the reactor was at 100% power.

This violation is associated with a Red SDP finding.

II. CON EDISON'S RESPONSE

A. Basis for Denial of the Violation

Con Edison respectfully denies the alleged violation based upon the fact that the 1997 steam generator tube inservice examination at Indian Point 2 was conducted in accordance with industry guidelines and requirements applicable at the time. Comprehensive reviews of the 1997 eddy current inspection program conducted by Con Edison and independent third-party experts confirm that the 1997 inspections used conservative approaches in both the selection of the inspection sample, and in the analysis guidelines and reporting requirements. All eddy current data were analyzed by experienced and qualified personnel who received site-specific training in accordance with Revision 4 of the EPRI PWR Steam Generator NDE Guidelines, which were in effect at the time of the inspection. Probes, techniques and procedures applied were the most advanced qualified technology available at that time. NRC Inspection Report No. 05000247/2000-010 does not reference any requirement, industry standard, benchmark or guidance that was not met in 1997 which could have lead to a failure to detect primary water stress corrosion cracking (PWSCC) tube defects.

In several significant respects, the planning and execution of the 1997 steam generator inspection exceeded then-current standards. Although not required by any standard at the time, licensee hired an independent eddy current expert to provide oversight of the principal contractor's eddy current work. The independent expert's activities included review and approval of the contractor's plans and procedures, including site-specific analyst training, and confirming that they met all requirements and industry guidelines.

During the course of the 1997 steam generator tube inspections, and in subsequent data analysis, reasonable and appropriate measures were taken to identify and address significant conditions adverse to quality involving the presence of PWSCC in steam generator tubing. The failure to detect instances of PWSCC in 1997 was associated with the inherent subjectively-based limitations of eddy current testing methodology at that time. Such limitations were contemporaneously acknowledged, including by the NRC with issuance of Information Notice 97-26 (May 19, 1997). 10 CFR 50 Appendix B, Criterion XVI necessarily presumes that candidate conditions adverse to quality are identifiable, utilizing examination techniques reasonably available and in use at the time of inquiry. For the reasons set forth herein and in the enclosed exhibits, with respect to Indian Point 2 steam generator tube low-row U-bends, this was not in all instances the case in 1997.

Guidance as to the appropriate mechanisms for interpreting and applying 10 CFR 50 Appendix B, Criterion XVI can be found in NRC Inspection Procedure 71152, "Identification and Resolution of Problems." IP 71152 provides assessment guidance relative to problem identification and resolution, and in pertinent part notes that licensee problem identification should be assessed "commensurate with its significance and ease of

discovery." (Ref. NRC IP 71152-03.01.c). It is clear from this that ease of discovery should be fully considered in evaluating licensee problem identification and resolution. In this instance, and as more fully described below, extensive efforts were made in 1997 with the intent to identify any steam generator tube indications that were potentially susceptible to significant leaks or rupture. In the case of tube R2C5 of steam generator 24, it is clear that the indication was not identified. It is noteworthy, however, that the ease of detection regarding the subject indication was questionable. This is supported by the fact that various experts consulted by the NRC have evidently reached different decisions on this matter, based on the same baseline information. (See NRC Indian Point 2 Steam Generator Tube Failure Lessons-Learned Report (TAC No. MA9163; October 23, 2000) at page 9.) Their differing viewpoints regarding the ease of discovery of this indication supports licensee's position. Based on the significant difficulty of discovery regarding the subject indication, Con Edison believes that a violation of 10 CFR 50, Appendix B, Criterion XVI cannot be sustained consistent with the actual facts and circumstances.

Con Edison presently submits that application of evolving steam generator inspection capabilities and standards of today retrospectively to circumstances at Indian Point 2 that existed in 1997 should not be a basis for NRC enforcement action. Compare the requirements of 10 CFR 50.109. The occurrence of a steam generator tube failure following an inspection does not mean in or of itself that the inspection was inadequate. When a licensee followed regulatory requirements, and particularly when the licensee also followed then-existing industry practices, and an event nonetheless occurred, then from a regulatory perspective the licensee should not be held liable for the event. Rather, the licensee and the NRC should work in unison to help ensure that similar events do not again recur.

Con Edison's positions are supported by seven affidavits which were prepared by several steam generator inspection and eddy current experts. These individuals have been immersed in steam generator inspections and eddy current testing for a significant number of years. They are well qualified to render an opinion of Con Edison performance and the state of steam generator NDE in 1997. While some of the experts differed with the way Con Edison may have implemented some of its inspection processes, there was agreement that Con Edison's performance was in accordance with all requirements and industry standards, and that its findings were within the range of acceptable performance.

Specific responses to each of the bulleted items cited within the Notice of Violation are as follows:

<u>Statement 1</u>

A PWSCC defect was identified for the first time, at the apex of one row 2 tube, signifying the potential for other similar cracks in the low-row tubes. However, Con Edison did not adequately evaluate the susceptibility of low-row tubes to PWSCC and the extent to which this degradation existed.

Response

During the 1997 steam generator inspections, reasonable and appropriate measures that were then available were taken to identify and correct primary water stress corrosion cracking (PWSCC) in low-row U-bends. During the 1997 inspection, a single U-bend PWSCC indication was detected at the U-bend apex of tube R2C67 in steam generator 24. The indication did not leak at the EOC-13. The response to detection of PWSCC in a low-row U-bend was appropriate and consistent with industry practice. R2C67 was removed from service by plugging.

The EPRI PWR Steam Generation Examination Guidelines: Revision 4, Volume 1, provide the recommended steam generator tube inspection frequency and inspection sample size. Figure 3-1 sets forth the specific recommendations for sample size. In 1997 the recommendation was to inspect a 20% sample of all tubes in all steam generators at each inspection. The plan at the outset to inspect 100% of the Row 2 & 3 tubes in the course of the 1997 Indian Point 2 steam generator examinations therefore exceeded this provision of the EPRI guidelines.

Table 3-2 of the Guidelines at Section 3.4.3 sets forth the critical area sampling for Westinghouse Steam Generators. Table 3-2 identifies both inspection scope and the examination techniques for steam generators with active damage mechanisms. The Table 3-2 requirement for U-Bend IGA/ODSCC/PWSCC is a 100% inspection of the Row 1 & 2 U-Bends with a qualified RPC (rotating pancake coil) examination technique or equivalent. The 100% inspection of Row 2 & 3 U-bends with a qualified, rotating + Point coil met this requirement in the 1997 examinations.

The indication found in 1997 was based on the first +Point inspection of the Indian Point Unit 2 low-row U-bends following years of prior inspections with a bobbin coil only. Discovery of a single U-bend indication in the +Point inspection after prior bobbin coil inspections was not an unusual event after close to 16 EPFY of operation. It was more reasonable to conclude that the detection of U-bend PWSCC in R2C67 was attributable to the enhanced detection capabilities of the +Point probe than to accelerated tube deterioration during Cycle 13. In contrast, the Surry-2 tube rupture occurred in a row 1 tube after about 2 EFPY of operation when denting progression was very active, and flow slot closure due to hourglassing in the upper support plate far exceeded that at the top tube support plate at Indian Point 2.

Although low-row cracking had been reported by the industry in operating SGs for many years, the incidence of PWSCC was relatively low, occurred predominantly in row 1 U-bends, and to a much lesser extent in the row 2 U-bends. Very few cracks had been reported in the row 2 U-bends, and no large leakage events due to row 2 cracking had been reported until the February 2000 Indian Point-2 leakage event. The following table presents a summary of row 2 U-bend indications in Westinghouse-supplied Model 44 and 51 steam generators. These data clearly show the historical trend, and confirm that

discovery of a single instance of PWSCC in a row 2 U-bend at Indian Point 2 in 1997 was consistent with industry experience.

Summary of Row 2 U-Bend Indications

Westinghouse Originally Supplied Model 44 and Model 51 Steam Generators

Plant	Year Ind. Found	Heat Treat	Probe	Crack Type		ID or OD Crack		U-Bend Location	
				Axial	Circ.	PWSCC	ODSCC	Near Apex	Near Tangent
				Row 2 Indications					
Farley-1	1991	Yes	Pancake	1 tube 2 ind.		1 tube 2 ind.			1 tube 2 ind.
	1994	Yes	Pancake	2			2		2
Farley-2	None	Yes							
Diablo Canyon-1	1992	Yes	Pancake	1		1			1
	1994		Pancake	1		1			1
	1997		+Point	1		1			1
Diablo Canyon-2	1996	Yes	+Point	1		1			1
	1998		+Point	1		1		1	
Kewaunee	1990	No	Bobbin/ Pancake		1				1
	2000	No	+Point	1 tube 2 ind.		1 tube 2 ind.(1)			1 tube 2 ind.
Prairie Island-1	None	No					1 MBM '81		1
Prairie Island-2	None	No							
Indian Point-2	1997	No	+Point	1		1		1	
	2000	No	+Point	8 tubes 15 ind.		8 tubes 15 ind.		8 tubes 15 ind.	

Note:
1. New inspection results under review as potential MBMs. Indications were plugged.

Based on the information available in 1997, reviewed from the perspective of the 1997 inspection without the benefit of either subsequently-improved inspection techniques, the passage of time or 2000 inspection results, no additional corrective actions beyond plugging the affected tube would have been appropriate in response to the indication identified in R2C67. The appearance of a single row 2 U-bend PWSCC indication was not an unusual event, and the characteristics of the indication were consistent with the data included in the SSPD training and testing materials. If anything, the detection of a PWSCC indication in 1997 tended to corroborate the effectiveness of the new NDE technique (viz., +Point probe) being utilized.

The detection of an indication in R2C67 of steam generator 24 was also not an unusual or unexpected event in the context of the extensive steam generator degradation tracking work that Con Edison had commissioned prior to the 1997 inspections, a meticulous and comprehensive level of effort that comprehended international industry experience. Following the 1995 SG inspection outage Con Edison retained Dominion Engineering to independently develop projections of degradation for all degradation

mechanisms that had been observed in the IP2 SGs to date or were expected to occur based on industry experience with similar SGs. Notably, low-row U-bend PWSCC was recognized and included in the projection analysis. The projections were developed using Monte Carlo analysis and were based on a Weibull distribution for each degradation mechanism.

The result of this analysis identified that U-bend PWSCC was expected to occur at IP2 following 20 cycles of operation, and that this occurrence would initially be marked by the detection of one or two such degraded tubes. That PWSCC was initially observed several cycles before the estimate of Dominion Engineering is within the expected margin of error for such statistical studies. The important issue, however, is that Con Edison was fully aware of the potential for PWSCC to occur. In response to this prior in-depth and plant-specific assessment of SG tube degradation mechanisms, the 1997 inspection effort at Indian Point 2 was specifically qualified to detect U-bend PWSCC. The scope of inspection included 100% of the tubes, and all low-row U-bends were inspected using the best probe available for PWSCC detection.

The initial detection of U-bend PWSCC during the 1997 SG inspection outage was therefore no surprise, and in fact tended to corroborate prior degradation mechanism tracking efforts. The response taken by Con Edison following the 1997 SG inspections was to recommission a further analysis by Dominion Engineering to reflect the latest ECT results for all degradation mechanisms. This new analysis predicted that the next occurrence of PWSCC would be as early as RFO 14, again with an incident of one or two tubes. Thus, Con Edison was fully aware of the potential for PWSCC in low-row U-bends at Indian Point 2, but with very limited instances of initial onset which would progress at a slow rate.

Moreover, following the detection of low-row U-bend PWSCC in the R2C67 tube during the 1997 inspection, every available opportunity for evaluating the susceptibility of other low-row tubes to PWSCC was pursued, and the potential for degradation in other tubes assessed to the full extent of then-current diagnostic capabilities. In particular, the 1997 Indian Point Unit 2 inspection program specified a 100% inspection of all row 2 and 3 U-bends in each steam generator using a mid-range +Point rotating probe, the best qualified technique available at the time. The +Point probe was qualified by EPRI and added to the EPRI performance demonstration database in May 1996.

This technique was identified in NRC Information Notice 97-26, "Degradation in Small-Radius U-Bend Regions of Steam Generator Tubes", as qualified for detecting indications in small radius U-bends "in accordance with enhanced qualification criteria developed by EPRI."

From a programmatic point of view, during the 1997 inspection additional analyst training was provided in those instances when the inspection findings were unexpected or not consistent with materials used to train analysts. For example, discovery of ODSCC/IGA in the hot leg tubesheet crevice region during the course of the Indian Point 2

1997 inspection resulted in additional analyst training and complete re-evaluation of data in the hot leg tubesheet crevice region. This was done as these indications were not considered "typical flaw responses" and differed, somewhat, from the materials the analysts had been trained on. For the reasons set forth above, the identification of PWSCC in the R2C67 tube was not such an instance of an unexpected finding, and thus did not elicit modifications to the inspection program. Nor were any such modifications available or availing. Since the U-bend eddy current inspection program already comprehended a 100% inspection using the most sophisticated qualified probe then available, there were no further opportunities for evaluating low-row tube PWSCC that were not already being utilized to the fullest extent possible.

Statement 2

> *Indications of tube denting were identified for the first time in low-row tubes at the upper tube support plate (TSP) when restrictions were encountered as ECT probes were inserted into those tubes. Restrictions in 19 low-row tubes signified increased probability of deformed flow slots (hourglassing) at the upper TSP. Hourglassing of the upper TSP increases the stress at the U-bend apex of tubes. These stresses are a prime precursor for PWSCC. However, Con Edison did not adequately evaluate the potential for hourglassing based on the indications of the low-row tube denting.*

Response

Denting of steam generator tubes and flow slot hourglassing were recognized as active degradation mechanisms at Indian Point 2 since at least 1978, by which time Con Edison was conducting inspections and actively applying corrective actions to address the problem.

These corrective actions, which were routinely communicated to the NRC at the time of development and application, included steam generator water chemistry improvements, visual inspection of the SG secondary side, removal and evaluation of a section of tube support plate, and metallurgical and mechanical characterization of dented tubes that had been removed from the bundle at the first support plate. The first incidence of ECT probe restriction in the U-bend occurred in 1984 in two Row 3 tubes of steam generator 22 that were restricted at 6H (the hot leg of the 6^{th} support plate). An additional restriction was detected in 1986 and two more in 1989, when the first row 2 tube in SG 21 was determined to be restricted at 6C.

Over the course of discovery of flow slot hourglassing and tube denting phenomena, various remedial actions were taken to assess and address these issues. Extensive efforts were taken to characterize dents and justify the application of a suitable plugging criteria. Since 1976 Con Edison was actively engaged in SG secondary side inspection activities related to flow slot hourglassing and secondary side support plate

integrity issues. By 1979, Con Edison had observed incidents of ligament cracking at lower support plate flow slots. To assess the efficacy of the various corrective actions that were being implemented, Con Edison was by 1978 monitoring the extent and progression of flow slot hourglassing. To facilitate visual inspection of the uppermost support plate, additional inspection ports (so-called "hillside ports") were installed in SG 22 and SG 23, which were perceived to be leading SGs in this degradation mechanism. The results of these inspections were regularly reported to the NRC. In response to the Surry incident, in 1982 Con Edison incorporated a requirement to inspect for and report "significant" hourglassing to the NRC in the plant Technical Specifications. That there were no explicit numerical criteria for "significant" hourglassing is a measure of industry consensus and understanding of the effect of hourglassing on tube integrity and the belief that visual inspections would reveal Surry-type degradation. Moreover, since the objective of monitoring support plate integrity was to prevent tube leaks, it was also believed that dent gauging and periodic ECT inspection of the tubes themselves would be sufficient and adequate to assure that tube integrity would be maintained. The efficacy of Con Edison's corrective actions at Indian Point 2 was evidenced by 1989, by which time the progression of hourglassing had slowed to the extent that changes in subsequent outage-to-outage visual observations were virtually imperceptible. Additionally, the incidence of tube denting had declined to a very low rate. This response was associated with significant improvements that had been implemented in the steam generator water chemistry program.

The 1997 low-row U-bend probe restrictions need to be evaluated in light of this historical experience. In 1997, 19 tubes had restrictions that prevented a 0.610-inch +Point probe from passing through the tube. The distribution was specifically discussed in our RAI response to Question 11 in Reference 3. An excerpt from that RAI response provides as follows:

> "Nineteen of the twenty tubes were identified as being restricted to a 610 mil bobbin probe at the hot and/or cold leg of the sixth tube support plate (TSP). The nineteen tubes were comprised of fifteen tubes in row 2, three tubes in row 3, and one tube in row 4. Three tubes of the nineteen, row 2 column 62 and row 2 column 63 in SG 22, and row 3 column 31 in SG 23, were at hard spot locations, which are not subject to hourglassing and possible U-bend ovalization. The twentieth tube, which was row 29 column 15 in SG 24, is not a low radius U-bend tube.... Details of the examination data showed restrictions to the 610 mil bobbin probes at the sixth TSP; that is, the probes were not able to get to the bends. The terminology used in 1997 that stated U-bend restrictions was used in a generic sense to describe that the restrictions to the probes were at the uppermost region of the steam generators."

The most significant factor in evaluating the occurrence of probe restrictions in 1997 was the differing physical geometry of the +Point probe. All previous U-bend examinations had been conducted with very flexible ball joint bobbin coil probes of a much different mechanical design. In the 1997 inspection itself, 14 of the 19 instances of restrictions with 0.610-inch +Point probes did not exhibit restrictions to passage when an

identically-sized 0.610-inch RPC coil was used to examine both legs. The remaining five (5) tubes exhibited restrictions on only one tube leg.

This demonstrates that the source of probe restrictions was principally if not entirely associated with the different physical dimensions of the +Point probe, rather than increased denting at upper TSPs. Since there were in fact no discernable indications of low-row tube denting, as distinguished from the observable consequences of utilizing a differently-shaped probe, there were no inferences to draw from the restrictions actually encountered.

For reasons of different probe geometry and the actual passage of 0.610-inch probes in straight-leg examinations in 1997, Con Edison concluded that most if not all of the probe restrictions encountered in 1997 were associated with conditions that had existed since prior to approximately 1989, and did not conclude that the restrictions signaled a resumption of a previously-arrested degradation mechanism. This belief was consistent with the following factors:

1) Increases in frequency were to a considerable extent attributable to an expansion of the scope of the inspection to 100% of all four steam generators.

2) Of the 19 restrictions, five (5) of the restrictions were in areas where the flow slots were visually inspected and no hourglassing was observed.

3) Three (3) of the 19 restrictions were at locations that did not line up with flow slots.

4) Thus for eight (8) of the 19 restrictions that occurred in 1997, there was no positive correlation to the symptom of denting and hourglassing.

Visual inspection of tube/support plate intersections was the accepted and customary practice throughout the industry in 1997 for assessing support plate flow slot deformation. Such inspections were thoroughly conducted at Indian Point 2 in 1997, and reported as visual inspections in Con Edison's subsequent written report to the NRC. Only three years later, in 2000, was additional knowledge gained through analysis that hourglassing resulting in leg displacement of as little as 0.1 inch could be sufficient to increase U-bend extrados stress to an extent that susceptibility to PWSCC was increased. This information was not known anywhere in the industry in 1997, and accordingly could not form the basis for a 1997 inspection performance standard.

The 1997 inspection experience thus reveals the consequences of the first-time utilization of a probe with a much different physical geometry, rather than evidence of increased tube denting. Flow slot deformation was examined visually, in accordance with then-prevailing industry custom and practice. However, even if conditions for denting- or hourglassing-related PWSCC precursors are presumed to have existed in 1997, and it is also presumed that they should have been detected, then the potential for those conditions to have contributed to low-row U-bend PWSCC were examined to the fullest extent

possible by the examination of 100% of the potentially susceptible row 2 and row 3 tubes utilizing the most advanced qualified +Point probe then available.

Statement 3

Significant ECT signal interference (noise) was encountered in the data obtained during the actual ECT of several low-row U-bend tubes. This significant noise level reduced the probability of identifying an existing PWSCC tube defect. However, the 1997 SG inspection program was not adjusted to compensate for the adverse effects of the noise in detecting flaws, particularly when conditions that increased susceptibility to PWSCC existed.

Response

During the 1997 inspection, a single U-bend flaw was detected in tube R2C67 of steam generator 24. At the time, a depth of 50% through-wall was estimated. A review of this data indicates that the flaw had an amplitude of 3.11 volts, whereas the background noise level was 1.04 volts peak-to- peak and 0.44 volts vertical maximum. The indication thus had a signal-to-noise ratio of approximately 3 to 1. This response was consistent with the U-bend data in the site-specific performance demonstration training and testing materials utilized for analyst training in connection with the 1997 Indian Point inspection. Moreover, the noise levels experienced at Indian Point in 1997 did not appear to differ appreciably from row 1 and 2 U-bend data from other plants. Thus at that time, it appeared that the eddy current technique was performing as expected.

In 1997 no formal industry criteria existed to evaluate noise in a quantitative manner. Furthermore, no data were available to establish a correlation between signal amplitude and depth. The only information then available consisted of the response data from R2C67, the EPRI data for technique 96511, and the response from the calibration standards. The EPRI qualification data set consists primarily of EDM notches placed in row 1 U-bend samples. It should be noted that EDM notches typically yield larger signal amplitudes for a given depth than PWSCC. In the absence of data from partial through-wall PWSCC specimens, the responses of the calibration notches were benchmarked along with the noise levels present in the EPRI samples. This benchmarking took place after the 2000 inspection program. The peak to peak and vertical maximum voltages are listed in the table below. All measurements were made from the 300 kHz component.

CALIBRATION STANDARD USED IN ETSS 96511

AXIAL EDM SLOTS	VOLTS PEAK to PEAK	VOLTS VERTICAL MAX
100 %	20.00	9.39
80 ID	5.40	1.96
60 ID	3.84	1.11
40 ID	2.17	0.44
20 ID	0.66	0.12

This data suggests that given the noise levels in R2C67, flaws ≥ 40% would be detectable (i.e. signal to noise for a ≥ 40% flaw is ≥ 1 to 1.)

The 1997 noise level in tube R2C5 from steam generator 24 was also evaluated. This data shows a peak to peak amplitude of 1.63 volts, and a maximum vertical amplitude of 0.98 volts. The results from this assessment suggest that flaw depths of approximately 50% through-wall and less may not be detected (signal to noise < 1 to 1). This observation is consistent with NRC IN 97-26.

The table below lists the EPRI samples, their noise levels, and the depth of the flaws in the U-bend.

ETSS 96511 FLAW MATRIX

SAMPLE	NOISE VPP	NOISE VM	DEPTH	DEPTH	DEPTH
Z5324	0.72	0.21	41	27	32
TVA-1	0.78	0.27	45	44	44
TVA-13	0.75	0.20	55	55	55
TVA-23	0.70	0.16	55	58	54
1019-I	1.26	0.29	40		
1019-III	1.39	0.61	50		
1019-IV	1.60	0.56	60		
1019-UB-I	1.22	0.41	60		
Z-5300	1.71	0.52	44	100	
TSL-126	1.19	0.19	>40		
TSL-15	1.33	0.16	>40		
TSL-2	1.03	0.20	100		
TSL-10	0.66	0.17	>40		
TSL-113	1.04	0.15	42	42	
TSL-115	1.27	0.16	62	62	
AVERAGE	1.11	0.28	N/A	N/A	N/A

The data shows that some samples had a noise level greater than that observed in R2C67, while other samples were less. Specifically, 9 of 15 samples were $\geq$ 1.04 volts peak to peak and 3 of 15 samples were $\geq$ 0.44 volts vertical maximum.

Attempting to posit ECT failures to detect indications based upon the quality of eddy current data obtained in 1997 would be unreasonable, since data quality criteria was not available in 1997. An industry effort to develop tube noise and data quality guidance was only initiated following the recent evaluations of R2C5. Not only were there no noise criteria in 1997, but there was also no database from which it could be postulated that noise effects could mask a flaw under circumstances such as those present in R2C5.

It is also not clear what 1997 SG inspection program adjustments could have been made to compensate for the effects of particular noise levels in diminishing the detectability of flaws even if those confounding influences had been appreciated. As indicated in response to Statements 1 and 2, there were no conditions revealed in the 1997 inspections from which an increased EOC 13 susceptibility to PWSCC could be inferred. However, even if there had been, the most sensitive qualified probe then available was already being utilized in a 100% inspection of susceptible low-row U-bend tubes, hence there were no compensatory programmatic adjustments that could have been made beyond those already being utilized.

Statement 4

As a result, a minimum of four tubes (with PWSCC flaws in their small radius U-bends) were left in service following the 1997 inspection, until the failure of one of these tubes occurred on February 15, 2000 while the reactor was at 100% power.

Response

The NRC's review of the 2000 eddy current inspection data states that during operating Cycle 14 there were three tubes in addition to tube R2C5 from steam generator 24 which had indications in their U-bend areas. These tubes were tubes R2C69 and R2C72 from steam generator 24, and tube R2C87 from steam generator 21. This is not an unusual event, and does not by itself support a conclusion of non-compliance with Appendix B, Criterion XVI. There have been many instances where indications detected during a current inspection program are found in prior outage inspection data when the review of historical data is conducted with the knowledge of subsequent inspection results. Furthermore, it is not clear that these three particular tubes exceeded servicability criteria in 1997. When the three tubes were identified during the 2000 inspection and subsequently in-situ pressure tested, acceptance requirements were met. This is further discussed in the 2000 CMOA, Table 3.2 contained in the U-Bend Section (Reference 1).

B. Corrective Steps That Will Be Taken to Avoid Further Violations

Notwithstanding Con Edison's denial of the alleged violations, it is appropriate to take further actions to ensure we protect the integrity of the newly-installed steam generators in addition to those steam generator program improvements that have already been implemented. Key actions in this regard are summarized below:

1. Secondary Side Chemistry Program Revisions

With the removal of the last copper containing Feedwater heater, the Secondary Side Chemistry Program will be altered slightly to minimize the transport of iron through the secondary system and potentially into the steam generators. This will reduce the rate at which iron oxides will accumulate in the steam generators, thereby reducing the potential for oxide generated noise during future eddy current testing. The addition of hydrazine serves to control pH in the secondary side of the plant. Prior to the 2000 outage the acceptable pH range was 9.2 to 9.6. To reduce the transport of iron, this pH range has been increased to 9.6 to 10.0. However, this will have a short-term effect of increasing copper concentrations slightly during the initial stages of operation. Residual copper will be placed into solution and purged by the Long Loop Recirculation System during start up (below 200 F) and by the steam generator blowdown system during operation.

2. Steam Generator Outage Support Engineering Specification Updates

Subsequent to the completion of the Steam Generator Replacement Project and the programmatic improvements mandated by SAO-180, specific engineering specifications will need to be updated. This will be completed prior to the next outage. Engineering specifications for conducting steam generator inspection and repair activities are as follows:

MP 72211 - Search & Recovery of Foreign Objects in SG
MP 72214 - Visual Inspections of SG Secondary Side
MP 72217 - Eddy Current Exams of SG Tubes
MP 72224 - Identification and Repair of Leaking Tubes in SG
MP 72238 - Inspection, Plugging or Replacement of SG Tube Plugs

3. Steam Generator Tube Failure Lessons Learned Report, dated October 23, 2000

The referenced report contains a list of recommendations from the task group on actions to prevent a similar type of event from occurring. Indian Point is actively participating is this effort with NEI and with EPRI. On December 20, 2000 NEI and industry representatives meet with regulatory representatives to present the results of our initial review of the recommendations. The Indian Point Steam Generator Project Manager participated in the meeting to develop the presentation on December 20th. Indian Point

will continue to participate in these types of industry actions to address the recommendations outlined in the report.

Date When Full Compliance Will be Achieved

Based upon the implementation of Station Administrative Order-180, "Administrative Steam Generator Program," and the completion of the Steam Generator Replacement Project, as discussed in the cover letter to this Attachment, full compliance has been achieved at the present time. Consequently, the elements of the violation that are being contested are in fact now remediated, and further violations will be avoided. We have concluded that the steam generator in-service inspection program at Indian Point 2 is currently in full compliance with 10 CFR 50, Appendix B, Criterion XVI. The basis for this conclusion is the various steps we have taken, including but not limited to steam generator replacement, as set forth more fully in the December 18, 2000 letter of Mr. J. Baumstark to the NRC (Reference 4).

References

1) 2000 Refueling Outage Steam Generator Inspection Condition Monitoring and Operational Assessment Reports, May 31, 2000, transmitted by Con Edison Letter dated June 2, 2000

2) Indian Point 2 Technical Evaluation Report of Steam Generator Tube Failure, Category C-3 Steam Generator Inspection Results, and Steam Generator Operational Assessment, transmitted by NRC Letter dated October 11, 2000

3) Con Edison Letter to NRC dated June 16, 2000

4) Con Edison Letter from Mr. J. Baumstark to Mr. H. J. Miller dated December 18, 2000

ATTACHMENT C TO NL-01-005

NEW REGULATORY COMMITMENTS

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247
JANUARY 2001

The following list identifies those actions committed to by Con Edison in this document. No further regulatory commitments are contained herein.

Commitment	Due Date
Subsequent to the completion of the Steam Generator Replacement Project and the programmatic improvements mandated by SAO-180, specific engineering specifications will be updated.	This will be completed prior to the next outage.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of:	)	
	)	
Consolidated Edison Company	)	Docket No. 50–247
of New York, Inc.	)	
(Indian Point Nuclear Station,	)	
Unit No. 2)	)	

AFFIDAVIT OF STEPHEN D. BROWN

I, Stephen D. Brown, being duly sworn, state as follows:

1. I have prepared this affidavit as an independent consultant.

2. I was recently asked to examine elements of a nondestructive examination (NDE) of the steam generators at the Indian Point 2 nuclear power plant conducted in the spring of 1997 utilizing a technique referred to as eddy current testing. Indian Point 2 is owned and operated by the Consolidated Edison Company of New York, Inc.

3. I did not participate in the Indian Point 2 steam generator inspections conducted in 1997 and 2000. I have recently participated in retrospective reviews of the 1997 examination on behalf of Consolidated Edison and Westinghouse.

4. My professional qualifications and experience are set forth in my curriculum vitae, which is attached as Exhibit 1. I have been involved in steam generator eddy current in excess of 50 plants over 26 years.

5. Prior to preparing this affidavit I reviewed the following documents: 1) IP2 1997 Data Information Package provided by Westinghouse consisting of a) the Data Analysis Guidelines, b) copies of the Analysis Technique Sheets, c) drawings for rotating probe calibration standards, d) data analysts training information distributed in 1997 and e) rotating probe eddy current data from SG 21,23 and 24; 2) NRC Special Inspection Report – Indian Point Unit 2 Steam Generator Tube Failure – Report NO. 05000247/2000-010 dated August 31, 2000; 3) Proposed Steam Generator Tube Examination Program – 1997; 4) Transmittal of the Indian Point 2 Steam Generator Tube Failure Lessons Learned Report dated November 1, 2000; 5) Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2 (NRC Inspection Report 05000247/2000-010) dated November 29, 2000.

6. The purpose of this affidavit is to evaluate issues surrounding the 1997 Indian Point 2 steam generator NDE raised by the Nuclear Regulatory Commission in a November 20, 2000 document entitled Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2 - Report No. 05000247/2000-010. This is accomplished by reviewing Indian Point 2 plus-point rotating probe eddy current data acquired and analyzed during 1997 in the context of data quality issues and the statistical/probabilistic nature of the eddy current examination process.

7. The specific NRC finding, as applied to the 1997 Indian Point 2 steam generator examination, states as follows: "Significant ECT signal interference (noise) was encountered in the data obtained during the actual ECT of several low-row U-bend tubes. This significant noise level reduced the probability of identifying an existing PWSCC tube defect. However, the 1997 SG inspection program was not adjusted to compensate for

the adverse effects of the noise in detecting flaws, particularly when conditions that increased susceptibility to PWSCC existed."

8. In understanding events that transpired at Indian Point 2 during that time frame, it is important to note that this unit had extensively dented steam generators.

9. Based on industry experience with the Surry and Turkey Point nuclear plants, the nuclear industry was aware that extensively dented steam generators were susceptible to inner row U-bend PWSCC.

10. Rotating probe eddy current technology, used for inner row U-bend examination, was not introduced into the field until the 1987 timeframe well after the Surry and Turkey Point steam generator replacements.

11. Thus, there was no industry rotating probe eddy current data from extensively dented units with apex cracking that could be used for reference or application during the 1997 Indian Point 2 steam generator examination.

12. Other industry rotating probe eddy-current data from non-dented units did exist. However, there was no factual basis that could be applied to this data to determine its adequacy (or inadequacy) since no extensively dented U-bend apex reference data set existed for comparison.

13. The inner-row U-bend examination that was conducted at Indian Point 2 during 1997 was done using a plus-point rotating probe which was considered one of the best probes in the industry for detection.

14. The use of this probe was approved by the NRC.

15. My review of the Indian Point 2 1997 outage plus-point rotating probe eddy current data used data from steam generator 24. I used analysis software with phase

rotation settings identical to those used by the two primary and secondary production analysts that analyzed data from tube R2C5 (the tube that leaked during February 2000).

16. As a general observation, while the U-bend data was qualitatively noisy, the data was able to be analyzed using 1997 industry practices and technology and was not atypical of noisy data encountered in other plants contemporary with or prior to the 1997 timeframe.

17. The type of noise I observed in the 1997 Indian Point 2 U-bends would normally be classified as tube noise i.e., inherent with the condition of the tubing or steam generator secondary side.

18. There were no industry requirements or guidelines in effect during 1997 that addressed tube noise or data quality.

19. Data quality noise practices that did exist during the 1997 timeframe typically addressed electronic sources related to instrumentation, probe cabling, etc.. Acceptance levels were often subjective and at the discretion of individual data analysts.

20. Extremes in U-bend tube noise levels are illustrated with the 300 kHz vertical channel strip chart data shown in Exhibits 2 and 3

21. Exhibit 2 shows vertical channel strip chart data from a tube (R2C74) with the highest noise level.

22. Exhibit 3 shows vertical channel strip chart data from a tube (R2C31) with the lowest noise level.

23. The ratio of the highest to lowest noise levels shown in Exhibits 2 and 3 is approximately 3 to 1.

24. I then compared eddy current data from tube R2C67 (which was plugged during 1997) with data from tube R2C5 (a tube with an unreported indication during 1997 that subsequently leaked during February 2000). This provides a context from which to assess the significance of the noise levels shown in the previous two exhibits.

25. Vertical strip chart data for the 1997 plugged tube R2C67 is shown in Exhibit 4. The noise level for this tube is comparable to the tube with the lowest noise level shown in Exhibit 3.

26. Exhibit 5 shows vertical strip chart data for the tube that leaked (R2C5) during February 2000. The noise in this tube is comparable to the highest noise level tube shown in Exhibit 2.

27. For the plugged tube R2C67 (Exhibit 4), the tube noise is relatively low in an absolute sense with the indication (signal) also exhibiting a relatively high signal-to-noise (S/N) ratio.

28. The opposite is true for R2C5 (Exhibit 5) which was the tube that leaked during February 2000. The tube had a higher absolute noise level with multiple indications (signals) exhibiting a lower (S/N).

29. A static Lissajous display for tube R2C67 with the only inner-row U-bend indication reported during the 1997 outage is shown in Exhibit 6.

30. The indication is seen as the large amplitude signal rising out of the strip chart data near the apex of the U-bend.

31. Isolation of one of these peaks in the Lissajous window shows an indication that met the Westinghouse analysis procedure reporting requirements in effect during 1997.

32. There was nothing unusual or unexpected about this indication. In my opinion, contrary to the NOV, finding this indication should not have resulted in any adjustments to the program then in progress at Indian Point 2 in 1997. Analysts often routinely deal with hundreds of indications as a part of their job and are not alarmed when an indication is first observed.

33. Exhibit 7 illustrates the static Lissajous display for indications in R2C5, which went unreported during 1997.

34. The right most strip chart shows a series of multiple peaks (noted as indications in the figure), which just barely exceed the local noise level.

35. Isolation of one of these peaks in the Lissajous window shows an indication that met the Westinghouse analysis procedure reporting requirements in effect during 1997.

36. A comparison of the eddy current graphics from Exhibits 6 and 7 shows the following.

37. The indications for the reported and unreported indications have comparable amplitudes i.e., 2.18 volts and 2.03 volts.

38. The strip chart data shows a much lower noise level for R2C67 than R2C5.

39. The indications in R2C5 are not nearly as prominent as those are in R2C67.

40. Exhibits 8 and 9 provide a visual representation of the dynamic aspects of U-bend tube noise and its relationship to detection as viewed in the Lissajous display.

41. Exhibit 8 shows a Lissajous display for R2C67 in which the screen persistence was maintained as the probe was pulled through the U-bend between the upper two supports. This display mode integrates the noise level throughout the U-bend.

42. The darker ellipsoidal region (noise ellipse) to the lower right of the Lissajous display, with its semi-major axis parallel to the horizontal axis, is the integrated noise level one observes as the probe is scanned through the U-bend.

43. The series of vectors (signal) directed to the upper left which arise out of the noise ellipse are indications associated with U-bend apex cracking. For this example, the flaw signals are clearly visible within the tube noise.

44. Exhibit 9 shows the dynamic tube noise for R2C5. As with the previous exhibit, an integrated Lissajous display is shown with the screen persistence maintained as the probe was pulled through the U-bend between the two upper support plates.

45. For this tube, the darkened ellipsoidal region (identified as the noise ellipse in the figure) near the center of the display with its semi-major axis located at an angle of approximately 75-degrees (left-handed coordinate system) is the integrated noise level.

46. The multiple signals directed towards the upper left are the signals of interest associated with apex U-bend cracking that were not reported. It should be noted that even though the integrated peak-to-peak signal-to-noise ratio is approximately unity, the signals of interest are discernable in the Lissajous display.

47. The conclusions drawn from reviewing the 1997 Indian Point 2 rating probe eddy current data are as follows; 1) The indication reported in R2C67 (the only tube reported with U-bend apex cracking) had a relatively high (S/N) ratio which increased detection probability. This was the first and only industry data point from which a conclusion could be drawn about data quality. Based on this single observation, there was no evidence that tube noise levels might be impacting detection; 2) The noise levels in the U-bend data were within other industry analysis experience prior to and contemporary

with the Indian Point 2 1997 timeframe. Thus, Indian Point 2 tube noise levels were not unique; 3) While the U-bend rotating probe data is noisy, this factor alone should not have prevented indications in R2C5 from being reported. The amplitude of the missed indication in R2C5 is comparable to the reported indication in R2C67 i.e., 2.31 volts versus 2.16 volts. However, the peak-to-peak noise level in R2C5 was higher by roughly a factor a four.

48. In order to have implemented an eddy current data quality or noise level requirement during the 1997 Indian Point 2 outage one significant item was necessary; a flaw signal data base from which to infer acceptable noise levels.

49. This database would be constructed from a set of eddy current signals obtained from tubes with denting assisted U-bend apex PWSCC.

50. Denoting the amplitudes of the eddy current signals as S_a, S_b, ... S_i, and defining an acceptable (S/N) ratio as (S/N) > k, where k is some number (usually assumed to be three), then the maximum acceptable noise level is given by $N < S_i/k$ where S_i is the amplitude (in volts) of the *smallest* signal required to be detected.

51. As mentioned previously, the type of data necessary to determine a maximum acceptable noise level did not exist prior to the 1997 Indian Point 2 steam generator examination since there was no rotating probe eddy current data from extensively dented units. Accordingly, it was not possible to realistically meet a data quality requirement. Any noise level that might have been chosen would have been selected on a somewhat ad hoc basis. It is again emphasized that based on the single indication reported in SG R2C67 during the 1997 outage there was no evidence of a data quality problem. The absence of rotating probe eddy current data from extensively dented

units would also have hampered and restricted the capabilities for analyst training on this type of flaw environment.

52. Basically what happened during the Indian Point 2 steam generator examination was that an indication in R2C5 went unreported which subsequently leaked during February 2000. In light of this event, it often goes unnoticed that the steam generation tube examination process is fundamentally statistical in nature. This is true for tube selection, data acquisition, and data analysis. For example, the minimum acceptable tube selection sample size, which is typically 20%, is based on sampling at least one degraded or defective tube at some confidence level. The success of this sampling scheme is dependent on the number of degraded or defective tubes being present in sufficient numbers, usually in excess of ten or so. Acceptable data acquisition technique performance is based on a cumulative 80% detection probability at a 90% confidence limit for discontinuities with depths in excess of 60% throughwall. Data analyst pass/fail criterion for the EPRI QDA program and many site-specific performance demonstrations is based on a cumulative 80% detection probability. The logical consequence of a statistically based i.e., imperfect, steam generator tube examination process is that defective tubes can be left in service. This is all that happened during the Indian Point 2 1997 steam generator examination.

53. The NRC has explicitly accepted a probabilistic approach to the steam generator examination process in its licensing of alternate repair criteria (ARC). Acceptance of a probabilistic approach recognizes that elements of the examination process are imperfect.

54. This imperfection was also inherent in the 1997 Indian Point 2 examination (and other plants) since the same examination process elements are present.

55. NDE related process elements typically include detection and sizing.

56. Imperfect detection is addressed using a detection probability function, an example of which is shown in Exhibit 10.

57. This exhibit shows that relatively deep cracks can inadvertently remain in service due to basic technique limitations or human factor effects.

58. I have kept track of industry-wide steam generator forced outages since PWR plants were first commercialized during late 1960.

59. While only a handful of tube ruptures have occurred, I have documented hundreds of leaker outages, which is what basically happened at Indian Point 2.

60. The cause of many of these leaker outages can be traced to the NDE process; in particular, human factor effects. However, for some reason, the historical regulatory reaction to eddy current examinations subsequently revealed to be imperfect pales in comparison with the response to the February 2000 Indian Point 2 tube leak event. I find no logical basis for this difference.

61. The foregoing statements are true and correct to the best of my knowledge and belief.

Stephen D. Brown

Stephen D. Brown

Sworn and subscribed to before me on this 18 day of January, 2001.

Frances M. Thurber

Notary Public

FRANCES M. THURBER
Commission # 1130906
Notary Public — California
San Diego County
My Comm. Expires Mar 23, 2001

My Commission expires: 03/23/2001

Exhibit 1

Curriculum Vitae

STEPHEN D. BROWN

SPECIALIZED PROFESSIONAL COMPETENCE

An expert in the development and application of nondestructive evaluation (NDE) techniques with more than twenty-five years of experience and extensive expertise from both practical and analytical viewpoints to the solution of NDE problems. Mr. Brown is a certified Level III and qualified data analyst (QDA) in accordance with the EPRI performance demonstration program.

Well-known industry consultant concerning all aspects of NDE of steam generator tubing. Mr. Brown has provided independent consulting services across the industry to vendors, utilities, and regulators. Actively involved in steam generator NDE since 1974 as Group Leader at Battelle Memorial Institute and later as Manager at the EPRI NDE Center. Experienced in the development of techniques to interpret all forms of steam generator tubing degradation. Knowledge and expertise is sought industry wide by vendors, foreign and domestic utilities, and the Electric Power Research Institute (EPRI). Prepared initial drafts (up through Rev. 5) of the "PWR Steam Generator ISI Guidelines", and was principal author of the "Steam Generator NDE Data Analyst Performance Demonstration Program" (i.e., EPRI QDA program) both of which are in use throughout the industry. Developed the statistical basis for steam generator tube sampling plans adopted by EPRI and the American Society for Mechanical Engineers (ASME).

EDUCATION AND PROFESSSIONAL BACKGROUND

- B.S. (Physics), The Ohio State University (1967)

- Degree, Electrical Engineer, The Ohio State University (1974)

Society/Committee Memberships:

— Institute of Electrical and Electronic Engineers
— American Society of Nondestructive Testing
— EPRI ISI Guidelines Committee
— ASME Task Group of Steam Generator Sample Plan Development
— EPRI Steam Generator Degradation Specific Management Committee for the Development of Alternate Plugging Criteria

- Awards

  — *Achievement Award for Best Technical Paper* Published in Materials Evaluation, American Society of Nondestructive Testing

  — Westinghouse General Managers Quality Achievement Award 1986 for Outstanding Accomplishments in the Managerial Category

  — Patent #4,876,506, *Apparatus and Method for Inspecting the Profile of the Inner Wall of a Tube*, October 1989

SELECTED REPORTS, PUBLICATIONS, AND INVITED LECTURES

Depth Based Structural Analysis Methods for SG Circumferential Indications, Electric Power Research Institute, EPRI Report TR-107197 (co-author) (November 1997).

Development of Wavelet Analysis Methods for Crack Characterization, Presented at the EPRI 16th Annual Steam Generator NDE Workshop, EPRI Report TR-108858 (September 1997).

Inversion of Rotating Probe Eddy Current Data for Structural Integrity Applications, Presented at the EPRI Condition Monitoring and Operational Assessment Meeting, Colorado Springs, CO (February 1997).

Inversion of Rotating Probe Eddy Current Data for Improved Lateral Resolution, Presented at the EPRI 15th Annual Steam Generator NDE Workshop, EPRI Report TR-107161 (November 1996).

Steam Generator NDE Performance Demonstration Program, Electric Power Research Institute, EPRI Report RP-S530 (June 1993).

PWR Steam Generator Examination Guidelines Rev. 2, Electric Power Research Institute, EPRI Report NP-6201 (December 1988).

Nondestructive Evaluation Methods to Measure Inside Diameters of Steam Generator Tubing, Electric Power Research Institute, EPRI Report NP-5902 (July 1988).

Template Matching - An Approach for the Machine Sorting of Eddy Current Data, Materials Evaluation (November 1985).

Evaluation of Eddy-Current Procedures for Measuring Wear Scars in Preheat Steam Generators, Electric Power Research Institute, EPRI NP-3928 (April 1985).

Steam Generator U-Bend Eddy Current NDE, Electric Power Research Institute, EPRI

NP-3010 (April 1983).

Eddy-Current NDE for Intergranular Attack, Electric Power Research Institute, EPRI NP-2862 (February 1983).

Automatic Analysis of Eddy Current Signals, Proceedings, 5th International Conference on Inspection of Pressurized Components, The Institute of Mechanical Engineers, London (with G.J. Dau) (October 1982).

Field Experience with Multifrequency-Multiparameter Eddy Current Technology, Electric Power Research Institute, EPRI NP-2299 (March 1982).

Steam Generator Mock-up Facilities, Electric Power Research Institute, EPRI NP-1785 (co-author) (April 1981).

Evaluation of Multiparameter Eddy-Current Technology for Inspection of Steam Generator Tubing, Brookhaven National Labs, NUREG/CR-1958 (March 1981).

In-Service Evaluation of Multifrequency/Multiparameter Eddy-Current Technology for the Inspection of PWR Steam-Generator Tubing, Eddy-Current Characterization of Materials and Structures, ASTM STP 722, American Society for Testing and Materials, pp. 189-203 (1981).

Evaluation of Selected Signal Processing Methods for the Characterization of Steam Generator Eddy Current Signals, Brookhaven National Labs, NUREG/CR-1007 (co-author) (August 1979).

An Evaluation of Eddy Current Inspection Methods for PWR Steam Generator Tubing, Electric Power Research Institute, EPRI NP-636 (co-author) (October 1978).

Nondestructive Evaluation of Steam Turbine Rotors - An Analysis of the System and Techniques Utilized for Inservice Inspection, Electric Power Research Institute, EPRI NP-744 (co-author) (April 1978).

Evaluation of the Eddy-Current Method for the Inspection of Steam Generator Tubing - Denting, Brookhaven National Labs, NUREG-50743 (co-author) (September 1977).

Evaluation of the Eddy-Current Method for the Inspection of Steam Generator Tubing, Brookhaven National Labs, NUREG-40679 (co-author) (September 1976).

Steam Generator Reference Book, Chapter 26, Nondestructive Examination, Electric Power Research Institute, EPRI Report TR-103824.

Exhibit 2
Strip chart data showing visual representation of tube noise extremes in SG 24 row 2 U-bends
- Highest noise level (R2C74) -

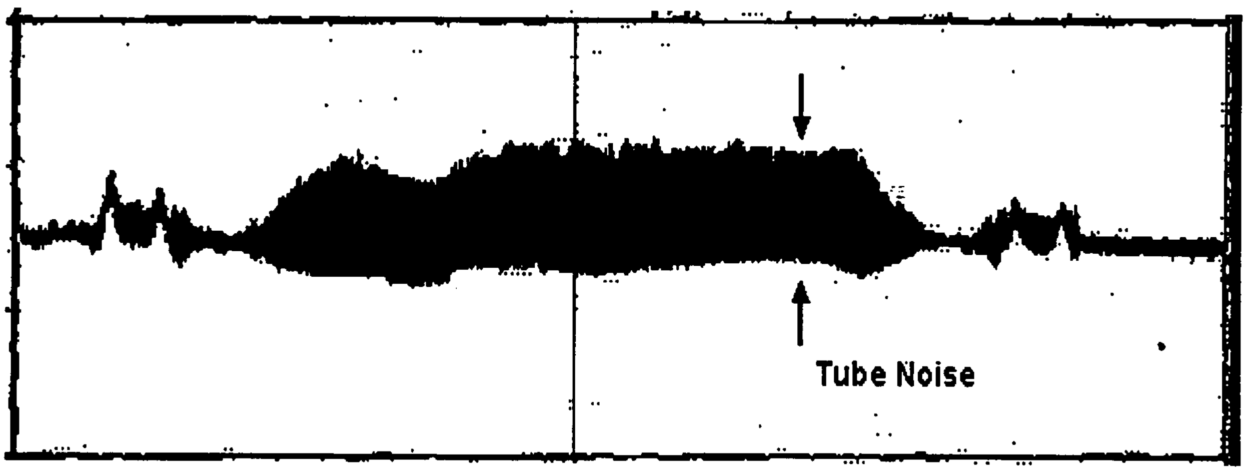


Exhibit 3
Strip chart data showing visual representation of
tube noise extremes in SG 24 row 2 U-bends
- Lowest noise level (R2C31) -

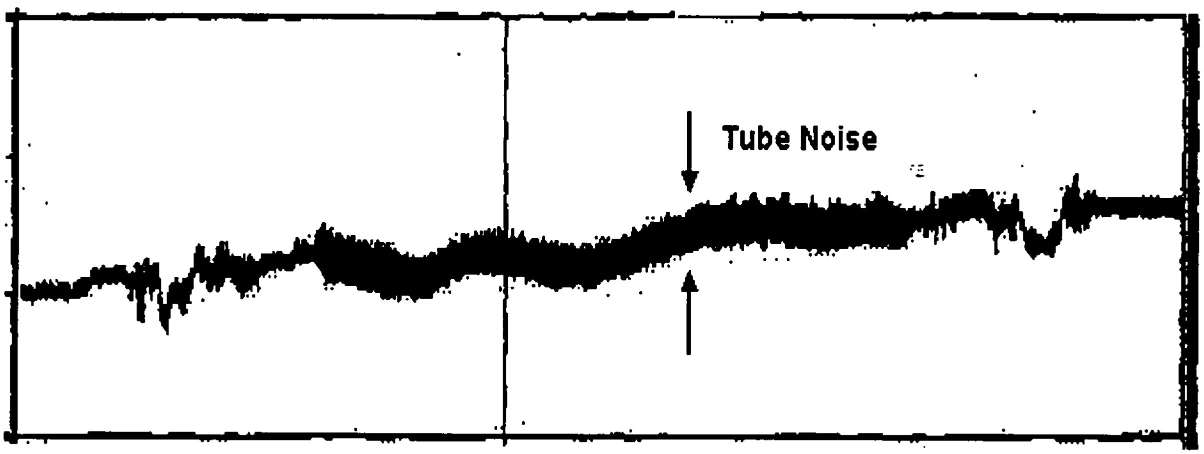


Exhibit 4
300 kHz vertical channel strip chart data showing noise levels in
SG 24 plugged tube (R2C67)
- Low noise level with high (S/N) indication -

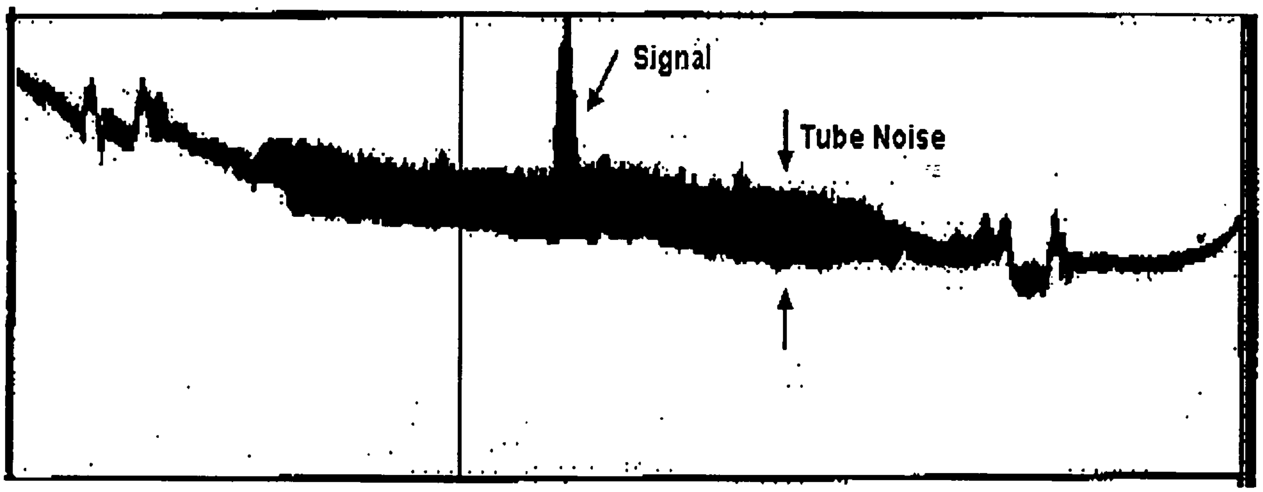


Exhibit 5
300 kHz vertical channel strip chart data showing noise levels in
SG 24 tube with unreported indications (R2C5)
– High noise level with low (S/N) indication -

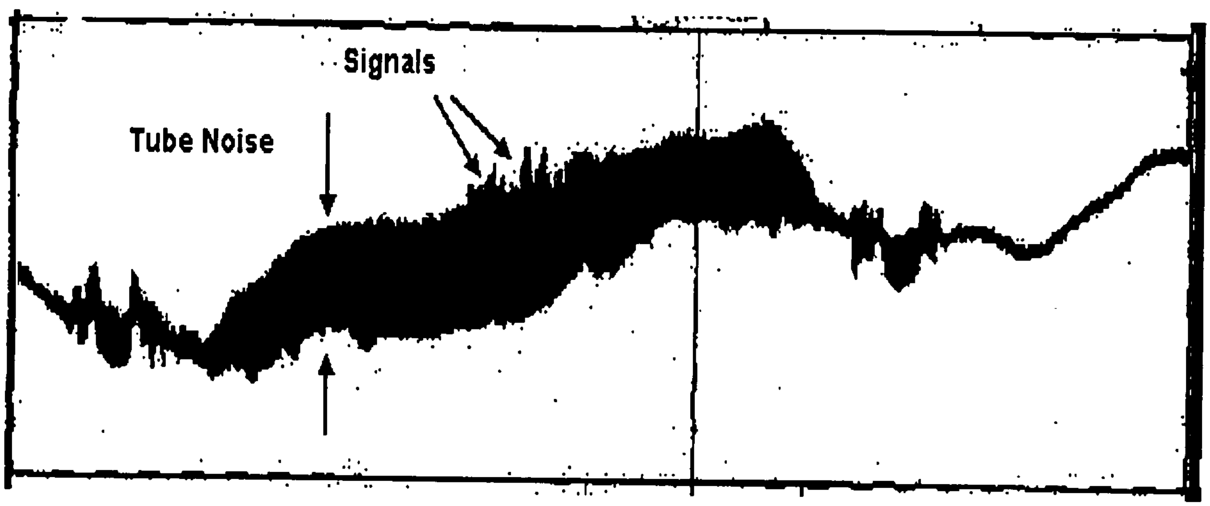


Exhibit 6
R2C67 plus point data for indication reported during 1997
- Lissajous display -

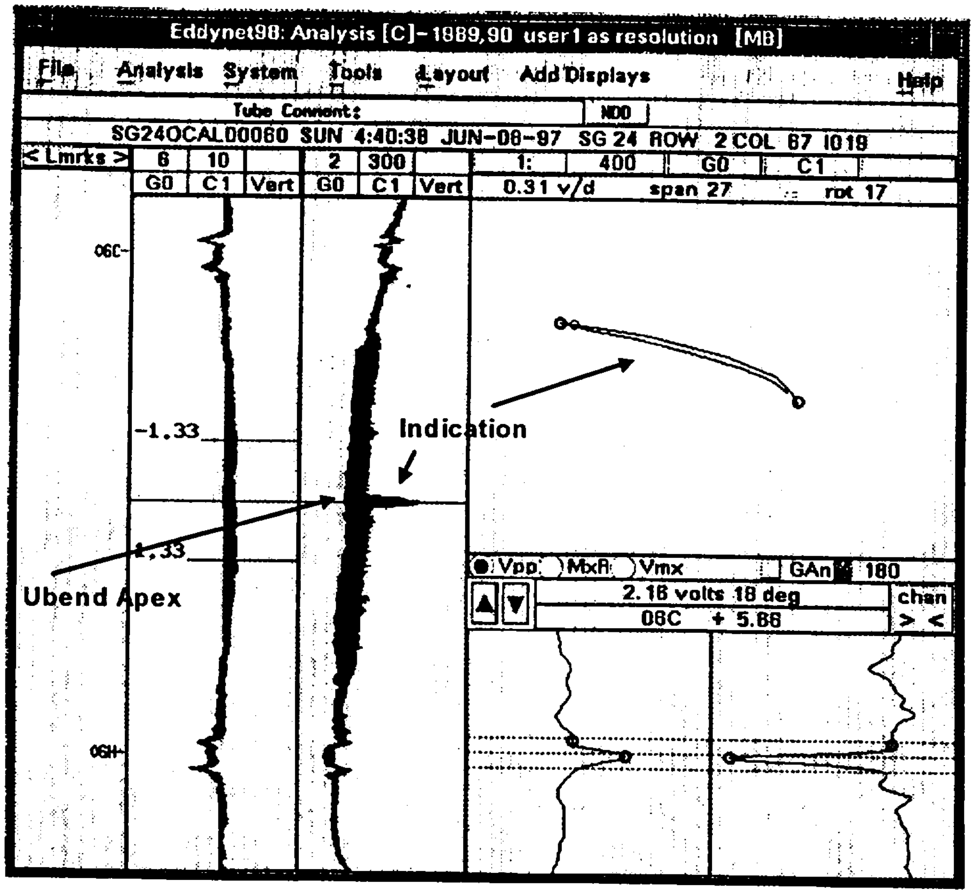


Exhibit 7

R2C5 plus point data for indication not reported during 1997

- Lissajous display -

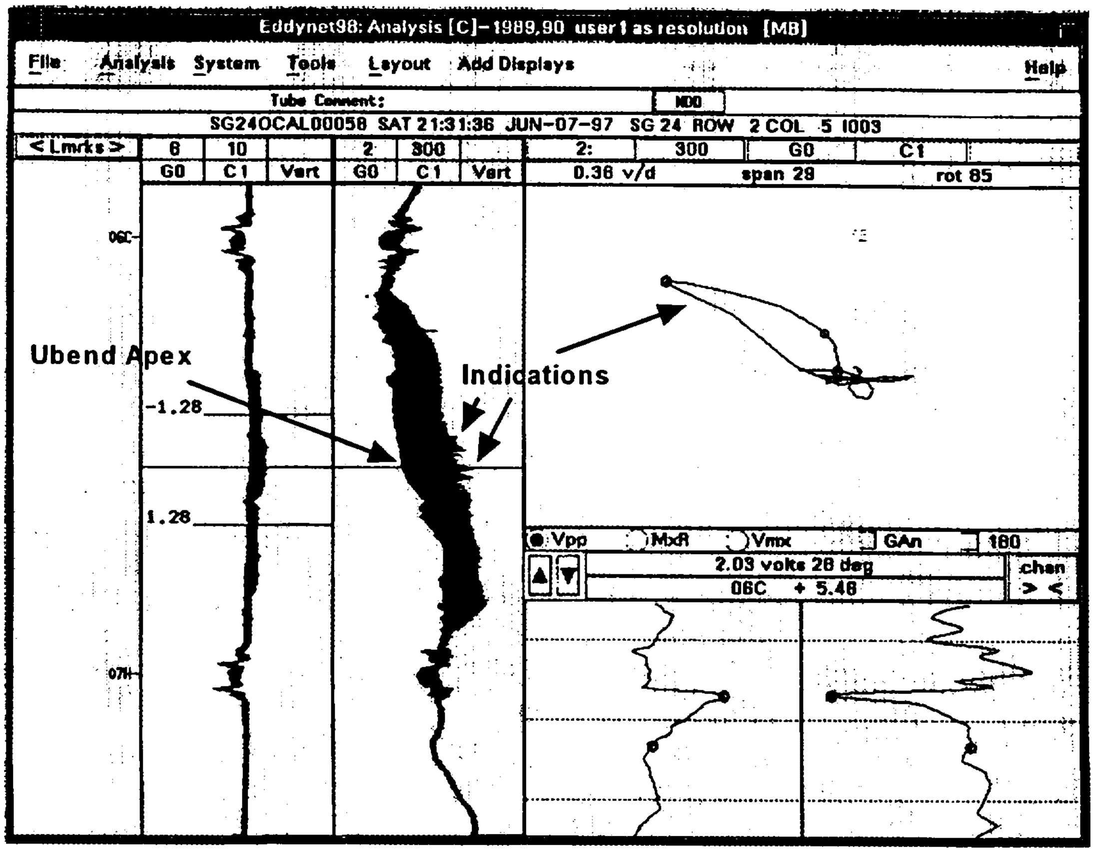


Exhibit 8
Lissajous display showing dynamic integrated noise levels in
SG 24 plugged tube R2C67 as the plus-point probe is pulled through the U-bend
– Low noise level with high (S/N) indication -

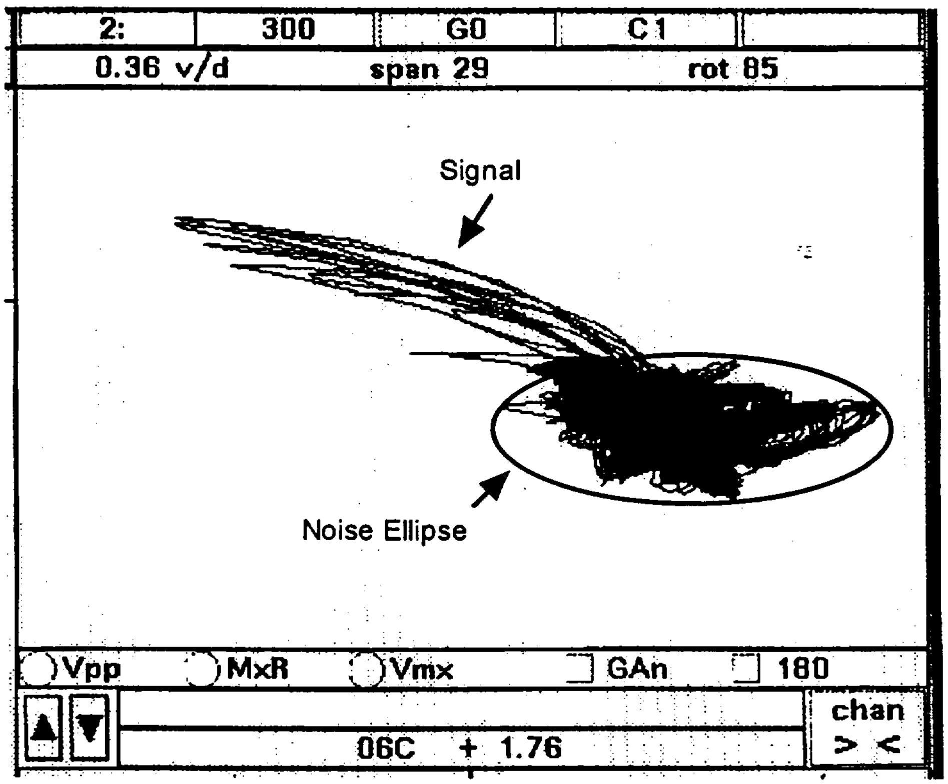


Exhibit 9
Lissajous display showing dynamic integrated noise levels in
SG 24 tube R2C5 as the plus point probe is pulled through the U-bend.
– Higher noise level with low (S/N) indication -

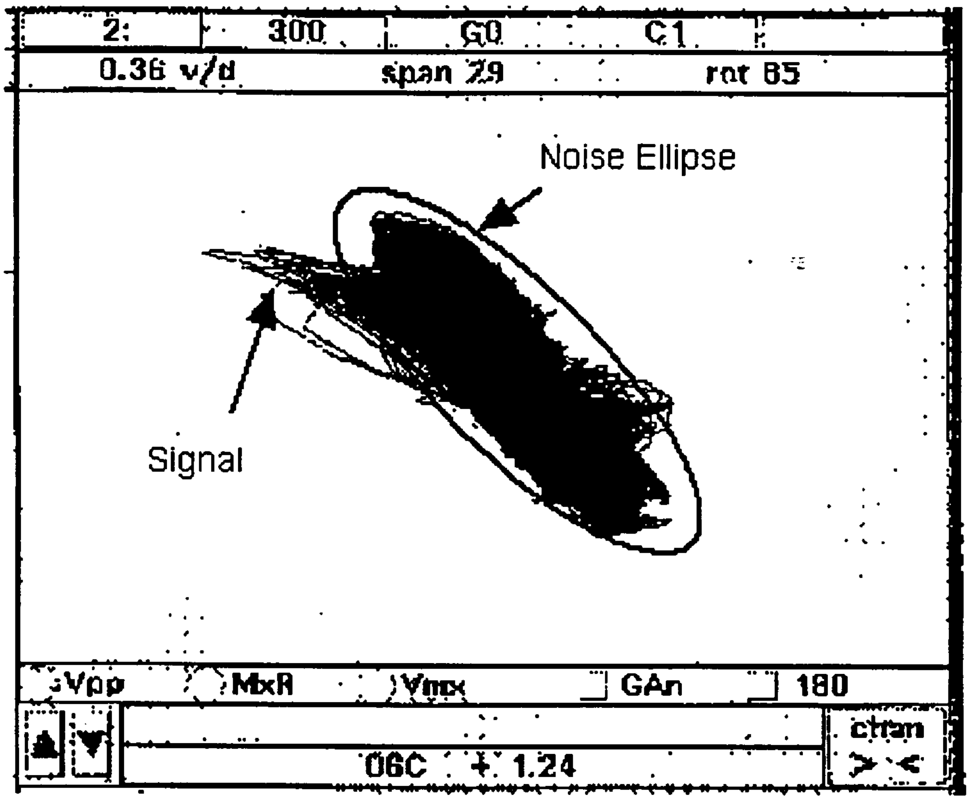
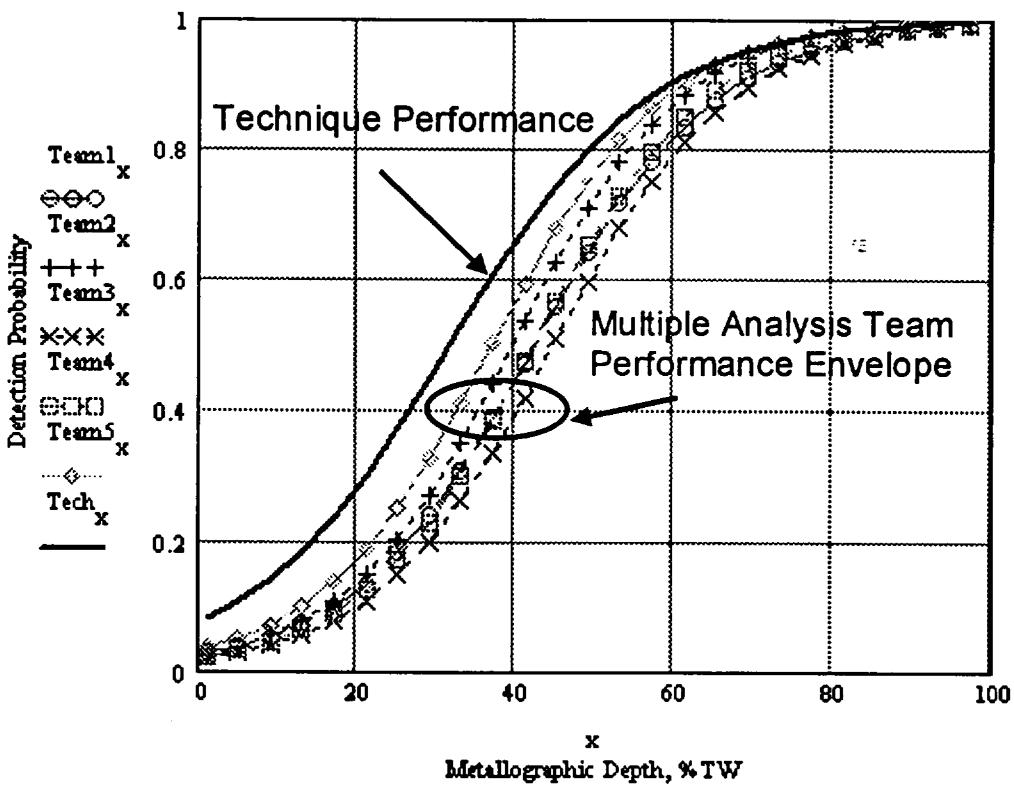


Exhibit 10
Probability of Detection Curve Illustrating Basic Technique and Human Factor Imperfections in the Detection Process



UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of:	)	
	)	
Consolidated Edison Company of New York, Inc.	)	Docket No. 50–247
(Indian Point Nuclear Station, Unit No. 2)	)	

AFFIDAVIT OF Kenneth R. Craig

I, Kenneth R. Craig, being duly sworn, state as follows:

1. I am currently a Principal in Kenneth R. Craig PhD conducting business at 215 Old Meadow Way, Palm Beach Gardens, FL 33418.

2. I was recently asked to examine elements of a nondestructive examination (NDE) of the steam generators at the Indian Point (IP-2) nuclear power plant conducted in the spring of 1997 utilizing a technique referred to as eddy current testing. IP-2 is owned and operated by the Consolidated Edison Company of New York, Inc.

3. I have had no previous involvement with Consolidated Edison or IP-2 regarding steam generator issues, including issues associated with steam generator inspections occurring in 1997 and 2000.

4. My 30 years experience in the Nuclear industry includes studies of corrosion of Alloy 600 at steam generator conditions, management of steam generator programs for a major utility and involvement in the management of more than 30 steam generator examinations. My professional qualifications and experience are provided in Exhibit 1 hereto.

5. Prior to preparing this affidavit I reviewed the following documents:

- Indian Point Unit 2 Technical Specifications 4.13 Steam Generator Tube Inservice Surveillance, Amendment No. 189
- Steam Generator Program Guidelines, NEI 97-06
- Steam Generator Tube Integrity , Draft Reg. Guide DG-1074, dated March 1998
- "Proposed Steam Tube Examination Program- 1997 Refueling Outage, " letter from Quinn to Document Control Desk, dated February 7, 1997.
- "Safety Evaluation by the Office of Nuclear Reactor Regulation Proposed Steam Generator Tube Examination Program Consolidated Edison Company of New York, Inc. Indian Point Unit 2, Docket No. 50-247" , dated May 29, 1997.
- "PWR Steam Generator Examination Guidelines: Revision 4, EPRI TR-106589s-V1, dated June 1996.
- "Steam Generator Tube Life Prediction Analysis for Indian Point Unit 2 ," DEI-442 DRAFT, dated October, 1995
- "Indian Point 2 Steam Generator Status Report", letter from Marks to Distribution, Transmitting Addendum 12 of the Subject Report, April 22, 1998.

6. The review also included Consolidated Edison internal documents describing the steam generator program, review of industry experience as documented in EPRI reports, and comparison to other steam generator programs with which I have been

associated. My review was intended to assess the programmatic completeness and efficacy of the steam generator eddy current examination performed at IP-2 during 1997.

7. The purpose of this affidavit is to provide my assessment of the IP-2 Steam Generator program as compared to the Technical Specifications requirements in effect in 1997 (Amendment 189), the status of the steam generator program and industry expectations based on knowledge in existence in 1997 and to evaluate issues surrounding the 1997 IP-2 steam generator NDE raised by the Nuclear Regulatory Commission in a November 20, 2000 document entitled "Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2 - Report No. 05000247/2000-010."

8. The IP-2 Technical Specifications (Amendment 189) contained some unique requirements that reflected the design specific details and the state of degradation of the steam generators. The unique details of the Technical Specifications are abstracted as provided in Exhibit 2.

9. My review considered the scope of each steam generator examination since IP 2 start-up. Each of these examinations met the requirements of the Technical Specifications then in effect. Later examinations exceeded the Technical Specifications scope through the examination of a larger fraction of the tubes than required by the Technical Specifications. This practice of exceeding the Technical Specifications scope is consistent with evolving industry practice and the general guidance contained in NEI 97-06.

10. The 1997 steam generator examination was conducted in accordance with the pre-outage examination plan discussed with and approved by the NRC and in accordance with Technical Specifications requirements. Several scope expansions were

required based on pre-outage expansion logic, EPRI PWR Steam Generator Examination Guidelines criteria, and the extent and location of degradation discovered during the examination. The 1997 examination met or exceeded the Technical Specification requirements as noted in Exhibits 3 and 4.

11. Technical Specification Section 4.13.C.2 required immediate notification, to the NRC if there is a significant increase in the rate of denting or significant change in the steam generator condition. The 1997 examination results were used to assess if immediate notification was required.

12. The historic progression of tube repair for denting was reviewed for IP 2 steam generator examinations from 1975 through 1997. Outage-specific data for tubes repaired for denting were entered into a database and a linear regression trend line was calculated. This analysis revealed that the number of tubes repaired due to denting in 1997 was less than the linear extrapolation prediction of expected number of dent-related tube repairs. This is illustrated in Exhibit 5.

13. Similar increases in the number of tubes repaired for denting were experienced in prior cycle examinations (see Exhibit 6). In my opinion, these increases in tubes repaired for denting reflect the scope of the specific outage examination and the time elapsed time between examinations of specific tubes. Based on my observations I conclude that the number of tubes repaired for denting, during the 1997 refueling outage, is an expected outcome of the examination and is reflective of a continuous slow denting rate as a result of either continued corrosion or reallocation of existing denting stresses in the drilled support plate.

14. Thus, the results of the examination do not reflect a significant increase in the rate of denting when compared to prior tube repair history and prior examination scopes. Immediate NRC notification was not required.

15. Primary Water Stress Corrosion Cracking (PWSCC) in one Row 2 U-bend was detected for the first time during the 1997 examination.

16. The occurrence of PWSCC, in original design steam generators with mill annealed Alloy 600 tubes is well documented in the annual updates of the EPRI Steam Generator Progress Report. Mill annealed Alloy 600 has experienced PWSCC in a large number of Row 1 U-bends and in a smaller number of Row 2 U-bends in similar designed steam generators. Thus, the occurrence of PWSCC was not an unexpected form of degradation for the IP-2 steam generators.

17. A 1995 Dominion Engineering predictive report, DEI-442, identified the potential for PWSCC at future cycles for the IP-2 steam generators. The bases for this report were industry experience, laboratory data and IP-2 specific design details (T_{HOT}, tube processing, etc).

18. The initial 1997 examination scope recognized the industry experience with PWSCC in inner row U-bends. The scope included examination of all active Row 2 and Row 3 U-bends using the best available technology in 1997 (Plus Point eddy current probes) per the EPRI Steam Generator Examination Guideline recommendations.

19. The inherent risks associated with projections of the first appearance of a form of degradation were well known in the industry as noted in the EPRI Steam Generator Examination Guidelines and in the DEI predictive report.

20. The discovery of PWSCC in one Row 2 U-bend, while earlier than

projected, was not an unexpected nor an unplanned for result.

21. The occurrence of a single PWSCC in the IP-2 steam generators prior to the projected initiation time in a mill annealed Alloy 600 tubed steam generator is not an unexpected result.

22. Based on the previous statements herein, the occurrence of a single Row 2 does not represent a significant change in the condition of the IP-2 steam generators.

23. Technical Specification 4.13.C.3 requires the submittal of a report assessing the long-term integrity of the low row U-bends for any finding of significant hour-glassing (closure) of the upper support plate flow slots.

24. The examination records for all Row 2 tubes plugged repaired during the 1997 outage, regardless of the reason for plugging, were reviewed to determine:

- The maximum diameter eddy current probe passed through the upper support plates (06H and 06C).
- The maximum diameter eddy current probe passed through the U-bend from 06H to 06C.
- The maximum diameter eddy current probe that could not be passed through the U-bend 06H to 06C.

25. The data for these tubes were entered into a table depicting the results from each tube and the 6 next nearest neighbor Row 2 tubes, Exhibits 7 to 10.

26. The status of tubes not repaired in 1997 were entered as either "OK" if they were inspected but not repaired or as "OSS" if they were repaired in prior outages. The data, for each tube repaired and it's 6 nearest neighbors, were reviewed for evidence

of a pattern of hour-glassing, which if occurring, was expected to affect several adjacent tubes.

27. Based on this review, I concluded that there was no evidence of significant flow slot hour-glassing in the upper support plates based on Row 2 tube repair data. A report on the long-term integrity of low row U-bends was not required.

28. Results from the visual inspection of flow slot closure, provided in an the post-outage updates of the "Indian Point 2 Generator Status Report ", were also reviewed to determine if there was evidence of significant hour-glassing available from the 1997 outage examinations.

29. The visual examinations are typically performed by the insertion of cameras and mirrors through handholes located between the secondary face of the tubesheet and the lower support plate or flow distribution baffle (if present).

30. Examination scope includes imaging the flow slots as seen looking upward through the flow slots in the lower support plate. As the lower support plate flow slot closes it becomes more difficult to image the flow slots in the higher support plates.

31. IP-2 installed inspection ports, referred to as hill side ports, in steam generators 22 and 23, the most severely dented steam generators at the time of installation of the inspection ports, to permit inspection of the flow slots in the upper support plates to monitor the flow slots of the upper support plates.

32. The view through the inspection ports was limited but was judged to be adequate to detect significant changes in hour-glassing. Trends in flow slot dimensions were routinely contained in an internal report, post outage update of the "Indian Point 2 Steam Generator Status Report".

33. There was no evidence from the 1997 inspection through the upper inspection ports of closure of the flow slots in the upper support plates. A report on long term integrity of the inner row U-bends was not required.

34. The results from the lower handhole inspection indicate that there were small changes in the dimensions of the lower support plate flow slots.

35. The minor changes in the lower flow slots are probably the result of continued slow denting and/or readjustment of the residual stresses from earlier denting.

36. Review of the flow slot closure data indicates that there was no evidence in the 1997 inspection data that the flow slots were experiencing significant hour-glassing.

37. The concept of formal steam generator program management was in the process of significant changes starting with Steam Generator Degradation Specific Management (SGDSM) since the late 1980's. The concept was to provide a uniform set of criteria, eddy current and tube structural integrity databases for the formalization of steam generator programs. Utilities were required to prepare written steam generator programs to ensure that examinations monitored the structural and accident induced leakage of their steam generators based on the databases.

38. Details of the content of steam generator programs, both programmatic and technical, were evolving with the industry promoting good practices via the EPRI Steam Generator Degradation Specific Management Program and a Reg. Guide, DG-1074 "Steam Generator Tubing Integrity", being developed by the NRC.

39. The final product of these efforts was the issuance, by the Nuclear Energy Institute, of an industry endorsed guideline, NEI 97-06 "Steam Generator Program Guidelines", dated December 1997.

40. By vote of the Nuclear Strategic Issues Advisory Council, US Nuclear utilities committed to implement the guidance contained in NEI 97-06 by the first refueling outages in 1999.

41. The intent of NEI 97-06 was to provide consistency in the application of industry guidelines to assist utilities in management of their steam generator programs. Written steam generator programs were to be prepared, based on the content of Electric Power Research Institute (EPRI) reports, with the form of the implementing document(s) left to individual utility discretion.

42. Although the 1997 IP-2 examination preceded the industry implementation of NEI 97-06, the outage plans proactively contained the essential elements from NEI 97-06, particularly in the areas specified in the EPRI PWR Steam Generator Examination Guidelines, Revision 4 and the concept of issuing a formal Condition Monitoring and Operational Assessment report.

43. The following programmatic aspects were in place prior to the 1997 examination

- Procurement Specification for Eddy Current Examination of Nuclear Steam Generator Tubes Indian Point 2 (NPE-72217, Revision 10) (00-191)
- EPRI Steam Generator Examination Guidelines, Revision 4 (001-189)
- Probe qualification reports for the CECCO 5/bobbin probe per the requirements of the EPRI PWR Steam Generator Examination Guidelines: Revision 4, Appendix H
- Site Specific Training and Testing Program for Eddy Current Analysts in accordance with EPRI PWR Steam Generator Examination Guidelines,

Revision 4, Appendix C.

- Use of Qualified Data Analysts per EPRI PWR Steam Generator Examination Guidelines, Revision 4 (00-191)
- Independent redundant teams of eddy current data analysts and data defined resolution process
- DEI report on comparison of IP2 degradation rates industry Experience
- Steam Generator Status Reports ((01-032, 01-036, 01-037) issued and updated after each outage to
- Identify active degradation mechanisms
- Provide historical information on other Model 44 steam generators to assist in trending degradation
- Project the impact of degradation mechanisms on component longevity
- Document results of secondary side visual inspections to monitor support plate hour-glassing
- Assess potential remedial action to preclude the continuation of degradation
    - Tube bundle replacement
    - Boric Acid Additions to mitigate denting
    - Sleeving to mitigate the impact of tube degradation
    - T_{HOT} Reduction
    - Chemical Cleaning
    - Minimization of Copper Transport

- Special Sludge Lancing Studies CECIL
- Steam Generator Replacement

44. Based on the foregoing discussion; the steam generator program in place prior to the 1997 IP-2 steam generator examination was a mature program with well documented examination histories, long range planning and identification of remedial actions.

45. The program met my expectation for the industry standards in existence during the 1997 steam generator examination with one exception. The outage report submitted to the NRC should have included the detection of the Row 2 U-bend defect in the written text in addition to its inclusion in the tabular listing of repaired tubes.

46. In my opinion there was not enough aggregate evidence to suggest that PWSCC of Row 2 U-bends, as a result of denting and/or flow slot hour-glassing, would be a significant event at IP 2 during the cycle of operation following the 1997 examination.

47. The re-evaluation of the 1997 outage results, in terms of examination results from the 2000 outage and the current knowledge and expectations for Condition Monitoring and Operational Assessments, is inappropriate.

48. In regards to the programmatic elements concerning monitoring of dent progression and flow slot hour-glassing, initial steam generator secondary side chemistry control was exercised through the implementation program of coordinated phosphate additions. This practice led to tube degradation, wall thinning or wastage, as a result of inherent difficulties in control of phosphate ratios in areas of low flow and sludge accumulations in the steam generators. The chemistry control practices were changed to a

non-solids treatment referred as All Volatile Treatment (AVT) which generally consisted of the addition of ammonia and hydrazine. This switch in chemistry control essentially eliminated the degradation associated with phosphate wastage.

49. The industry later realized that AVT treatments were not as effective in buffering the local tube-to-support chemistry and an additional degradation mechanism called denting was detected.

50. A number of Model 44 steam generators were replaced (Surry Units 1 and 2 , Turkey Point Units 3 and 4, etc) as a result of continued tube leakage outages due to primary water stress corrosion cracking as a result of denting. The program at IP-2 utilized the information from these other plants to assist them in the assessment of progression of denting as documented in "Indian Point 2 Steam Generator Status Report Addenda 9 through 12" which were updated after each steam generator examination.

51. There are 4 sources of information available to monitor the progression of denting:

a. In-situ profilometry measurement of dent diameters
b. Eddy current probe tube plug gauging
c. Visual examination of the support plate flow slots
d. Extrapolation of dent progression data from similarly designed steam generators

The status and use of each of these tools in the IP-2 steam generator program were reviewed.

52. Consolidated Edison took the industry lead in the development of eddy current profilometery and shared the information with the industry through the EPRI

Steam Generator Reliability Program. The technique proved to be time consuming and man-rem intensive to implement in the field due to the time required to complete the examinations and the frequent need to change eddy current probes.

53. Better understanding of the impact of deformation, from the profilometry studies and laboratory stress corrosion testing led to the use of eddy current probes as tube plug gauges.

54. The IP-2 Technical Specifications Amendment 189 includes the use of eddy current plug gauging, with an acceptance criterion of passing a 610 mil eddy current probe, as an acceptable technique to implement tube repairs prior to the deformation reaching the level where PWSCC is of concern.

55. Eddy current probe plug gauging was used during the 1997 outage to identify tubes requiring repair. There was no evidence of significant hour-glassing of the upper support plate in the 1997 tube plug gauging.

56. There is evidence of the continuation of tube deformation as a result of either slow dent progression and/or readjustment of residual stresses from prior denting. This evidence of minor continued denting does not suggest a significant increase in dent rate. The use of eddy current probe plug gauging is compatible with industry expectations.

57. Through 1997 IP-2 had routinely monitored the status of flow slot hour-glassing by the practice of visual inspection through the lower handholes. This technique was used through out the industry to monitor hour-glassing in original design steam generators subject to denting.

58. Additional inspection ports were installed to aid in the inspection of the upper support plates in the two steam generators displaying the greatest amount of

deformation in the lower support plate flow slots. Results of these inspections were trended in the post outage update of the Steam Generator Status Report. There was no evidence of significant hour-glassing from the 1997 visual inspections.

59. The history of dent progression and tube repair reasons for similarly designed steam generators is summarized in the post outage update of the Steam Generator Status report. This information was used to assist in monitoring tube deformation resulting from denting. IP-2's use of visual inspection technique met industry expectations for monitoring tube support plate hour-glassing.

60. My review as documented herein led to the following conclusions regarding the NRC stated reasons for issuance of a "Red" violation.

61. The occurrence of 1 Row 2 U-bend PWSCC was neither an unexpected nor an unplanned event and did not constitute a significant change in the condition of the IP 2 steam generators.

62. There was not enough aggregate data available from the 1997 examination to conclude that there was a significant increase in dent rate nor in flow slot hour-glassing.

63. The IP-2 steam generator program in existence during the 1997 examination met industry standards and my expectations.

64. The foregoing statements are true and correct to the best of my knowledge and belief.

Kenneth R Craig

Kenneth R. Craig
Kenneth R. Craig PhD

Sworn and subscribed to before me on this 18 day of January, 2001.

Frances M. Thurber

Notary Public

FRANCES M. THURBER
Commission # 1130906
Notary Public — California
San Diego County
My Comm. Expires Mar 23, 2001

My Commission expires: 03/23/01

Exhibit 1 Summary of Professional Qualifications and Experience for Kenneth R. Craig

BACKGROUND

Dr. Craig has over 30 years experience in various phases of the Nuclear Industry. He has specialized in Steam Generator Technology and Nuclear Metallurgy for the past 25 years. In this capacity he has, served on Steam Generator Design Committee's, performed in excess of $10M worth of Research and Development, and served on numerous Industry Groups involved with Steam Generator Longevity. He has managed or participated in over 30 steam generator in-service inspections. Dr. Craig has provided independent consultation services to Utilities since 1996 via his consulting company, Kenneth R. Craig PhD. Background details are as follows:

KENNETH R. CRAIG PhD

Principal

Provided consultation services as follows
- Steam Generator Program Reviews
- Tubing metallurgy for replacement steam generators
- Legal consultation concerning steam generator issues
- Steam Generator Review Panels

APTECH ENGINEERING SERVICES, INC

Program Manager, Nuclear Division, and August 1998 to Present

Accountabilities

Management of all technical activities for the Nuclear Division
NEI 97-06 Reviews and Preparation of supporting documentation, Degradation Assessments, Condition Monitoring and Operational Assessments
Directed development of OPCON Condition Monitoring and Operational Assessment Software

FLORIDA POWER AND LIGHT COMPANY

MANAGER, COMPONENTS, SUPPORTS AND INSPECTIONS, May 1996 to August 1998. Retired

Accountabilities

- Steam Generator Longevity Programs and Inspection
- Component Specialists
- Metallurgical Laboratory
- Non-Destructive Test Laboratory
- Materials degradation Issues
- CEOG Representative
- Member NEI Steam Generator Taskforce and Working Group
- Member FPL's Corporate Nuclear Review Board

ACTING VICE PRESIDENT NUCLEAR ENGINEERING AND LICENSING, February 1996 to May 1996

Accountability

- Restructure of the Engineering Department

MANAGER OF NUCLEAR TECHNICAL SUPPORT
February 1995 to February 1996

Accountabilities:

- Fuels Engineering
- Configuration Management
- Nuclear Information Services
- Critical Steam Generator Issues
- Member of NEI Steam Generator Taskforce
- Member of ABB/CE Owner's Group
- Member of FPL Corporate Nuclear Review Board

SENIOR CONSULTANT, SUPERVISOR MATERIALS PROGRAMS May, 1986 to February, 1995

Accountabilities:

- Steam Generator Reliability program (St. Lucie and Turkey Point)
- Development of St. Lucie Unit 1 Steam Generator Strategic Model
- Heat Exchanger Reliability Program
- Technical advisor for all materials/metallurgy projects
- Representative to EPRI Steam Generator Reliability Program
  - Chairman of Materials and Corrosion Subcommittee (3 years)
  - Chairman of Technical Advisory Group (1 year)

Member of ABB/CE Steam Generator Taskforce
Member of NEI Steam Generator Taskforce
Member of steam Generator Replacement Group (significant involvement in the development of Specification for Replacement Steam Generators)

COMBUSTION ENGINEERING April 1977 to May 1986

Manager of Materials and Chemistry Technologies
Accountabilities
Management of multiple discipline Department involving Metallurgy, Chemistry, Corrosion and Steam Generator Technology
Metallurgical failure analyses
Development of Chemical Processes
Steam Generator Chemical Cleaning
Steam Generator Channel Head Decontamination
Performance of Internally and Externally funded Research and Development Programs involving Steam Generators
Customer Consultation on Steam Generator degradation and remedial measures
Member of Corporate Steam Generator Design Review Committee

WESTINGHOUSE ELECTRIC CORPORATION, BETTIS ATOMIC POWER LABORATORY 1974 to 1979

Manager Materials Design Engineering
Accountabilities
Management of Department responsible for materials selection for core structural applications
Extensive applied Research on stress corrosion cracking of Alloys 600 and
X-750
Lead Engineer for Alloy X-750

Exhibit 2 IP-2 Unique Technical Specification requirements.

4.13.A.3 Basic Sample Selection and Examination

a. At least 12% of the tubes in each steam generator to be examined shall be subjected to a hot-leg examination.

b. At least 25% of the tubes inspected in Specification 4.1 3.A.3.a above shall be subjected to a cold-leg examination.

d. Examination for deformation ("dents") shall be either by eddy current or by profilometry.

e. Examination for degradation other than deformation shall be by eddy current techniques, using a 700-mil diameter probe. If the 700-mil diameter probe cannot pass through the tube, a 610-mil diameter probe shall be used. For examination of the U-bends and cold-legs of tubes in rows 2 through 5, a 540-mil diameter probe may be used, provided it is justified by profilometry measurement within the tensile strain criterion.

f. In addition to the minimum sample size as determined by Table 4.13-1, all F* tubes shall be inspected within the pertinent tubesheet region. The results of F tube inspections are not to be utilized as a basis for additional inspections per Table 4.13-1.

4.13.A.4 Additional Examination Criteria

2. Degradation Caused by Denting

a. Additional examinations, for degradation caused by denting, shall be performed as described in the most recent steam generator examination program approved by the NRC.

4.13.B . ACCEPTANCE CRITERIA AND CORRECTIVE ACTION

1. Tubes shall be considered acceptable for continued service if:

a. depth of degradation is less than:

- 40% of the tube wall thickness, or
- 23% of the sleeve wall thickness

AND

b. the tube will permit passage of a 0.540' diameter probe and the strain in the tube wall (if measured) is less than the tensile strain criterion as specified in the approved examination program, or the tube will permit passage of a 0.610' diameter probe in the absence of strain measurement.

c. the tube is an F* tube and meets a. and b. above the F* region.

4.13.C. REPORTS AND REVIEW AND APPROVAL OF RESULTS

1. The proposed steam generator examination program shall be submitted for NRC staff review and concurrence at least 60 days prior to each scheduled examination.

2. The results of each steam generator examination shall be submitted

to NRC within 45 days after the completion of the examination. A

significant increase in the rate of denting or significant change in steam generator condition shall be reportable immediately.

3. An evaluation which addresses the long term integrity of small radius U-bends beyond row I shall be submitted within 60 days of any finding of significant hour-glassing (closure) of the upper support plate flow slots.

Exhibit 3. Actions Demonstrating Compliance with Technical Specification 4.13.A.3

Technical Specification Requirement	1997 Compliance with Technical specification Section 4.13.A.3
4.13.A.3.a	100 % of all active tubes were inspected based on combinations of CECCO5/bobbin, Plus Point and bobbin probes
4.13.A.3.b	100 % of all active tubes were inspected based on combinations of CECCO5/bobbin, Plus Point and bobbin probes
4.13.A.3.c	100 % of all active tubes were inspected based on combinations of CECCO5/bobbin, Plus Point and bobbin probes
4.13.A.3.d	Dents were tested by eddy current. Dents that would not pass a610 bobbin probe were repaired by plugging
4.13.A.3.e	Degradation from TEH to 06H and from TEC to 06C was inspected by a combination of CECCO5/bobbin, bobbin and Plus Point Probes. U-bends were inspected with Plus Point probes
4.13.A.3.f	All F* tube were inspected
4.13.A.4.1.a	Required examination expansions were made in accordance with this TS and EPRI Examination Guidelines
4.12.A.1.b	F* inspections were limited to the affected tube sections in the tubesheet
4.12.A.1.c	100 % of all active tubes were inspected based on combinations of CECCO5/bobbin, Plus Point and bobbin probes
4.13.A.2.a	Additional examinations for denting were performed in accordance with pre-outage test plan submitted to and approved by NRC

Exhibit 4 Actions Demonstrating Compliance with Technical Specifications 4.13.B and 4.13.C

Technical specification Requirement	1997 Compliance with Technical Specification 4.13.B and 4.13.c
4.13.B.1.a	Tubes with degradation sized at greater or equal to 40% wall thickness and all crack like indications outside of the F* region were repaired by plugging. Tube with degradation meeting the F* criteria were left in service
4.13.B.1.b	Tubes were repaired by plugging if they did not permit passage of a 610-mil probe
4.13.B.1.c	F* tubes were repaired if they did not meet criteria 4.13.B.1.a and b. above the F* region.
4.13.B.2	Tube plugs predicted to be or identified as leaking were repaired by removal of the existing tube plug and plugging with 690-TT plugs
4.13.C.1	The steam generator program plan was submitted to the NRC on 2/07/97 and approved by the NRC on5/29/97
4.13.C.2	The results from the 1997 outage were submitted to the NRC on 7/29/97.
4.13.C.3	A report was not issued since there were no findings indicating significant hour-glassing of the support plate flow slots
4.13.C.4	NRC restart approval was not required

Exhibit 5. Probe Passage Data for Row 2 Tubes Repaired in 1997 and Six Nearest Neighbors
Steam Generator 21

SG	TUBE	U-bend Max Diameter tested	06H Max Diameter tested	06C Max Diameter Tested	1997 RESULTS/HISTORY FOR ROW 2 TUBES PLUGGED						
21	R02C07	620ZB	680C	680C	R02C04	R02CO5	R2C06	R2C07	R02C08	R02C09	R02C10
					OK	OK	OK	620ZB	OOS	610 rst	OK
21	R02C09	610A RST, 1991 610EB	640C	640C	R02C06	R02C07	R02C08	R02C09	R02C10	R02C11	R02C12
					OK	620ZB	OOS	610A RST	OK	OK	OK
21	R02C23	610A RST, 1991 610EB	640C	640C	R02C20	R02C21	R02C22	R02C23	R02C24	R02C25	R02C26
					OK	OK	OK	610A RST	OK	OK	OK
21	R02C53	not tested	610A	610A	R02C50	R02C51	R02C52	R02C53	R02C54	R02C55	R02C56
					OK	OOS	OK	NT	610A RST	OK	OK
21	R02C54	610A RST, 1991 610EB	640C	640C	R02C51	R02C52	R02C53	R02C54	R02C55	R02C56	R02C57
					OOS	OK	NT	610A RST	OK	OK	OK
21	R02C62	620ZB	610A	700C	R02C59	R02C60	R02C61	R02C62	R02C63	R02C64	R02C65
					OK	OK	OK	620ZB	620ZB	OK	OK
21	R02C63	620ZB	700C	680C	R02C60	R02C61	R02C62	R02C63	R02C64	R02C65	R02C66
					OK	OK	620ZB	620ZB	OK	OK	OK
21	R02C70	610A RST, 1991 610EB	610A	610A	R02C67	R02C68	R02C69	R02C70	R02C71	R02C72	R02C73
					OK	OK	OK	610A RST	OK	OK	OK

OOS= Tube Repaired Prior to 1997
OK = Tube Inspected in 1997 Not Repaired

Exhibit 6. Probe Passage Data Row 2 Tubes Repaired in 1997 and Six Nearest Neighbors
Steam Generator 22

SG	TUBE	U-bend Max Diameter tested	06H Max Diameter tested	06C Max Diameter Tested	1997 RESULTS/HISTORY FOR ROW 2 TUBES PLUGGED						
22	R02C89	610A RST, 1991 610EB	610A	610A	R02C86 OK	R02C87 OOS	R02C88 OOS	R02C89 610A RST	R02C90 OK	R02C91 OK	R02C92 OK
22	R02C85	610A RST, 1991 610ZS	640C	610A	R02C82 OK	R02C83 OK	R02C84 OOS	R02C85 610A RST	R02C86 OK	R02C87 OOS	R02C88 OOS
22	R02C63	610A RST, 1991 610EB	640C	610A	R02C60 OOS	R02C61 OOS	R02C62 610A RST	R02C63 610A RST	R02C64 OK	R02C65 OK	R02C66 OK
22	R02C62	610A RST, 1991 610EB	610A	610A	R02C59 OOS	R02C60 OOS	R02C61 OOS	R02C62 610A RST	R02C63 610A RST	R02C64 OK	R02C65 OK
22	R02C52	610A RST, 1991 610EB	680C	610A	R02C49 OOS	R02C50 OOS	R02C51 OOS	R02C52 610A RST	R02C53 OOS	R02C54 OOS	R02C55 OK
22	R02C48	620ZB	680C	700C	R02C45 OOS	R02C46 OOS	R02C47 OOS	R02C48 620ZB	R02C49 OOS	R02C50 OOS	R02C51 OOS
22	R02C28	620ZB	640C	610A	R02C25 OOS	R02C26 610A RST	R02C27 OK	R02C28 620ZB	R02C29 OOS	R02C30 OOS	R02C31 OOS
22	R02C26	610A RST, 1989 610ZS	640C	610A	R02C23 OOS	R02C24 OOS	R02C25 OOS	R02C26 610A RST	R02C27 OK	R02C28 620BZ	R02C29 OOS
22	R02C22	610A RST, 1989 610ZS	610A	610A	R02C19 OOS	R02C20 OOS	R02C21 610A RST	R02C22 610A RST	R02C23 OOS	R02C24 OOS	R02C25 OOS
22	R02C21	610A RST, 1991 610EB	610A	640C	R02C18 620ZB	R02C19 OOS	R02C20 OOS	R02C21 610A RST	R02C22 610A RST	R02C23 OOS	R02C24 OOS
22	R02C18	620ZB	640C	640C	R02C15 OOS	R02C16 OOS	R02C17 OOS	R02C18 620ZB	R02C19 OOS	R02C20 OOS	R02C21 610A RST
22	R02C13	620ZB	640C	680C	R02C10 OOS	R02C11 OK	R02C12 NT	R02C13 620ZB	R02C14 OOS	R02C15 OOS	R02C16 OOS
22	R02C12	not tested	640C	610A	R02C09 OOS	R02C10 OOS	R02C11 OK	R02C12 NT	R02C13 620ZB	R02C14 OOS	R02C15 OOS

OSS=Tube Repaired PRIOR TO 1997
OK=Tube Inspected in 1997 Not Repaired

Exhibit 7. Probe Passage Data for Row 2 Tubes Repaired in 1997 and Six Nearest Neighbors
Steam Generator 23

SG	TUBE	U-bend Max Diameter tested	06H Max Diameter tested	06C Max Diameter Tested	1997 RESULTS/HISTORY FOR ROW 2 TUBES PLUGGED						
23	R02C60	620ZB	640C	700C	R02C57 OK	R02C58 OK	R02C59 OOS	R02C60 620ZB	R02C61 OOS	R02C62 OOS	R02C63 OOS
23	R02C49	610A RST, 1991 610EB	700C	610A	R02C46 OOS	R02C47 OOS	R02C48 OOS	R02C49 610A RST	R02C50 OOS	R02C51 OK	R02C52 OOS
23	R02C43	620ZB	700C	700C	R02C40 OK	R02C41 OK	R02C42 OK	R02C43 620ZB	R02C44 OOS	R02C45 OOS	R02C46 OOS
23	R02C33	620ZB	700C	680C	R02C30 620ZB	R02C31 OOS	R02C32 OOS	R02C33 620ZB	R02C34 OK	R02C35 OK	R02C36 OK
23	R02C30	620ZB	700C	610A	R02C27 OK	R02C28 OK	R02C29 620ZB	R02C30 620ZB	R02C31 OOS	R02C32 OOS	R02C33 620ZB
23	R02C29	620ZB	700C	680C	R02C26 OK	R02C27 OK	R02C28 OK	R02C29 620ZB	R02C30 620ZB	R02C31 OOS	R02C32 OOS

OSS= Tube Repaired Prior to 1997
OK= Tube Inspected in 1997 Not Repaired

Exhibit 8. Probe Passage Data Row 2 Tubes Repaired in 1997 and Six Nearest Neighbor tubes
Steam Generator 24

SG	TUBE	U-bend Max Diameter tested	06H Max Diameter tested	06C Max Diameter Tested	1997 RESULTS/HISTORY FOR ROW 2 TUBES PLUGGED						
24	R02C76	620ZB	680C	610A	R02C73 OK	R02C74 OK	R02C75 OK	R02C76 620ZB	R02C77 OK	R02C78 OOS	R02C79 OOS
24	R02C67	620ZB	640C	700C	R02C64 OK	R02C65 OK	R02C66 620ZB	R02C67 620ZB	R02C68 OOS	R02C69 OK	R02C70 OOS
24	R02C66	620ZB	640C	700C	R02C63 OK	R02C64 OK	R02C65 OK	R02C66 620ZB	R02C67 620ZB	R02C68 OOS	R02C69 OK
24	R02C31	not tested	680C	680C	R02C28 OK	R02C29 OK	R02C30 OK	R02C31 NT	R02C32 OK	R02C33 OK	R02C34 OOS
24	R02C07	not tested	640C	610A	R02C04 OK	R02C05 620ZB	R02C06 OK	R02C07 NT	R02C08 OOS	R02C09 OOS	R02C10 OK
24	R02C05	620ZB 2000 LEAKER	640C	700C	R02C02 OOS	R02C03 OK	R02C04 OK	R02C05 620ZB	R02C06 OK	R02C07 NT	R02C08 OOS

OSS= Tube Repaired Prior to 1997
OK = Tube Inspected in 1997 Not Repaired

Exhibit 9. Plot of Cumulative Number of Tubes Plugged as Function of EFPY Showing Linear Regression

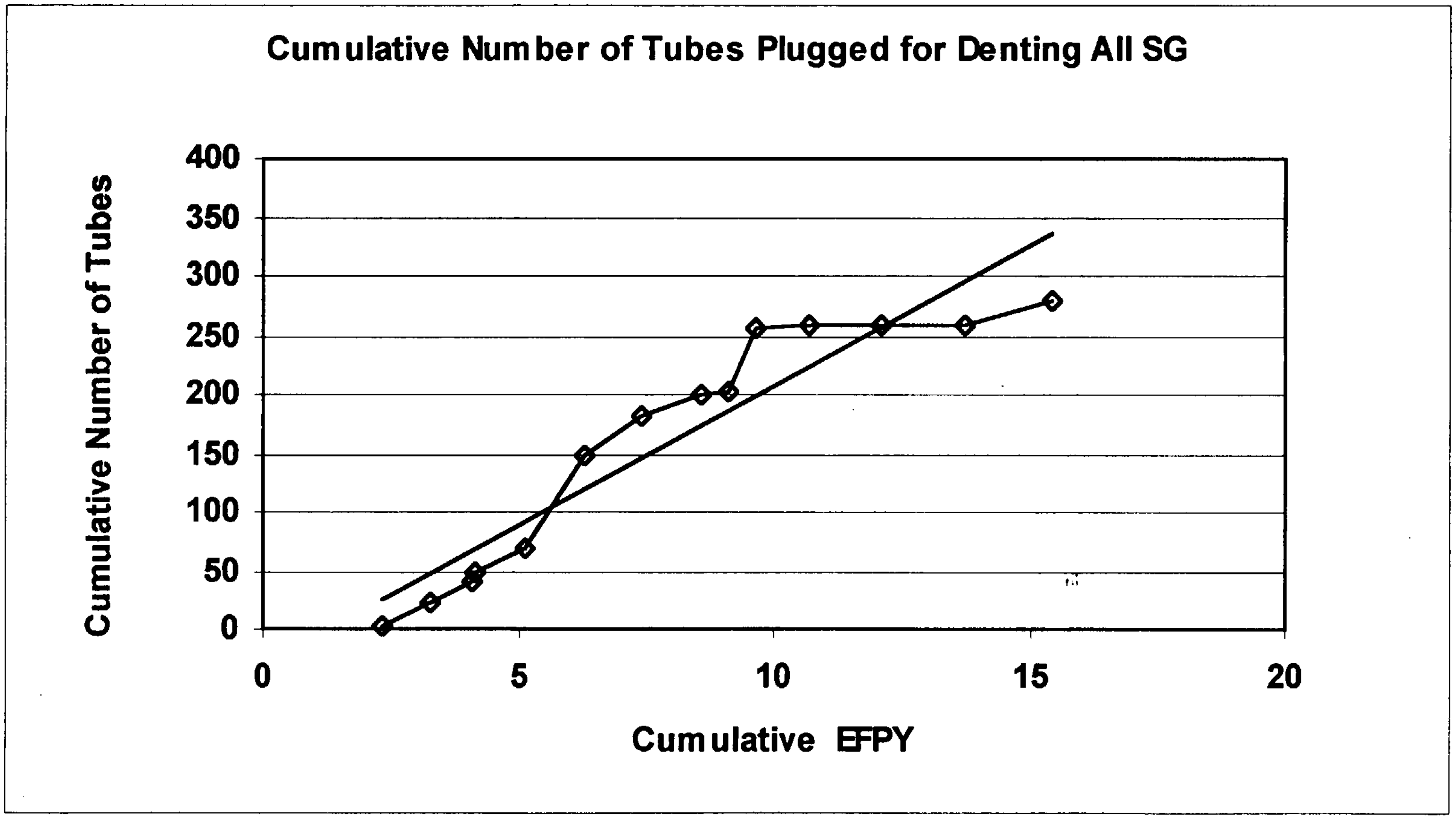
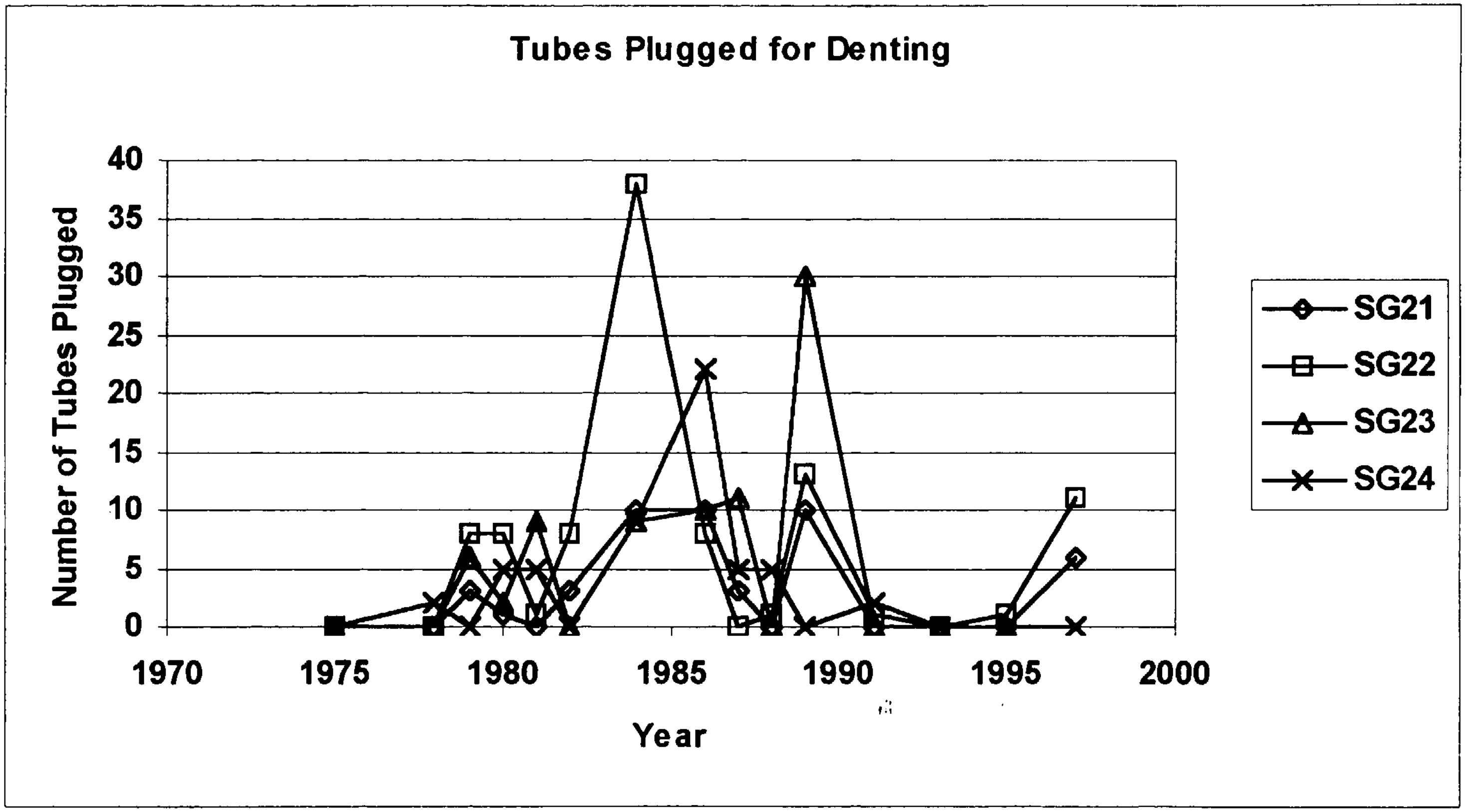


Exhibit 10. Plot of Outage Specific Repairs Showing Variation in Number of Repairs



UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of:	)	
	)	
Consolidated Edison Company	)	Docket No. 50–247
of New York, Inc.	)	
(Indian Point Nuclear Station,	)	
Unit No. 2)	)	

AFFIDAVIT OF GARY L. HENRY

I, Gary L. Henry, being duly sworn, state as follows:

1. I am currently employed by EPRI. I am currently a Manager in the Steam Generator Management Project.

2. My professional qualifications and experiences are provided in Exhibit 1 to this affidavit.

3. I was recently asked to provide a factual description of the nuclear industry standards for eddy current testing as related to technique and personnel qualification, the role of EPRI and inspection guidelines in the eddy current technology, the status of the plus point probe and to the status of NEI 97-06 "Steam Generator Program Guidelines", as they existed in 1997.

4. I have had previous involvement with Consolidated Edison and Indian Point-2 regarding steam generator issues, including issues associated with steam generator inspections occurring in 1997 and 2000. These include for 1997: technique qualification activities related to dented locations, the inspection program elements, sample size and scope of the examination. At the request of Consolidated Edison, I reviewed data after the February 2000 leakage event, I also identified areas that must be completed to meet the requirements on NEI 97-06, Revision 5 of the PWR SG Examination Guidelines and examination technique specification sheets.

5. The purpose of this affidavit is to describe events have occurred on or about the dates specified and are presented in a time sequenced order:

6. Revision 3 of the PWR SG Examination Guidelines was issued in 1992 and required the use of qualified data analysts (QDA's) trained and tested in accordance with Appendix G of the PWR SG Examination Guidelines. Revision 3 of the PWR SG Examination Guidelines Appendix G established the requirement that a statistically significant sample of flaws to demonstrate at an 80% probability of detection at a 90% confidence level that flaws greater than or equal to 40% TW will be detected on a damage mechanism and technique basis. Statistically significant sample size is defined by a binomial distribution used to determine the probability of detection and confidence level required. This was the first time the industry had established a requirement for personnel qualification for SG tubing data analysis.

7. Revision 3 of the PWR SG Examination Guidelines Appendix G also defined a standard and requirement for analyst variability in sizing. The acceptable root mean square (RMS) error is less than or equal to 10% of the determined truth for those indications deemed, by peer review, to be sizable. Implementation of Appendix G process is controlled by the certifying organization. The American Society of Mechanical Engineers (ASME) requirement of NDE certification are provided by Recommended Practice Number SNT-TC-1A " Personnel Qualification and Certification in Nondestructive Testing ". Certifying Agency is defined in SNT-TC-1A as the employer of the personnel being certified. Analyst variability was first measured as an industry standard in 1992.

8. The technique qualification for eddy current is described in the PWR SG Examination Guidelines, Appendix H and defines the essential variables that must be documented and demonstrated using a statistically valid sample size as defined above using a binomial distribution. The essential variable documentation provides reasonable assurance that if the same test were run on the same sample set using different equipment, similar results would be obtained.

9. The process for qualifying technological improvements typically occur in the following order: 1) the technique is tested for function before trying it in the field, 2) field trial used as a diagnostic technique 3) are advantages present and should technique qualification proceed, 4) Qualification of the technique per Appendix H of the PWR SG Examination guidelines, 5) the technique must meet the minimum requirements identified in Appendix H for detection, 6) a minimum of five QDA's must determine if the technique is qualified

during the peer review and 7) documentation of the peer review results. For a qualification data set it is preferred that pulled tubes are used. However, pulled tubes are not always available and therefore the use of laboratory crack and/or EDM notches are acceptable per Appendix H of the PWR SG Examination Guidelines.

10. Since 1992, it has been industry practice to upgrade the technique as laboratory crack samples or pulled tubes become available. Documentation of the technique results are designated as acquisition technique sheets (ACTS) and analysis technique sheets (ANTS). The ACTS and ANTS provide the details of sample set used, essential variables (e.g., frequencies, cable lengths, probe, instrument) and the performance indices for the sample set.

11. The plus point probe was developed to improve the signal to noise ratio from the conventional pancake and directional coils. The initial use of the probe in the field was approximately spring of 1995 as a nonqualified technique and was primarily used at the top of tube sheet and expansion transition regions. The plus point coil was designed to operate at approximately 300 kHz and was included as the third coil, where the first two coils were the 0.115" diameter midrange (MR) and the 0.080" MR pancake coils on a 3-coil rotating probe. The initial use of this plus point coil arrangement was as a diagnostic technique.

12. In 1995 Maine Yankee suspected that PWSCC was present in the expansion transitions and a high frequency (HF) pancake coil was suggested for use. This pancake coil had a

typical center frequency of ~ 600 kHz (designated as HF 0.080" pancake) and replaced the 0.080" MR pancake coil for straight leg examinations. This particular configuration had not been qualified per Appendix H of the PWR SG Examination Guidelines at the time of first use.

13. The three coil probe now contained a plus point MR directional coil pair, 0.115" MR Pancake coil, and 0.080"high frequency (HF) pancake coil. This probe was subsequently qualified to the PWR SG Examination guidelines in June 1995. The data-set set used at the time contained one pulled tube, 6 laboratory cracks and 12 EDM notches. This qualification represents the first qualification of the plus point coil for straight leg examinations meeting the requirements of the PWR SG Examination Guidelines Appendix H.

14. INPO review visits were initiated by the Steam Generator Management Program Executives in late 1995 and kicked off by INPO in April 1996 using pilot plants to test the process. "The goals were to provide reviews to minimize preventable steam generator tube leaks and to ensure effective station actions are planned in the event a tube leak or rupture occurs. The main aspects of the steam generator management program include steam generator in-service inspection (ISI) and repair, and the steam generator primary-to-secondary leak monitoring." As stated in the INPO "Engineering Support Department HOW TO PE-1.2 , Revision 0, Title: Evaluation of Steam Generator Inspection, Repair, and Leak Monitoring Programs", Dated 11-15-95. As a consequence of INPO visits, plant(s) initiated internal self-assessments.

15. Revision 4 of the PWR SG Examination Guidelines were published June 1996, Vol. 1. The technical content from Appendices G and H had not changed from Revision 3 to Revision 4. However the site specific performance demonstration aspects were strengthened. Additionally, those techniques that are not demonstrated in the QDA performance demonstration database require a site specific performance demonstration, at a statistically valid sample size.

16. Revision 4 of the PWR SG Examination Guidelines also contained expansion guidance upon the discovery of a new degradation mechanism. This guidance included, but was not limited to, expansion based on u-bend indications. Guidance was strengthened in several areas of Revision 4 of the PWR SG Examination Guidelines. However, this document was deemed as somewhat vague after the fall of 1996 outage season. Immediately, plans for Revision 5 were being introduced. Input from the INPO review visits as well as comments from the end users were being collected. It was also determined that a more definitive and concise document was needed to aid in the review visit evaluations.

17. U-bend Qualifications were performed in June 1996 for MR plus point coils and August 1996 for the MR 0.110 " pancake coil. The samples used for the qualification contained two pulled tubes, three laboratory cracks and twenty-one EDM notches. The peer review teams accepted and approved the techniques as meeting the requirements of Appendix H of the PWR SG Examination Guidelines. All available data were used, and no additional samples have been added since 1996.

18. In July of 1996 plus point data was added as a new technique to the performance demonstration database where successful completion provides the analyst with a qualified data analyst status. The existing QDA's would be required to pick-up the new mechanism as part of the re-qualification. Any new analyst going through the QDA performance demonstration database would receive plus point data as another mechanism provided that version of software was used to draw the examination.

19. Indian point 2 eddy current examination was underway in early June 1997.

20. Nuclear Entergy Institute issued NEI 97-06 August 1997 with an implementation date 1-1-99. "This guideline defines the industry initiative that establishes a framework for strengthening existing steam generator programs. The guideline discusses the fundamental programmatic elements and directs licensees to consensus industry documents where detailed guidance is provided. EPRI will maintain the majority of the detailed guidelines through the Steam Generator Strategic Management Program consensus process. Revisions to the EPRI documents will follow the protocol as noted in this guideline."

21. The PWR SG Examination Guidelines Revision 5, Vol. 1 was sent out for industry comment in late spring of 1997. Comments were resolved during the summer and approved for publishing in September 1997 with an implementation date of February 1, 1998. During the development of Revision 5, some knowledge was available, on the yet

to be released, Draft Regulatory Guide 1074 and this information was considered in the development of Revision 5 of the PWR SG Examination guidelines.

22. The requirements of Appendix G and H of the PWR SG Examination Guidelines were not changed as the result of DG 1074. The peer review process has grown in time since 1992 such that the requirements are documented and the examination technique specification sheets (ETSS), formerly referred to as ACTS and ANTS, are now controlled under a 10 CFR 50 Appendix B program.

23. DG 1074 was formally released for comment in draft to the industry in March 1998.

24. The foregoing statements are true and correct to the best of my knowledge and belief.

Gary L. Henry

Sworn and subscribed to before me on this 18th day of January 2001.

Notary Public

My Commission expires: 9-27-2004

EXHIBIT 1

Gary L. Henry

Current Position

1988 - Present - Manager Steam Generator NDE Program, EPRI NDE Center, Charlotte, North Carolina.
Responsibilities include Managing, Budgeting, Technology Transfer, and Technical Evaluation of Stream Generator Inspections.

Career Experience

1987 - 1988 - NDE Forman - Materials Engineering Inspection Services, Research and Sciences Department, Rochester Gas & Electric, Rochester, New York.

1985 - 1987 - NDE Technician - Materials Engineering Inspection Services, Research and Sciences Department, Rochester Gas & Electric, Rochester, New York.

1983 - 1985 - Field Engineer - Field Inspection Services, Special Products & Integrated Field Services, Nuclear Power Division, Babcock & Wilcox, Lynchburg, Virginia.

1981 - 1983 - NDE Technician - Inservice Inspection Section, Nuclear Power Division, Babcock & Wilcox, Lynchburg, Virginia.

1979 - 1981 - USAF Non Commissioned Officer in Charge, NDE, Minot Air Force Base, Minot, North Dakota.

1974 - 1979 - NDE Specialist, United Sates Air Force,

Education

Graduate, United Township High School, East Moline, IL.
Currently pursuing Engineering Degree

Professional Association

American Society for Nondestructive Testing

Mr. Henry has over twenty-six years experience in the development and application of all NDE methods, with special interests in the electromagnetic field, specifically in the eddy current method. At the EPRI NDE Center he is responsible for Managing, Budgeting, Technology Transfer, and Technology Evaluation for Steam Generator Inspections. This multi-task program involves work to improve inspection, technology, and procedures for steam generator inspections.

While at Rochester Gas and Electric, Mr. Henry had a variety of responsibilities in the development and application of the major NDE methods. As the Rochester Gas and Electric corporate Eddy Current Level III, the responsibilities of planning, executing, and reporting Eddy Current results for steam generators and balance of plant heat exchangers. As the NDE Forman, he was also responsible for all NDE work performed, including Fossil and gas distribution. Additional responsibilities included revenue generation for RG&E. This involved the utilization of idle equipment and personnel during off peak periods. Mr. Henry also certified Level II in radiography, ultrasonic, visual 1 & 3, magnetic particle, and dye penetrant. He was active as an EPRI utility member and has consulted for a number of electric utilities.

With Babcock and Wilcox as a field engineer, Mr. Henry was responsible for various tasks assigned, from project engineer to NDE technician for pre-service and inservice examinations, including steam generator eddy current examination and data analysis. During this time Mr. Henry was also involved with research and development of steam generator NDE.

While serving in the United States Air Force, Mr. Henry held the equivalency of Level III in all NDE disciplines. As the non-commissioned officer in charge of the NDE Laboratory his responsibilities included training of personnel, scheduling, technique development, technical order writing for new techniques and the utilization of existing techniques to inspect the aircraft and weapon systems assigned to the base.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of: Consolidated Edison Company of New York, Inc. (Indian Point Nuclear Station, Unit No. 2)	))))))	Docket No. 50–247

<u>AFFIDAVIT OF JON J. FUNANICH</u>

I, JON J. FUNANICH , being duly sworn, state as follows:

1. I am an Eddy Current Level III-QDA employed by MoreTech, Inc. located at 406 Military East, Benicia, California.

2. I was recently asked to examine elements of a nondestructive examination (NDE) of the steam generators, at the Indian Point 2 Nuclear Power Plant, conducted in the spring of 1997, utilizing a technique referred to as eddy current testing. Indian Point 2 is owned and operated by the Consolidated Edison Company of New York, Inc. The purpose of this affidavit is to provide my assessment of the adequacy of the 1997 IP2 steam generator inspection program, the application of that program to the 1997 examination of the IP2 steam generators, and to evaluate issues surrounding the 1997 IP2 steam generator nondestructive examination (NDE) reviewed by the Nuclear Regulatory Commission in a November 20, 2000 document entitled, "Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2 – Report No. 0500247/2000-010.

3. I have had no previous involvement with the Consolidated Edison Company or Indian Point 2 regarding steam generator issues, including those issues associated with steam generator inspections occurring in 1997 and 2000.

4. My professional qualifications and experience are set forth in Exhibit 1 hereto. I have also been involved with over 200 eddy current campaigns and approximately 80 of those as the Lead Analyst.

5. Prior to preparing this affidavit, I reviewed Westinghouse Data Analysis Technique Procedure DAT-IP2-001 Rev.0, Analysis Technique Specification (ANTS) Sheets IP2-97-E; "Mag Plus Point U-Bend"; Specification NO. NPE-72217 "Eddy Current Examination of Nuclear Steam Generator Tubes Indian Point 2"; "PWR Steam Generator Guidelines, Revision 4 Volume 1, dated June 1996"; and "Examination Technique Specification Sheet, ETSS # 96511" which is part of the Performance Demonstration Data Base Appendix, A.

6. Low row U-Bends have had a long history of problems. Leakage events in Westinghouse Steam generators were common during examinations in the 1970's and early 1980's when eddy current bobbin coil was the only exam technique available. Operators of several plants, including IP2, opted to plug all the row 1 tubes in their steam generators to prevent forced outages or steam generator leakage during operation. With the development of rotating probe technology the detection of low row U-Bend degradation was significantly improved. Plus point technology which was developed in the mid 1990's improved again on rotating technology enabling detection of smaller degradation.

7. Eddy current analysis of low row U-Bends, in my experience, has had an enhanced level of awareness and requires unique attention during data analysis.

8. The 1997 IP2 initial plan to examine 100% of rows 2 and 3 with a plus point probe for this model steam generator met the industry standard and practice that existed at that time.

9. The PWR Steam Generator Examination Guidelines: Revision 4 dated June 1996 (further referenced as Rev 4.) states, in part, the following requirements for EDM notch standards utilized in 1997 for rotation probe technology including plus point probes:

> "Electro-discharge machining (EDM) and laser-machined notch standards are typically used to establish setup conditions for rotating probe technology. The notches should be of:
>
> Both axial and circumferential orientation, and
>
> Standard length and depths on the OD and ID."

Rev. 4 did not have a requirement for specific depths, lengths, or widths to be utilized. The EDM notch requirement for a specific examination would be determined by the applicable qualified technique.

10. The qualified technique, ETSS-96511 requires the use of a 40% ID axial and circumferential notch for the plus point probe calibration.

11. The calibration standards used by IP2 for the U-bend examination contained both ID and OD circumferential and axial notches. Missing, however, was the 40% ID axial notch which is stated in the approved technique for U-Bend examinations, ETSS-96511. This states that the 40% ID notch is set to a rotation value of between 10

and 15 degrees. This requirement can be met without the inclusion of a 40% ID notch if another notch on the standard is set to a phase setting which would position the 40% ID notch in the required range.

12. I reviewed the raw data sets from the qualified technique, ETSS-96511, which has the required indication on the standard to determine if the phase setting resulted in positioning the 40% ID notch in the required range. When the 100% axial EDM notch is set to 30 degrees in both the 400 kHz and 300 kHz channels, the 40% ID axial notch's phase angles are 11 and 13 degrees respectively. Therefore, the calibration was within the qualified technique's required range. Based on this evaluation, I have concluded that the IP2 calibration met the requirements of ETSS-96511.

13. The IP2 Data Analysis Technique Procedure met the requirements of the PWR Steam Generator Examination Guidelines: Revision 4, Volume 1 Section 5 regarding eddy current analysis; including scope, responsibilities, personnel qualifications, calibration, flaw identification, criteria, reporting requirements, evaluation, recording and resolution.

14. The screening requirements in Data Analysis Technique Procedure, Para. 10.3.2 states, "Scroll the entire test extent with all frequencies as necessary to confirm any possible indications and to locate the largest amplitude signal with respect to the applicable steam generator structure. C-Scan, Lissajous and strip chart displays shall be monitored during this process".

15. Data Analysis Technique Procedure, Para. 11.4, third paragraph, third sentence also states, "The analyst shall scroll through the region of interest while

reviewing the Lissajous (X-Y) display for possible indications". This approach met the requirements of the qualified technique, ETSS-96511.

16. Data Analysis Technique Procedure, Para. 11.3.2, states "Where probe motion (lift-off) is evident set it to be horizontal on the pancake coils. The rotation of **all** channels should be adjusted such that the ID EDM notches on the standard provide a positive vertical response. This may make the 100% EDM lie at an angle somewhat greater than 20 degrees channels (e.g. the plus point channels will most likely rotate such that the 100% defect is 30 – 35 degrees off of the horizontal)."(emphasis included) I have concluded that the Data Analysis Technique Procedure provided the necessary instructions to the data analysts which met the requirements of ETSS-96511.

17. Data Analysis Technique Procedure, Table 7, "Set-Up For +Point", specifies a phase setting for Plus-Point Axial Flaws be set with probe motion horizontal and with the axial notch between 30 – 35 degrees.

18. When the 100% axial indication is set between 30 – 35 degrees, the phase angle of the 40% axial notch would therefore had met the requirements of ETSS-96511 (10-15 degrees). This was verified by reviewing the ETSS-96511 qualification data set.

19. Data Analysis Technique Procedure, Table 7, "Set-Up For +Point", states that the 40% OD notch be set to 50% full screen height.

20. When the 40% OD axial notch is set to 50% full screen height, the 40% ID notch equals 10 divisions. Therefore this exceeds the requirements of ETSS-96511 (2 divisions on the 40% ID notch). This was verified by reviewing the ETSS-96511 qualification data set. Therefore, I conclude that the phase and span settings requirements of ETSS-96511 were met.

21. The Analysis Technique Specification (ANTS) Sheets IP2-97-E "Mag Plus Point U-Bend", met the requirements of ETSS-96511 in all but one area. It does not state that the 100% axial notch lie between 30 – 35 degrees as stated in the Data Analysis Technique Procedure or that the 40% ID axial notch be set between 10 - 15 degrees as stated in ETSS-96511.

22. The following table summarized my review of the analyst's setups:

				Primary Setup		Secondary Setup	
SG	Row	Col	Cal#	100% Phase 400/300	40%OD Ax Span 400/300	100% Phase 400/300	40%OD Ax Span 400/300
21	2	87	H191	22°/21°	2.5/3.0	20°/21°	1.6/0.1
23	2	85	C14	32°/31°	4.0/4.5	32°/30°	2.4/3.4
24	2	4	H13	18°/18°	1.4/2.5	18°/18°	1.2/2.3
24	2	5	C58	29°/27°	1.1/1.0	29°/27°	1.1/1.0
24	2	67	C60	26°/25°	1.0/1.2	27°/25°	1.2/1.6
24	2	69	C60	26°/25°	1.0/1.2	27°/25°	1.2/1.6
24	2	71	C60	26°/25°	1.0/1.2	27°/25°	1.2/1.6
24	2	72	H21	40°/40°	0.8/1.2	21°/22°	1.4/2.4
24	2	74	H21	40°/40°	0.8/1.2	21°/22°	1.4/2.4

23. The Analysis Technique Procedure and U-Bend ANTS, IP2-97-E, state that the 40% OD axial notch be set at 50% full screen height which is approximately 2.5 divisions. As the table shows, very few of the setups met these requirements. The Data Analysis Technique Procedure states that the 100% Axial EDM notch be set between 30 – 35 degrees. Again, very few of these setups met that requirement. As stated earlier, the U-Bend ANTS, IP2-97-E, does not state the phase angle requirement but states probe motion horizontal. This may account for the phase angles below 30 degrees by the analyst attempting to set "probe motion horizontal".

24. The impact of shallower than required phase angle setups would effect the vertical component of the C-scan display which could result in a shallow PWSCC

indication not being detected. Additional screening requirements listed in the Data Analysis Technique Procedure, paragraph 10.3.2, "Scroll the entire test extent with all frequencies as necessary to confirm any possible indications and to locate the largest amplitude signal with respect to the applicable steam generator structure", should have overcome this deficiency. Therefore, I conclude that except for this minor deficiency the analyst should have been able to detect any significant degradation.

25. There are two U-Bend plus point training data sets; DISK_TRN_097A_02H1 cals 12 and 20 and three testing data sets; DISK_TST_097A_02H1 cals 7, 12, and 22. These data sets included axial PWSCC cracking at the tangent points and apex circumferential PWSCC. Therefore, I conclude that this training and testing of analysts at IP2 was representative of industry practice in 1997.

26. The data that was provided to me on the tubes listed in paragraph 27 of this affidavit, seemed typical of U-bend examinations in other plants. There did not appear to be excessive deposits, noise, or lift off signals.

27. The plus point probe did have a signal that I attribute to the ovality of the U-bends. This signal was present throughout the U-Bend area of several tubes. Those tubes were:

SG	Row	Col	Cal#	Ovality
21	2	87	H191	Yes
23	2	85	C14	Yes
24	2	4	H13	No
24	2	5	C58	Yes
24	2	67	C60	No
24	2	69	C60	No
24	2	71	C60	No
24	2	72	H21	Yes
24	2	74	H21	Yes

28. This "ovality" signal could mask small ID PWSCC indications if the analyst relied on the c-scan display only. However, the Data Analysis Technique Procedure, para. 10.3.2 states; "Scroll the entire test extent with all frequencies as necessary to confirm any possible indications and to locate the largest amplitude signal with respect to the applicable steam generator structure. C-Scan, Lissajous and strip chart display shall all be monitored during this process." I conclude that the ovalization signal should not have masked any indications of significant depth.

29. In conclusion, the Indian Point #2 Data Analysis Technique Procedure was in compliance PWR Steam Generator Guidelines, Revision 4, Volume 1, dated June 1996. The training of the IP2 analysts in regards to U-Bend plus point was similar to other plant's training programs during 1997 and met the requirements of the PWR Steam Generator Guidelines: Revision 4, Volume 1 dated June 1996 Section 6. I believe that the production analyst's actual setup files utilized during the evaluation of the Row 2 U-Bends were adequate for the detection of PWSCC in the tangent points and apex of the tubing.

34. The foregoing statements are true and correct to the best of my knowledge and belief.

John J. Funanich

John J. Funanich

Sworn and subscribed to before me on this 18th day of January, 2001.

Brad Farmer

Notary Public

My Commission expires:

BRAD FARMER
Comm. # 1123229
NOTARY PUBLIC - CALIFORNIA
County & City of San Francisco
My Comm. Expires Jan. 20, 2001

MoreTech

EXHIBIT #1

RESUMÉ

Jon J. Funanich

Residence:
2439 Seabrook Ct.
Fairfield, CA 94533

Business:
MoreTech, Inc.
406 Military East
Benicia, CA 94510

Relevant Skills and Experience

Mr. Funanich has applied the last 21 years to becoming a force in the eddy current industry that has become a standard many peers try to live up to. His dedication to constantly improve his skills has given him the ability to become a Level III that is highly regarded for his acumen and integrity. He is currently the assistant QA Manager at MoreTech, Inc.

His experience is comprised of eddy current data analysis, development and execution of technological advances, industry procedures, guidelines, training and testing programs, coordination of eddy current analysis projects, generating, maintaining, and approving evaluation summaries and technical documents, pc and unix system setup, administration, networking.

Mr. Funanich brings an abundance of experience, knowledge, technical abilities, and facilitation skills to help Utility power companies accomplish eddy current projects of nuclear components that are strictly regulated by national and government agencies.

Education

Vanden High School	Diploma, General Education	1972
Solano College	.Associates Degree, Electronics	1975
Conam Nuclear, Inc.	Supervisor Awareness Program	1993
Conam/Rockridge Tech.	Eddy Current Training Levels I,II,III	3/78-1999

Employment Summary

MoreTech, Inc.	Eddy Current Level III, QDA	2/99-Present
Conam/Rockridge Tech.	Eddy Current Level III, QDA	6/94-1/99
Conam Nuclear, Inc.	Eddy Current Level III	4/93-6/94
Conam Nuclear, Inc.	Eddy Current Level III	10/89-4/93
Conam Inspection	Eddy Current Level III	8/83-10/89
Conam Inspection	Eddy Current Level IIA	8/79-8/83
Conam Inspection	Eddy Current Level II	2/79-8/79
Conam Inspection	Eddy Current Level I	5/78-5/79
Conam Inspection	Eddy Current, trainee	3/78-5/78

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of:	)	
	)	
Consolidated Edison Company	)	Docket No. 50–247
of New York, Inc.	)	
(Indian Point Nuclear Station,	)	
Unit No. 2)	)	

AFFIDAVIT OF GREGORY M. TURLEY

I, Gregory M. Turley, being duly sworn, state as follows:

1. I am a shareholder of CoreStar International Corporation (CoreStar) and hold the title of Vice President Operations.

2. I was recently asked to examine elements of a nondestructive examination (NDE) of the steam generators (SG) at the Indian Point 2 (IP2) nuclear power plant conducted in the spring of 1997 utilizing a technique referred to as eddy current testing (ECT). Indian Point 2 is owned and operated by the Consolidated Edison Company (ConEd) of New York, Inc.

3. I have had previous involvement with the Consolidated Edison Company, Indian Point 2 regarding steam generator issues, including those issues associated with steam generator inspections occurring in 1997.

4. I was involved with the 2000 SG ECT inspection as follows. My involvement was at the conclusion of the inspection and at ConEd's request:

• I interfaced with the ConEd Project Manager to negotiate the terms of a contract for CoreStar to perform an independent review of the Westinghouse inspection database to confirm that all tubes that required plugging were on the final tube plug list.

• I interfaced with the ConEd Project Manager during the independent database review process to discuss deliverables and schedule logistics.

• I did not personally perform the independent database review tasks. The tasks were assigned to and performed by CoreStar personnel that report to me.

5. My professional qualifications and experience are outlined in Exhibit 1.

6. Prior to preparing this affidavit I reviewed the following documents and data sources:

• 2/7/97 ConEd letter to NRC describing 1997 SG ECT inspection program plans

• Slides from 4/24/97 ConEd presentation to NRC (re: SG ECT inspection program)

• 5/29/97 NRC letter to ConEd approving SG ECT inspection program plans

• Westinghouse data analysis guideline DAT-IP2-001, Revision 0

• Westinghouse field service report from 1997 SG ECT inspection

• 7/16/97 NRC Integrated Inspection Report 50-247/97-07

• 1997 plugged tube list (and history) for row 2 and 3 tubes

• 11/1/00 NRC Lessons Learned Task Force Report

• 11/20/00 NRC Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2 – Report No. 05000247/2000-010.

7. The purpose of this affidavit is to summarize the 1997 SG ECT inspection activities at Consolidated Edison's (ConEd) Indian Point Unit 2 station (IP2). Topics

covered herein will address the NRC criticisms contained in the NRC Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2 – Report No. 05000247/2000-010. The affidavit will contain three major sections. The first section will list the industry codes and standards in effect at the time of the 1997 outage. The second section will summarize the pre-outage activities. The third section will summarize the outage oversight activities.

8. My roles and responsibilities during the preparation and execution of the 1997 SG ECT inspection included:

- Technique qualification oversight at Westinghouse's Waltz Mill facility
- ACTS and ANTS development and/or review
- Data analysis guideline development and/or review
- NRC interface support
- Site specific performance demonstration (SSPD) data set development and/or review
- Proctoring of SSPD (i.e. Data analyst training & testing)
- Data review during SG ECT inspection for procedure/guideline validity and adherence

9. The following codes and standards were in effect at the time of the 1997 outage at IP2. The list forms the basis for measuring compliance to industry approved methodologies for SG ECT inspection activities. The codes and standards were reviewed for their applicability to the SG inspection activities at IP2 in 1997.

- ASME Boiler & Pressure Vessel Code, Section XI, "Rules for In-Service Inspection of Nuclear Power Plant Components"

• EPRI TR-106589, Revision 4, "Pressurized Water Reactor SG Examination Guidelines"

• ETSS 96511, "EPRI qualification for PWSCC detection in low row u-bends"

• Plant Technical Specification

• NRC Generic Letters, 95-03 & 95-05

• NRC Information Notices 90-49, 91-67, 92-80, 94-88, 95-40, 96-09, 96-38, and 97-26

10. Exhibits 2-5 contain tables that summarize the requirements of the industry codes and standards. The industry requirement is noted in the table on a paragraph by paragraph basis. The means of implementation and compliance to the requirement is noted in the "1997 Reference" column. All requirements have been complied with unless the comment section indicates otherwise.

11. Exhibit 2 contains a table of the requirements set forth in Section XI of the ASME Boiler & Pressure Vessel Code. All Code requirements were complied with as indicated in the table.

12. Exhibit 3 contains a table of the requirements set forth in Revision 4 of the EPRI PWR SG Examination Guidelines. A non-compliance is noted in the table. The non-compliance involves a deviation between the EPRI defined parameters for proper calibration of data for low row u-bend exams versus the parameters implemented at site. The EPRI eddy current technique specification sheet (ETSS) 96511 called for EDM notch standards with a 40% ID circumferential notch to be used in the data analysis setup. While the calibration standards used at site contained many more

notches than the calibration standards used in the EPRI qualification, the site calibration standards did not contain the required 40% ID circumferential notch.

13. ETSS 96511 also required the data analyst to set the phase of the 40% ID circumferential notch at 10 degrees. The analysis technique sheet (ANTS) called for probe motion to be set horizontal. While the site setup parameters failed to meet the absolute requirements of the EPRI ETSS, setting probe motion horizontal proved to be equivalent. In other words, setting probe motion horizontal results in a calibration setup that is equivalent to setting the 40% ID circumferential notch to 10 degrees. This has been proven and documented by Westinghouse. All other EPRI requirements were complied with as indicated in the table. Based upon my review and considering the non-compliance had no effect on the end result, I believe it can stated that we met the intent of the requirements set forth in Revision 4 of the EPRI PWR SG Examination Guidelines.

14. Exhibit 4 contains a table of regulatory guidance available to the industry at the time of the 1997 outage at IP2. NRC Generic Letters (GL) and Information Notices (IN) with content concerning SG ECT inspection activities were reviewed. All recommendations and requirements were complied with as indicated in the table.

15. Newer codes and standards [Revision 5 of the EPRI PWR SG Examination Guidelines (released September 1997), NEI 97-06 "SG Program Guidelines" (released April 1998), and DG-1074 "Draft Regulatory Guide for SG Tube Integrity"(still a draft today)] have been distributed within the industry since the spring 1997 outage at IP2. I recognized prior to the 1997 outage that there were draft codes and standards in the

process of industry review and eventual release to the industry, but chose not to address them since the content was still evolving.

16. The first order of business in any SG ECT inspection project is to develop inspection plans commensurate with the critical regions of the tubes and known degradation morphologies expected in a particular model SG.

17. The IP2 SGs are Westinghouse model 44 designs.

18. The definition of the critical regions for the 1997 outage was based on industry experience in like SG designs and past experience at IP2. The critical tube regions of the IP2 SGs were defined to be the tubesheet (TS) crevice, sludge pile above the tubesheet, dented tube support plates (TSP), and low row u-bends. The definition of critical regions does not mean that other regions of the tube were non-critical and would be ignored.

19. The 1997 tube inspection plans at IP2 were designed to meet or exceed the requirements set forth in Revision 4 of the EPRI PWR SG Examination Guidelines, which governed the requirements at the time. Revision 4 of the EPRI PWR SG Examination Guidelines required minimum sample sizes >=20% of all tubes in all SGs with 100% inspection required within 60 effective full power months (EFPM).

20. A summary of the initial inspection plan can be found in Exhibit 5, hereto. The freespan and dented TSP plans were subsequently expanded to 100% full length during the outage as a result of degradation indications found at the TSPs. All other critical tube regions had a 100% sample size defined pre-outage. Since the sample size for all critical tube regions was >20%, it can be stated that the 1997 inspection plan exceeded the requirements of Revision 4 of the EPRI PWR SG Examination Guidelines.

21. Qualified inspection techniques must be utilized for SG ECT tube examinations per Revision 4 of the EPRI PWR SG Examination Guidelines.

22. The inspection techniques were chosen for each critical region of the tube based on the list of industry-qualified techniques summarized in Table 7-1 in Revision 4 of the EPRI PWR SG Examination Guidelines lists. Specific to the low row u-bend exams, the mid-range (MR) frequency +Point probe was used.

23. Industry peer review of the MR +Point probe qualification data provided evidence that the MR +Point probe was the best available technique for PWSCC detection in low row u-bends. The MR +Point probe was generally accepted in the industry to be state of the art. The NRC also endorsed the use of the MR +Point probe over its predecessor techniques, namely the bobbin coil and various pancake coil probes. There are direct and indirect statements in the NRC GL and IN documents to validate this statement of general industry endorsement.

24. Beaver Valley, Diablo Canyon, and Sequoyah are three domestic utilities that began to use the MR +Point probe for their low row u-bend exams in the 1996-1997 timeframe. Therefore, IP2 was not the first utility to implement the MR +Point probe for low row u-bend exams.

25. Consistent with the requirements set forth in Revision 4 of the EPRI PWR SG Examination Guidelines, the following documents were developed:

- Data acquisition procedure (MRS 2.4.2 GEN-35, Revision 6)
- Acquisition technique sheets (ACTS IP2-97-001 through IP2-97-012, various revisions)
- Data analysis guidelines (DAT-IP2-001, Revision 0)

• Analysis technique sheets (ANTS IP2-97-A through IP2-97-G, all revision 0).

MRS 2.4.2 GEN-35 was a generic Westinghouse data acquisition procedure. I provided no review or approval to MRS 2.4.2 Gen-35. The ACTS and ANTS documented the site specific data acquisition and data analysis parameters respectively. DAT-IP2-001 was the site specific data analysis guideline. I reviewed and approved the ACTS and ANTS prior to use. I reviewed DAT-IP2-001 prior to use.

26. Westinghouse was responsible to develop the first draft of each of the aforementioned documents. It was my responsibility to review them for compliance to the industry codes and standards of the time. My comments and input were formally transmitted to Westinghouse for inclusion in the final documents. Within the data analysis guideline, we incorporated detailed language and/or evaluation flowcharts for each probe type.

27. The repair logic planned for the 1997 outage was very conservative. All tubes with Cecco 5, bobbin, or +Point degradation indications were to be plugged. A degradation indication is defined to be any signal representative of tube wall degradation. Percent through wall and I-codes are two examples of degradation indications. Our practice of plugging degradation indications based on detection by any one qualified technique exceeded the industry norm in that most other plants required +Point confirmation of Cecco 5 and/or bobbin degradation indications prior to plugging those tubes. The plugging logic at IP2 applied to all degradation indications at all tube locations.

28. The week of February 24-28, 1997, ConEd was visited by an INPO audit team. INPO audit teams were focusing on plants with Inconel 600 (I600) mill annealed (MA) tubing like IP2. The INPO audit team goals were defined to be:

- Identify increased potential for tube rupture
- Identify strengths and weaknesses of SG maintenance programs

29. ConEd personnel stated that they believed the good SG performance (to date) was attributable to low T_{hot}, Huntington Alloy tubes, and good chemistry controls and condenser in-leakage controls.

30. At the exit meeting, the INPO audit team noted three strengths and seven recommendations related to the SG program. All of the recommendations were incorporated in the 1997 outage inspection and repair plans. INPO strongly suggested ConEd strive to meet the requirements of Revision 4 of the EPRI PWR SG Examination Guidelines. INPO added a closing comment that ConEd may want to consider a meeting with the NRC prior to the outage. The thought process was that ConEd could present its overall inspection and repair plan to the NRC to seek the NRC's comments.

31. IP2's plant technical specification required ConEd to submit its SG inspection program to the NRC for review and approval. ConEd submitted its proposed 1997 SG tube examination program plans to the NRC in February 1997. The SG program plan included the MR +Point probe for low row u-bend tube regions. On April 24, 1997, a meeting was held with the NRC Staff to present the overall inspection and repair plan. In the April 24, 1997 meeting, the NRC Staff communicated their believe that the MR +Point probe was the best available technique for SCC detection in all critical tube regions. On May 29, 1997, the NRC stated in a letter to ConEd, "The NRC Staff has

completed its review of the proposed 1997 refueling outage SG tube examination program and finds it acceptable based on the information submitted. In addition, the number of tubes scheduled to be examined exceeds the requirements of the IP2 technical specifications." The 5/29/97 NRC letter also concluded "... that the proposed program to inspect the IP2 SG tubes during the 1997 refueling outage is acceptable because it sufficiently covers the areas of the tube bundle that are susceptible to degradation."

32. I was responsible to proctor the SSPD program. The SSPD program consisted of a written exam and a practical exam. The written exam tested the QDA's knowledge of the data analysis guidelines. The practical portion of the SSPD program included ECT data from past IP2 inspections (all techniques except MR +Point for low row u-bends) and ECT data from past inspections at similar plants (MR +Point for low row u-bends). All of the data sets utilized were representative of the degradation morphologies expected in the critical regions of the tubes. All of the data sets, except the MR +Point for low row u-bends, met the statistical rigor required by Revision 4 of the EPRI PWR SG Examination Guidelines. Flawed (1/3 of total) and un-flawed (2/3 of total) grading units are required to build a statistically valid data set for SSPD purposes. Low row u-bend data were requested from Beaver Valley, Diablo Canyon, and Sequoyah. Only Diablo Canyon agreed to supply data to IP2. Less than twenty tubes of data were obtained. All of the data represented flawed tubes because Diablo Canyon did not want to release data for un-flawed tubes that were still in service. As is stated above, this did not meet the statistical rigor of the time, but was a "best effort" with the data available.

33. During the inspection process I performed the role of resolution (RES) analysis oversight, which exceeded the requirements of Revision 4 of the EPRI PWR SG Examination Guidelines. I reviewed all degradation indications (i.e. degradation) that were called by either PRI or SEC or both, that were being discarded by RES. If I did not concur with the decision to discard the degradation indication, Westinghouse was obligated to keep the degradation indication and repair the tube in accordance with the inspection/repair plan. Revision 4 of the EPRI PWR SG Examination Guidelines defines the minimum expected requirements for the PRI/SEC/RES process as:

- PRI and SEC analysis of all tube data
- RES analysis of PRI/SEC discrepancies only

34. Neither the RES analysts or myself were required by IP2 procedure or any other industry document to review the low row u-bend MR +Point data unless a PRI/SEC discrepancy was noted, a repairable indication was reported, or a degradation indication was being discarded by the RES process. Since the degradation indication in Row 2 Column 67 was reported by both PRI and SEC, the tube was placed on the repair list. No further action was warranted or taken. There was precedence in the industry to justify our action of plugging the tube upon detection of an degradation indication. Additional actions such as re-training of analysts and re-analysis of data was unwarranted due to the text book nature of the signal detected. In other words, the analysts were trained to detect the type of signal that was found in Row 2 Column 67.

35. During the initial days of the SG ECT inspection, daily conference calls were held between the site and the remote data analysis facility. The overall lead analyst, the RES lead analyst, the PRI/SEC analysts, and myself discussed hits, misses, and

overcalls from the previous days analysis activities. Hits are defined to be calls made by the PRI and/or SEC analysts that RES agrees should have been reported. Misses are defined to be calls missed by the PRI or SEC analysts that RES feels should have been reported. Overcalls are defined to be calls made by the PRI and/or SEC analysts that RES feels should not have been reported. This process of reviewing hits, misses, and overcalls exceeded the industry requirements of the time. Revision 4 of the EPRI PWR SG Examination Guidelines did not require this process in 1997. It was not formally documented and computerized as it is today, but it occurred nonetheless. Today, this process is commonly referred to as analyst performance tracking.

36. An example of the benefits realized by the early form of analyst performance follows. The example also exemplifies mid-course corrections taken to address an emergent issue in the SG ECT inspection results. On May 21, 1997, a non-quantifiable indication (NQI) was detected in the hot leg tubesheet of a tube in SG 22. After discussing the situation amongst the ECT Level IIIs from Westinghouse and myself, a better approach for the data analyst training and testing process was identified. The actions that were immediately taken included:

- Communication with all data analysts on that day to inform them of this condition.
- Instructed the data analysts to no longer trust only the Cecco 5 probe in this critical tube region.
- Instructed the data analysts to analyze the Cecco 5 and bobbin data for the entire length of this critical tube region. Provided graphics illustrating proper detection and measurement techniques for both techniques.

• Selected a group of experienced QDAs for re-analysis of this critical tube region for all tube data collected up to that point.

37. Another example of mid-course corrections taken involves the Cecco 5 sample plan for the dented TSPs. The initial inspection plan included 100% TSH-2H, 100% TSC-1C, and 33% full length. If one or more TSP locations above 2H or 1C exhibited degradation indications, the sample plan was to be expanded based on the logic contained in a decision tree. One or more degradation indications was encountered above the 2H elevation noted above. The Cecco 5 and bobbin sample plans were expanded to 100% full length in all SGs at that point.

38. The low row u-bend exams (i.e. rows 2 & 3) were examined for the first time with a rotating probe technique. Industry experience at the time of the 1997 SG ECT inspection at IP2 suggested that we should expect to find 1-2 degradation indications. My experience prior to the 1997 SG ECT inspection at IP2 including a review of performance at plants with similar SG designs (i.e. Model 44 and 51), suggested that two or fewer degradation indications had been detected in low row u-bend rotating probe exams in any given outage. At the plants where I had direct involvement, to my knowledge no re-analysis of the low row u-bend tube data or retesting of tubes occurred upon detection of a degradation indication following the first application of a rotating probe. In such instances, the tubes were plugged. The IP2 plan from the start included a sample size of 100% with the best available inspection technique. If one or more degradation indications was found the tube was to be repaired by plugging both tube ends. This is not atypical of low row u-bend methodologies and inspection results implemented at other plants as described in NRC IN 97-26.

39. A single axial indication (SAI) was found in Row 2 Column 67 during the course of the MR +Point low row u-bend exams. The signal was detected and reported by both PRI and SEC analysts. The RES analyst confirmed the degradation indication at which point the tube was added to the repair list for plugging. As far as I was concerned, the plan was implemented as intended and as set forth in the inspection plan and the examination described to the NRC in the February 7, 1997 submittal and April 24, 1997 meeting with the NRC Staff. There was nothing unique about the degradation indication; it was a "text book" SAI, consistent with the SSPD training program. It validated the belief that the MR +Point probe was functioning properly. It also validated the industry experience model. In other words, we found one degradation indication, which is consistent with past experience at similar plants with similar SG designs.

40. The identification of the degradation indication in Row 2 Column 67 is noted as a finding in the NRC Final Significance Determination for a Red Finding and Notice Of Violation report 05000247/2000-010, dated November 20, 2000. The finding goes on to state that:

- "... a PWSCC defect was identified for the first time, at the apex of one row 2 tube, signifying the potential for other similar cracks in low row tubes""
- "ConEd did not adequately evaluate the susceptibility of low row tubes to PWSCC and the extent to which this degradation existed"

I do not concur with the NRC statements. The sample size for low row (i.e. rows 2 & 3) u-bend MR +Point exams was already 100%. The entire critical region of concern was bounded by the sample size. In addition, the best available and qualified technique was employed. From an ECT perspective, there was no industry experience or site specific

condition that would suggest an action plan more extensive than the tube plugging actions taken in 1997.

41. Row 2 Column 5 is the tube that leaked in February 2000. Noise has been suggested to be the cause of the missed degradation indication in 1997. This item was noted as a finding in the NRC Final Significance Determination for a Red Finding and Notice Of Violation report 05000247/2000-010, dated November 20, 2000. The finding goes on to state that:

- "significant ECT signal interference (noise) was encountered in the data ..."
- "... significant noise level reduced the probability of identifying an existing PWSCC tube defect"
- "... the 1997 SG inspection program was not adjusted to compensate for the adverse effects of the noise ..."

I do not concur with the NRC statement that the 1997 SG Program was susceptible to adjustments to compensate for noise. There was no evidence that the data quality was suspect in 1997. The tubes exhibited varying degrees of ovality and outside diameter (OD) deposits. Ovality and OD deposits are sometimes referred to as noise in low row u-bend exams. The amount of ovality and OD deposits in the 1997 data was not deemed to be atypical of low row u-bend rotating probe data seen elsewhere. Flaw detection was not believed to be compromised by the site-specific conditions. A degradation indication in Row 2 Column 5 cannot be readily detected. It is only with hindsight that one can reasonably be expected to detect a degradation indication in Row 2 Column 5. A statement quoted from the November 2000 NRC Lessons Learned report coincides with the previous statement. In that report the NRC states "Experts

that the Task Group interviewed held different views on whether the flaw in Row 2 Column 5 could have reasonably been detected from the data."

42. The ECT sample size for the low row u-bend region was at 100% with the best available technique. Westinghouse/ConEd employed a group of QDA personnel from all over the country to support the SG ECT inspection program. Individuals were encouraged to request tube retests if they questioned data quality. A large percentage of the QDA personnel assigned to this job have worked for other inspection vendors and at other plants, thus their experiences are diverse. None of the individuals expressed a concern with the MR +Point data in terms of being atypical of their knowledge and experience with its application elsewhere in the industry.

43. Nineteen (19) row 2 and 3 tubes were preventatively plugged in 1997 because they would not permit passage of a 0.610" probe. This item was noted as a finding in the NRC Final Significance Determination for a Red Finding and Notice Of Violation report 05000247/2000-010, dated November 20, 2000. The finding goes on to state that:

- "... indications of denting were identified for the first time ..."
- "Restrictions ... signified increased probability of deformed flow slots (hour-glassing) at the upper TSP"
- "Hour-glassing ... increases stresses at the u-bend apex ..."
- "...stresses are ... precurser for PWSCC"
- ConEd did not adequately evaluate the potential for hour-glassing based on the indications of the low row tube denting"

I do not share the NRC's viewpoint that ConEd did not adequately evaluate hour-glassing. Let's examine two of the nineteen tubes from SG 24 a little more closely. Row 2 Column 7 and Row 2 Column 76 were plugged based on a "610 obstruction at 6C". If you examine the results database carefully you will find that both of those tubes passed a 0.610" bobbin probe through 6C in 1995 and 1997. This indicates that denting had not progressed at the top TSP location. The 6C intersection would not pass a straight-section rotating probe in 1997. A 0.610" bobbin probe is designed to traverse the full length of SG tubes including the low row u-bend region. The bobbin probe head has a rigid length of approximately one inch. Approximately six inches of flex shaft interface the bobbin probe head to the poly shaft. The straight-section rotating probe head has a rigid length of approximately three inches. Approximately three inches of flex shaft interface the rotating probe head to the motor unit that spins the probe head. The motor unit has a rigid length of approximately three to four inches. The motor unit is attached directly to the poly shaft. It is my opinion that the 6C intersection could not be traversed by the straight-section rotating probe because of the significant mechanical differences of the probe design. I do not believe any ECT inspection information presented itself in 1997 to indicate denting had progressed at the top TSP locations. In fact, the only logical inference to be drawn was that the probe dimensions rather than the tube denting caused the probe passage results experienced in the 1997 inspection.

44. It is unfortunate that a leak occurred in February 2000. I do not think the leak can be attributed to a lack of focus or attention to detail on the 1997 inspection. The pre-outage plan and emergent issues were acted upon in a prudent and conservative manner.

45. Qualified techniques, personnel, and procedures were utilized. Every applicable industry code and standard of the time was met or exceeded. INPO's feedback was included in the overall SG program. The inspection results were consistent with industry experience. I concur with this report, which is well documented and supported by direct NRC observation of the 1997 inspection.

46. On July 16, 1997 NRC Integrated Inspection Report 50-247/97-07 was submitted to ConEd. In the report, the Region 1 Inspection Specialist stated that ConEd's ISI Program, with particular emphasis on the ISI of SGs, was effectively monitored and controlled. The Inspection Specialist measured ConEd's ISI Program against plant technical specification, ASME Section XI, and EPRI PWR SG Examination Guideline requirements. It was concluded in the report that the techniques, personnel, and procedures were both qualified and acceptable.

47. Perfection is a great objective, but let's face the fact that the industry standard for qualified techniques, personnel, and procedures results in a probability of detection (POD) of 80% with a 90% confidence level. Statistically speaking, that means we, as an industry, recognize and accept that missed degradation indications will happen.

48. The foregoing statements are true and correct to the best of my knowledge and belief.

Gregory M. Turley

Sworn and subscribed to before me on this 18 day of January 2001.

Notary Public

My Commission expires:

Notarial Seal
Marion Rayman, Notary Public
Hempfield Twp., Westmoreland County
My Commission Expires Aug. 5, 2002

Exhibit 1
Resume of Gregory M. Turley

Education

BS Applied Mathematics, University of Pittsburgh, 1986

NDE Credentials

ET Level III/Qualified Data Analyst

Work Experience

May 1996 – Present
CoreStar International Corporation

Title:	Vice President Operations/Shareholder
Responsibilities:	Manage all aspects of HX and SG ET inspection projects, including personnel training, data acquisition procedure development, data analysis guideline development, data management guideline development, inspection plan development, schedule logistics, and project management.

February 1986 – May 1996
Westinghouse Electric Company

Title:	Manager, NDE Field Operations
Responsibilities:	Managed data analysis and data management aspects of SG ET inspection projects, including personnel training, data analysis guideline development, data management guideline development, inspection plan development, schedule logistics, and project management.

Other Relevant Experience

- Have 15 years experience in the application of ET inspection techniques.
- Have been closely involved in hundreds of HX and SG inspection projects.
- Have a thorough knowledge of the industry codes and standards.
- Have been involved in ET system and technique qualifications.

Exhibit 2
ASME Boiler & Pressure Vessel Code
Section XI Compliance

Section/Paragraph	Requirement	1997 Reference	Comments
	Rules for Inservice Inspection of Nuclear Power Plant Components		
IWA-2233	Eddy current examination of heat exchanger tubing shall be in accordance with the provisions of Appendix IV		Details to follow in Appendix IV below
IWA-2300	Qualifications of NDE personnel	See certifications for assigned personnel & written practices for each NDE vendor	References ASNT SNT-TC-1A
Appendix IV	*Eddy Current Examination of Nonferromagnetic SG Heat Exchanger Tubing*		
IV-2100	Written procedures required. Certain information shall be included:	MRS 2.4.2 GEN-35 DAT-IP2-001	
a)	Tube material, diameter, & wall thickness	ACTS	
b)	Size & type of probe, manufacturers name, description or part #, & length of probe & probe ext. cables	ACTS	
c)	Examination frequencies	ACTS	
d)	Manufacturer & model of ET equipment	ACTS	
e)	Scanning direction & speed during examination	ACTS	
f)	Inspection technique e.g. hand	ACTS	

Exhibit 2
ASME Boiler & Pressure Vessel Code
Section XI Compliance

Section/Paragraph	Requirement	1997 Reference	Comments
	probe, mechanized probe driven, remote control fixture		
g)	Description of calibration procedure & calibration stds.	MRS 2.4.2 GEN-35 ACTS	
h)	Description of data recording equip. & procedures	MRS 2.4.2 GEN-35 ACTS	
i)	Procedure for analysis of examination results & applicable criteria for reportable indications	DAT-IP2-001 ANTS	
j)	Procedure for reporting examination results	DAT-IP2-001 ANTS	
k)	Personnel requirements	MRS 2.4.2 GEN-35 DAT-IP2-001	
l)	Fixture location verification	MRS 2.4.2 GEN-35	
IV-2200	Personnel		
a)	Data acquisition personnel shall receive specific training	See certifications for assigned personnel & written practices for each NDE vendor	References ASNT SNT-TC-1A
b)	Data analysis personnel shall receive specific training	See certifications for assigned personnel & written practices for each NDE vendor	References ASNT SNT-TC-1A
IV-2310	General data acquisition		
a)	Multi-frequency instrument	TC6700 complies	
b)	Phase & amplitude output	TC6700 complies	
c)	Can detect dimensional, metallurgical, deposits, & flaws (OD & ID)	TC6700 complies	
IV-2331	Digital instrument requirements		
a)	30 samples per inch of tubing	TC6700 complies	

Exhibit 2
ASME Boiler & Pressure Vessel Code
Section XI Compliance

Section/Paragraph		Requirement	1997 Reference	Comments
	b)	12 bits per data point resolution	TC6700 complies	
	c)	Frequency response +/- 2%	TC6700 complies	
	d)	Selectable lissajous display	ANSER complies	
	e)	Lissajous 7 bits full scale	ANSER complies	
	f)	2 strip chart traces	ANSER complies	
	g)	Selectable strip chart display	ANSER complies	
	h)	Strip chart 6 bits full scale	ANSER complies	
IV-2332		Recording system		
	a)	Record & play back all test frequencies	ANSER complies	
	b)	Record & play back all text information	ANSER complies	
	c)	12 bits per data point resolution	ANSER complies	
IV-2410		Bobbin coils		
	a)	Detect calibration standard flaws	ACTS	Per EPRI Appendix H requirements
	b)	Operate at frequencies for flaw detection & sizing	ACTS	Per EPRI Appendix H requirements
IV-2510		General data analysis system		
	a)	Display all test frequencies	ANSER complies	
	b)	Multiparameter mixes	ANSER complies	
	c)	Record tube ID	ANSER complies	
	d)	Phase in 1 degree increments	ANSER complies	
	e)	Amplitude in 0.1 volt increments	ANSER complies	
IV-2531		Digital data analysis system display		
	a)	Present signals & text	ANSER complies	
	b)	12 bits per data point resolution	ANSER complies	
	c)	Lissajous 7 bits full scale	ANSER complies	
	d)	Selectable strip chart display	ANSER complies	
	e)	Strip chart 6 bits full scale	ANSER complies	
IV-2532		Digital data analysis system recording		
	a)	Play back signals & text	ANSER complies	

Exhibit 2
ASME Boiler & Pressure Vessel Code
Section XI Compliance

Section/Paragraph		Requirement	1997 Reference	Comments
	b)	12 bits per data point resolution	ANSER complies	
IV-2700		Fixture location verification		
	a)	Verify visually & record	MRS 2.4.2 GEN-35	
	b)	Errors shall result in reexaminations	MRS 2.4.2 GEN-35	
IV-3210		General cal std		
	a)	Shall be same mat'l spec, heat treatment, & nominal size	Complied	See as-built drawings
	b)	Different heat treatments must be approved by ANII	Complied	Reference Code Case N-402
	c)	UNS alloy N06600 may be used in lieu of a) & b) requirements	N/A	
	d)	As-built drawing & ET response shall be recorded	Complied	See as-built drawings
IV-3220		Bobbin coil cal stds		
	a)	Shall contain 100%TW hole 0.067" dia, 4 x 100% TW holes 0.033" dia (90 degrees apart in same plane), 60% TW hole 0.109" dia, 40% TW hole 0.187" dia, & 4 x 20% TW holes 0.187" dia (90 degrees apart in same plane)	Complied	See as-built drawings
	b)	Depths shall be within +/- 20% or 0.003", whichever is less	Complied	See as-built drawings
	c)	Discontinuities shall be sufficiently separated to avoid interference	Complied	See as-built drawings
IV-3400		Digital system calibration shall be performed off line by data analysts	DAT-IP2-001 ANTS	
IV-3500		System calibration verification		
	a)	Any change to ET system (i.e. Probe, probe extensions, & test instrument) shall require recalibration	MRS 2.4.2 GEN-35 DAT-IP2-001	

Exhibit 2
ASME Boiler & Pressure Vessel Code
Section XI Compliance

Section/Paragraph	Requirement	1997 Reference	Comments
b)	System calibration shall occur at beginning & end of data set	MRS 2.4.2 GEN-35 DAT-IP2-001	
c)	Data analyst determines retest requirements if system found out of calibration	MRS 2.4.2 GEN-35 DAT-IP2-001	
IV-4100	General examination		
a)	ET data for all test frequencies shall be recorded	MRS 2.4.2 GEN-35 ACTS	
b)	Bobbin coil must be sensitive to 100% TW hole (i.e. 50% FSH)	MRS 2.4.2 GEN-35 ACTS	
IV-4200	Probe traverse speed shall not exceed frequency response & sensitivity to cal std flaws	MRS 2.4.2 GEN-35 ACTS	
IV-5111	Depths shall be correlated to cal std that has been qualified	DAT-IP2-001 ANTS	Per EPRI Appendix H
IV-5112	Indications shall be reported from qualified frequencies or mixes	DAT-IP2-001 ANTS	Per EPRI Appendix H
IV-5210	Reporting criteria		
a)	Location along tube length	DAT-IP2-001 ANTS	
b)	Depth through tube wall	DAT-IP2-001 ANTS	If technique qualified for sizing
c)	Signal amplitude	DAT-IP2-001 ANTS	
d)	Frequency or mix channel	DAT-IP2-001 ANTS	
IV-5220	Flaws >=20% TW shall be reported	DAT-IP2-001 ANTS	
IV-5300	NQI shall be considered a flaw until otherwise resolved	DAT-IP2-001 ANTS	
IV-5410	Tube support members shall be used as reference points for location	DAT-IP2-001	Dimensions taken from drawings in SG design handbook

Exhibit 2
ASME Boiler & Pressure Vessel Code
Section XI Compliance

Section/Paragraph	Requirement	1997 Reference	Comments
IV-6100	Record identification		
a)	Owner	ANSER summary	Stored on optical disk
b)	Plant site	ANSER summary	Stored on optical disk
c)	SG ID	ANSER summary	Stored on optical disk
d)	Data storage unit #	ANSER summary	Stored on optical disk
e)	Date of exam	ANSER summary	Stored on optical disk
f)	Serial # of cal std	ANSER summary	Stored on optical disk
g)	Operators ID & level	ANSER summary	Stored on optical disk
h)	Exam frequencies	ANSER summary	Stored on optical disk
i)	Length of probe & probe extension cables	ANSER summary	Stored on optical disk
j)	Size & type of probe	ANSER summary	Stored on optical disk
k)	Probe manufacturer, part #, & description	ANSER summary	Stored on optical disk
IV-6200	Tube identification		
a)	Each tube shall be identified	MRS 2.4.2 GEN-35	
b)	Recorded tube ID shall correlate with actual tube ID	MRS 2.4.2 GEN-35	
IV-6300	Records		
a)	Owner or agent shall prepare report of exams	See W report	
b)	Report shall contain tubes examined, scanning limitations, location & depth of reported flaws, ID & level of operators & analysts	See W report	
c)	Report shall identify tubes removed from service or repaired	See W report	

Exhibit 3
EPRI PWR SG Examination Guidelines
TR-106589 Revision 4 Compliance

Section/Paragraph	Requirement	1997 Reference	Comments
Section 4	*Data Acquisition Procedures*		
4.1	Volumetric exams (i.e. ET)	ACTS	Used ET
4.2.1	Digital instrumentation	ACTS	Used digital instruments
4.2.2	Multi-frequency tests	ACTS	Ran 3 or more frequencies
4.2.3.1	Bobbin coils for detection of axial & volumetric flaw types	ACTS	Used bobbin in unison with C5
4.2.3.2	Rotating coils for detection of circumferential flaw types & in critical areas (i.e. u-bend)	ACTS	Used + Point
4.2.3.3	Array coils for critical areas (i.e. dented TSP)	ACTS	Used C5 in unison with bobbin
4.3	Qualified techniques (i.e. recommended applications)	ACTS	Used best qualified technique for each application
4.4.1	Rotating coils for diagnostic exams	ACTS	Used + Point
4.4.2	Rotating coils for signal characterization	ACTS	Used + Point
4.5	Calibration standards defined (EDM definition is generic)	ACTS	Used ASME, AVB, & EDM as applicable. See affidavit text for description of non-compliance with EDM standards used.
Section 5	*Data Analysis Procedures*		
5.1	Structured approach for data analysis	DAT-IP2-001 & ANTS	
5.2	Independent analysis teams & definition of responsibilities & data handling	DAT-IP2-001	Two independent analysis teams employed. Recommended categories covered.
5.3	Written analysis guidelines	DAT-IP2-001 & ANTS	Recommended categories covered
5.4	Analysis methods	DAT-IP2-001 & ANTS	"Analysis rules" consistent with qualified techniques. See affidavit text for description of non-compliance with

Exhibit 3
EPRI PWR SG Examination Guidelines
TR-106589 Revision 4 Compliance

Section/Paragraph	Requirement	1997 Reference	Comments
			EDM standards used.
5.5	Computer data screening	N/A	Not used
5.5.1	Simple threshold data screening	N/A	Not used
5.5.2	Rule based threshold data screening	N/A	Not used
5.5.3	Computer based analysis	N/A	Not used
Section 6	*Qualification of Data Analysts*		
6.1	Qualified data analysts	See individual QDA training records	All data analysts held valid QDA certifications
6.2	Site specific performance demonstration	See SSPD documentation	Written & practical exams implemented.
6.2.1	Lecture and laboratory session	See SSPD documentation	Implemented a self-study review of data analysis guidelines followed by Lead Analyst Q&A session. Recommended course topics covered.
6.2.2	Practical examination content	See SSPD documentation	Practical exams contained IP2 specific data except for + Point technique. This is because "... lack of associated data (required) reliance on similar plants with active damage mechanisms to assemble a data set."
6.2.3	Acceptance criteria	See SSPD documentation	All recommended criteria measured except false calls. Did not want analysts to be non-conservative due to complexity of data.
6.2.4	Re-examination	See SSPD documentation	Applied as applicable
6.2.5	Site specific re-qualification	N/A	Not applied
6.2.6	Documentation	On file with ConEd	

Exhibit 3
EPRI PWR SG Examination Guidelines
TR-106589 Revision 4 Compliance

Section/Paragraph	Requirement	1997 Reference	Comments
Section 7	*Qualification of Examination Techniques*		
7.1	"NDE of SG tubes shall be conducted using techniques capable of detecting and/or sizing the types of degradation known or reasonably expected to exist in accordance with industry experience. An inspection technique is qualified if sensors used have been proven capable by performance demonstration to meet the requirements of Appendices H and/or J."	See ACTS and Westinghouse documentation for qualification of C5 probe	Best available techniques used.
7.2	Technique qualifications shall comply with the minimum acceptance criteria of App. H	ACTS	All techniques were qualified to meet or exceed the App. H requirements. See affidavit text for description of non-compliance with EDM standards used.
7.3	Qualified techniques (list)	See ACTS and Westinghouse documentation for qualification of C5 probe	Industry peer reviews existed for all techniques used except the C5 probe. Other than the C5 probe, the applied techniques were documented in the EPRI "List of Qualified Techniques".

Exhibit 4
NRC Generic Letter
& Information Notice Compliance

Letter or Notice	Section/Paragraph	Requirement	1997 Reference	Comments
Generic Letters	*95-03*	*Circumferential Cracking of SG Tubes*		
	Reference plant	Circ cracking at Maine Yankee		
	Alerts licensees to	Importance of performing comprehensive exams using techniques & equipment capable of reliably detecting degradation	Inspection plans MRS 2.4.2 GEN-35 ACTS	Used techniques qualified to EPRI Appendix H
	Discussion	Detection factors are scope, technique, analysis guideline, training, etc.	Inspection plans MRS 2.4.2 GEN-35 ACTS DAT-IP2-001 ANTS SSPD	Used techniques qualified to EPRI Appendix H
	Licensee action	Develop plans for next scheduled SG tube inspections. Plans need to include scope including expansion plans, methods, equipment, criteria, & personnel training & qualification	Inspection plans MRS 2.4.2 GEN-35 ACTS DAT-IP2-001 ANTS SSPD	Used techniques qualified to EPRI Appendix H
	95-05	*Voltage Based Repair Criteria for Westinghouse SG Tubes Affected by ODSCC*	N/A	Applies to non-dented TSPs only

Exhibit 4
NRC Generic Letter
& Information Notice Compliance

Letter or Notice	Section/Paragraph	Requirement	1997 Reference	Comments
Information Notices	*90-49*	*SCC in PWR SG Tubes*		
	Reference plant	Millstone 2		
	Discussion	Circ SCC is a source of significant degradation to PWR SG tubes		Concur
		Circ SCC not detectable with bobbin		Concur. Cecco 5 and/or +Point used in critical areas where circ cracking could be present
		Low S/N ratios challenge detection & sizing of SCC	DAT-IP2-001 ANTS	Concur.
		Voltage threshold reporting is non-conservative	DAT-IP2-001 ANTS	Zero voltage threshold used
		Distorted or undefined signals should be dispositioned conservatively	DAT-IP2-001 ANTS	Concur.
	91-67	*Problems With Reliable Detection of IGA of SG Tubing*		
	Reference plant	Trojan		
	Discussion	Plant employed voltage threshold of >= 1.5 volts for reporting & missed 2,500 signals	DAT-IP2-001 ANTS	Zero voltage threshold used
		Experience further underscores non-conservatisms with voltage amplitude criteria	DAT-IP2-001 ANTS	Zero voltage threshold used

Exhibit 4
NRC Generic Letter
& Information Notice Compliance

Letter or Notice	Section/Paragraph	Requirement	1997 Reference	Comments
	92-80	*Operation of SG Tubes Seriously Degraded*		
	Reference plant	ANO-2		
	Discussion	Lack of data analysis guideline training	DAT-IP2-001 ANTS SSPD written exam implemented	
		Lack of performance demonstration test for data analysts	DAT-IP2-001 ANTS SSPD practical exam implemented	
		Inherent difficulties with interfering signals (i.e. geometry & deposits)	DAT-IP2-001 ANTS	
		Use of inappropriate probes for tube locations with circumferential crack potential	MRS 2.4.2 GEN-35 ACTS	Used techniques qualified to EPRI Appendix H
	94-88	*Inservice Inspection Deficiencies Result in Severely Degraded SG Tubes*		
	Reference plant	Maine Yankee		
	Discussion	Inadequate ET test procedures & inappropriate probes used	MRS 2.4.2 GEN-35 ACTS DAT-IP2-001 ANTS	Used techniques qualified to EPRI Appendix H
		Demonstrates importance of optimizing test methods to minimize electrical noise & signal interference & to maximize flaw sensitivity	MRS 2.4.2 GEN-35 ACTS DAT-IP2-001 ANTS	Used techniques qualified to EPRI Appendix H
		Demonstrates importance of	DAT-IP2-001	Used techniques qualified to EPRI

Exhibit 4
NRC Generic Letter
& Information Notice Compliance

Letter or Notice	Section/Paragraph	Requirement	1997 Reference	Comments
		anticipating potential sources of interfering signals (i.e. liftoff, geometry, etc.) & the effects on flaw detection	ANTS	Appendix H
		Demonstrates importance of developing adequate analysis procedures for the conditions noted above	DAT-IP2-001 ANTS	
		Demonstrates importance of being alert to plant specific conditions necessitating special procedures	DAT-IP2-001 ANTS	
	95-40	*Supplemental Information to GL 95-03*		
	Reference plant	Maine Yankee		
	Discussion	Licensee compared the ET techniques used to detect & size the indications & concluded the 0.080" HF pancake coil was the most sensitive technique	MRS 2.4.2 GEN-35 ACTS DAT-IP2-001 ANTS	0.080" HF pancake coil was not an industry recommended technique for low row U-bend exams. It was also not EPRI Appendix H qualified.
	96-09	*Damage in Foreign SG Internals*		
	Reference plant	Foreign plant		
	Discussion	Need to assess TSP integrity for upper most elevation		G. Pierini, Westinghouse, performed an assessment. See report of results.
	96-38	*Results of SG Tube Examinations*		
	Reference plant	Various		
	Discussion	Comprehensive exams with	Inspection plans	Used techniques qualified to EPRI

Exhibit 4
NRC Generic Letter
& Information Notice Compliance

Letter or Notice	Section/Paragraph	Requirement	1997 Reference	Comments
		appropriate techniques are paramount to ensure tube integrity	MRS 2.4.2 GEN-35 ACTS DAT-IP2-001 ANTS	Appendix H
		Generically qualified techniques may need to be supplemented to account for plant specific conditions (i.e. test variables, probe designs, & frequencies should be optimized)	Inspection plans MRS 2.4.2 GEN-35 ACTS DAT-IP2-001 ANTS	Used techniques qualified to EPRI Appendix H. No other supplemental techniques existed.
		Degradation mechanisms with no qualified depth sizing technique shall be considered defective	DAT-IP2-001 ANTS	Used techniques qualified to EPRI Appendix H.
	97-26	*Degradation in Small Radius U-bend Regions of SG Tubes*		
	Reference plant	Various		
	Discussion	Recent findings emphasize importance of using appropriate inspection techniques	Inspection plans MRS 2.4.2 GEN-35 ACTS DAT-IP2-001 ANTS	Used techniques qualified to EPRI Appendix H
		Indications are plugged on detection due to lack of sufficient tube pull ground truth results	DAT-IP2-001 ANTS	That is exactly what we did with R2C67

Exhibit 5
Initial SG ET Inspection Plan

Region	Initial Extent of Test	Probe Type
Tubesheet crevice	100%	MR +Point
Sludge pile	100% TSC to 1C 100% TSH to 2H	Cecco 5
Sludge pile	20% TSC + 20" 20% TSH + 20"	MR +Point
Freespan	33% full length per SG 100% TSC to 1C 100% TSH to 2H	Bobbin
Dented TSP	33% full length per SG 100% TSC to 1C 100% TSH to 2H	Cecco 5
Low row u-bends	100% rows 2 & 3	MR +Point
Dents restricted > 0.680"	100%	Cecco 5
Dents restricted > 0.640"	100%	MR +Point
Rerolled tubesheets for F* verification	100%	Combo RPC/Bobbin

TSC = Tubesheet Cold Leg
TSH = Tubesheet Hot Leg
1C = 1st TSP Cold Leg
2H = 2nd TSP Hot Leg

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of:	)	
	)	
Consolidated Edison Company	)	Docket No. 50–247
of New York, Inc.	)	
(Indian Point Nuclear Station,	)	
Unit No. 2)	)	

AFFIDAVIT OF Richard S. Maurer

I, Richard S. Maurer, being duly sworn, state as follows:

1. I am a Corporate NDE Level III QDA currently employed by Westinghouse Electric LLC (Westinghouse) . I am currently a consulting engineer in Westinghouse's steam generator services organization. Until April 2000, I was employed by ABB Combustion Engineering Nuclear Power, Inc. (ABB-CE) as the manager of the Data Analysis and Data Management department. Westinghouse purchased the nuclear business of ABB-CE effective as of May 2000.

2. I was recently asked to examine elements of a nondestructive examination (NDE) inspections of the steam generators at the Indian Point 2 nuclear power plant conducted in the spring of 1997 utilizing a technique referred to as eddy current testing (ECT). Indian Point 2 is owned and operated by the Consolidated Edison Company of New York, Inc (Consolidated Edison). The purpose of this affidavit is to provide my assessment of the adequacy of the 1997 inspection of Indian Point 2 steam generators low row u-bends and to evaluate issues surrounding the 1997 Indian Point 2 steam generator non-destructive examination (NDE) inspection raised by the Nuclear Regulatory Commission in a November 20, 2000 document entitled "Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2 – Report No. 0500247/2000-010.

3. I have not participated in any steam generator inspections at the Indian Point Unit 2 Nuclear Plant (Indian Point 2), either in my capacity as an employee of ABB-CE or now as an employee of Westinghouse.

4. Beginning in July 2000, I have at various times in my present position at Westinghouse consulted for Consolidated Edison or Indian Point 2 personnel regarding steam generator issues, including those issues associated with the steam generator eddy current testing (ECT) inspections at Indian Point 2 occurring in 1997 and 2000.

5. My professional qualifications and experience are set forth in my resume, which is attached as an exhibit hereto. I have over 22 years of experience in eddy current testing of steam generator tubing and I have conducted inspections at or provided consulting services for over 20 different plants.

6. Prior to preparing this affidavit I reviewed the following documentation relative to the 1997 and 2000 steam generator eddy current testing inspections at Indian Point Unit 2:

a) 7/27/2000 NRC Steam Generator Special Inspection Preliminary Inspection Results
b) 8/31/2000 NRC Steam Generator Special Inspection Final Inspection Report
c) 11/20/2000 NRC Final Significance Determination for a Red Finding and Notice of Violation
d) 6/2/2000 Condition Monitoring and Operational Assessment (Excerpts)
e) 4/14/2000 Consolidated Edison Root Cause Evaluation (Steam Generator Tube Leak Event)
f) 11/1/2000 NRC Lessons Learned Task Force Report
g) 5/3/2000 Root Cause Evaluation and Recovery Activities Technical Material (Excerpts)
h) 2/7/1997 Consolidated Edison Letter to NRC Describing 97 SG Inspection Program Plans and 5/29/1997 NRC Approval
i) Slides from 4/24/1997 Consolidated Edison Presentation to the NRC on the 97 Inspection Program (Excerpt)
j) 7/24/1997 Consolidated Edison Letter to NRC Responding to Oral RAI re Cecco and Plus Point Data Analysis
k) Indian Point-2 Steam Generator Inspection Technical Specifications
l) 1997 Inspection Specification
m) 1997 Westinghouse Analysts Guidelines for Plus Point Inspections (Excerpts)
n) 1997 SG Inspection- Westinghouse Field Service Report Summary
o) 1997 SG Inspection 45 day Letter to NRC dated 7/29/1997
p) 8/6/1997 Condition Monitoring & Operational Assessment
q) 6/27/1997 Consolidated Edison Presentation to EPRI on 1997 IP-2 SG Inspection Results
r) 7/16/1997 NRC Inspection Report 97-07
s) EPRI Steam Generator Guidelines, Rev. 4
t) 1997 Westinghouse Data Analysis Technique Procedure DAT-IP2-001, revision 0.

7. I have also reviewed relevant ECT data from the 1997 SG inspection of low row u-bends. My technical position regarding the adequacy of the 1997 Consolidated Edison ECT inspection of low row u-bends is described in items 8 through 18 below.

8. **Compliance with EPRI Guidelines and Standards**

Revision 4 of the EPRI PWR Steam Generator Examination Guidelines, which was in effect in 1997, required a minimum sample size of 20% of the row 1 and 2 u-bends be inspected using a qualified ECT technique. All row 1 tubes in the Indian Point 2 steam generators were plugged prior to startup as a precaution. In 1997 Consolidated Edison conservatively elected to inspect 100% of the u-bends in all row 2 tubes and all row 3 tubes. According to the examination plan submitted by Consolidated Edison to the NRC on February 7, 1997, the original proposed inspection of row 2 and 3 u-bends was to be performed with a bobbin / cecco-5 combination probe. U-bends which would not permit the passage of this probe type would be examined with a rotating pancake coil. However, the inspection technique that was actually used in 1997 was a [mid-range] rotating plus point coil. This inspection technique was qualified by EPRI and is identified as Examination Technique Specification Sheet (ETSS) 96511. The plus point inspection technique was the most sensitive eddy current examination available in 1997 for the detection of PWSCC in the u-bend area.

The 1997 Consolidated Edison inspection of 100% of the row 2 and 3 u-bends with a [mid-range] plus point coil satisfied the EPRI Guidelines requirements for examination scope, and the plus point coil satisfied the requirement for use of a qualified technique. The examination program also satisfied the requirements of the IP-2 Plant Technical Specifications, which required that this inspection program be submitted for NRC staff review and concurrence prior to the examination.

9. **Data Analyst Training Materials**

The plus point test for low row u-bends was relatively new in early 1997 and only a handful of plants had used the technique prior to this time. Revision 4 of the EPRI Guidelines section 6.2 states "For units with limited operating experience, or a lack of active damage mechanisms and associated data, reliance should be placed on similar plants with active damage mechanisms to assemble a data set."

The u-bend plus point data used at IP-2 for the analyst training session prior to the 1997 ECT inspection satisfied this requirement. The data consisted of two laboratory samples and three tubes from an operating steam generator. All of the tubes used for training were the same configuration as the installed tubing at IP-2 (7/8" OD x 0.050" nominal wall thickness) with flaws in the u-bend area of a row 1 bend radius. The lab samples had flaws (presumably EDM notches) at the bend tangent, and the three tubes from an operating steam generator consisted of three axial flaws near the bend tangent points as well as one circumferential flaw at the bend apex.

A larger training data set would have been preferable; however the industry as a whole did not have a significant data library of u-bend plus point data available to use as analyst training materials. ABB-CE also had commenced implementing the plus point technique

in late 1996 and early 1997; and our organization did not have extensive training materials available either.

10. Instructions Provided to Data Analysts

The instructions for plus point analysis of low row u-bends used for the 1997 Indian Point 2 inspection is contained in Westinghouse procedure DAT-IP2-001, revision 0, "Data Analysis Technique Procedure" dated April 28, 1997. This procedure includes an Analysis Technique Specification Sheet (ANTS) IP2-97-E "U-bend Plus Point RPC" which specifically addresses the calibration requirements for this inspection technique.

There were some differences in the specific setup the data analysts were instructed to employ in the 1997 examination versus EPRI technique ETSS 96511, none of which were material to the adequacy of the setup utilized.

ANTS IP2-97-E establishes the span set-point at 50% screen height for a 40% OD axial flaw, versus the 96511 set-point of 2 grid divisions for the 40% ID axial and circumferential flaws. This alternate setup used at Indian Point 2 results in a span value that is lower (signal appears larger) than the EPRI requirements.

In addition, ETSS 96511 establishes phase (10 - 15 Degrees) on the 40% ID notch. The plus point technique, per ANTS IP2-97-E, sets phase such that residual probe motion was horizontal with the 100% axial notch at 30 to 35 degrees. A review of the calibration standard used in ETSS 96511 shows that when probe motion is set to horizontal with the 100% axial notch at 30 to 35 degrees, the resultant phase of the 40% ID axial notch is at approximately 11 degrees. Therefore the set-point in IP2-97-E used in the 1997 Indian Point 2 inspection satisfied the lower end EPRI guidance threshold for phase.

For data screening, the EPRI ETSS required the analyst to scroll through the area of interest while viewing the lissajous, as well as a review of terrain plots. These requirements are specified in section 11.4 of Westinghouse procedure DAT-IP2-001, Revision 0. In addition, although not addressed in the EPRI ETSS, the Westinghouse procedure appropriately includes the following passage which is intended to encourage analysts to report flaws "The phase relationships and confirmation by other coils should be viewed in the light of other influences which the probe experiences. The analyst should feel free to use his/her discretion in reporting signals which are felt to be indicative of a degraded condition, but do not necessarily meet all of the criteria indicated above. The over-riding rule of analysis should be: if you think there is an indication, report it."

11. Review of EDM Notch Standard Utilized

The calibration standards which were used during the 1997 Indian Point 2 inspection met industry standards and followed the then-current EPRI guidance – EPRI PWR Steam Generator Examination Guidelines, Rev. 4.

Section 4.5 states of the EPRI Guidelines, Revision 4 states:
"Electro-discharge machining (EDM) and laser-machined notch standards are typically used to establish setup conditions for rotating probe technology. The notches should be of:

- both axial and circumferential orientation, and
- standard lengths and depths on the OD and ID."

This methodology was employed in the 1997 inspection. There is no further guidance provided for specific depths of the notches.

EPRI ETSS 96511 set-up parameters show the phase and span values are established on the 40% ID notch. The EPRI ETSS' sometimes use additional calibration artifacts that are not required generically by the EPRI Guidelines.

The calibration standards used at Indian Point 2 in 1997 contained a variety of axial and circumferential notches, but they did not include a 40% ID axial notch. However, Section H.4.3 of the EPRI Guidelines, Revision 4 states: "Alternate calibration methods may be used without re-qualification if it can be demonstrated that the calibration method is equivalent to those described in the qualified acquisition technique or qualified analysis technique."

Alternate calibration methods are discussed in greater detail below. Although the 1997 IP-2 calibration standards did not include a 40% ID notch, they satisfied the EPRI requirements at that time based on the acceptability of using alternate calibration methods.

12. Analyst Experience/Qualification With U-Bend Plus Point Data

Since this was a relatively new technique, the majority of the analysts in the industry in 1997 would not have been qualified to EPRI Appendix G criteria for the analysis of plus point coil data. The Appendix G criteria requires that the analyst has an 80% probability of detection at a 90% confidence level for flaws which are $\geq$ 40% through-wall depth. An integral premise of this criteria therefore, is the acknowledgement that not all flaws will be detected by the analysts.

The EPRI QDA program was revised in the fall of 1996 to include plus point data for the first time; however, earlier versions did not include this probe type. This does not reflect an inadequacy in the qualification of the analysts under the standards at the time of the Indian Point 2 inspection in the spring of 1997. This is due to the fact that there simply wasn't sufficient plus point data available in the industry at this time to construct a test which would satisfy the statistical confidence factors required under Appendix G. All plants desiring to use the plus point coil for u-bend examinations during this time frame would have confronted this problem.

Moreover, Section G.6 of the EPRI Guidelines, Revision 4 contains the following guidance for analyst qualification on new techniques and damage mechanisms.
"New technique/damage mechanism qualification may be accomplished during annual training or may be deferred until re-qualification. The testing requirements shall be the same as the initial QDA examination. The individual shall be considered qualified if the requirements of G.4.2.2.2 are met. After the qualification requirements are successfully met, individuals' records should be updated to reflect re-qualification on new technique/damage mechanisms."

13. **Review of Restrictions at Top Tube Support**

The row 2 u-bend tubes which were noted as restricted in 1997 show a bobbin test extent of either 06C or 06H. According to the 1997 Westinghouse data analysis procedure, DAT-IP2-001, Revision 0, Section 7.3.8: "Extent tested for a restricted tube (RST) shall be reported as the furthest complete support structure, tubesheet, or tube end." Therefore the 0.610" diameter bobbin probe actually passed through the support structure but was restricted in the u-bend itself. In addition, the restrictions may well have been attributable to the use of a different design bobbin probe than had been used previously. According to the
Consolidated Edison response to question 11 in the NRC Request for Additional Information (RAI) received on April 28, 2000, the bobbin probe used during inspections prior to 1997 in the low row u-bends was a 0.610" diameter ball joint flex probe. This probe type is specifically designed to negotiate tight radius u-bends. The probe used in 1997, however, was a standard bobbin probe which inherently is more difficult to insert through a u-bend.

14. **Review of Eddy Current Data**

I first reviewed the 1997 plus point data for Indian Point 2 SG 24 Row 2 Column 67 to formulate an opinion on whether there was something unique in the data which would indicate that a detection problem existed so that some additional action should have been taken. This indication is relatively straightforward and the data quality is good in this u-bend. This would indicate to me that the technique was performing as expected. Although this was the first PWSCC reported at IP-2, it's appearance in 1997 would not have been surprising, given that this is a Westinghouse design steam generator with over 20 years of operation and that prior examinations had been conducted with a much less sensitive bobbin coil technique.

I also reviewed the 1997 data for the tube which leaked in February 2000, Row 2 Column 5 in steam generator 24, to determine whether this indication could have been reported in the 1997 inspection. I am of the opinion that it is not a certainty that the flaw in SG 24 R2 C 5 could or should have been identified during the 1997 inspection based on the standards and guidelines appropriately used and in effect at the time.

With the benefit of hindsight and the review conducted in the 2000 time frame after the leak event, the indication in R 2 C 5 can be detected in the 1997 plus point data.

However, the use of circumferential filters in the data analysis software utilized during the 2000 reviews suppresses much of the geometry effects from tube ovalization occurring at the point of the flaw and results in a more clearly defined flaw response. In addition, monitoring the horizontal component on a strip chart during the 2000 reviews indicates a suspect area of the u-bend which would cause the analyst to further interrogate this region. However, no specific guidance or requirement was included in the EPRI Guideline Revision 4 technique in effect during 1997 that would have influenced the analysts to use these tools. The examinations conducted by ABB-CE during this timeframe also did not use circumferential filters or horizontal strip charts. It is my opinion that only through the insight gained from the 2000 review of the 1997 data that these tools have been shown to be an effective means of enhancing flaw detection.

It is also important to observe that, given the nature of eddy current technology, none of the ECT techniques used for steam generator inspections will detect all of the flaws all of the time. The POD is never assumed to be 100% in any industry guidance or standard. This is equally as true in the year 2000/2001 as it was in 1997. In addition, data analysts may not detect 100% of the flaws present 100% of the time. The actual industry requirement for a QDA is an 80% probability of detection at a 90% confidence level.

With the benefit of hindsight, the 1997 data for SG 24 Row 2 Column 5 can be considered as containing high noise due to tube ovality and OD deposits. However in 1997, there were no industry criteria available for analysts to evaluate in a quantitative manner what was and was not high noise. Senior analysis personnel would not have reviewed data from this tube as neither the qualified primary or secondary analyst reported an indication in this u-bend. Since the u-bend plus point technique was relatively new in 1997 and a significant volume of training data was not available, data analysis personnel could not be expected to have had extensive exposure to poor quality data or noisy data for use in comparing plus point data generated during an actual inspection.

15. During a July 26, 2000 meeting between the Nuclear Energy Institute Steam Generator Task Force (NEI SGTF) and NRC, a paper was presented by a representative on the Task Force from Northern States Power Company titled "U-Bend Noise Study". The study quantified plus point coil noise levels from the tube samples used in the EPRI technique (ETSS 96511) and compared those values to Indian Point 2 and two other Westinghouse design plants. The data presented shows that the average peak to peak and vertical maximum values for the EPRI data set were approximately 1.1 volts and 0.4 volts respectively. The data from Indian Point 2 yielded approximately 1.4 volts and 0.7 volts. Thus, the IP-2 data is only "slightly noisier" than the tubing used in the EPRI qualification. The results for the other two Westinghouse design plants showed noise levels that were lower than the EPRI data set.

However, during the spring of 1997, contemporaneous to the Indian Point 2 ECT inspection, ABB C-E was also conducting plus point coil examinations of low row u-bends at the Maine Yankee plant. A 50 tube review of noise levels from this inspection that I had conducted in August 2000 showed peak to peak and vertical maximum values

of 1.63 volts and 0.51 volts respectively. This level of noise does not differ appreciably from the Indian Point 2 1997 data. Prior examinations at Maine Yankee had been conducted with a pancake coil. While the data contained more noise than the EPRI qualification, the perspective of the inspection team at the time, including my perspective, was that we were using the best technique available at the time which offered improved detection capability relative to the previous pancake coil examinations.

16. Similarly, at Indian Point –2 in the spring of 1997, the first use of the plus point for low row u-bends followed bobbin coil examinations during previous inspections. This represents a quantum leap forward in terms of probability of detection. During the same time frame, there was no industry data available for use by analysts from which they could infer that deep PWSCC indications could be masked by the influence of ovality and OD deposits.

By 1997 only a few plants had conducted plus point coil testing of low row u-bends; and this was considered a new, albeit magnitude better, technique for use by the industry to inspect steam generators. Based on the limited information and training base available to the data analysts with this new technique, the absence of the development at that date of industry data quality standards for the technique, and the absence of plus point data in the QDA program it is an unlikely expectation that the 1997 IP-2 data should have been recognized as "too noisy".

17. Finally, I also reviewed the 1997 plus point data from several tubes with flaws identified in the 2000 inspection to determine whether they could have been identified during the 1997 inspection. There were a total of eight row 2 tubes with u-bend indications reported in the 2000 inspection, which it is claimed should have been identified in the 1997 inspection. Row 2 Column 5 is discussed above. The additional 7 u-bend tubes with 1997 indications, as identified in 2000, are listed below along with whether the flaw was detected with both the plus point mid-range coil and the high frequency plus point coil or <u>only</u> the high frequency plus point coil.

<u>Tube Identification</u>	**<u>Detection Coil</u>**
SG 21 Row 2 Col 87	Both
SG 23 Row 2 Col 85	High Frequency Coil Only
SG 24 Row 2 Col 4	High Frequency Coil Only
SG 24 Row 2 Col 69	Both
SG 24 Row 2 Col 71	High Frequency Coil Only
SG 24 Row 2 Col 72	Both
SG 24 Row 2 Col 74	High Frequency Coil Only

Since the high frequency coil did not exist in 1997, my review of prior data was limited to those indications which were detected by both coils in the 2000 inspection. Of the three tubes noted above that were detectable with both probe types in the 2000 examination, a re-analysis of the 1997 data (although it was conducted with the knowledge of the 2000 data that the flaw exists) identifies small indications present in the 1997 time frame as well. However, the fact that the indications were not reported in 1997

is not unexpected given the relatively new use of the plus point coil by the QDAs during this timeframe, coupled with a probability of detection for any ECT technique which always is less than 100%.

18. It is also relevant that current steam generator inspections are invariably followed by historical ECT data reviews to determine growth rate which is used in the operational assessment. In my experience, it is the norm, rather than the exception, that plants with active stress corrosion cracking detect flaws in prior cycle data during subsequent inspections that had not been reported during the earlier inspection time. Another reason that this occurs, beyond growth of the indications with the passage of time, is that the state of ECT is not static; and the technology has historically improved with the passage of time. Thus, in 1997, the mid-range plus point coil was the state-of-the-art qualified technique for low row u-bend ECT inspections. Three years later, the data and knowledge base for this probe technique had greatly expanded. Moreover, the additional techniques noted above, as well as a qualified high frequency plus point probe that did not exist in 1997, were also available for use in conducting the historical ECT data review of the 1997 Indian Point 2 data. Therefore, it is my opinion that identifying three indications in the subsequent 2000 inspection that previously existed, but were not identified during the 1997 inspection using the same probe (which was state-of- the- art in 1997) is not unexpected.

My opinion in this regard is further supported by recent industry experience. During the July 2000 EPRI Steam Generator workshop, two utilities presented papers on U-bend examinations. Both utilities showed existing u-bend indications which had been dispositioned as a non-flaw in previous inspections. Subsequently, in the case of one utility, the tube leaked during shutdown and in the other case the tube leaked during an in-situ pressure test.

The foregoing statements are true and correct to the best of my knowledge and belief.

Richard S. Maurer

Richard S. Maurer
Corporate Level III Consulting Engineer
Westinghouse Electric Company LLC

Sworn and subscribed to before me on this 18th day of January, 2001.

Julianne Sheridan
Notary Public

My Commission expires: 1-31-05

Exhibit 1

RESUME OF RICHARD S. MAURER

SUMMARY OF QUALIFICATIONS

Mr. Maurer is directly responsible for the planning, execution, and reporting of results for inservice steam generator examinations. He has been involved in eddy current testing since 1978 and currently holds a Level III QDA certificate. Mr. Maurer helped develop the original QDA program by serving on the EPRI Implementation Team. He also served on the EPRI ISI Guidelines committee to develop revision 4 of the PWR Inspection Guidelines. Mr. Maurer has authored numerous papers presented at industry technical forums. He is the NDE representative on the CEOG Steam Generator Task Force and is the Westinghouse representative on the NDE task group for the NRC/Argonne National Laboratory steam generator mockup program.

EXPERIENCE

WESTINGHOUSE ELECTRIC COMPANY

Corporate Level III Consulting Engineer **4/2000 to Present**

As the corporate Level III Mr. Maurer is responsible for oversight of the Westinghouse certification program and works closely with the condition monitoring and operational assessment group. Mr. Maurer continues to provide consulting services and is assigned as the Senior Analyst or Independent QDA on several inspections per year.

ABB COMBUSTION ENGINEERING NUCLEAR POWER 1978 to 4/2000

Manager – NDE Technology

As a manager, Mr. Maurer was responsible for the Data Analysis and Data Management groups. In addition, Mr. Maurer was the Principal ECT Level III and provided oversight of the training and certification programs within CENP. Mr. Maurer continued to provide consulting services and was assigned as the Senior Analyst on several inspections per year.

Consulting Engineer – Steam Generator Data Analysis **1988 to 1993**

As a Consulting Engineer, Mr. Maurer was responsible for the technical accuracy of all SG ECT examinations conducted by Combustion-Engineering. This included R&D activities for technique development as well as the supervision of analysis activities on complex inspections.

Principal Field Service Engineer - Examination Services & Products **1985 to 1988**

As a Principal Field Service Engineer, Mr. Maurer's responsibilities included the overall planning, implementation, and evaluation of eddy current examination programs. As a Level III in Eddy Current Testing it was also his responsibility to ensure compliance with all applicable codes and regulations, as well as to ensure that the optimum testing techniques were employed and that the resultant data was correctly interpreted.

Exhibit 1

RESUME OF RICHARD S. MAURER

Senior Field Service Engineer - Inspection Services **1984 to 1985**

As a Senior Field Service Engineer, Mr. Maurer was responsible for the administrative and technical management of inservice steam generator examinations. Mr. Maurer also acted as a liaison between C-E and utility management.

Field Service Engineer, Inspection Services Group **1983 to 1984**

As Field Service Engineer, Mr. Maurer was responsible for the preparation of examination programs, procedures, and instructions which form the task program. It was also his responsibility to supervise the examiners on site, implement the examination program, and ensure that the resultant data was interpreted correctly. At the home office, Mr. Maurer conducted R&D work to enhance inspection techniques, wrote inspection reports, and provided support for ongoing field inspection programs.

Development Engineer, Nuclear Systems Services **1982 to 1983**

As a Development Engineer, Mr. Maurer was responsible for the refinement of irradiated fuel inspection fuel inspection techniques, planning and logistics of field inspections, and the preparation of procedures and inspection reports. He also assisted utilities with fuel and control element transfers, incore detector removal and installation, reactor internal disassembly and inspection, etc.

Engineering Specialist, Systems Integrity Services **1981 to 1982**

As an Engineering Specialist, Mr. Maurer was responsible for the maintenance of equipment and inspection hardware used in fuel and reactor examinations. He also conducted field inspection and service programs at various nuclear facilities. At the home office, Mr. Maurer generated proposals, wrote procedures, and provided support for field activities.

Technician, Engineering Development and Services, **1978 to 1981**

As a technician Mr. Maurer's duties included: damaged fuel reconstitution, fuel sipping, visual support for fuel transfer and reactor disassembly, and eddy current testing of fuel components, heat exchangers, and steam generators.

MULTI-CIRCUITS, INC.

Chemical Technician - Quality Assurance Department **1977 to 1978**

Mr. Maurer was responsible for the analysis of plating solutions used in the manufacture of printed circuit boards. His duties also included the sectioning and microanalysis of P/C boards for Quality Assurance.

Exhibit 1

RESUME OF RICHARD S. MAURER

PRATT & WHITNEY AIRCRAFT

Chemical Technician - Pollution Control Laboratories **1973 to 1976**

Mr. Maurer was responsible for the identification and analysis of toxic chemicals in concentrated form and in dilute rinse water, determination of proper neutralization processes and the operation of primary, secondary and tertiary treatment plants.

<u>EDUCATION</u>

Mohawk Valley Community College - 1970 - 1972

State of New York - High School Equivalency Degree - 1970

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of:	)	
	)	
Consolidated Edison Company Of New York	)	Docket No. 50–247
(Indian Point Nuclear Station, Unit No. 2)	)	
	)	
	)	

<u>AFFIDAVIT OF THOMAS C. ESSELMAN</u>

I, Thomas C. Esselman, being duly sworn, state as follows:

1. I am an engineer and President of Altran Corporation. I have been the President of Altran Corporation since its formation in 1986. Altran is a consulting company that provides consulting primarily for the nuclear power industry. Many of our projects and much of Altran's expertise relates to issues involving the degradation, structural integrity, and stress evaluations of pressure boundary components.

2. I was recently asked to examine elements of non destructive examinations (NDE) of the steam generators at the Indian Point Unit 2 (IP2) nuclear power plant conducted in the spring of 1997 and again during the first half of 2000. Indian Point 2 is owned and operated by the Consolidated Edison Company of New York, Inc.

3. I have been providing consulting services to Consolidated Edison of New York with regards to Indian Point Unit 2's (IP2) steam generator (SG) related issues for the last twelve years, including those issues associated with steam generator tube integrity in 1997 and 2000. Specifically, my involvement with the IP2 steam generators has included feedwater nozzle cracking, shell cracking at the girth weld, feedwater nozzle thermal sleeve design, shell stress analysis, shell penetration design, tube support plate integrity, row 2 and 3 tube integrity, tube rolling effectiveness in the tubesheet, and tube integrity related to primary water stress corrosion cracking (PWSCC).

4. Altran was involved with the hourglassing issue at IP2 for the first time in 1996 when Altran was asked to assess the structural integrity and the effect of the ligament cracking in the tube support plates in IP2's Steam Generators. I was the Project Manager for that project. At that time, I reviewed the Con Edison secondary side inspection program for IP2 and results from previous inspections of the support plates. Since 1996, I have been primarily involved with tube denting, support plate degradation mechanisms, tube integrity, and primary water stress corrosion cracking (PWSCC).

5. My professional qualifications and experience are set forth in Exhibit 1 that is attached hereto.

6. During my work for Consolidated Edison, I reviewed the following documents relevant to this affidavit. I was involved in the preparation of the documents below attributed to Altran.

- Indian Point Unit No. 2, "Nuclear Steam Generator, Status Report", Addenda 1 to 12.
- Consolidated Edison Company of New York, Indian Point Unit No. 2, "Steam Generator Examination – 1997 Refueling Outage."
- Altran Corporation, "Steam Generator Tube Support Plate Cracking Evaluation of the Indian Point Unit 2 Steam Generators," Technical Report 96245-TR-001.
- Altran Corporation, "Secondary Side Condition Monitoring and Operational Assessment," Technical Report No. 00603-TR-004.
- Altran Corporation, "Overview Of Small Radius U-Bend Tube Susceptibility To PWSCC For Indian Point 2 Steam Generators," Technical Report No. 00603-TR-005.

- Failure Analysis Associates, "Steam Generator Support Plate Analysis for Indian Point Unit 2," FAA-79-01-3.

The purpose of this affidavit is to i) provide my assessment of the adequacy of Con Edison's inspection and trending program of the tube support plates on the secondary side of the steam generators and ii) to evaluate issues surrounding the 1997 Indian Point 2 steam generator NDE raised by the Nuclear Regulatory Commission in a November 20, 2000 document entitled "Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2" (NRC Inspection Report 05000247/2000-010).

7. As indicated by the steam generator inspection program of other utilities (Revisions 14 and 15 of the Electric Power Research Institute (EPRI) "Steam Generator Progress Report"), visual examinations have been a common method of inspection of the secondary side of steam generators.

8. Inspection and trending of the degradation of the secondary side of the IP2 steam generators was required by the Indian Point Unit 2 Technical Specifications. To facilitate this inspection, Con Edison installed inspection ports in the shell of the IP2 steam generators in the late 1970s that allowed the visual and photographic inspections of the TSPs, including the top TSP in steam generators 22 and 23. The IP2 steam generator inspection reports, filed with the NRC after each inspection, indicate that visual inspection was also Con Edison's inspection standard of the secondary side, similar to that of other utilities as reported in the EPRI progress report. Specifically, the submitted1997 IP2 post-inspection report described the tube support plate hourglassing examination as conducted visually.

9. During my work on denting and tube support plate integrity for IP2 in 1996 and 1997, I reviewed visual inspection results (including photographs and videotapes) of the extent of flow slot hourglassing in the tube support plates. The inspections were made through the lower handholes near the tubesheet looking upward and from the inspection ports in SG 22 and

23 near the upper tube support plates. The visual inspections did not provide any indications of hourglassing in the top tube support plates.

10. The IP2 Technical Specifications require that an integrity evaluation of small radius U-bends be performed when significant hourglassing of the top support plate flow slots is found. I was aware of other industry experience including the severe denting at the Turkey Point and Surry units. I was aware that Surry Unit 2 had a Row 1 U-bend failure in 1976 that was attributed to severe hourglassing of the top support plate flow slots. I have subsequently learned that the Surry 2 average flow slot closure had been greater than 1.25 inches, compared to the as-manufactured flow slot opening dimension of 2.75 inches (i.e. 45% flow slot closure), as reported by Westinghouse in their "Indian Point 2 U-Bend PWSCC Cycle 14 Condition Monitoring and Cycle 15 Operational Assessments," report No. SG-00-05-008. Thus, although the term "significant hourglassing" was not explicitly defined for the IP2 inspections, it was appropriate at that time, in my judgement, to conclude that if hourglassing was not reasonably recognizable or discernable by visual examination, it was not "significant".

11. Tube denting results from the accumulation of corrosion products around the tubes in the tube hole crevices. Based on my review of the IP2 steam generator examination report from the 1997 outage, denting was noted to exist at the tubes in the top tube support plate as indicated by the eddy current test results of 1997. The accumulation of the corrosion products that cause denting results in in-plane compressive loads in the tube support plate that in turn may result in hourglassing of the flow slots. Although the tests indicated the presence of denting of the tubes in the IP2 upper support plates, the extent of hourglassing is normally not derived, and to my knowledge cannot be derived, from this data.

12. Videotapes were made from fiberscope examinations of the top tube support plates in SG22 and SG23 from above the top of the plate via the inspection ports in the shell during steam generator examinations in 1997. Based on my review of these videotapes in 1997

and my re-review of these videotapes in 2000, I did not observe any indication of hourglassing in the top support plates.

13. Since the IP2 visual examinations, up to and including those during the 1997 inspections, had not indicated any visually observable hourglassing of the top plates and knowing that all the Row 1 tubes in the IP2 SGs were plugged, I was of the opinion in 1997 that any minor -- non-observable -- hourglassing at the top support plate, if it existed, would not pose a significant threat of crack initiation or crack growth in the U-bend region of Row 2 tubes (Row 1 tubes at IP2 were plugged). This opinion was based on my experience and lack of industry data that indicated that small radius U-bends could be sensitive to a very small amount of hourglassing in the top TSP. Available data indicated that failures in Row 1 U-bends were the result of significant top support plate hourglassing such as that noted in the Surry 2 flow slot closure. Furthermore, based on the Surry data (see the Virginia Electric and Power Company letter from C.M. Stallings to B.C. Rusche, USNRC, Serial No. 260C/092276, dated January 3, 1977 providing supplemental data for continued operation of Surry Unit No. 1), no cracks were detected in laboratory examination of Row 2 tubes taken from steam generators that had experienced Row 1 tube cracking.

14. Based on my knowledge, as described above, IP2's tube support plate inspection program appeared to me to be complete, consistent with industry practices (as presented in the EPRI Steam Generator Progress Reports), and sufficient to identify "significant hourglassing," which, in my opinion, was correctly interpreted based on knowledge at the time as hourglassing that was recognizable by visual inspection.

15. As a part of an extensive investigation of the tube support plate condition undertaken in 1997 by Altran for Con Edison, I looked broadly at the hourglassing data and the secondary region of the steam generator comprised of the wrapper, tubes, and tube support plates. I had concluded at that time, that other than the evaluation of the tube support plates that was performed and documented, no other area of this region, including the U-bend region of the

Row 2 tubes, was at risk or required analysis. If I had thought that the effect of hourglassing at the top support plates was a potential threat to the U-bend region of the low row tubes, I would have identified and proposed to address the tube integrity issue as part of the 1997 investigation.

16. My investigations in 2000 concentrated on the secondary side of the steam generators and the effects of hourglassing on the PWSCC susceptibility of the low row U-bends. This was an extensive investigation of the extent and effects of hourglassing of the top tube support plate on the U-bends. Altran staff members, under my direction, used both laboratory and advanced analytical techniques (such as three dimensional non-linear finite element analysis) to investigate the sensitivity of the low row U-bends to PWSCC resulting from hourglassing of the top support plate. This investigation consisted of the following elements and activities:

- Determination of the displacement profile of the tubes in the flow slot region of the top TSP using a non-linear finite element model of the plate for a given amount of hourglassing.
- Investigation of the extent and importance of the initial ovality resulting from bending during the manufacturing of the U-bends.
- Laboratory testing of similar U-bend tubes as those used in the IP2 SGs to determine material behavior, residual stresses from bending during manufacturing, and response to U-bend leg deformation.
- Development of a finite element model of the Row 2 and 3 U-bend tubes consistent with the results of the ovality investigations (from above) using appropriate stress-strain behavior and yield stress values, and benchmarking it against the laboratory test results.
- Determination of the stresses, using the finite element model of the U-bends, for the level of deformation of the top TSP calculated and including the normal operating stresses and residual stresses derived experimentally.

- Assessment of the susceptibility to PWSCC initiation and crack growth based on the above results.

17. The results of the above investigation of 2000 indicated a high sensitivity of the Row 2 U-bends to PWSCC when subjected to small levels of hourglassing at the top TSP. Based on the investigations, it was concluded that:

- Hourglassing in the top TSP is a primary contributor to PWSCC rates at the apex of low row U-bends.
- Hourglassing levels as low as 0.1 inch could cause crack initiation and crack propagation like that experienced at IP2.
- Row 3 tubes are much less susceptible to the IP2 observed PWSCC mechanism than the Row 2 tubes.

18. My conclusion, based on my experience and the work that I and others have performed for Con Edison (see for example the Failure Analysis Associates report listed in item 6 above), is that Con Edison had a pro-active and thorough hourglassing inspection, trending, and investigative program. Con Edison acted appropriately when they determined that there could be a potential threat to the plant. This resulted in several investigations (as indicated by the reports listed in item 6 above) that were performed because of hourglassing that was noted in the steam generators in the lower tube support plates. The level of hourglassing that has been occurring over the years at the top support plates, which contributed to the Row 2 tube leak in February, 2000, could not have been noted in 1997 through the secondary side visual inspection methods.

19. Based on the information provided in this affidavit, the activities pursued in 2000 as a result of the tube leak in February 2000 have expanded the state of knowledge as to the sensitivity of PWSCC susceptibility of the low row u-bends to hourglassing at the top support plates. The hourglassing that was occurring in the lower tube support plates had been recognized

for years and was repeatedly measured and trended. The level of hourglassing that has been occurring over the years at the top support plates, which contributed to the Row 2 leak in 2000, was viewed over the years by visual inspection and was thought to be not significant.

20. It is my opinion and testimony that, based on the information provided in this affidavit, the inspections, trending, analytical investigations, and actions taken by Con Edison on the flow slots of the secondary side of the steam generators at IP2 up to and including the 1997 outage, were consistent with the industry practices and responsive to the state of knowledge at the time.

21. The foregoing statements are true and correct to the best of my knowledge and belief.

Thomas C. Esselman

Thomas C. Esselman

Sworn and subscribed to before me on this 18th day of January 2001.

Ilene Sagall

Notary Public

ILENE SAGALL
Commission # 1219845
Notary Public - California
San Francisco County
My Comm. Expires Jun 9, 2003

My Commission expires: June 9, 2003

Exhibit 1

I have a Bachelor of Science degree in Mechanical Engineering from Case Institute of Technology in Cleveland, Ohio; a Master of Science degree in Engineering Mechanics from Case Western Reserve University, Cleveland, Ohio; a Ph.D. in Engineering Mechanics from Case Western Reserve University, Cleveland, Ohio, and a MBA from the University of Pittsburgh, Pittsburgh, Pennsylvania. My technical specialties are in engineering mechanics, materials performance, component degradation, failure analysis, root cause analysis, and component and system design. I am Vice Chairman, Codes and Standards, Pressure Vessel and Piping Division of the American Society of Mechanical Engineers. I am also a member of the American Society of Mechanical Engineers and a member of the American Nuclear Society. I have over 28 years experience in the nuclear industry. My responsibilities have included performance and management of a large variety of engineering, engineering design, and engineering evaluation issues. I consult frequently on component design issues, material degradation issues, pressure-retaining component failures, plant and system aging issues, and material evaluation. My consulting has included work on tube integrity in heat exchangers.

I was previously at Westinghouse Electric Corporation where I was responsible for Structural Design, Engineering Analysis, Component Design, and Plant Design. Specific responsibilities varied from managing large-scale power plant design and analysis activities of up to 320 people, to developing the design of nuclear steam generators. I specifically supervised reactor coolant loop qualification, ASME Class 1 analyses, and component stress and fatigue analyses for Westinghouse NSSS components. While at Westinghouse, I worked extensively on design and qualification of the steam generators, including the assessment of tube integrity. I held several technical and management positions in the Steam Generator Engineering organization at Westinghouse.