APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-445/94-01
50-446/94-01

Licenses: NPF-87
NPF-89

Licensee: TU Electric
Skyway Tower
400 North [illegible]e Street, L.B. 81
Dallas, Texas

Facility Name: Comanche Peak Steam Electric Station, Units 1 and 2

Inspection At: Glen Rose, Texas

Inspection Conducted: January 24-27 and February 7-11, 1994

Inspectors: I. Barnes, Technical Assistant
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Approved: Jocelyn A. Mitchell 3/10/94
Jocelyn A. Mitchell, Acting Deputy Director Date
Division of Reactor Safety

Inspection Summary

Areas Inspected (Units 1 and 2): Regional initiative, announced inspection to review the history and material condition of steam generator tubing ard to assess the effectiveness of licensee programs in detection and analysis of degraded tubing, repair of defects, and correction of conditions contributing to tube degradation.

Results (Units 1 and 2):

- Comanche Peak Steam Electric Station has used a hot-leg temperature of 618.8°F for both units since commercial operation began in August 1990 (Unit 1) and August 1993 (Unit 2). The inspectors noted that this temperature was one of the higher values used by pressurized water reactors (Section 2.1).

- The most significant differences noted by the inspectors between the Units 1 and 2 steam generators were: (a) the Unit 1 use of mill annealed Inconel 600 tubing, drilled carbon steel tube support plates, and the use of both mechanical rolling and explosive expansion of tubes into the tube sheet; versus (b) the Unit 2 use of Inconel 600 tubing that had received an additional thermal treatment, Type 405 ferritic stainless steel tube support plates with quatrefoil hole design, and hydraulic expansion of tubes into the tube sheet. The inspectors considered that these differences should make the Unit 2 steam generators less vulnerable than those in Unit 1 to long-term denting and stress corrosion cracking damage (Sections 2.1, 2.2, and 2.3).

- Actions were taken by the licensee to minimize tubing wear in the preheater section of the Units 1 and 2 steam generators by expanding tubes at two baffle plate locations, and actions were also taken to improve the resistance of Unit 1 steam generator tubing to stress corrosion cracking by onsite shot peening of the tube expansion transition areas and heat treatment of low radius U-bends. Heat treatment of Unit 2 low radius U-bends was performed by Westinghouse following forming of the U-bends (Section 2.5).

- No tubes have required plugging in the Unit 1 steam generators due to service-related degradation, as of Refueling Outage 1RF03 (2.4 effective full power years of operation) (Section 2.4).

- The procedures (and supporting training) that were to be used by operators in response to primary-to-secondary leakage were good. Guidance was not found, however, regarding implementation by chemistry personnel of Procedure CLI-704, "Determination of Primary to Secondary Leakrate" (Section 3.1).

- Licensee evaluation of radiological instrument alarm setpoints used to detect primary to secondary leakage was thorough and effective (Section 3.2).

- Limited review of handling of steam generator generic communications suggested that management expectations had not been clearly communicated on this subject, and that oversight of the operational experience review program could be improved (Sections 3.3 and 5.2.2).

- During Refueling Outages 1RF01 and 1RF02, the contractor exhibited good control of tools and equipment entering the steam generator areas (Section 4.1).

- The licensee did not define the scope of visual examination of the secondary side of the steam generators beyond a reference to Generic Letter 85-02 (Section 4.1).

- Eddy current sample sizes consistent with Electric Power Research Institute recommendations have been examined by the bobbin coil method since Refueling Outage 1RF01 (Section 5.2.1).

- A noncited violation was identified pertaining to the failure during Refueling Outage 1RF03 to comply with the requirements of Technical Specification (TS) 4.0.6.2 for random selection of tubes for eddy current examination (Section 5.1).

- As of Refueling Outage 1RF03, the licensee had developed only limited plant-specific data analysis guidelines and had not implemented plant-specific training and testing of eddy current data analysts. Use of the motorized rotating pancake coil was restricted to examination of locations producing distorted or ambiguous bobbin coil signals. Motorized rotating pancake coil examinations of tube expansion transition areas have not currently been performed for enhanced detection of circumferential cracking (Sections 5.2.1 and 5.2.2).

- The eddy current test program lacked criteria for determining what tube conditions would be subjected to ongoing monitoring (Section 5.2.1).

- The licensee has maintained excellent control of secondary water chemistry, with only one significant out-of-specification chemistry condition noted since plant startup. This condition involved a significant Unit 1 out-of-specification sodium concentration in March 1991, which was the result of a major condenser tube leak and required unit cool down (Section 6.2 and 6.5).

- The very small sludge quantities removed from the Unit 1 steam generators were considered a further indicator of excellent secondary water chemistry control (Section 6.2).

- The licensee was considered proactive in its attempts to reduce corrosion product transport to the steam generators by use of alternative amines (Section 6.1).

Summary of Inspection Findings:

- A noncited violation was identified (Section 5.1).

Attachment:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 STEAM GENERATOR TUBE INTEGRITY REVIEW (42001, 73755, 79501, 79502)

The objectives of this inspection were: (a) to ascertain the history and material condition of the Units 1 and 2 steam generator tubing; and (b) to assess the effectiveness of licensee programs in detection and analysis of degraded tubing, repair of defects, and correction of conditions contributing to tube degradation.

2 STEAM GENERATOR MATERIALS AND TUBE DEGRADATION HISTORY

2.1 Steam Generator Description

Comanche Peak Steam Electric Station (CPSES), Units 1 and 2, are Westinghouse-designed 1160 megawatt electric pressurized water reactors, which commenced commercial operation on August 13, 1990, (Unit 1) and August 3, 1993 (Unit 2). The CPSES unit design utilizes four Westinghouse D-Series recirculating steam generators, Model D4 in Unit 1 and Model D5 in Unit 2. These models of steam generator contain a preheater section and utilize Inconel 600 (ASME Material Specification SB-163) U-tubes with a nominal diameter and wall thickness, respectively, of 0.75 inches and 0.043 inches. The number of tubes in a steam generator is slightly different between the two steam generator models (i.e., 4578 in the Unit 1 Model D4s and 4570 in the Unit 2 Model D5s). Secondary side tube support structures consist of a flow distribution baffle (FDB) and seven tube support plates on the inlet or hot-leg side of the U-tubes; the FDB, five preheater baffle plates, and five tube support plates on the outlet or cold-leg side of the U-tubes; and anti-vibration bar assemblies in the U-bend region. Separation between the cold-leg side preheater region and the hot-leg side is achieved by a partition plate, which extends from just above the FDB to the tube support plate that is located fourth from the tube bundle U-bend region.

Unit 1 tube support and baffle plates are fabricated from carbon steel, whereas the Unit 2 plates are fabricated from Type 405 ferritic stainless steel. The inspectors additionally ascertained that the tube hole configuration in the tube support plates differs between the Unit 1 and Unit 2 steam generators, with drilled holes being employed for Unit 1 and a quatrefoil design used for Unit 2. The inspectors considered that the difference in tube support materials and tube support hole configuration should make the Unit 2 steam generators less susceptible than those in Unit 1 to long-term denting and stress corrosion damage, due to the potential in Unit 1 for magnetite buildup and entrainment of corrosion products in the interstices between the tubes and the carbon steel tube supports.

The inspectors were informed that a primary side inlet hot-leg temperature of 618.8°F is used in operation of both units. The inspectors noted that, based on available Electric Power Research Institute (EPRI) information, the CPSES hot-leg temperature is one of the higher values used by pressurized water reactors. It was also observed by the inspectors that reduction of hot-leg temperature is being pursued by other individual licensees as an approach to limit initiation and propagation of stress corrosion cracking. Licensee staff informed the inspectors that they were cognizant that temperature is a major factor in tubing corrosion and that a scoping study was being performed to determine the feasibility of hot-leg temperature reduction.

2.2 Tubing Material

The inspectors reviewed the technical requirements for CPSES, Units 1 and 2, steam generator tubing contained, respectively, in Westinghouse Material Specifications 2656A84, "Material-Nickel-Chromium-Iron Tubing (High Yield Strength per Code Case 1484)," and 2655A65, "Material-Special Thermal Treated Inconel Tubing (High Yield Strength per Code Case 1484)." The inspectors noted that these documents invoked ASME Material Specification SB-163 and Code Case 1484. The Unit 1 tubing was specified to be furnished in the annealed condition, with test requirements including a hydrostatic test at 3106 psig, ultrasonic examination, and eddy current examination. The requirements for the Unit 2 tubing were, with one significant exception, the same. The exception pertained to an additional thermal treatment that was performed on the tubing. Details of the specific thermal treatment performed have not been included in the inspection report, as a result of the specification being considered proprietary by Westinghouse. The inspectors compared the thermal treatment cycle against data contained in EPRI Report NP-1354, "Optimization of Metallurgical Variables to Improve the Stress Corrosion Resistance of Inconel 600," dated March 1980, and concluded that the cycle should enhance the resistance to primary water and caustic stress corrosion cracking.

The inspectors noted that the material specifications did not identify the annealing temperature to be used for the ASME SB-163 (Inconel 600) tubes. The certified material test reports (CMTRs) furnished by the tubing manufacturer also did not indicate the actual annealing temperature used. Review by the inspectors of the CMTRs showed a wide range of reported 0.2 percent yield strength and ultimate tensile strength values for the tubing from both units. The reported 0.2 percent yield strength values for Unit 1 spanned the ASME Case Code 1484 allowable range of 40,000 to 65,000 psi. The corresponding values for Unit 2 ranged from 40,000 to 58,000 psi. The tensile strengths for both units ranged from 82,000 to 115,000 psi. ASME Material Specification SB-163 required a minimum tensile strength of 80,000 psi. The inspectors considered the most probable cause for the spread in mechanical properties to be variations (temperature and/or time) in the annealing cycle used for the tubing. The lower spread of 0.2 percent yield strength values in the Unit 2 tubing was attributed by the inspectors to the effects of the thermal treatment cycle on microstructure. The reduced maximum 0.2 percent yield strength value in the Unit 2 tubing was also considered to be another indicator of increased resistance to primary water stress corrosion cracking.

2.3 Tube-to-Tube Sheet Expansion

The inspectors were informed by licensee personnel that tubes were expanded after insertion into the tube sheet (i.e., the forging used to support the

U-tube bundle) by either mechanical rolling or explosive expansion (Wextex process) for the Unit 1 steam generators, with hydraulic expansion used for the Unit 2 steam generators. The inspectors requested that the applicable tube-to-tube sheet expansion procedures be obtained for review. These documents were furnished by Westinghouse and were indicated to contain proprietary information. The inspectors noted from review of the documents (i.e., Process Specification 81007 JA, "Full Depth Rolling of Steam Generator Tubes," effective December 8, 1977; Process Specification NPT-46, "Explosive Tube Expansion," effective October 3, 1974, and including a change dated December 11, 1974; and Process Specification 81013 RM, "Hydraulic Tube Expansion," effective July 12, 1979) that all processes provided for full-depth expansion of the tubes in the tube sheet. The inspectors noted that the inspection verification requirements were fairly detailed for the hydraulic expansion process, but limited in scope for the mechanical rolling and explosive expansion methods.

2.4 Steam Generator Tube Degradation History

Prior to operational service, Unit 1 steam generators contained a total of 31 plugged tubes (i.e., Steam Generator 1-1, 12; Steam Generator 1-2, 3; Steam Generator 1-3, 5; Steam Generator 1-4, 11). Eddy current examinations were performed on a sample of steam generator tubes during Refueling Outages 1RF01 (Fall 1991), 1RF02 (Fall 1992), and 1RF03 (Fall 1993), with no repairable indications found. These refueling outages occurred, respectively, after 0.9, 1.7, and 2.4 effective full power years (EFPYs) of operation. The inspectors noted from review of Refueling Outage 1RF03 eddy current data that five distorted indications were identified by bobbin coil examinations to be present in tubes at tube support plate locations in Steam Generator 1-4. Two of the steam generator tubing indications were located at the third support on the hot-leg side (i.e., H3), with the remaining three indications located at the fifth support on the hot-leg side (i.e., H5). The inspectors observed that the location of the distorted indications in the tubing was recorded as being at either the mid-thickness position of the support plate, or 0.06 inches from the mid-thickness position. The inspectors considered the location of the indications to be potentially indicative of the onset of stress corrosion cracking. Motorized rotating pancake coil (MRPC) examinations were performed of the tube locations exhibiting the five bobbin coil identified distorted indications, with no evidence, however, of defects found.

Prior to operational service, Unit 2 steam generators contained a total of 20 plugged tubes (i.e., Steam Generator 2-1, 5; Steam Generator 2-2, 3; Steam Generator 2-3, 3; Steam Generator 2-4, 9). Unit 2 is currently in its first cycle of operation, with approximately 0.5 EFPYs of operation accrued as of this inspection, and thus no inservice eddy current examinations have been performed to date.

2.5 Licensee Actions Taken to increase Tubing Stress Corrosion Cracking Resistance and Minimize Wear

The inspectors were informed by licensee personnel that onsite shot peening was performed of the inside diameter of all tubes in each Unit 1 steam generator prior to operational service, in the area of the tube sheet through the tube expansion transition region. This activity was performed on the hot-leg and cold-leg side of the tube bundle to induce surface compressive stresses and thus increase resistance to primary water stress corrosion cracking. The inspectors additionally ascertained that an onsite thermal stress relief was performed of the low radius Rows 1 and 2 U-bends in each Unit 1 steam generator prior to unit operation, in order to increase the resistance of the bend region to stress corrosion cracking.

Licensee staff informed the inspectors that similar onsite shot peening and heat treatment activities were not performed for the Unit 2 steam generators, due to the expected increased resistance to primary water stress corrosion cracking resulting from the thermal treatment given to the tubing. The inspectors ascertained, however, during the review of tubing material specifications that a thermal stress relief was performed of the low radius U-bends by Westinghouse subsequent to the forming operation. Reviews were not performed by the inspectors of procedural conformance by the contractor in accomplishing these activities.

Modifications were also made by the licensee in the preheater section of the steam generators prior to Units 1 and 2 operation, for the purpose of minimizing wear resulting from tube vibrations. The modifications consisted of hydraulic expansion of 140 tubes at the preheater "B" and "D" baffle plate locations.

2.6 Conclusions

- CPSES, Units 1 and 2, utilize Westinghouse D-Series steam generators in the plant design, Model D4 in Unit 1 and Model D5 in Unit 2.

- These units have been operated with a hot-leg temperature of 618.8° F, which appeared from available EPRI information to be one of the higher temperatures used by pressurized water reactors. It was noted by the inspectors that reduction of hot-leg temperature is being pursued by individual licensees, including CPSES, as an approach to limit initiation and propagation of stress corrosion cracking.

- The most significant differences noted by the inspectors between the Units 1 and 2 steam generators were: (a) the Unit 1 use of mill annealed Inconel 600 tubing, drilled carbon steel tube support plates, and the use of both mechanical rolling and explosive expansion of tubes into the tube sheet; versus (b) the Unit 2 use of Inconel 600 tubing that had received an additional thermal treatment, Type 405 ferritic stainless steel tube support plates with quatrefoil hole design, and hydraulic expansion of tubes into the tube sheet. The inspectors considered that these differences should make the Unit 2 steam generators less vulnerable than those in Unit 1 to long-term denting and stress corrosion cracking damage.

- Actions were taken by the licensee to minimize tubing wear in the preheater section of the Units 1 and 2 steam generators by expanding tubes at two baffle plate locations; and actions were also taken to improve the resistance of Unit 1 steam generator tubing to stress corrosion cracking by onsite shot peening of the tube expansion transition areas and heat treatment of low radius U-bends. Heat treatment of Unit 2 low radius U-bends was performed by Westinghouse following forming of the U-bends.

- Five distorted signals were identified by bobbin coil examination in Steam Generator 1-4 at or close to the mid-thickness position of the H3 and H5 tube support plates. Licensee examination of these tube locations using an MRPC probe did not identify any defects to be present.

- No tubes have required plugging in the Unit 1 steam generators due to service-related degradation, as of Refueling Outage 1RF03 (2.4 effective full power years of operation).

3 DETECTION OF AND RESPONSE TO PRIMARY-TO-SECONDARY LEAKAGE

During this part of the inspection, the inspectors reviewed from an operational perspective the licensee's efforts and programs concerned with detection of and response to steam generator tube leakage and rupture. The areas reviewed included effectiveness of related procedures, operator training, handling of generic communications related to steam generator tube integrity, engineering assessment of installed instrumentation, and management expectations of personnel performance.

3.1 Related Procedures and Training

The licensee had created and put into effect off-normal and emergency operating procedures (EOPs) to address steam generator tube leakage and rupture. In addition, procedures had been developed to provide guidance to chemistry and operations personnel in the interpretation and trending of steam generator tube leak rate.

The inspectors reviewed Procedure ABN-106, "High Secondary Activity," Revision 2. This procedure was applicable to both units and had been implemented to provide control room operators guidance necessary for continued monitoring, assessment, and response to identified primary-to-secondary leakage. The procedure was intended for implementation during facility license defined Operating Modes 1, 2, or 3. Entry into this procedure was initiated by high radioactivity in the steam generators detected by the normal sample process, or by the response procedures for annunciators that would possibly alarm in response to steam generator tube leakage. The procedure contained two different sections for addressing steam generator tube leakage, dependent on leak rate. The first section was implemented for a leakage condition known to be less than Technical Specification (TS) limits, or if the leak rate was unknown. This section provided guidance for identifying the leaking steam generator(s) and continued unit operation with enhanced sampling, monitoring, and trending of the leakage conditions, to assure the unit was operated in accordance with the facility license limits.

The second section of the procedure was implemented when the primary-to-secondary leak rate was greater than the TS limits. This section initially provided the detailed guidance necessary to positively identify the affected steam generator(s). The inspectors verified that the continued implementation of this procedure section would result in isolating the affected steam generator(s), unit shutdown, and the performance of reactor coolant system (RCS) cooldown and depressurization to mitigate the leak and stop the release of radioactive material. The inspectors also verified that an increased leak rate beyond the capability of this procedure would require the operators to transition to another off-normal conditions procedure which addressed high RCS leakage. The inspectors also noted that the off-normal procedure for high RCS leakage contained criteria and instructions for transitioning to the emergency operating procedures.

Emergency operating procedures (EOPs) were called emergency response guidelines (ERGs) at the CPSES site. The ERGs complied with the EOP format endorsed by the Westinghouse Owners Group. Because of some slight differences between the units, the licensee had developed unit specific ERGs. Unit 1 or 2 procedures were identified by an A or B at the end of the procedure number. Within the applicable portions of the ERGs reviewed, there were no significant unit differences to be considered. Therefore, unit differences are ignored for the remainder of this discussion. The inspectors reviewed the applicable ERGs to ascertain that they would be effective in the mitigation of a steam generator tube rupture and stopping any subsequent release in either unit. Another goal of this review was to ascertain that the ERGs would not delay the mitigation of a steam generator tube rupture and related release by failing to recognize that some indication would return to near normal values after the occurrence of automatic action, following a tube rupture. Information about the problem of failing to implement correct procedures due to the use of snapshot indication for event diagnosis had been relayed to licensees in NRC Information Notice (IN) 93-56, which reported circumstances related to the tube rupture event at Palo Verde Nuclear Station in March 1993.

The entire set of ERGs was currently in Revision 6 for Unit 1 and Revision 0 for Unit 2. The ERGs were entered through Procedure EOP-0.0, "Reactor Trip or Safety Injection." Step 24 of this procedure tasked the operator to determine if a steam generator tube rupture existed by observing five different indications. Any of these indications not in a normal range or condition would force the operator to transition to EOP-3.0, "Steam Generator Tube Rupture." There were two more steps within EOP-0.0 using different indication, that directed the operator to EOP-3.0. Should any of these three steps fail to direct the operator to the correct procedure, the operators were trained to enter Procedure EOS-0.0, "Rediagnosis," which would also direct that EOP-3.0 be entered. However, should all methods of attaining entry into the optimal procedure fail, the ERG scheme would force a functional type recovery from a tube rupture event.

Once the correct procedure (i.e., EOP-3.0) was entered, the operator was immediately tasked to identify the steam generator(s) with a ruptured tube or tubes. This identification would result in isolation of the affected steam generator, followed by cooldown and depressurization of the RCS. If the ruptured steam generator could not be identified, the procedure was continued toward a plant condition of cooled down and depressurized with all steam generators isolated and core cooling provided by the residual heat removal system.

In accordance with NRC Bulletin 88-02, the licensee had developed methods of enhanced steam generator tube leak rate monitoring. Procedure CLI-704, "Determination of Primary to Secondary Leakrate," Revision 3, provided analytical methods which chemistry personnel could use to accurately assess steam generator tube leakage. Any of three methods could be used to determine and trend the steam generator tube leak rate. The inspectors verified that the procedure provided guidance on the preferred method to be used for given conditions. The procedure also provided the recommended sample frequency dependent on the most recently identified leakrate. However, the inspectors could not locate any guidance regarding when to use Procedure CLI-704. Licensee personnel stated that implementation of Procedure CLI-704 was governed by procedures which addressed high RCS leak rate or high secondary activity. The inspectors reviewed these latter procedures but could not confirm this information.

The inspectors reviewed licensee training requirements and discussed training methods with personnel involved in initial and requalification training for licensed operators. The inspectors identified a total of 13 tasks directly related to operator response to tube leaks or failures, which were identified in one or both programs. These tasks appeared to require all of the elements necessary for operators to detect, evaluate, and respond to steam generator tube leakage or rupture. The tasks were implemented in the simulator and classroom lesson plans. Simulator instructors informed the inspectors, on two separate occasions, that licensed operators and candidates were routinely instructed to trend the installed radiological instrumentation that would detect a leaking tube and identify the affected steam generator.

The inspectors asked how the training programs were kept current in response to industry events and generic communications. The CPSES training department was on distribution for all generic communications, industry events, procedure revisions, and design modifications. All of this documentation was addressed by the training department Training Impact Assessment Program and systematically evaluated for inclusion into one or more of the existing training programs. The inspectors verified that the program had evaluated NRC

IN 93-56 and this evaluation had resulted in a modification to Lesson Plan LO21.SK2.XG4, "Steam Generator Tube Rupture," (EOP-3.0), to address the ramifications of the Palo Verde event for CPSES. The training department program appeared to function independently of the licensee's operational experience program, in that the licensee response to the IN had not been finalized at the time of this inspection.

3.2 Effectiveness of Installed Instrumentation

The inspectors evaluated the bases for the alarm setpoints of radiological monitoring instrumentation that could potentially detect or monitor a steam generator tube leak or rupture. Each CPSES unit contained four different installed radiological monitoring systems, capable of detecting a steam generator tube leak, and possibly identifying the affected steam generator. The instruments for these systems could all be trended on the PC-11 Radiological Monitoring System in the unit control room. These monitoring instruments are described below:

- Condenser Off Gas Radiation Monitor, RE-2959, was an off-line gaseous monitor through which a portion of condenser vacuum pump discharge was passed. Due to the noble gas concentration in the steam of a steam generator with a leaking tube, this monitor was expected to be the first to see an increase in secondary activity.

- Main Steamline Radiation Monitors, RE-2325 through -2328, were Geiger-Mueller detectors configured to detect radiation within an individual steam generator steam line. This arrangement provided a capability for the likely identification of the affected steam generator following a tube rupture.

- Steam generator Blowdown Sample Radiation Monitor, RE-4200, was a shielded gamma sensitive scintillation detector that monitored the radiation in a common steam generator blowdown sample line. The monitor alarm would cause automatic closure of the isolation valves in the individual steam generator blowdown sample lines. Identification of the affected steam generator was possible by overriding each of the sample line isolation valves in order to draw individual steam generator blowdown samples.

- The steam generator Blowdown Radiation Monitor, RE-5179, consisted of a shielded gamma sensitive scintillation detector that monitored the radiation downstream of the blowdown cleanup system demineralizer. An alarm on this monitor would automatically close the blowdown valves and the blowdown effluent control valve. Although the ERGs identified this monitor as an indicator of primary-to-secondary leakage, it more accurately monitored the efficiency of the blowdown cleanup system. In the event that primary-to-secondary leakage occurred, detection by this monitor would be delayed until the blowdown cleanup demineralizer lost efficiency or exhausted. Therefore, the inspectors were not concerned about the setpoint for this monitor.

The inspectors reviewed the assumptions and calculations for the alarm setpoint bases for those instruments that would detect, monitor, and identify a steam generator tube leak or rupture.

According to an assessment of the setpoint validity performed by CPSES Nuclear and Mechanical Analysis, the condenser exhaust radiation monitor alarm setpoint was based on the ability to identify the maximum allowable total primary-to-secondary leakage of 1 GPM, allowed by the facility license. The inspectors reviewed this assessment and concluded that the licensee had used correct assumptions and conservative values to arrive at a valid conclusion regarding the adequacy of the alarm setpoint.

The licensee had also assessed the blowdown sample radiation monitor alarm setpoint. This setpoint was also based on identifying the maximum total leak rate permitted by the facility license. The inspectors evaluated the assumptions made by the licensee and determined them to be complete and conservative. The 1 GPM licensed limit for primary-to-secondary leakage was based on assuring that dosage contribution from tube leakage would be limited to a small fraction of the 10 CFR 100 dose guideline values in the event of a tube rupture or steam line break.

The alarm setpoint for the main steamline radiation monitors was based on reactor coolant radioactive nitrogen-16, noble gasses, and halogen concentrations present in the steam of a main steam line following a steam generator tube rupture. Through previous safety analysis, the licensee had bounded the maximum leak rate due to a single tube at about 400 GPM. After assuming 100 percent power operation, calculations were made to verify that the alarm set point would be reached. In order to assure reliability, the licensee assumed various conditions down to a power level of 20 percent and a leak rate of 20 percent of the bounded maximum. With the lowest assumed set of initiating conditions, calculations verified that actual radiation levels at the monitors would be close to twice that necessary to actuate the alarm. The inspectors reviewed and agreed with the licensee's assessment that the steam line radiation monitors would provide indication of a tube rupture at 20 percent power with 20 percent of the maximum leak rate.

3.3 Generic Communications and Management Expectations

The inspectors reviewed the licensee's handling of specific generic communications related to steam generator tube integrity.

NRC Bulletin 88-02 was issued as a result of a tube rupture at the North Anna facility. The Bulletin was issued to encourage licensees to develop methods to determine impending tube failure. The response required by the Bulletin was dependent on the licensee's previous identification of tube denting at the uppermost support plate in steam generators. When the Bulletin was received, neither CPSES unit had been operated, and there had been no indication of tube denting. The licensee initially responded that the Bulletin did not apply to CPSES. However, the Bulletin required licensees to take action in the future should the inspection program reveal the presence of tube denting at the upper support plate. The required response for any future indication of denting was to implement an enhanced eddy current inspection effort and develop enhanced leak rate monitoring capabilities.

At the time of this inspection, the licensee's inspection program had already identified the occurrence of minor tube denting at the upper support plate in at least one Unit 1 steam generator. The inspectors were able to verify that the licensee had developed enhanced leak rate monitoring capabilities in the form of previously addressed Procedure CLI-704. The inspectors were initially unable to determine how the licensee intended to comply with the future enhanced eddy current inspection requirement. A licensee representative then showed the inspectors Commitment 18309, which committed to the enhanced inspection by inserting a requirement in Section 6.2.9 of Procedure STA-733, "Steam Generator Tube Inspection." The requirement stated that the enhanced inspection requirement of NRC Bulletin 88-02 was to be implemented when denting was identified. During discussion with cognizant licensee personnel, the inspectors were informed that the decision to implement enhanced inspection had not been made, and management expectations regarding the implementation of enhanced inspection effort were not known.

The inspectors also reviewed the licensee's action related to NRC IN 88-99, which referenced a tube failure at Indian Point 3. This notice was issued to alert licensees to potential problems in detecting and monitoring sudden or rapidly increasing leakage through steam generator tubes. The inspectors were unable to determine what the licensee had done with this information beyond identifying documents, procedures, drawings or programs that were possibility related. During review of the licensee's official working package, which had been closed, the inspectors observed a copy of Westinghouse Letter WPT-13994 dated October 4, 1991, and entitled, "Fatigue Cracking of Steam Generator Tubes with AVB Support," lying loose in the package. This letter, which was perceived by the inspectors to not be part of the package, alerted TU Electric that an assessment of the Indian Point tube crack event had established that conditions for that occurrence were not consistent with the analytical methodology developed in response to NRC Bulletin 88-02. The inspectors attempted to determine how the licensee's program handled this Westinghouse information. It was ascertained that no action items had been generated as a result of receipt of the Westinghouse letter. The letter was closed out with a comment that the issue was under review and no action was required. Licensee personnel did not know why the letter had been placed loose in the file folder. The inspectors were not aware of any specific action taken in response to the IN except to determine possibly affected areas.

The inspectors reviewed the licensee's actions related to NRC IN 93-56, "Weakness in Emergency Operating Procedures Found as a Result of Steam Generator Tube Rupture." The IN was issued because of procedural problems identified during review of the March 14, 1993, tube rupture event at the Palo Verde Nuclear Station. The licensee had already closed this item within the operational experience program. According to licensee personnel, the program goal was to complete an action plan within 90 days, and close the issue within 180 days of the generic communication. Following is a timetable of circumstances related to the licensee's handling of the information notice:

March 14, 1993	The event occurs at Palo Verde,
March 17, 1993	Industry group Occurrence Event Report 5872 issued,
April 9, 1993	Industry group Significant Event notification issued,
April 13, 1993	Licensee Event Report issued,
July 22, 1993	NRC IN 93-56 issued, and
September 20, 1993	Industry group Significant Occurrence Event Report 93-1 issued.

At the time of the inspection, the packages for the industry group occurrence event report (OER) and the IN had been closed. There was no significant action specified in either of these packages. The inspectors received an explanation that the concerns noted in the IN would be addressed in the OER, and the OER concerns would be addressed by the significant occurrence event report. The inspectors observed that efforts to address the significant occurrence event report had not been completed. The inspectors noted and told the licensee that the intention to address the concerns expressed by generic communications had not been met for IN 92-56, in that more than 180 days had elapsed and a final resolution had not been reached regarding the adequacy of the EOPs to address a steam generator tube rupture.

The inspectors believed that some of the packages reviewed did not contain sufficient documentation to indicate satisfactory resolution of concerns raised by generic communications.

3.4 Conclusions

The inspectors concluded that procedures used by operators and the training to support the performance of those procedures were good. For Procedure CLI-704, the procedure content was good, but there was a lack of guidance regarding when to use the procedure. The licensee's effort to validate the adequacy of specific radiological instrument alarm setpoints had been thorough and effective. During review of the licensee's handling of generic communications, observations made by the inspectors indicated that management had not clearly communicated their expectations to personnel on how steam generator tube integrity issues should be addressed. The lack of completeness of some of the closed packages were considered by the inspectors to be an indicator of needed improvement in oversight of the licensee's onsite operational experience review program.

4 VISUAL EXAMINATION OF THE SECONDARY SIDE OF THE UNIT 1 STEAM GENERATORS

4.1 Review of Program Requirements and Inspection Data

The inspectors reviewed the programmatic requirements which applied to the control of tools and equipment entering the steam generators and visual inspection prior to closure. The programmatic requirements were contained in Station Administration Manual Procedures STA-607, "Housekeeping Control," Revision 14, and STA-612, "System Cleanness Control and Cleaning," Revision 3. As the contractor, Westinghouse used Westinghouse Procedures SSS 2.2.2 GEN-1, "Steam Generator Tubesheet Cleaning," Revision 5, and SSS 2.4.2 TBX, "Remote Examination and Removal of Foreign Objects," Revision 0, for control of sludge lancing and examination of Unit 1 Steam Generators 1-1 and 1-2 in Refueling Outage 1RF01. Sludge lancing and examination of Steam Generators 1-3 and 1-4 in Unit 1 were performed by Westinghouse in Refueling Outage 1RF02 using Westinghouse Procedures SSS 2.2.2 TUE-1, "Steam Generator Tubesheet Cleaning," Revision 0, and SSS 2.4.2 TUE-1, "Remote Examination and Removal of Foreign Objects," Revision 0. In review of Procedure STA-607, Revision 14, the inspectors noted that all tools and materials entering the steam generator area were required to be logged prior to entry and accounted for prior to closure of the steam generator. This procedure also required that the logs be signed by the responsible quality control personnel, but did not specify that they be retained. The inspectors noted that the logs were included in the Westinghouse outage reports for both Refueling Outages 1RF01 and 1RF02. The logs indicated that the contractor had exhibited good control of tools and equipment entering the steam generator areas.

Visual inspection of the secondary side of the steam generators was controlled by Section A, "Post-Work Test Guide," of Procedure STA-612, Revision 3. This procedure required visual inspection to be performed in accordance with Generic Letter 85-02. This generic letter recommends visual inspection of the steam generator secondary side along the periphery of the tube bundle and in the vicinity of the tubesheet for loose parts, foreign objects, and external damage to peripheral tubes. The inspectors noted that the licensee had no criteria for visual inspection of the secondary side of the steam generators away from the tubesheet area. In review of the Westinghouse outage reports for Refueling Outages 1RF01 and 1RF02, the inspectors observed that visual inspection consisted of fiber optic examination of the tubesheet area and tube bundle periphery for loose objects and foreign material after sludge lancing. Items removed from the steam generators during Refueling Outage 1RF01 were as follows: (a) Steam Generator 1-1, a piece of slag and two wire bristles; (b) Steam Generator 1-2, two pieces of slag, a wire bristle, a metal sliver, a plastic object, and a flashlight switch internal part; (c) Steam Generator 1-3, scale, a metal sliver, a spring, and a metal ring; and (d) Steam Generator 1-4, slag, and a flapper wheel chuck. No foreign objects were observed in either Steam Generator 1-1 or 1-2 subsequent to sludge lancing during Refueling Outage 1RF02. Items removed from the other steam generators during this outage were as follows: (a) Steam Generator 1-3, a piece of 1/4-inch roll stock and a piece of slag; and (b) Steam Generator 1-4, a small metal sliver, a piece of 1/8-inch roll stock, and a piece of slag.

Other than the reference to Generic Letter 85-02, no references were made to visual examination for external tube damage in either licensee or contractor documents. The secondary side of Steam Generators 1-1 and 1-4 were not opened during Refueling Outage 1RF03, as a result of sludge lancing not being performed; therefore, no visual examinations were performed.

4.2 Conclusions

- During Refueling Outages 1RF01 and 1RF02, the contractor exhibited good control of tools and equipment entering the steam generator areas.
- The licensee did not define the scope of visual examination of the secondary side of the steam generators beyond a reference to Generic Letter 85-02.

5 REVIEW OF TUBE EXAMINATION HISTORY, PROGRAM REQUIREMENTS, AND DATA

5.1 Review of Tube Examination History

Prior to Units 1 and 2 operation, the licensee performed a full-length bobbin coil examination of all active tubes in each steam generator. In addition, MRPC examinations were performed of the Unit 1 low radius U-bends following onsite thermal stress relief. During the first refueling outage (1RF01) for Unit 1 in the Fall 1991, the licensee performed a full-length bobbin coil examination of approximately a 20 percent random sample of the active tubes in each steam generator (i.e., the sample sizes examined in Steam Generators 1-1, 1-2, 1-3, and 1-4 were, respectively, 22.3, 23, 23, and 22.4 percent). In Refueling Outage 1RF02 (Fall 1992), a full-length bobbin coil examination was performed of 41.7 and 43.2 percent, respectively, of the active tubes in Steam Generators 1-2 and 1-3. A full-length bobbin coil examination was performed of 40.1 and 43.2 percent, respectively, of the active tubes in Steam Generators 1-1 and 1-4 during Refueling Outage 1RF03 (Fall 1993). MRPC examinations were performed of ambiguous or distorted bobbin coil signals that were noted during Refueling Outages 1RF02 and 1RF03. No repairable indications were identified during these examinations, as previously discussed in Section 2.4.

The inspectors noted during review of the eddy current examination data for Refueling Outage 1RF03 that the tube sampling was not performed randomly (i.e., blocks of adjacent tubes were examined in Steam Generator 1-1 and the examinations of Steam Generator 1-4 tubes were performed primarily in two zones of the steam generator). The inspectors informed licensee staff that, while it was acknowledged that the 40 percent tube sample selected from Steam Generators 1-1 and 1-4 was considerably above TS minimum requirements, the selection method did not appear to satisfy the random selection basis specified by TS 4.0.6.2. Licensee staff were additionally informed that this matter would be discussed with cognizant staff in the Office of Nuclear Reactor Regulation subsequent to the inspection. Subsequent discussion with Office of Nuclear Reactor Regulation staff identified that the sampling approach at CPSES, Unit 1, did not literally appear to meet TS 4.0.6.2 random selection requirements, but did not create a significant technical concern. Licensee staff affirmed in an additional exit meeting held by telephone on March 7, 1994, that future sampling of steam generator tubes would include a random programmed element that was consistent with TS requirements. The violation of TS 4.0.6.2 requirements is not being cited because the criteria specified in Section VII.B.1 of Appendix C to 10 CFR Part 2 have been met.

5.2 Review of Examination Program Requirements

5.2.1 Current Program

The inspectors reviewed the eddy current test program requirements which were contained in: (a) Procedure STA-733, "Steam Generator Tube Examination," Revision 1; (b) Procedure STA-731, "ASME Section XI Repair and Replacement Activities," Revision 4; (c) Comanche Peak Unit 1, "Steam Generator Eddy Current Data Analyst Guide," Revision 3; (d) Westinghouse Procedure MRS 2.4.2 TUE-35, Eddy Current Inspection of Preservice and Inservice Heat-Exchanger Tubing for Comanche Peak," Revision 0; (e) Westinghouse Procedure MRS 2.4.2 TUE-36, "WL-II and SM-10W Operating Procedure for Comanche Peak-Westinghouse System," Revision 0; and (f) Westinghouse Guideline DAT-GYD-001, "Data Analysis Guidelines," Revision 6. The inspectors also compared the current program against the recommendations contained in Electric Power Research Institute (EPRI) NP-6201, "PWR Steam Generator Examination Guidelines," Revision 3. It was ascertained during this review that, although no commitment was observed in the current program to the EPRI guidelines, dual analysis of eddy current data was performed, and the examination sample size was fully consistent with the EPRI recommendations. Instances were noted, however, where the current program was not consistent with EPRI recommendations. The more significant examples noted were: the absence of plant-specific performance demonstration testing of data analysts; existing licensee data analysis guidelines which did not meet EPRI recommendations in regard to subject scope; and the absence of a programmed random element, in the tube sampling process, whereby tubes were randomly selected over the entire area of the examined steam generators (see also Section 5.1 above). The program additionally did not provide any guidance concerning the EPRI NP-6201 recommendation for establishment of criteria for noisy data.

The inspectors additionally observed that the program lacked criteria for determining what tube conditions would be subjected to ongoing monitoring, other than the TS required monitoring of degraded tubes. Examples noted where it was not clear from the current program what future examinations would be performed were as follows:

- No criteria were observed which would mandate that the tubes in Steam Generator 1-4, that were identified during Refueling Outage 1RF03 to contain distorted bobbin coil signals, would be subjected to future examinations.

- No specific position was observed in regard to monitorir, pr(gression of denting.

- No position was noted in regard to monitoring of tubes in the preheater section of the steam generators, an area indicated by EPRI data to be potentially subject to degradation.

- During review of tubing material properties, the inspectors noted that a Westinghouse Nonconformance Report (NCR), 86-0140, Revision 1, had been generated as a result of overheating occurring during the onsite thermal stress relief of a Unit 1 low radius U-bend. The disposition of the NCR was accept-as-is based on a recommendation for inclusion of the tube for eddy current examination monitoring. This tube was examined during Refueling Outage 1RF01, but was not re-examined during Refueling Outage 1RF03. The cognizant licensee technical staff were aware of the NCR as a result of prior reviews, but had not formally defined monitoring requirements for the tube.

The inspectors observed during review of Westinghouse Guideline DAT-GYD-001, Revision 6, that it permitted resolution analysts to perform resolutions on reels on which they have performed primary or secondary analysis. The inspectors considered this practice to be less than optimal, but did not pursue the matter as a result of it not being applicable to the last refueling outage (i.e., the primary and secondary analysis were performed at a remote location, with the resolution analysis performed onsite by different Westinghouse data analysts). All the analysts used in Refueling Outage 1RF03 were either Level IIA or Level III certified analysts. The inspectors reviewed the certification and testing records for the analysts, with no problems noted.

5.2.2 Response to Generic Communications

The inspectors performed a limited review of the licensee's handling of NRC generic communications pertaining to steam generator problems. The sample used for this review was Bulletin 89-01, "Failure of Westinghouse Steam Generator Tube Mechanical Plugs," and INs 90-49, "Stress Corrosion Cracking in PWR Steam Generator Tubes," and 91-67, "Problems With the Reliable Detection of Intergranular Attack (IGA) of Steam Generator Tubing."

The review indicated that the licensee had appropriately responded to Bulletin 89-01. The inspectors noted with respect to INs 90-49 and 91-67, that the applicable licensee operating experience reports were not explicit with respect to plans for MRPC use, but indicated potential use during Refueling Outage 1RF01 in the context of IN 90-49 and Refueling Outage 1RF02 in regard to IN 91-67. The inspectors ascertained that specific MRPC examinations had not been conducted with respect to the subject material of the two INs. The current eddy current program required MRPC use to characterize ambiguous signals, but not as a detection tool. A management approved plan or procedure was not seen by the inspectors, which documented, in particular, the licensee approach for assuring that circumferential stress corrosion cracking was not present in tube expansion transition areas adjacent to the tube sheet. It also appeared to the inspectors that no updating of the operating experience reports had occurred to reflect any changes in organizational thinking regarding MRPC use. The status of the two packages was considered a further indicator, to those discussed in Section 3.3 above, of inadequate oversight of the licensee's onsite operational experience review program. The inspectors requested a management position on the use of MRPC. The licensee station engineering manager subsequently committed, at the exit interview for the inspection, to: (a) the development and implementation in Refueling Outage 1RF04 of site specific data analysis guidelines and performance demonstration testing of eddy current data analysts; and (b) the utilization of the MRPC method in Refueling Outage 1RF04 for examination of a sample of locations that were more susceptible to degradation (e.g., tube-sheet roll transition and hot-leg tube supports), with screening of individual freespan indications for inclusion in this program.

5.2.3 Eddy Current Program Oversight

The inspectors requested to see available records pertaining to licensee oversight of eddy current contractors. Four surveillance reports (Inspection Reports 91-0190, 91-0191, 91-0198, and 91-202) were provided with respect to oversight of Refueling Outage 1RF01 eddy current activities. These reports indicated that ongoing surveillance was performed of eddy current data acquisition, calibration, and data analysis activities. The reports were also noted to provide only limited information on assessment methodology and specific activities witnessed. Two surveillance reports (Inspection Reports 92-0184 and 92-0185) were provided with respect to oversight of Refueling Outage 1RF02 eddy current activities. These reports pertained to observation of two shifts of eddy current data collection and three shifts of data analysis, and were similar to those generated for Refueling Outage 1RF01 with respect to only limited information being provided relative to oversight activities. One surveillance report (ISEG-FN-93-593) was provided with respect to oversight of Refueling Outage 1RF03 eddy current activities. This report was slightly more detailed than the prior reports with respect to attributes reviewed, and also identified that tube degradation exceeding 20 percent through wall was reviewed by a TU Electric Level III examiner. The report also indicated that overview was performed with respect to resolution of the five distorted indications detected by bobbin coil in Steam Generator 1-4 (see Section 2.4 for additional information). The inspectors noted that each of the eddy current surveillances was performed by the Level III examiner referenced above. A review was performed of the eddy current certification records for the Level III examiner, with no discrepancies noted.

The inspectors ascertained that the dual analysis of eddy current data during Refueling Outage 1RF03 was performed, for the first time, at an offsite location by Westinghouse. Data was transmitted from CPSES using a dedicated telephone line. Direct overview of the analysis process at the offsite location was not performed by licensee personnel. The inspectors were informed by licensee personnel that Westinghouse had conducted an audit of the analysis process at the offsite location. The inspectors requested to see the audit records for this activity. It was noted from review of the furnished documents that a surveillance, not an audit, had been conducted by a Westinghouse quality assurance engineer who held no current eddy current certifications. It was additionally ascertained that the surveillance lasted a total of 1.5 hours, and addressed only two of the analysts that were involved in evaluation of the Refueling Outage 1RF03 eddy current data. The results were telephonically transmitted to Westinghouse personnel at the CPSES site for incorporation into a surveillance report, rather than preparation and transmittal of a report by the person performing the surveillance. The inspectors questioned both this practice and whether the surveillance was performed by Westinghouse on behalf of the licensee. Licensee quality assurance staff informed the inspectors that the surveillance reflected verification by the contractor of implementation of its 10 CFR 50, Appendix B, quality assurance program, and was not performed by the contractor as an organization who had been approved to perform audits for the licensee.

The inspectors additionally noted that the resolution process for differences in "calls" between the primary and secondary analysts was performed onsite during Refueling Outage 1RF03, and was subject to at least limited overview during licensee surveillance activities.

5.3 Review of Tube Examination Data

The inspectors reviewed a sample of bobbin coil and MRPC data that were obtained from the Refueling Outage 1RF03 examinations of Unit 1 steam generator tubing. The sample included: (a) five tubes that the analysts had reported as exhibiting throughwall degradation in the range of 32-38 percent, and (b) the bobbin coil and MRPC data for the five Steam Generator 1-4 tubes discussed above, which showed distorted bobbin coil indications. The inspectors noted no problems in regard to the bobbin coil "calls" made by the Westinghouse analysts, and confirmed that the MRPC examination data for the five distorted bobbin coil indications showed no evidence of tube defects. Attention was also placed on free span indications that had been classified as "manufacturer's buff marks." No anomalies were noted by the inspectors during review of this data, with good correlation noted for the sample reviewed between the results from Refueling Outage 1RF03 and prior examination results.

5.4 Conclusions

- Eddy current sample sizes consistent with EPRI recommendations have been examined by the bobbin coil method since Refueling Outage 1RF01 (1991).

- A noncited violation was identified pertaining to the failure during Refueling Outage 1RF03 to comply with the requirements of TS 4.0.6.2 for random selection of tubes for eddy current examination.

- Licensee use of MRPC, as of Refueling Outage 1RF03, has been restricted to examination of locations producing distorted or ambiguous bobbin coil signals. MRPC examinations of tube expansion transition areas have not currently been performed for enhanced detection of circumferential cracking.

- The current eddy current program lacked criteria for determining what tube conditions would be subjected to ongoing monitoring.

- As of Refueling Outage 1RF03, the licensee had developed only limited plant-specific data analysis guidelines and had not implemented plant-specific training and testing of eddy current data analysts.

- The licensee utilized a Level III examiner for oversight of eddy current contractor activities during each refueling outage. The surveillance documentation provided, however, only limited information on assessment methodology and specific activities witnessed.

6 REVIEW OF SECONDARY WATER CHEMISTRY CONTROLS AND HISTORY

Many impurities that enter the secondary side of steam generators can contribute to corrosion of steam generator tubes and support plates. While the concentration of impurities needed to cause corrosion problems is normally much higher than that present in steam generator bulk water, concentration of impurities to aggressive levels is possible in occluded areas where dryout occurs. Typical areas where dryout and resulting concentration of impurities can occur are tube sheet crevices, tube support plate crevices, and sludge piles. Impurities known to contribute to tube denting (i.e., squeezing of tubes at tube supports or tube sheets as a result of the pressure of corrosion products) are chlorides, sulfates, and copper and its oxides. Pitting of steam generator tubes has been attributed to the presence of copper and concentrated chlorides. Concentrated sulfates and sodium hydroxide are believed to be major causes of intergranular stress corrosion cracking and intergranular attack in steam generator tubes. Iron oxide tube deposits and sludge promote local boiling and concentration of impurities leading to these damage mechanisms.

6.1 Program Evolution

The inspectors reviewed the licensee's secondary chemistry control program for CPSES. It was ascertained that initial chemistry controls for both units utilized morpholine/hydrazine secondary water treatment. This treatment has been in use throughout commercial operation of Unit 1. Secondary water chemistry requirements were based on EPRI NP-6239, "PWR Secondary Water Chemistry Guidelines," Revision 2, dated December 1988, and included specified blowdown values for pH range, conductivity, sodium, chloride, sulfate, oxygen, and silica. The alternative amine trials in the secondary water chemistry of both units were viewed as proactive by the inspectors.

Shortly after Unit 2 went into commercial operation, hydrazine was replaced with diethylhydroxylamine (DEHA). The licensee chose DEHA over hydrazine in an effort to improve control of dissolved oxygen, molar ratio and sludge accumulation. Preliminary industry studies indicated that DEHA was superior to hydrazine. The licensee's results have not been conclusive and the licensee has suspended the DEHA program on Unit 2.

In an effort to reduce steam generator tube fouling due to the transport of corrosion products, the licensee elected to evaluate the use of dimethylamine (DMA) in secondary water chemistry. In July 1993, the licensee initiated a DMA injection program in the Unit 1 secondary water chemistry. Initially, the licensee maintained a DMA concentration of approximately 200ppb in the secondary water. After one month of operation with DMA the concentration was increased to approximately 400ppb. The licensee's preliminary results indicated a reduction in corrosion product particle size and transport. The licensee has elected to pursue further evaluations of DMA at higher concentrations over longer periods. The inspectors reviewed the 10 CFR 50.59 analysis that was performed relative to the addition of DMA to the secondary water. No anomalies or problems were noted during this review.

The inspectors compared the current secondary water chemistry program requirements against the criteria contained in the referenced EPRI guidelines. The program requirements, which were contained in Station Administration Manual Procedure STA-610, "Secondary Water Chemistry Control Program," Revision 5, were found to fully conform to the EPRI guidelines with respect to scope of chemistry parameters, analytical frequency, limits for critical parameters, and required actions when critical parameters were exceeded.

The inspectors additionally noted that the licensee was actively monitoring cation-to-anion molar ratios, with the intent of maintaining a neutral or slightly acidic environment in crevices. Use of pre-morpholated resins in the condensate polishers had been determined to be beneficial in attaining this goal. If successful, molar ratio control could significantly inhibit the onset of intergranular attack and stress corrosion cracking in steam generator tubing.

6.2 Secondary Side Operating History

The inspectors reviewed the history of the CPSES, Unit 1 and 2, steam generators with respect to significant chemistry events and compliance with the EPRI secondary water chemistry guidelines. Details on off normal chemistry are discussed below in Section 6.5.

In review of the chemistry monthly reports and trend charts, the inspectors determined that the licensee maintained excellent secondary water chemistry control in accordance with EPRI guidelines. All control parameters were routinely maintained within procedural limits, with few minor excursions. Response to chemistry excursions was prompt and effective in returning to within prescribed limits. The only parameter which approached its limits with any regularity was feedwater dissolved oxygen.

The inspectors also obtained historical information from the licensee pertaining to the weight and chemistry of sludge removed from Unit 1 steam generators. The sludge data are summarized below in Table 1:

TABLE 1

UNIT 1 STEAM GENERATOR SLUDGE ANALYSIS AND WEIGHT REMOVED

REFUELING OUTAGE	STEAM GENERATOR	SLUDGE REMOVED, LBS	Cu/Fe RATIO	Pb % by weight
1RF01	1-1	4	NDA	NDA
	1-2	5	NDA	NDA
	1-3	8	0.625	0.005
	1-4	9	NDA	NDA
1RF02	1-1	2.5	0.05	0.003
	1-2	3	0.445	0.040
	1-3	4	0.028	0.008
	1-4	1	0.605	0.053

NDA - No data available on these parameters.

The very small quantity of sludge removed from the steam generators during the first two refueling outages was considered a further indicator of excellent control of secondary water chemistry. The copper-to-iron ratio values for the sludge were considered surprisingly high by the inspectors, in that the secondary side of the plant was free of copper alloys. Licensee staff informed the inspectors, however, that the presence of copper was attributed to hot functional tests of Unit 1 that were performed prior to replacement of copper alloy tubing in the condenser with titanium alloy tubing. The copper content of the sludge was expected to decline in the future. The lead content of the sludge appeared to the inspectors to be low. Some work performed for EPRI suggests that lead may contribute to intergranular stress corrosion cracking. Sludge lancing was not performed during Refueling Outage 1RF03.

6.3 Self Assessment of Primary and Secondary Water Chemistry

The inspectors reviewed licensee audit and surveillance reports pertaining to the primary and secondary water chemistry control programs. The reports included four audits performed during the period February 1990 through June 1993 and two surveillances performed during February and May 1990. The inspectors found the scope of the audits and surveillances to be comprehensive and appropriate for evaluation of the water chemistry programs. In review of the audit and surveillance findings, the inspectors found no significant findings which would bring into question the quality of the water chemistry programs.

6.4 Chemistry Instrumentation

The inspectors toured the secondary chemistry laboratories and observed the analytical instrumentation used for grab sample analysis. The inspectors also observed the secondary sampling panels for in-line process chemistry analysis. The inspectors verified that necessary in-line and laboratory equipment were available for the analysis of the diagnostic and control parameters specified in the secondary water chemistry control program. The inspectors noted a concerted effort to upgrade the in-line process and laboratory instruments needed to perform the required chemical analyses. Among the recent additions were: individual steam generator sodium analyzers; sodium analyzers for individual condenser hotwell sections; corrosion product transport sample points; portable in-line total organic compounds analysis; and portable in-line panel sodium, conductivity, and dissolved oxygen analyzers. In response to a QA audit observation, some pH meters in the laboratories which allowed only one point calibration have been replaced with pH meters having multiple point calibration capability. In addition to the stated upgrades, an in-line instrumentation data acquisition and management system upgrade was in progress to provide enhanced analysis and trending capabilities.

6.5 Off-Normal Secondary History

The inspectors reviewed documentation of out-of-specification secondary water chemistry conditions that occurred since commercial operation of the units began. Only one significant out-of-specification condition was noted which could contribute to degradation of the steam generators. The condition pertained to a major condenser tube leak (i.e., estimated average leak rate of 30 gpm) which occurred in Unit 1 in March 1991. The ingress of lake water into the condensate resulted in EPRI Action Level 3 chemistry (i.e., steam generator blowdown sample sodium level exceeding 500 ppb) in 30 minutes from the time of leak recognition. Action Level 3 chemistry required unit shutdown. The licensee completed power descent in 5.25 hours, with cool down being completed in 20 hours. The inspectors observed that the peak sodium level in the steam generator blowdown exceeded 5000 ppb during this event. Steam generator secondary water chemistry was returned to normal using a drain and refill process.

6.6 Conclusions

- The licensee has maintained excellent control of secondary water chemistry, with only one significant out-of-specification chemistry condition noted since plant startup. This condition involved a significant Unit 1 out-of-specification sodium concentration in March 1991, which was the result of a major condenser tube leak and required unit cooldown.

- The secondary water chemistry program has utilized EPRI guidelines since commercial operation of CPSES.
- The very small sludge quantities removed from the Unit 1 steam generators were considered a further indicator of excellent secondary water chemistry control.
- The licensee was considered proactive in its attempts to reduce corrosion product transport to the steam generators by use of alternative amines.
- Progressive upgrades of in-line process and laboratory instruments have been made to enhance secondary water chemistry monitoring capabilities.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

*J. Barker, Independent Safety Evaluation Group Manager
**O. Bhatty, Regulatory Affairs
*R. Bird, Planning and Scheduling Manager
*M. Blevins, Nuclear Overview Manager
*M. Bozeman, Chemistry Manager
J. Brau, Operations Support Supervisor
**D. Buschbaum, Technical Compliance
*R. Byrd, Construction Operations Support Group Manager
*D. Davis, Plant Analysis Manager
*S. Ellis, Work Control Manager
**D. Foken, Senior Analyst
*W. Guldemond, System Engineering Manager
**T. Hope, Regulatory Compliance Manager
J. Hoss, System Engineer
*D. Kross, Operations Support Manager
*J. La Marca, Unit 1 Outage Manager
*H. Lawroski, Operations Review Committee
#F. Madden, Mechanical Engineering Manager
**R. Mays, Supervisor, Codes and Standards
*D. McAfee, Quality Assurance Manager
*D. Moore, Maintenance
*J. Muffett, Station Engineering Manager
C. Rice, Instructor
*G. Ruszala, Chemistry
*E. Schmitt, Operations Training Manager
*D. Snow, Regulatory Affairs
*G. Stein, Maintenance
*J. Stevens, Chemistry
*C. Terry, Vice President, Nuclear Operations
L. Wojcik, Nuclear and Mechanical Analysis Supervisor

1.2 Hartford Steam Boiler Inspection and Insurance Company

*J. Hair, Authorized Nuclear Inservice Inspector

1.3 NRC Personnel

*D. Graves, Senior Resident Inspector
*K. Kennedy, Resident Inspector
#T. Gwynn, Director, Division of Reactor Safety
#L. Yandell, Chief, Project Branch B
#G. Werner, Acting Project Engineer

In addition to the personnel listed above, the inspectors contacted other personnel during the inspection.

*Denotes personnel attending the February 11, 1994, exit meeting.

**Denotes personnel attending both the February 11 and March 7, 1994, exit meetings.

#Denotes personnel attending the March 7, 1994, exit meeting.

2 EXIT MEETING

An exit meeting was conducted on February 11, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. Procedures identified by Westinghouse as containing proprietary information were reviewed during this inspection. No information was included in the inspection report that was considered proprietary. A second exit meeting was held by telephone on March 7, 1994, to inform the licensee of the results of the discussion with Office of Nuclear Regulation staff concerning the random sampling requirements of TS 4.0.6.2. Licensee staff were informed that a noncited violation would be identified in regard to the failure to select a random tube sample in Refueling Outage 1RF03.