UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-327/88-08, and 50-328/88-08

Licensee: Tennessee Valley Authority
6N 38A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2901

Docket Nos.: 50-327 and 50-328 License Nos.: DPR-77, DPR-79

Facility Name: Sequoyah 1 and 2

Inspection Conducted: January 11 - 15, and January 25 - 29, 1988

Inspectors: _____ March 17, 1988
J. York, Senior Resident Inspector, Date Signed
Bellefonte, Team Leader

_____ March 17, 1988
G. Walton, Senior Resident Inspector, Date Signed
Watts Bar, Assistant Team Leader

Team Members: W. Bearden
W. Ross

Approved by: _____ March 18, 1988
S. Elrod, Section Chief Date Signed
Division of TVA Projects

SUMMARY

Scope: This special inspection covered the Sequoyah program for the layup and preservation of equipment.

Results: In the areas inspected, violations or deviations were not identified.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*S. Smith, Plant Manager
*I. Biase, Maintenance Special Programs
#*R. Briggs, Lead Materials Engineer
*R. Buchholz, Site Representative
*C. Earls, Chemistry Project Manager
*G. Fiser, Chemistry Program Manager
#*D. Goetcheus, Chemistry Group Manager
*T. Howard, Operations Quality Assurance Supervisor
*J. Johnson, Aquatic Biologist
#*G. Kirk, Compliance Licensing Manager
#*C. Landstrom, Licensing Engineer
*J. Maddox, Lead Engineer, Engineering Assurance
*J. Miller, Assistant Maintenance Supervisor
*W. Nestel, Chemistry Program Manager
*D. Pearson, Chemistry Engineer
*N. Romano, Senior Maintenance Specialist
#*E. Sliger, Manager of Projects
#*R. Strickland, Chemistry Engineer
*J. Sullivan, Supervisor Plant Operations Review Staff

Other licensee employees contacted included construction craftsmen, technicians, and office personnel.

NRC Attendees

*W. Bearden
*W. Ross
*G. Walton
#*J. York

*Attended exit interview on January 15, 1988
#Attended exit interview on Jaunary 29, 1988

2. Exit Interview

The inspection scope and findings were summarized on January 15 and January 29, 1988, with those persons indicated by an asterisk in paragraph one. The inspectors described the areas inspected. Proprietary information is not contained in this report. No dissenting comments were received from the licensee.

Note: A list of abbreviations used in this report is contained in paragraph 7.

3. Layup and Preservation of Equipment (92050, 79701)

A layup and preservation team inspection was performed during the period January 11 - January 29, 1988, to review and assess the effectiveness of the licensee's program to preserve, during a period of inactivity, the physical condition and operational ability of components, systems, and selected structures of both Sequoyah units. The team was divided into two groups with one group emphasizing adequacy of the system layup according to industry standards and walking down systems to determine if layup and preservation were performed to site procedures (paragraph 4). The second group selected fewer systems and concentrated on integration of preservation requirements into the preventive maintenance (PM) program along with vendor preservation requirements (paragraph 5). A third area shared by both groups addressed the microbiological induced corrosion (MIC) portion of the layup and preservation program (paragraph 6).

4. Layup and Preservation of Equipment with Emphasis on Industry and Site Requirements

a. Background

This inspection was the third, and most comprehensive, review of the actions being taken by the licensee to protect both the primary and secondary coolant systems from degradation since August 1985 when both units were shut down (see Inspection Reports 50-327, 328/86-14 dated March 24, 1986, and 50-327, 328/87-33 dated June 8, 1987).

b. Status of the Layup Program

Because of the indefinite extent of the outages, the licensee had maintained both units in wet layup during most of the interim period. The conditions for wet layup had been based on chemistry control guidelines developed and recommended by the Steam Generator Owners Group (SGOG) and the Electric Power Research Institute (EPRI).

The primary coolant systems of both units had been continuously maintained under appropriate conditions to reduce corrosion of stainless steel pipe and components (pH of 4.5 to 5.2, dissolved oxygen less than 10 ppb, and a nitrogen atmosphere in the pressurizer).

The secondary systems could not be maintained in similar conditions because of intermittent maintenance activities. During the initial twelve months of the outage, major modifications of the steam generators, feedwater heaters, moisture separator reheaters, and blowdown recovery systems had been performed. Consequently, the hotwell, condensate and feedwater lines (including the tube side of the feedwater heaters) as well as the steam generators had been cycled several times through filled and drained conditions. Main steam lines downstream of the isolation valves, extraction steam lines, and other carbon steel components of the feedwater heater

drain and vent systems had remained in a drained condition since shutdown.

When in wet layup, the steam generators had been protected from general corrosion by ensuring 25-50ppm of excess hydrazine was maintained to eliminate dissolved oxygen; by maintaining a pH of 10 to minimize acid corrosion; and by keeping a nitrogen atmosphere over the water, throughout the upper internals of the steam generators and in the main steam lines as far as the main steam isolation valves. During the layup period, the high pH of the steam generator water had caused dissolution of copper. The copper had been transported earlier from the feedwater heater tubes and subsequently plated out or "hidden" in crevices within the steam generators. The licensee had several times drained and filled the steam generators specifically to remove the dissolved copper and thus reduce future problems with steam generator tube denting.

In March 1987 EPRI published guidelines for laying up plant systems in a dry (dehumidified) condition (Plant Layup and Equipment Preservation Sourcebook, EPRI NP-S-106) and recommended that consideration be given to dry layup of plants or systems that would be shutdown for extended periods. During the May 1987 inspection, the inspector had been informed that Sequoyah Unit 1 would be layed up dry, and that the necessary dehumidifiers had been ordered. Unit 2 was to remain in wet layup in anticipation of restart. Subsequently, the Chemistry Unit was given responsibility for designating a Layup Coordinator and for implementing dry layup of the entire secondary coolant (power conversion) system, except the Unit 1 steam generators. The plant's Maintenance Department was given responsibility for ensuring that an adequate preventive maintenance (PM) program was developed to support wet and dry layup procedures.

In a concurrent program, the licensee was also implementing an erosion/corrosion assessment (Surveillance Instruction SI-704) that addressed the concerns expressed in NRC Inspection and Enforcement (IE) Notice 86-106. This program was designed to identify areas of the secondary system that might have been susceptible to degradation by erosion or corrosion during both plant operation and shutdown. This program is discussed further in paragraph 6 of this report.

c. Review and Assessment of the Unit 1 Layup Program

Through discussions with the Layup Coordinator, review of pertinent Special Maintenance Instructions (SMIs) and Plant Configuration Drawings, and system walkdowns, the inspector assessed the protection against corrosion that was being given to the carbon steel piping and components in the secondary coolant system.

(1) Secondary System Dry Layup

As discussed in Inspection Report Nos. 50-327, 328/87-33, the licensee had made the decision to layup all Unit 1 systems, except steam generators, in a drained and dehumidified condition. For this goal the Layup Coordinator had divided all systems that carried water or steam (on both tube and shell sides) into three major subsystems and began developing procedures (actually Special Maintenance Instructions) for providing "detailed steps for implementing dry layup ... through isolation, drainage, and the continuous purge of independent flow paths with dry air obtained from desiccant-type dehumidifiers."

The following three SMIs had been developed, and implementation had begun on the following schedule:

- SMI-1-2-1, Condensate and Feedwater Dry Layup Procedure. Layup was started in July 1987.

- SMI-1-1-6, Low Pressure Turbine and Heater Dry Layup Procedure. Layup was started in September 1987.

- SMI-1-1-7, High Pressure Turbine/Heater Dry Layup Procedure. Layup was started in November 1987.

Each of these procedures referenced specific Plant Configuration Drawings that had been used to establish subsystem boundaries and flow paths for the purging air. In each procedure a precaution section provided guidance to ensure operational and radiological safety measures were taken. One measure required installation of high efficiency particulate (HEPA) filters on each dehumidifier process air outlet to prevent lithium chloride desiccant carryover into the lines being purged. Another measure required that all temporary modifications be logged and that all equipment that was removed or disassembled be tagged, properly stored, and logged. Further, the procedures required documentation of Permits, Hold Orders, and valve alignments. Finally, the procedure required that each step be initialed as it was completed.

The completely documented procedure was retained by the Layup Coordinator who remained the point of contact for other plant personnel, e.g., Operations and Maintenance personnel.

(2) Review of Flow Paths

Through the use of Plant Configuration Drawings, the Layup Coordinator specified the placement of dehumidifiers, HEPA filters, and air exhaust points. These drawings were also used to determine multiple flow paths and specify methods to ensure

that each independent path had been purged until it was considered to be dry; i.e., to have less than 30 percent relative humidity.

The inspector and Layup Coordinator walked down the three major Unit 1 systems that had been layed up using SMI-1-1-7, SMI-1-1-6, and SMI-1-2-1. The Layup Coordinator identified principal and secondary exhaust points and demonstrated that, in all but one subsystem, the air contained significantly less than 30 percent relative humidity. As the result of this review, the layup conditions under which these systems were maintained were considered to meet the EPRI guideline criteria and to be adequate for preventing general corrosion of the carbon steel piping.

(3) Unit 1 Steam Generator Layup

The inspector was informed that the steam generators in Unit 1 had been maintained in wet layup continuously since the NRC inspection in May 1987. The inspector reviewed the current chemistry control data and observed that key parameters such as pH, hydrazine, sulfate, and sodium were within the licensee's administrative limits for steam generator water purity. The concentrations of sulfate (40-70 ppb) and sodium (10-20 ppb) were significantly less than the 1,000 ppb upper limit recommended by the SGOG to reduce corrosion.

(4) Reactor Coolant System Layup

As discussed in previous inspection reports, the Unit 1 reactor coolant system had remained filled with borated (but not lithiated) water since plant shutdown. Since lithium hydroxide had not been used to control pH, the reactor coolant pH had remained slightly acidic (pH of 4.7) throughout the shutdown period. The licensee's program for protecting the stainless steel components of the reactor coolant system was considered to be acceptable.

(5) Component Cooling Water System Layup

This closed cycle system had been maintained in a filled condition. The water was being treated with sodium molybdate to prevent corrosion.

d. Review and Assessment of the Unit 2 Layup Program

Through discussions with cognizant licensee personnel and an audit of recent chemistry control data, the inspector assessed the effectiveness of the layup conditions being used for the primary and secondary coolant systems of Unit 2.

(1) Primary Coolant System Layup

Throughout the entire shutdown period, the primary coolant system had been filled with borated water with low concentrations (approximately 10 ppb) of dissolved oxygen. Sufficient lithium hydroxide (approximately 1 to 2 ppm) had also been added to maintain the pH nearly neutral.

Instead of the normal hydrogen overpressure used during plant operation, the pressurizer gas space had been filled with nitrogen to eliminate the presence of air.

(2) Secondary System Wet Layup

The licensee had considered dry layup of all of the secondary coolant system, except the steam generators, but had chosen to continue the wet layup conditions that had been in effect during most of the shutdown period. These current conditions are summarized as follows:

(a) Condenser/Hotwell

The hotwell was filled with demineralized water with sufficient hydrazine to maintain the pH at 8.8-9.2 and the dissolved oxygen level below 100 ppb. During the inspector's previous site visit in May 1987, the desired dissolved oxygen level could not be maintained because the turbine/condenser was open to air. In the interim period the licensee had isolated the condenser and had established sufficient condenser vacuum (by means of the plant's auxiliary boiler and the condenser air ejector) such that the level of dissolved oxygen in the hotwell water was being kept below 10 ppb.

(b) Condensate/Feedwater

Corrosion control of the carbon steel piping of these systems was being accomplished by cycling the hotwell water (by means of hotwell pumps) through the "short cycle," i.e., through the condensate lines, condensate polishers and feedwater lines to the discharge of the Number 4 heaters and then back to the hotwell. The remainder of the feedwater lines upstream of the main feed isolation valves, were also filled with chemically treated water, but could not be cycled continuously through the "long cycle" because of a design problem associated with the steam generator layup configuration. The inspector was informed that in November 1987 the licensee took advantage of a shutdown of the steam generator layup system to actuate "long cycle" cleanup. Although the purity of the water in the hotwell

had been diminished briefly, the condensate polishers quickly restored the water in the entire "long cycle" to the desired level. This indicated that only low levels of oxidation (corrosion) products had been present in the entire condensate/feedwater system, including the tube sides of the seven sets of feedwater heaters.

As reported previously, the copper alloy tubes in Feedwater Heaters 1 and 2 had been exchanged with stainless steel tubes, thereby increasing their resistance to corrosion.

(c) Feedwater Heaters

The shell side of the low pressure and high pressure feedwater heaters and the moisture separator reheaters had been drained at shutdown in August 1985 but were not in a layup or dehumidified condition.

e. Sequoyah Pipe Wall Degradation Monitoring Program

In response to concerns about the integrity of the secondary water system, that were expressed in Inspection Report Nos. 50-327, 328/87-33, the licensee provided a list of actions to be taken to assess the condition of these systems before startup of each Sequoyah unit (see letter from R. Gridley to the NRC dated July 29, 1987). In part, these actions consisted of the development of surveillance procedures for use before and after startup. Two of these procedures were reviewed by the inspector during this inspection.

- SI-714, Extraction Steam Pipe Wall Degradation Monitoring Program, Rev. 0, June 26, 1987.

- SI-733, Wall Degradation Monitoring Program for the Feedwater/ Condensate Piping, Turbine, and Heater Drain Lines, Rev. 0, July 24, 1987.

Both of these surveillances consisted of ultrasonic testing of localized areas of piping to monitor pipe wall thinning. Although impetus for the development of this surveillance program had resulted from erosion/corrosion problems in the industry (see IE Notice 86-106), the program also was to be used to establish criteria for operability of these systems after the extended shutdown period.

The expanded surveillance program and associated preventive maintenance activities were considered to guard against wall thinning as long as the tests covered regions that might be susceptible to corrosion during the extended outage (i.e., low points, dead legs or other stagnant or low flow regions) as well as regions susceptible to erosion/corrosion under conditions of higher flow, turbulence, or temperature.

f. Conclusions

The current layup conditions for Unit 1 were considered to afford state-of-the-art protection against corrosion. Limited visual examinations of the interior of the carbon steel piping in the secondary coolant system did not identify degradation caused by wet layup or "drained but not dried" conditions during the initial two years of the extended outage. An expanded surveillance program of ultrasonic examinations of the secondary coolant system will be performed prior to and after startup of this unit.

Because of uncertainties related to Unit 2 startup, the low and high-pressure piping, drains, vents, etc., in this unit had remained in either a filled or "drained but not dried" condition for 2.5 years. Audits made during three inspections during this extended outage showed that wet layup conditions, when in force, often did not meet the criteria recommended by the SGOG/EPRI for protection against corrosion. However, data obtained by the licensee during a "long-cycle" cleanup of the hotwell/condensate/feedwater pipes in November 1987 were indicative of low levels of solid or soluble impurities and thereby, insignificant corrosive attack of the carbon steel piping. The integrity of these pipes has been, and will continue to be, monitored by the expanded ultrasonic testing program.

5. Program Inspection Emphasizing Vendor Requirements and Preventive Maintenance

The inspectors selected for review eight components or groups of similar components from a list of Unit 1 safety-related components and requested that the licensee provide evidence of performance for selected preventive maintenance (PM) requirements associated with these components. In all cases the licensee provided adequate evidence of performance of the stated preventive maintenance requirement. In some cases the documentation as requested was not available but the licensee was able to provide evidence that the PM requirement had been satisfied as part of a newer PM instruction due to the older instruction being cancelled and incorporated into another instruction. The following PM requirements were reviewed for technical adequacy and evidence of completion:

1-PMP-003-142, Turbine Driven Auxiliary Feedwater Pump, Routine Equipment Rotation.

0-MTRA-067-0456-B, ERCW Pump P-B, Sample and or Replace Pump Lubrication.

2-MVOP-067-297B, Upper Containment ERCW Isolation Valve, Lubricate Valve.

2-CLR-063-144, Safety Injection Pump Oil Cooler, Inspect ERCW Heat Exchanger.

1-FCV-001-VAR, Various Main Steam Isolation Valves, Lubricate Valves.

0-PMP-024-185, RCW Booster Pump B, Inspect Pump Packing.

0-FCV-065-28A & 0-FCV-065-28B, EGTS Train A Cooldown Valves, Cycle Valves.

2-FCV-999-VAR, Various Limitorque Valve Operators, Inspect Valve Operators.

Additionally the inspectors reviewed the licensee's program for motor and equipment rotation. This program is necessary to prevent rotating equipment from remaining idle for extended periods, especially during plant shutdown. Damage to bearing surfaces could result under these conditions due to lack of lubrication. The inspector determined from review of completed records, that the licensee had an adequate program which provided for routine equipment rotation. Surveillance Instructions SI-699.1 and SI-699.2, Unit 1 and 2 Monthly Equipment Rotation, require that each piece of equipment be rotated by one of the following means:

Verification from logs or other records that a particular component has been operated during that month

Swapping between redundant equipment

Hand rotation of equipment that can not be otherwise operated

All areas reviewed were found acceptable.

The inspectors toured selected areas of both Units 1 and 2 and observed the plant status with regard to layup and preservation of equipment. In addition, the inspectors met with the licensee personnel responsible for layup and preservation of equipment. Since Unit 2 is presently in a planned start-up mode, no further inspections were conducted on Unit 2.

On Unit 1 the inspector observed that the secondary non-safety-related systems were in dry lay-up, except the steam supply from the main steam line to the turbine driven auxiliary feedwater pump. The licensee advised that the valve was closed, and tagged, and the line was drained.

The inspector requested a low point drain valve be opened on the main steam system to verify the line was dry. The inspector was present when the licensee opened the drain valve. No water was present.

The inspector interviewed the licensee's on site Quality Assurance Auditors to determine the adequacy of the licensee audit on layup and preservation of equipment. The on site auditors advised they had not performed independent audits, but Corporate QA had audited the program in the Spring of 1986. Further, the area was scheduled for a second audit two years from the Spring 1986 timeframe. The inspector obtained copies of the corporate QA report and reviewed the findings and corrective

actions implemented. The audit report indicated the review was thorough, and identified some problems in the chemistry control area. The licensee implemented adequate corrective actions.

All areas reviewed by the inspector were acceptable.

6. Microbiological Induced Corrosion

Summary of Meeting in Bethesda

A presentation was made by TVA to the NRC on the microbiological induced corrosion (MIC) program for Sequoyah on December 15, 1987. Following is the TVA summary for that presentation:

> The structural attack of stainless steel butt welds in the Essential Raw Cooling Water (ERCW) system has been the most significant problem associated with MIC during inspections at Sequoyah. To address this problem, Sequoyah has developed a program to inspect for leakage, evaluate the damage, and repair as required. Also, Sequoyah will perform an ongoing investigation of corrosion damage in these welds to monitor this damage and subsequently verify the effectiveness of water treatment when the new water treatment program is implemented.

Site Inspection of MIC Program

a. Stainless Steel MIC Program

During this inspection, the inspectors walked down all of the stainless steel piping in the ERCW System for both units. MIC attacks occur at butt welds in the stainless steel piping systems. Originally there were 405 butt welds for both units (new and additional welds are added as sections of pipe with leaking welds are replaced). Of the 405 welds, 67 were radiographed to determine if MIC damage was present. Of these 67 welds, 28 were leaking. When removing the 28 leakers, sections of pipe with more welds than those leaking were removed and the licensee examined most of these additional welds. Three additional welds in the ERCW were found to leak after December 15, 1987, and before start of heat up of Sequoyah Unit 2 to Mode 4. All of the known leaking welds were repaired before the start of heat up. The ERCW pipe is 316 stainless steel, but the weld metal at Sequoyah is type 308. While the percentage of Chromium is approximately the same for both alloys, alloy 316 has much higher Molybdenum for increased pitting resistance. This higher alloy content is postulated to make the base metal cathodic and the weld anodic. A large cathode and a small anode is not desirable from a corrosion standpoint. All new welds at Sequoyah for the ERCW stainless steel piping will be 316 weld metal.

In comparison, the ERCW pipes at Watts Bar are alloy 316, but they are welded with 316 weld metal. No MIC attack was noted in the

comparable welds at Watts Bar. One stagnant leg in the stainless steel system at Watts Bar did have MIC attack on some of the welds.

Of the 405 welds examined, approximately 85 were in 3 in. diameter piping (others were in the 6 in. diameter piping) and no leaking was found in these welds. The flow velocity may have been greater in the smaller pipes. Therefore, the presence of MIC attack may be influenced by a combination of weld metal and flow rate (literature indicated flow rate is definitely a factor).

The licensee has committed to walk down and visually inspect all of welds on the ERCW stainless steel piping every six months. The following four PM documents are used for identifying the welds:

- PM 2220 - Unit 2, ERCW Supply Piping
- PM 2221 - Unit 1, ERCW Return Piping
- PM 2222 - Unit 2, ERCW Return Piping
- PM 2223 - Unit 1, ERCW Supply Piping

Originally the supply and return piping for each unit were placed on a separate PM number in order to spot any trends in leaking. Since the return lines are warmer, it was anticipated that the rate of pitting would be greater and thus more leaking welds would be present. Actually, a few more leaking welds were found in the supply lines.

If any leaking welds are found during the semi-annual inspections or during routine daily walkdowns required by Sequoyah housekeeping procedure (SQA-66), the welds in the stainless steel ERCW lines will be evaluated by Technical Instruction TI-109, "Nondestructive Testing of Stainless Steel Butt-Welds to Assess Damage Resulting from Microbiological-Induced Corrosion (MIC)". This technical instruction addresses radiographic testing of butt welded stainless steel piping for potential MIC damage. The licensee states that the results of this testing will be used to trend rates of weld degradation, determine the necessary corrective actions, and quantify the effects. The licensee stated that this TI (Rev. 1, dated August 28, 1987) would be revised to remove the ultrasonic testing (UT) option for evaluating defect length. Ultrasonic testing for MIC damage, when compared to sectioned samples, does not give the desired accuracy.

During the presentation in Bethesda the licensee committed to changing PMs 2220 thru 2223 and TI-109 so that when a leak is discovered, the following actions will be taken:

- During Modes 5 and 6 the repair work will be a restart requirement.

- During Modes 1, 2, 3, and 4, TI-109 will be used to evaluate corrosion damage (by radiography), and the instruction will be revised to specify that this will occur within seven days after

discovery of the leak. This data will be compared against specific criteria and if this is exceeded a detailed seismic analysis will be performed within an additional seven days. The licensee's experience indicated that all of the data at Sequoyah (from the 67 radiographed welds) have been within the screening criteria, but should the seismic analysis be evaluated as structurally inadequate, appropriate Technical Specification actions will be taken.

If the leaking welds found are determined to be structurally sound, appear to have very little leakage, and do not have the potential for leaking on safe shutdown equipment, then they will be scheduled for repair at the next outage. These welds will be noted in preventative maintenance (PM) document 2240 for Unit 1 and PM 2241 for Unit 2. These PMs require that a radiographic evaluation be performed per TI-109 on a quarterly basis until the leaking welds are fixed or replaced. The welds listed on revision 0 of these two PMs have all been cut out so any new leaking welds found during operation will be added to these documents. During the MIC presentation, the licensee stated that six to ten welds, some with MIC damage and some new welds, would be monitored to determine growth of MIC indications and development of new indications. This monitoring will continue until an effective water treatment is in place. These welds will be monitored under PMs 2240 and 2241.

The inspectors reviewed Design Change Notice No. X00073A which dealt with the licensee's concern that if a seismic event took place and MIC damage were in a weld that water could be sprayed on class 1E equipment and affect the safe shut down of the reactor. The licensee located these areas on the ERCW stainless steel piping and placed individual spray protection boots over each weld. The inspectors observed the location of these boots and the electric equipment during the walkdown of the stainless steel ERCW piping. The boot consists of a silicone rubber fabric reinforced with fiberglass. The seams and ends of the boot are sealed with Dow Adhesive No. 732. The ends of the boots are clamped with stainless steel bands. A plastic fitting in the boot with plastic tubing attached diverts any leakage inside the boot away from class 1E electrical equipment.

b. Carbon Steel MIC Program

Although the presentation at Bethesda by the licensee indicated that the only problem identified with carbon steel was flow restriction, some thru wall pitting has been observed at Sequoyah in both safety-related and non-safety-related systems. Following is a summary of this experience at Sequoyah.

(1) Leakage History

(a) Essential Raw Cooling Water (ERCW) Piping - 3 Leaks (All Replaced)

One sample was analyzed, one sample was lost for analysis purposes, and one sample is currently at the Singleton Materials Engineering Laboratory for analysis.

(b) High Pressure Fire Protection (HPFP) - 2 Leaks

One was in an Office Building adjacent to a hose station, the other was in an Auxiliary Building bypass line from the storage tank (7 thru-wall holes were present)

(2) Ultrasonic Grid Experience

(a) Essential Raw Cooling Water

SI-704 has 30 grids (30 pipe areas with grid networks) for cavitation evaluation. None show pitting damage, even in grids which are normally in stagnant flow areas and which do not have active cavitation.

(b) High Pressure Fire Protection

The licensee has currently tested 13 Grids - No wall thicknesses were less than the nominal wall thickness.

(c) Raw Service Water (Non-Safety-Related)

2 Grids were Tested:

- One was on a pipe adjacent to a leaker, (0-SW-1). No measurements were less than nominal wall thickness.

- The other was on a storage tank. Nominal wall thickness was 0.25 in. The measured minimum thickness was 0.21 in. The acceptance criteria is that actual thickness cannot vary more than 12.5 percent less than nominal thickness. This condition was 16% less than nominal.

(d) Raw Cooling Water (Non-Safety-Related)

2 Grids were tested. One had no damage. No. 2-RCW-1 had damage in 4 in. diameter piping. The acceptance limit was 0.237 in. The wall thickness found was 0.15 in. to 0.25 in.

(3) Other (Non-Safety-Related) Experience

Raw Service Water (RSW) Piping Samples removed as part of modifications projects:

- During part of one of the RSW modifications, the licensee found up to 46% pitting depth.

- During another RSW modification, the minimum piping thickness found was 0.220 in., and the nominal wall thickness was 0.322 in. The acceptance criteria was that the minimum wall thickness cannot be more than 12.5 percent less than the nominal thickness. This measurement was 31.6% less than the nominal wall thickness.

The inspectors reviewed Engineering Assurance audit deficiency No. 86-26-03 which states that no evidence was found that an evaluation of internal corrosion was performed by the Sequoyah Mechanical Design Project as part of TVA's commitment to paragraph C.2 of Regulatory Guide 1.29. Part of the answer to this deficiency (memorandum No. B25871117 016) stated that a report entitled, "Corrosion in Carbon Steel Raw Water Piping", had been submitted to the NRC. In addition, the memorandum stated that TVA continues to evaluate the effect of corrosion on carbon steel.

In the Quality Information Release attached to this memorandum for answering the deficiency, the grid systems used for monitoring and on some of the leakers mentioned in the preceding information were discussed. Several of the points mentioned were:

- leaks in carbon steel had been occasionally identified and in each case, ultrasonic (UT) mapping found the leak was caused by discrete pits without large areas of degradation.

- All of the leaks in carbon steal have resulted in a steady drip instead of a spray, because the heavy build up of corrosion in the pit tends to restrict the opening and prevent spraying.

The Quality Information Release gave the following information as a summary and conclusion:

> "The experience of TVA has been that carbon steel piping may periodically develop leaks which result from through-wall pits. However, gross wall loss that would greatly compromise the piping integrity has not been identified. The category I(L) piping may cause problems resulting from unanticipated leakage, but gross pipe failures resulting from excessive corrosion thinning is not expected to occur, even in a seismic event.
>
> Individual pits are difficult to locate (in carbon steel) using ultrasonic test techniques. A large area of piping may test without identification of damage, but random pitting can occur in any untested area. This indicates that the only reliable method of identification of pitted areas is by leakage detection."

Several recommendations were mentioned in the release stating that trending, generic applicability, and testing of each leaking area should be performed. Also, a technical instruction for carbon steel

(such as TI-109 for stainless steel) will be generated to document the methodology and frequency of the inspections. The licensee stated that this TI was scheduled to be in place by August 1988.

c. Development of a Biocide

The inspector met with the licensee to discuss their program for the development of a water treatment method using a biocide to prevent or minimize MIC attack on piping and welds. Long term, this is a very important part of the MIC program.

Initially the engineering group (Knoxville) had recommended Biosperse 305 as the biocide. However, a corporate chemistry group (Chattanooga) has recommended considering the following:

- Nalco Company's Actibrom 1338 is a liquid solution containing sodium bromide and a biodispersent. This compound would be injected simultaneously with sodium hypochlorite into the ERCW system (sodium hypochlorite is currently being injected year round into the ERCW system).

- Betz Company's Slimicide C78P is a granular organic material that releases both chlorine and bromine when dissolved in water.

- Calgon Company's H950 is a liquid solution of sodium bromide and would be injected simultaneously with the sodium hypochlorite into the ERCW system.

Where applicable, these products have Environmental Protection Agency (EPA) certificates and have been corrosion tested for most of the alloys that they would be in contact with in the ERCW system. Some compounds use a surfactant, which is a wetting agent, that improves the efficiency or allows penetration by chlorine or bromine, and some compounds use dispersents which attempt to eliminate the deposits left in the pipes since some bacteria concentrate under these deposits.

The chemistry group is coordinating development activities with Engineering and other groups within TVA. All of these activities were in the planning stage at the time of the inspection and an approximate target date to have this system in effect is October 1988.

The ERCW system is intended to have its own biocide injection system. The Condensate Cooling Water (CCW), Raw Cooling Water (RCW), RSW, and the HPFP systems will share a separate injection system. The Sequoyah site chemistry department is handling the planning for the water treatment MIC protection for the CCW, RCW, RSW and the HPFP systems. The site group is evaluating Betz Company's Clam-trol CT-1 for protection against MIC and for clam control.

d. Visit to Singleton Material Laboratory (Maryville, TN)

The TVA Singleton Materials Laboratory is performing the metallurgical failure analyses for the MIC problems, and is performing corrosion tests of materials. A discussion was held with the laboratory personnel about past failure investigations and some MIC samples that were currently being evaluated, e.g., a two inch diameter carbon steel elbow with a MIC thru wall penetration in the socket weld and a four inch diameter carbon steel straight pipe section out of the High Pressure Fire Protection System.

Another area concerning the MIC program at the laboratory involves the corrosion testing facilities. One once-through loop would test the metallurgical specimens in raw lake water only. The laboratory does not have a permit to dump chemicals into the lake. Two closed loops would test various biocides. A number of base metals, weld metals, and combinations will be tested within the next six months to a year to support the MIC water development program. The inspector reviewed in part the following procedures that will be used in this testing:

- Procedure No. SME-CORL-9, Rev. 0, "Measurement of the Corrosivity and Fouling Characteristics of Raw Lake Water", dated December 1, 1987.

- Procedure No. SME-CORL-10, Rev. 0, "Method For Dispersion/ Biocide Test on Stainless Steel or Carbon Steel Pipe", dated November 1, 1987.

- Procedure No. SME-CORL-11, Rev. 0, "Method For Determination of Corrosivity of Biocides To Metals In Raw Water Systems", dated November 24, 1987.

Within this area, no violations or deviations were identified.

7. List of Abbreviations, Units 1 and 2

CCW - Condensate Cooling Water
EPA - Environmental Protection Agency
EPRI - Electric Power Research Institute
ERCW - Essential Raw Cooling Water
HEPA - High Efficiency Particulate
HPFP - High Pressure Fire Protection
IE - Inspection and Enforcement
MIC - Microbiological Induced Corrosion
PM - Preventive Maintenance
RCW - Raw Cooling Water
RSW - Raw Service Water
SI - Surveillance Instruction e.g., SI-704
SGOG - Steam Generator Owners Group
SMI - Special Maintenance Instruction
UT - Ultrasonic Testing