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

SEP 15 1988

Report Nos.: 50-327/88-38 and 50-328/88-38

Licensee: Tennessee Valley Authority
6N38 A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

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

Facility Name: Sequoyah 1 and 2

Inspection Conducted: July 25-29, 1988

Inspector: R. R. Marston 9/15/88
R. R. Marston Date Signed

Accompanying Personnel: W. J. Ross

Approved by: John B. Kahle 9/15/88
J. B. Kahle, Section Chief Date Signed
Division of Radiation Safety and Safeguards

SUMMARY

Scope: This routine, unannounced inspection was in the areas of plant chemistry, corrosion control, and pipe wall thinning.

Results: The licensee had maintained good chemistry control of Sequoyah Unit 2 during the startup of this unit after an extended outage. Considerable attention and resources were being directed towards such key secondary water system components as the steam generators, condensate polishers, and makeup water treatment plant as well as to increased surveillance for pipe thinning. The Essential Raw Cooling Water System was continuing to be degraded by microbiological induced corrosion.

The licensee was initiating actions to restart Unit 1. The secondary coolant system and steam generators of this unit were still layed up dry.

Major elements of the licensee's chemistry control program (such as stabilizing staffing, finalizing procedures, and implementing online analytical instrumentation) were still not complete. However, the licensee's program met the intent of Technical Specifications, Generic Letter 85-02, and the SGOG/EPRI guidelines for PWR chemistry control. The use of a single, crowded laboratory to implement radiochemistry analyses, trace-level non-radiochemistry analyses, and environmental chemistry work was considered to be less than adequate.

No violations, deviations, or program weaknesses (other than stability of staffing) were identified.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

D. Adams, Technical Support Supervisor, Chemistry Group
J. Barker, Instrumentation Supervisor, Chemistry
J. Bates, Manager, Corporate Chemistry Support Group
*D. Briggs, Supervisor, Materials Technology
*R. Burch, Chemistry Supervisor, Chemistry Group
E. Camp, Mechanical Engineer, Steam Generator Group
*D. Craven, Assistant to the Plant Manager
E. Elam, Mechanical Engineer, Steam Generator Group
*G. Fiser, Manager, Chemistry Group
*D. Goetcheus, Manager, Steam Generator Group
M. Ira, Chemical Engineer, Corporate Chemistry Support Group
D. Kelley, Manager, Water and Waste Process Group
M. Koss, Engineer, Materials Technology
P. Maclaren, Process Control Supervisor, Chemistry Group
W. Nestle, Chemist, Corporate Chemistry Support Group
B. Roberts, Engineer, Materials Technology
W. Williams, Chemical Engineer, Water and Waste Process Group

Other licensee employees contacted during this inspection included chemistry, technicians, and administrative personnel.

NRC Resident Inspectors

K. Jenison
*P. Harmon

*Attended exit interview

2. Plant Chemistry (79701)

This inspection was a continuation of a program designed to assess the licensee's capability to prevent degradation of the primary coolant pressure boundary, in particular, as well as other plant components from corrosion and/or erosion. During this inspection major emphasis was given to the status of the secondary coolant system of Unit 2 after restart of this unit from an extended outage during which this system had been layed up wet. In addition, because of major changes that had been made in the chemistry staff during the past six months, the principal elements of the licensee's water chemistry program were reviewed and assessed for their effectiveness in providing the level of chemistry control recommended for PWRs by the Steam Generator Owners Group (SGOG) and the Electric Power Research Institute (EPRI).

a. Effectiveness of Components in Providing Protection Against Corrosion and Erosion.

At the time of this site visit, Unit 2 was operating at essentially full power after restart, in May 1988, from an extended outage (since August 1985). The licensee plans to restart Unit 1 (in its fourth fuel cycle) in the near future, and then reduce the power level of Unit 2 so as to extend the current fuel cycle (that was interrupted by the outage) until the end of 1988. Unit 1 remained in dry layup throughout this inspection; consequently, the status of the components of this unit was not addressed.

By means of discussion with cognizant licensee personnel and through an audit of chemistry control data, the inspector reviewed the performance of the major components of the Unit 2 secondary cooling cycle during the period since the last inspection in this area in May 1987 (see Inspection Report Nos. 50-327/87-33 and 50-328/87-33). During all of this period the secondary cooling cycle had been layed up wet, under AVT (all-volatile treatment) chemistry control, with chemically treated water in the steam generators, and chemically treated water in the condensate/feedwater lines circulating in a "long cleanup cycle" but bypassing the condensate polishers.

(1) Main Condenser

During the past year, the licensee took two positive actions to ensure the integrity of the main condenser as a barrier against ingress of potentially corrosive species in the condenser cooling water (water from the Tennessee River/Chickamauga Reservoir). On December 1[illegible], 1987, a new Technical Instruction (TI-111, Sequoyah Nuclear Plant Condenser Integrity Program) was issued. This instruction was written, in part, to meet the intent of NRC Generic Letter 85-02 to enhance overall condenser integrity and promote steam generator preservation. Responsibilities were shared by the Operations Group (for operating and monitoring condenser condition), the Mechanical Maintenance Group (for inspecting and cleaning the condenser's tube sheets, water boxes, and tubes), the Chemistry Group (for establishing chemistry criteria for controlling operating parameters for the condensers), and the System Engineering Section (for monitoring unit power levels to determine if condenser leaks have caused reductions in power).

Also in December 1987, the licensee performed eddy current tests (ECT) on approximately five percent of the 58,860 condenser tubes in Unit 2 to ascertain the extent of attack on the 90-10 copper-nickel tubes that may have resulted from debris (e.g., pitting or other forms of under-deposit attack). Although these tests indicated widespread wall loss damage, further examination of two pulled tubes did not confirm these data. However, evidence of pitting was observed and attributed to reduced water flow through the tubes and waterboxes. No condenser tubes were plugged as the result of these ECTs; however, the licensee planned to place increased emphasis on maintaining flow and inspection/cleaning of condenser tubes.

During the interval since startup of Unit 2 no water leaks had been observed. Consequently, the quality of water in the condenser hotwells and condensate remained high (e.g., concentrations of sodium, chloride, and sulfate less than 1 ppb). Inleakage of air into the condenser was relatively high (greater than 30 SCFM) throughout this period; however, these leaks did not adversely affect the dissolved oxygen concentration of the hotwell water (typically less than 3 ppb). Leakage of air in the condenser was considered to be detrimental to the copper-nickel condenser tubes and possibly to the low pressure turbine rotors and disks. Consequently, the licensee had an ongoing program to identify and repair air leaks.

(2) Essential Raw Cooling Water (ERCW) System

During the extended outages microbiologically induced corrosion (MIC) had been observed extensively throughout the ERCW piping, especially in weld regions. The licensee had repaired or replaced sections in Unit 2 that had through-wall indications (i.e., weeping of ERCW water) prior to this unit's return to power. However, the inspector was told that more recent tests had identified new leaks (ten in Unit 2 and seven in Unit 1) in stainless steel ERCW lines.

The licensee stated that MIC attack had been observed also at some of the licensee's other nuclear power plants, consequently, a comprehensive search for an effective biocide had been initiated at the corporate level. During the interim, the ERCW water at Sequoyah was being chlorinated (to obtain a residual chlorine level between 0.2 and 2.0 ppm) in an attempt to control the offensive microorganisms. At the time of this inspection plans were being made to augment the chlorination agent (sodium hypochlorite) with water-soluble compounds that contained bromine and a dispersant. The inspector was informed that samples of materials that will come in contact with this experimental mixture of biocides had been tested for corrosiveness and determined to be acceptable. The licensee agreed to keep the NRC apprised of all chemicals being used and the results of corrosion rate measurements being taken during these studies. This matter will be followed as an inspector followup item (IFI) 50-327, 328/88-38-01.

(3) Water Treatment Plant/Makeup Water System

As will be discussed further in Paragraph 2.a(4) of this report, the licensee continued to require large amounts of demineralized water for regenerating condensate polishers as well as for makeup purposes. At the time of this inspection the output of the water treatment plant was being adversely affected by mechanical problems related to the agitator in the clarifier tank. Consequently, sufficient demineralized water (approximately 50,000 gallons per polisher) was not available to maintain all six condensate polisher beds regenerated and available. The licensee was actively pursuing the cause of the mechanical problems with the agitator and attempting to return the equipment to operation.

The product of the water treatment plant was stored in two Condensate Storage Tanks (CST), one for each unit. The CST for Unit 1 still had a bladder and nitrogen sparging system that kept the dissolved oxygen content of the water at less than 50 ppb. (The Unit 2 CST no longer had a bladder but still had a sparging system.) During this inspection period the cation conductivity of the Unit 2 CST water exceeded the licensee's administrative limit (i.e., 0.2-0.3 umho/cm vs a limit of 0.15 umho/cm). This problem was attributed, in part, to ingress of air (carbon dioxide) as the volume of water in the CST was drawn down during periods when the water treatment plant was inoperable.

(4) Condensate Cleanup System

Through a review of startup chemistry data, the inspector observed that cleanup of the secondary coolant system had progressed very efficiently. As mentioned before, throughout most of the extended outage the low-pressure lines in the secondary coolant system (condensate-feedwater) had been layed up by circulating chemically treated water through the "long cycle." During this time the high pressure steam and drain lines had been drained but not dehumidified. When the condensate polishers were placed back in service, immediately before startup began, they removed both soluble and insoluble impurities so effectively that a lengthy "chemistry hold" was not needed when the plant reached power.

As the power level increased additional cleanup of the high pressure as well as low pressure lines was achieved by blowing down the steam generators (to waste or cycled back to the condensate line) and cycling the drain lines back to the condenser. Consequently, a second mandated 'chemistry hold' at 30 percent power also had been very brief because the quality of the feedwater met the criteria prescribed for combined feedwater from condensate and feedwater heater drains.

Once the plant had reached full power, the licensee had not been able to maintain full-flow polishing of the condensate because the required five polisher beds could not always be maintained regenerated. However, partial-flow polishing of the condensate, including all of the steam generator blowdown stream, had been maintained with at least two polishers. The principal cause of the regeneration problem had been the shortage of demineralized water and difficulties involved with efficient separation of sulfuric acid from the regenerated resins.

The chemistry staff had been devoting significant attention to ensuring very high quality feedwater for the steam generators while using such high concentrations of ammonia (to ensure a pH of 9.0 - 9.2) that the cation resins of the condensate polishers became saturated with ammonia after a few days use. The polishers were being regenerated whenever sodium concentrations in the feedwater exceeded 1 ppb in an effort to stay below the sodium limit (20 ppb) established by Westinghouse and the SGOG for the steam generator water. In an effort to improve the detection of sodium, as well as chloride and sulfate "throw", the licensee was installing an in-line ion chromatograph to monitor the effluents of the individual polishers.

(5) Feedwater Heaters

As reported in Inspection Report Nos. 50-327/87-33 and 50-328/87-33 (dated May 1987), the copper-nickel tubes in the high and intermediate pressure feedwater heaters had been replaced by stainless steel tubes during the early part of the extended outage. The inspector could not confirm definite plans for the similar replacement of tubes in the four low-pressure feedwater heaters. Consequently, the remaining copper-nickel heater tubes must be considered a potential source of copper corrosion products that will be transported to the steam generators.

(6) The Steam Generators

The steam generators in Unit 1 had been placed in dry layup since the last inspection in this area while those in Unit 2 remained filled with chemically-controlled and circulating water until restart of this unit. In April 1988, a primary-to-secondary leak had been detected in the "U-bend" region of a Row 1 steam generator tube in Unit 2. All Row 1 tubes were subsequently plugged as a precautionary measure until these tubes could be heat treated for primary stress corrosion cracking. (All the Row 1 tubes in the Unit 1 steam generators had already been heat treated.)

Recently (July 1988), all plugs in steam generator tubes in Unit 1 had been removed and full-tube eddy current tests (with an improved probe) had been made of 3263 tubes in the four steam generators. As the result of these tests 62 tubes were replugged because of U-bend indications. Also one tube was staked and plugged as the result of further analysis by Westinghouse in response to IE Bulletin 88-02 (February 1988), relating to the tube break in July 1987, at the North Anna Nuclear Power Plant. A similar analysis of Unit 2 tubes had been scheduled for the next refueling outage in early 1989. In addition, revisions had been made to maintenance and operations procedures to upgrade monitoring for primary to secondary leaks. The limit for radiation releases through such leaks also had been lowered from 1.0 uCi/g to 0.75 uCi/g.

(7) Moisture Separator Reheaters (MSR)

During the extended outage, the copper-nickel tubes in the MSRs of both Sequoyah units had been replaced with stainless steel tubes. This action had been taken to increase the efficiency of the MSRs as well as to eliminate these tubes as a potential source of copper corrosion products that could be transported to the steam generators and initiate tube denting.

(8) Pipe Wall Thinning

As a followup of IE Notice 86-106 and IE Bulletin 87-01 related to the pipe rupture at the Surry Nuclear Power Plant in December 1986, the inspector reviewed actions being taken to prevent pipe rupture at Sequoyah. During the past year two new surveillance instructions had been issued to cover ultrasonic testing of localized areas in extraction steam lines as well as feedwater/condensate piping and turbine/heater drain lines. The inspector reviewed these instructions and also the results of an inspection program for Unit 2. Seventy pipe areas (in both single-and two-phase systems) had been examined for wall thinning by ultrasonic testing. Two areas on the condensate-feedwater lines and one area on the high pressure operating vent lines were found to have been damaged. Significant thinning was found downstream of the 12-inch feedwater valves. All of the damaged pipe sections were subsequently replaced.

The licensee was also trying to minimize general corrosion of carbon steel pipes by modifying AVT chemistry control to provide less acidic environments in both single and two-phase lines. Even though the secondary coolant system contains copper-containing components (condenser tubes and feedwater heater tubes) that are more conducive to corrosion at increased concentrations of ammonia, the licensee had increased the pH limits of the feedwater to 9.0-9.2. This action had further complicated the operation of the condensate polishers because the cation resins were being saturated (loaded) with ammonia more quickly and required regeneration more frequently. In an effort to achieve high pH levels in two-phase lines, such as extraction steam lines, as well as in water-solid lines the licensee's corporate chemistry group had initiated an investigation into use of morpholine as part of AVT chemistry control. Information reported by EPRI and individual utilities has shown that morpholine may provide increased control because of its greater solubility in the liquid phase of two-phase systems. The licensee is directing its study, in part, towards establishing the effect of morpholine on structural materials and ion exchange resins. This study will be tracked as IFI 50-327, 328/88-38-02, Feasibility of Using Morpholine for Secondary Chemistry Control.

(9) Conclusions

The cleanliness of the secondary coolant cycle at the end of the extended outage for Unit 2, as reflected by the short "chemistry holds" during startup, indicated that the wet layup procedures followed during the outage had been effective in minimizing corrosion. Likewise the integrity of the condenser had been maintained by circulating river water through the tubes throughout the outage. However, the chemical treatment program for the ERCW system had not been effective and continued to require priority attention. The approaching startup of Unit 1 will require the licensee to make a similar assessment of the effectiveness of a wet or drained layup program for two years followed by dry layup of the secondary coolant system during the last year. This subject will be designated IFI 50-328/88-38-03, Assessment of the Effectiveness of Unit 1 Layup.

The licensee was able to maintain chemistry control of both the primary and secondary coolant systems much more effectively than the criteria recommended by the SGOG and EPRI. However, because of past and potential design/materials problems (especially the use of copper alloy heat exchanger tubes) and transport of iron and copper corrosion products the licensee was continuing to devote considerable resources to protecting the steam generators. The additional need to minimize general corrosion and thinning of carbon steel pipe had placed constraints on plant design and operation, as well as chemistry control. Consequently, the licensee had taken the additional positive actions of replacing copper alloy components, and enhancing surveillance of the condenser, steam generator, and piping.

b. Effectiveness of the Licensee's Water Chemistry Program

During his last inspection in May 1987 (see Inspection Report Nos. 50-327/87-33 and 50-328/87-33), the inspector had observed that the Chemistry Group had undergone a major reorganization since the extended outage began. The new organization had begun a review and upgrade of the various elements of the Sequoyah Water Chemistry Program. However, the licensee had again completely reorganized the Chemistry Group during the past year. All of the managerial and supervisory positions had been filled with new personnel. The Chemistry Manager continued to report directly to the Plant Manager.

The Chemistry Group currently consisted of 58 personnel including a four-person Environmental Section, a 37-person Chemistry Section, an 11-person Technical Support Section, and a two-person Process Control Section. The Chemistry Section was further divided into three groups dedicated to analytical responsibilities (e.g., primary and secondary control, counting room work, and instrumentation specialists). The seven shift supervisors and 18 laboratory analysts under the Analytical Supervisor had been grouped into six rotating shift crews. Each crew had at least two ANSI qualified analysts in addition to an ANSI qualified shift supervisor. The two analytical chemists and two analysts under the Instrumentation Supervisor were experienced TVA chemistry employees who had been trained as specialists and dedicated to the state-of-the-art manually operated and in-line analytical instrumentation (e.g., ion chromatographs, atomic absorption spectrophotometer, and total organic carbon analyzer). The other analysts were being, or had been, qualified to perform the remaining analyses involved in primary and secondary chemistry (but not in counting room activities). A two-year training program, on-the-job and classroom, had been designed for this purpose.

In addition to the Technical Support Section within the Chemistry Group, the Sequoyah chemistry program was being supported by a recently organized corporate chemistry staff. This staff had been involved in the development of a corporate policy statement (ONP-POL-5.8) and a corporate directive (ONP-DIR-5.8) that established philosophy, directions, responsibilities, etc., for the chemistry programs for all TVA nuclear power plants. The inspector reviewed the implementing document for Sequoyah (Standard Practice SQE22 - Sequoyah Nuclear Plant Chemistry Program, Revision 10) and confirmed that the Sequoyah Water Chemistry Program endorsed the principal philosophical and technical guidelines recommended by the SGOG and EPRI. Consequently, this program was considered to meet the intent of Generic Letter 85-02. However, the inspector observed that procedure SQE22 had undergone six revisions during the last 18 months. Also a new corporate standard was being developed to provide further guidance for establishing an acceptable chemistry program at each TVA site. The inspector expressed concern that the continuing revamping of key elements of the Sequoyah Chemistry Program would delay development of a stable program and the type of chemistry control recommended by the SGOG. The licensee recognized this concern, but considered further changes as being necessary steps toward achieving an acceptable program.

As indicated by the appointment of a Process Control Supervisor, the licensee was emphasizing the need for quality control of all aspects of the chemistry program to meet the stringent criteria recommended by the SGOG (as well as by EPRI and the NSSS vendor, Westinghouse) to prevent corrosion. The inspector reviewed the elements of the chemistry quality control program with the process control supervisor and with other supervisory personnel. The inspector also requested that the chemistry staff analyze a series of samples prepared for the NRC by the Brookhaven National Laboratory. These samples were aqueous solutions of chemistry species typically monitored in PWRs. The purpose of this request was to make an independent evaluation of accuracy and precision and, where relevant, to identify causes for errors (i.e., procedure, instrument calibration, comprehension and technique of the analyst). The samples were analyzed in triplicate by three different analysts (where possible).

These analyses had not been completed at the end of the inspection; however, a preliminary assessment indicated that results obtained by ion chromatography were close to the values established by Brookhaven analysts. These data will be provided to the inspector when all analyses have been completed, and an assessment of the results will be issued in a later inspection report. This item will be tracked as IFI 50-327, 328/88-38-04, Evaluation of the Non-Radiological Confirmatory Measurement Results.

The inspector considered the environment within the chemistry laboratory to reflect a level of professionalism and housekeeping conducive to good analytical/process chemistry. The Chemistry Group was equipped with state-of-the-art analytical instrumentation. The inspector observed two specific conditions within the laboratory that were brought to the attention of the chemistry personnel. Both primary and secondary chemistry analyses were being performed within the limited space of a single laboratory, thereby reducing control of contamination by the radioactive primary samples. Similarly, the limited laboratory bench space was essentially covered with analytical instruments and left very little space for other activities, such as sample preparation. Especially on the day shift there were as many as five to ten personnel working in the restricted area of this laboratory.

Conclusion

During this part of the inspection no violations or deviations were identified. The licensee was considered to be satisfactorily implementing the major elements of the SGOG guidelines and to be abreast of current corrosion technology. The Chemistry Staff had controlled plant chemistry effectively during the startup of Unit 2. The inspector reemphasized the need for stability in staffing, continuing qualification and requalification of all personnel as individuals and as a cohesive team, increased emphasis on quality control, making more effective use of in-line instrumentation, and taking precautions to prevent contamination of the limited laboratory space.

3. Followup on NRC Information Notices (92701)

   a. (Closed) Information Notice 327,328/88-IN-22: Disposal of Sludge from Onsite Sewage Treatment Facilities. The inspector reviewed documentation which showed that the licensee had reviewed the Notice, acknowledged its applicability, and considered that the subject was not an immediate problem for the plant.

   b. (Closed) Information Notice 327,328/88-IN-31: Steam Generator Tube Rupture Analysis Deficiency. The inspector reviewed licensee documentation which showed that TVA had been notified of the problem described in the Information Notices by Westinghouse in December 1987. The licensee reanalyzed the Steam Generator Tube Rupture event, using conservative assumptions. As a result of this analysis, the licensee made a commitment to the NRC to institute an interim administrative limit of 0.75 microcuries per gram dose equivalent iodine in the primary coolant (Technical Specification limit was 1.0 microcuries per gram), and to notify NRC if the limit is exceeded.

4. Exit Interview

   The inspection scope and results were summarized on July 29, 1988, with those persons indicated in Paragraph 1. The inspector described the areas inspected and discussed in detail the inspection results. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.