UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-327/96-01 and 50-328/96-01

Licensee: Tennessee Valley Authority
6N 38A 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 Units 1 and 2

Inspection Conducted: January 7 through February 17, 1996

Lead Inspector: S. E. Sparks for 3/14/96
W. E. Holland, Senior Resident Inspector Date Signed

Inspectors: R. D. Starkey, Resident Inspector
D. A. Seymour, Resident Inspector
S. E. Sparks, Project Engineer, Paragraph 6.1
C. F. Smith, Reactor Inspector, Paragraph 4.2
G. T. MacDonald, Reactor Inspector, Paragraphs 3.4, 3.5, 3.6
R. L. Watkins, Resident Inspector, Paragraph 2.2
L. D. Wert, Senior Resident Inspector, Paragraph 2.2

Approved by: M S Lesser 3/14/96
Mark S. Lesser, Branch Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

Inspections were conducted by the resident and/or regional inspectors in the areas of plant operations, maintenance, engineering, plant support, and effectiveness of licensee controls in identifying, resolving and preventing problems. In addition, special reviews were conducted relating to the Updated Final Safety Analysis Report. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift and weekend activities at the plant.

Enclosure

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Results:

Plant Operations - Tagging evolutions related to a charging pump room cooler replacement were performed in a good manner (paragraph 2.4). The Plant Operations Review Committee activities were conducted in a good manner and were more thorough than observed during previous inspections (paragraph 2.7). Licensee management has developed and supported various initiatives to improve the overall safety performance of the facility (paragraph 6.1). Management demonstrated good initiative and involvement in improving plant performance by initiating a third party evaluation of the licensee's corrective action program (paragraph 6.2). The licensee's Nuclear Assurance organization continued to provide meaningful assessments of performance in operations, maintenance and other areas (paragraph 6.3). However, some non-licensed operators were not responding to in-plant annunciators properly (paragraph 2.2.2).

Maintenance - Good performance was observed during a review of radiation monitor maintenance involving the process for tracking the status of work orders (paragraph 3.1) and maintenance and temporary alteration activities associated with replacement of the 2B-B charging pump room cooler (paragraph 3.3). In addition, personnel performing a residual heat removal system quarterly test and an emergency diesel generator operability test were knowledgeable of the procedures and the surveillances were conducted in a good manner (paragraph 3.7). Weaker performance included: Activities associated with removal of a temporary alteration for Essential Raw Cooling Water (ERCW) pipe repair were not well controlled and indicated additional attention was needed in this area (paragraph 2.6). The licensee did not adequately plan the maintenance activity on diesel generator (DG) 2A-A to minimize Limiting Condition of Operation (LCO) ACTION statement entry time or to ensure that all scheduled maintenance was completed prior to running the DG operability test (paragraph 3.2). Maintenance associated with DG 2B-B appeared to be fragmented and not thoroughly coordinated (paragraph 3.5). Licensee evaluations of recent main feedpump steam supply check valve failures and main transformer sudden pressure relay failures were acceptable (paragraph 3.6.3). One non-cited violation was identified for failure to perform a Technical Specification required surveillance (paragraph 3.8).

Engineering - A lack of reliable control room ERCW pump house heat trace status and traveling screen differential levels placed additional burdens on operators in determination of ERCW system operational status. In addition, the ERCW chlorination system continued to experience operational problems (paragraph 2.6). The licensee's problem evaluation report investigations of the root causes of equipment failures were generally acceptable. Technical evaluations and tests/examinations performed to determine equipment failure were thorough and competently performed. The extent of condition investigation performed by the licensee was determined to be adequate; however, expeditious resolution of deficiencies was not demonstrated. A contributing factor was inadequate organization to organization interface between both internal and external TVA organizations (paragraph 4.2). Feedwater flow nozzle fouling was closely monitored by engineering during operation and conservative flow correction factors were added in power output calculations prior to any operational or safety limits being reached (paragraph 4.1).

Plant Support - Several housekeeping discrepancies were noted specifically in the ERCW pumping station and in the auxiliary building (paragraphs 2.2 and 2.6). Also, the licensee did not aggressively implement appropriate compensatory actions to prevent recurrence of a contamination event, although the eventual corrective action plan was satisfactory (paragraph 5.1). A review of radiation monitor outage time over 3 years concluded that although some monitors experienced long periods of inoperability, they were properly reported and compensated for (paragraph 5.2)

REPORT DETAILS

Acronyms used in this report are defined in paragraph 10.

1.0 PERSONS CONTACTED

Licensee Employees

*Adney, R., Site Vice President
*Baumstark, J., Plant Manager
Brock, D., Maintenance Manager
Bryant, L., Outage Manager
Burzynski, M., Engineering & Materials Manager
Clift, D., Planning and Technical Manager
Cooper, M., Technical Support Manager
*Driscoll, D., Nuclear Assurance & Licensing Manager
Fink, F., Business and Work Performance Manager
*Flippo, T., Site Support Manager
*Enterline, G., Operations Manager
*Kent, C., Radcon/Chemistry Manager
Lagergren, B., Manager of Projects
*Meade, K., Compliance Manager
Poage, L., Site Quality Assurance Manager
*Rausch, R. Maintenance and Modifications Manager
*Reynolds, J., Acting Operations Superintendent
Robertson, J., Independent Analysis Manager
Shell, R., Site Licensing Manager
Smith, J., Regulatory Licensing Manager
*Summy, J., Assistant Plant Manager

Nuclear Regulatory Commission Employees

Lesser, M., Chief, Branch 6, Division of Reactor Projects
*Holland, W., Senior Resident Inspector
*Seymour, D., Resident Inspector
*Starkey, R., Resident Inspector

* Attended exit interview.

Other licensee employees contacted included operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

2.0 PLANT OPERATIONS (71707 and 92901)

2.1 PLANT STATUS

Unit 1 began the inspection period in power operation. The unit operated at power for the duration of the inspection period.

Unit 2 began the inspection period in power operation. The unit operated at power for the duration of the inspection period.

2.2 DAILY INSPECTIONS

The inspectors conducted selective examinations on a day-to-day basis which involved control room tours, plant tours, and management meetings. The following activities were specifically reviewed:

GENERAL OPERATIONS OBSERVATIONS

The inspectors noted operations shift turnover briefings involved plant support organizations as well as engineering and maintenance, providing an effective forum for communication of plant status and coordination of daily plant activities. Control room traffic and activity were low, and the small number of alarms and annunciators provided a low level of distraction to the control room operators. However, the inspector noted that control room operators did not monitor control board indications rigorously (operators at the controls routinely had their backs to the control board panels for up to seven or eight minutes at a time.)

During extended control room tours the week of February 5, 1996, the inspector noted that control room operators seemed to be very involved in the completion of paperwork. The inspector noted that the operators did not spend as much time monitoring their panels as is typically observed. The operators (both the reactor operators and the senior reactor operators) seemed to be heavily occupied by substantial stacks of SIs and PIs. The inspector noted that the control room personnel consistently responded to annunciators, used repeat backs and were formal. The observations were discussed with operations management.

PLANT HOUSEKEEPING

During routine tours the week of January 29, 1996, the inspector noted room coolers for emergency core cooling system components maintained sufficiently low ambient temperature to preserve and protect vital equipment from heat-induced degradation. Auxiliary building ventilation/cooling systems also maintained a comfortable working environment for plant workers. Contamination zones were minimized in some areas (e.g., the RHR heat exchangers and containment spray heat exchangers) although the contamination zones of the emergency core cooling system pumps included the perimeter of the pump skids. The inspector noted the centrifugal charging pump 1B-B skid area contained a shallow accumulation of water, oil and debris, indicating some equipment leakage.

The small number of leaks and clean appearance of floors and some equipment indicated a conscientious effort in the area of general housekeeping. Specifically, the flooring in most of the radiologically controlled areas was painted and clean, and the RHR heat exchangers and containment spray heat exchangers, and associated piping, were insulated with minimal signs of boron, rust or corrosion. However, during routine tours the week of February 5, 1996, the inspector noted several housekeeping discrepancies. There was a substantial number of cigarette butts on the floor in the ERCW pumphouse. Handtools were "stored" on a beam in the auxiliary building. There was a number of hoses and electrical cords left in place after work activities were secured. In some cases, while the hoses or cords were removed, plastic tie wraps were left in place in locations such as instrument racks. The intake screens for the cabinet ventilation fans on several operating RMs were very dusty.

The inspector observed examples of poor housekeeping in the auxiliary building. These included: a metal bar, caution roping, and electrical cords on the 714' elevation mezzanine; folded lab coats, electrical cords, and pieces of rope, tape and string on the mezzanine in the 2B RHR/containment spray heat exchanger room. The inspector concluded that although housekeeping in most areas of the auxiliary building was generally good, less traveled areas were not kept as clean.

CONTROL OF PORTABLE LADDERS AND TEMPORARY PLATFORMS

During the week of January 29, 1996, the inspector noticed the pervasive use of step and extension ladders in the auxiliary building. Many ladders were used by operations as access to overhead areas for monitoring. The inspector identified several extension and step ladders stored around the auxiliary building without tags or restraints. In particular, an unrestrained, untagged step ladder was stored behind containment spray heat exchanger pressure and flow instrument racks. An unrestrained, untagged step ladder was erected in a corner of the 1B-B centrifugal charging pump room as well. The practice of storing and erecting ladders around safety-related or important-to-safety equipment without adequate controls reveals a lack of sensitivity to potential seismic events and the associated risk to plant systems and components.

During the week of February 5, 1996, the inspector noted a large number of ladders and temporary platforms present in the auxiliary building and reviewed the controls associated with these items. The inspector observed that some platforms had been in place over safety related equipment for extended periods. For example, the 2A-A MDAFW pump has had a platform over it since December 1994. Another platform was located above feedwater instrumentation labeled "unit trip hazard". The inspector reviewed SSP-7.55, GUIDELINES FOR THE ERECTION OF SCAFFOLDS AND LADDERS INCLUDING THOSE IN SEISMICALLY QUALIFIED STRUCTURES, Rev. 7. Several of the temporary platforms were examined by the inspector and verified to be in accordance with the SSP guidelines. On a few platforms, the inspector could not locate the required scaffolding tags, but licensee personnel subsequently located the tags and verified them to be properly completed. The inspector concluded that although there was a large number of temporary platforms in safety related areas of the plant, the platforms were constructed in accordance with the procedural guidelines and efforts were being made to monitor them.

Section 3.7 of SSP-7.55 specifically addressed the use of portable ladders. The inspector noted numerous examples in which the "In Use" tags mounted on the ladders were not completed. On some ladders the tags had been filled out a long time ago. Some ladders had tags which clearly indicated their purpose, while others did not. While no ladders were observed to be in danger of falling on safety related equipment, it appeared that the controls over the use of the ladders were not strong. There seemed to be some ladders in the plant that were unnecessary. These observations were discussed with plant management. No specific degradation of safety equipment was noted due to the ladders.

OBSERVATIONS IN RADWASTE CONTROL PANEL AREA

On February 7, the inspector entered the radwaste control panel area and noted that the high radiation annunciator was lit for the waste liquid monitor. The inspector was aware that an effluent release had been in progress. Discussion with the operators indicated that the alarm actuates as part of the initial setup of the RM in preparation of a release. It appeared that the alarm may have remained actuated throughout the release. The inspector noted that the annunciator panel labeling did not reflect the numbering in the Alarm Response Procedures. The procedure stated (among other requirements) that if the alarm actuated, the operator was to check the indicated effluent radiation level. The inspector noted that the local indicator was marked with a work order sticker indicating that it was not reading properly. The inspector also observed that many of the panel indicators in the room had work order tags on them. The inspector questioned how the operators responded to the alarm. These observations and the discussion indicated that some operators (AUOs) were not responding to in-plant annunciators properly. This specific incident was limited in safety significance since there are redundant indications and alarms in the MCR. These observations were discussed with operations management who indicated that the operator's actions did not meet management's expectations.

2.3 BIWEEKLY INSPECTIONS

The inspector conducted a biweekly inspection, using the licensee's Individual Plant Examination information, to verify operability of a selected Engineered Safety Features train.

Sequoyah's Individual Plant Examination's importance analysis of plant system failure modes to total core damage frequency lists the CCS system as a high contributor to core damage frequency in the event of CCS hardware failures.

The inspector reviewed 1-SI-OPS-070-032.A, COMPONENT COOLING WATER VALVES POSITION VERIFICATION TRAIN A, Revision 8. On February 13, 1996, the inspector performed a walkdown of selected portions of the CCS. The inspector verified that accessible valves were correctly positioned; that power was correctly removed from Appendix R valves by visual inspection of breaker positions; and that valves required to be throttled were appropriately tagged and sealed. The inspector visually inspected for housekeeping, adequate component labeling, WR tags, leakage, proper lubrication, and any other conditions which might prevent fulfillment of the CCS functional requirements. No deficiencies were identified during the walkdown and SI review.

Based on this review, the inspector concluded that the configuration of the CCS was satisfactory.

2.4 MONTHLY INSPECTIONS

During this period, the inspector reviewed the hold orders implemented to conduct maintenance for replacement of the Unit 2 B train charging pump room cooler. The inspection specifically focused on sequencing of the hold orders associated with electrical power for the cooler motor power supply. This power supply was used to provide power to the temporary cooling system during cooler replacement in accordance with the temporary alteration requirements.

Hold order 2-HO-96-0373 was used to electrically tag out the room cooler and connect the temporary fan in support of the temporary alteration. Hold order 2-HO-96-0461 was used to electrically tag out the temporary fan in support of the temporary alteration. Both hold orders were properly executed and sequenced as required by the maintenance activity. However, a minor discrepancy was noted on the clearance cover sheet for both hold orders. The temporary alteration referenced on the cover sheets for each hold order was the A train charging pump room temporary alternation instead of the B train charging pump room temporary alteration. This discrepancy did not affect performance of the actual hold order activities for the evolution reviewed.

The inspector concluded proper tagging evolutions were performed for this maintenance activity, and with the exception of the administrative discrepancy noted, the evolutions were conducted in a good manner.

2.5 TRIMONTHLY INSPECTIONS - REVIEW OF POSTING REQUIREMENTS

During the inspection period the inspector verified that the licensee was adhering to the posting requirements of 10 CFR 19.11 and 10 CFR 21.6. The inspector reviewed SSP-4.7, POSTING NRC NOTICES AND INFORMATION TO EMPLOYEES, Revision 3, which implements and establishes the requirements for posting licensing notices and documents in accordance with NRC requirements. Postings at Sequoyah are located at the Gatehouse entrance, two locations in the Engineering Complex, and at the Training Center.

The inspector reviewed the postings at the Gatehouse and the two postings at the Engineering Complex. The inspector also reviewed the results of the licensee's quarterly inspection of posted documents, dated December 19, 1995. This inspection was required by SSP-4.7. The inspector noted the licensee did not identify any deficiencies during the quarterly inspection.

The inspector determined that SSP-4.7 met the intent of the 10 CFR posting requirements, and that the posting locations inspected contained the required documents, or stated where the documents could be examined.

2.6 SEMI-ANNUAL INSPECTIONS - ENGINEERED SAFETY FEATURES SYSTEM WALKDOWN

During this period, the inspectors conducted an in-depth review of selected portions of the Essential Raw Cooling Water system. The inspection included a review of the UFSAR, TSs, system design requirements, and 10 CFR 50, Appendix A. In addition, system walkdowns were conducted using flow diagrams and verified lineup procedures; and discussions were held with the system engineer regarding areas with noted discrepancies.

On January 30, 1996, one of the inspectors performed a walkdown of the ERCW pumping station. Mechanical Flow Diagram CCD No. 1,2-47W845-5 was used as the reference document during the walkdown. The inspector observed several examples of poor housekeeping. These included improperly stored hoses and electrical extension cords, and trash on the pump room floors such as candy wrappers and pieces of 2x4 lumber. These observations were brought to the attention of the maintenance manager on January 31, 1996. Additional observations included a disconnected emergency battery powered light in Bay 1A which apparently had been inoperable since December 10, 1995, as indicated by a WR sticker C342801 which was attached to the light. Also noted was WR C270744, attached to a broken handwheel on valve 0-76-726B, the manual discharge isolation valve for ERCW pump M-B. The WR was dated February 20, 1995, which indicates the handwheel had been broken for approximately one year.

On February 5, 1996, the licensee entered the 72-hour Action Statement of LCO 3.7.4, Essential Raw Cooling Water System, when both B-train ERCW intake traveling screens became inoperable due to frozen discharge pressure sensing lines for screen wash pumps B-B and C-B. The traveling screens are designed to start when adequate discharge pressure is sensed at the discharge of the screen wash pumps. On this occasion, when the screen wash pumps were started, inadequate discharge pressure was sensed at the pressure switch, due to the frozen pressure sensing line, and the traveling screens would not start. Licensee investigation further identified that the sense lines had cracked or ruptured due to freezing. Subsequently the damaged sense line piping was replaced and the traveling screens were returned to service on February 6, 1996. Discussions with the licensee's technical support staff revealed that the cause of the sense line freezing was loss of continuity on one of the freeze protection circuits and incorrect setpoint adjustments on both of the failed heat tracing.

On February 8, one of the inspectors performed a walkdown of the control room indication, annunciation and control portion of the ERCW system. Two recent WR tags were attached to a flow and pressure indicator. Other observations included annunciation deficiencies associated with ERCW pump heat trace and ERCW traveling screen level differential indicators. The inspectors discussed these items with operators and were informed that the annunciation associated with ERCW pump heat trace was unreliable. In addition, the inspector noted that the level differential indicators were identified as being unreliable and not available to operators for use.

The inspectors reviewed the UFSAR relative to the ERCW traveling screen level differential indicators and determined that these instruments had been deleted from the UFSAR in the 1990 time frame. The inspectors reviewed the documentation supporting this deletion and determined that the instruments had been unreliable since installation. The actions taken by the licensee for this issue were to eliminate an automatic start condition for the screen wash pumps/traveling screens based on a level differential signal, to require operator actions to start the screen wash pumps/traveling screens in the event a condition existed that required operation of this system.

On February 16, the inspector discussed his observations with the system engineer. The system engineer provided additional information relating to traveling screen design. In addition, the engineer recommended that Sequoyah should obtain reliable, accurate instruments for traveling screen differential level indication as part of a response to PER No. SQ950050PER in March of 1995. When the inspection period ended, Sequoyah had not decided on a final course of action for this issue.

During the week of January 29, 1996, one of the inspectors performed a walkdown of selected portions of accessible ERCW components located in the auxiliary building. Mechanical Flow Diagrams CCD No. 2-47W845-4, 1,2-47W845-2, and 1,2-47W803-2 were used as reference documents during the walkdown.

On February 14, one of the inspectors performed a walkdown of accessible portions of the ERCW system located in the diesel generator building. Equipment appeared to be in good condition. During the walkdown, the inspector observed maintenance activities associated with replacement of a section of ERCW piping in the 2A-A emergency diesel generator room. The piping was being replaced due to through-wall leakage caused by erosion. The inspector noted a temporary alteration (metal pipe jacket) installed on an ERCW line in the 2B-B emergency diesel generator room. The inspector reviewed the temporary alteration documentation in the control room and determined that the same temporary alteration applied to the section of pipe being removed from the 2A-A DG ERCW line as well as the 2B-B DG ERCW line. The inspector questioned the licensee concerning the adequacy of control of the temporary alteration. The licensee reviewed the issue and determined that proper control did not exist between the temporary alteration being removed on the 2A-A DG ERCW line and the work order replacing the degraded pipe. The inspector judged that this does not represent a regulatory issue. PER No. SQ960328PER was written describing the deficiencies. Licensee maintenance management discussed these deficiencies with the inspector on February 16, 1996.

During this inspection, the inspectors noted continuing problems with the ERCW chlorination system. Only two out of four chlorination headers were operable due to leaks within the chlorination piping. The inspectors were briefed by the Chemistry Manager and the ERCW system engineer concerning the ERCW chlorination system. The licensee stated that parts of the ERCW chlorination system piping had deteriorated and that plans were being developed to either replace or repair the chlorination system. The inspectors consider that the ERCW chlorination system was receiving attention; however, actions to date have not made the system reliable.

The inspectors concluded that the ERCW system was being maintained in a manner that supported plant operation, controlled drawings accurately depicted the system configurations, and system lineups were as required for the current mode of operation. In addition, lack of reliable control room indication associated with ERCW pump house heat trace status and traveling screen differential levels placed additional burdens on operators in determination of system operational status. Also the ERCW chlorination system continued to experience operational problems, and activities associated with removal of a temporary alteration for a ERCW pipe repair were not well controlled and indicated additional attention was needed in this area.

2.7 EFFECTIVENESS OF LICENSEE CONTROLS

The inspector attended the PORC meeting which was held on January 18, 1996. The PORC reviewed two temporary alterations associated with replacement of the Unit 2 charging pump room coolers. The temporary alterations installed a replacement cooling system for the period of time that the maintenance/modification activity was in progress. This activity is discussed in paragraph 3.3.

The inspector noted the PORC review was thorough and that the committee asked several questions of the presenter associated with the alteration. Examples included assurances that the work process would minimize LCO ACTION time, additional review to address potential over cooling, and review of additional applicable procedures affected. Approval of the temporary alterations was deferred until the PORC questions were addressed.

The inspectors concluded PORC activities were conducted in a good manner. The thoroughness of the review was better than observations from previous inspections in this area.

2.8 LICENSEE NUCLEAR REGULATORY COMMISSION NOTIFICATIONS

On February 2, 1996, the licensee made a call to the NRC as required by 10 CFR 50.72. The issue involved notification to the plant that greater than 30 percent of the emergency sirens in Sequoyah's 10 mile emergency preparedness zone were without power. The cause of the loss of power was due to weather related heavy icing conditions on power lines due to freezing rain in the vicinity of the plant.

2.9 FOLLOWUP REVIEW

(Closed) LER 50-328/95-05, Closure of the 2A-A Safety Injection Pump Suction Valve Placed the Unit in Limiting Condition for Operation 3.0.3. The issue involved the closure of the 2A-A SIP suction valve and both cross-tie valves for maintenance activity on the pump, which placed the unit in LCO ACTION 3.0.3, because portions of both trains of ECCS were made inoperable. The closure of these valves resulted in the isolation of the suction path to the centrifugal charging pumps from the B-train RHR pump for containment sump recirculation operation. The design basis of the ECCS system is to provide two independent trains of ECCS for accident mitigation. This condition was identified by operations personnel and existed for approximately 2½ hours before the safety injection system was returned to its normal standby alignment. The licensee determined that the root cause of the event was the failure of plant personnel to recognize the inter-dependency of the system design relative to TS compliance. A contributing factor was that the system design and inter-dependence were not adequately included in design documents or training material.

The inspector reviewed the following licensee corrective actions: Caution Orders were placed on Units 1 & 2 2A-A safety injection pump suction valves and the associated cross-tie valves stating that closure of the valves at power would render both trains of ECCS inoperable. Permanent labels subsequently replaced the caution orders. Operator training was revised to address the inter-dependency of the system design. A review of other system configurations was performed to determine if other system inter-dependency existed which had not been previously addressed. As a result of that review and as an interim measure, Standing Order 96-005 was written which listed the results of the system inter-dependency review and stated that an SRO should evaluate whether valve operation would result in TS 3.0.3 entry. Labels, which will accomplish the long term solution of identifying inter-dependency valves, were ordered and will be attached to each identified device with a notice as to the possible effect on plant operation. Finally, the UFSAR was revised to note the effect on both trains of ECCS of closing the A-train safety injection pump suction isolation valve.

Within the areas inspected, no violations were identified.

3.0 MAINTENANCE OBSERVATIONS (62703, 61726, and 92902)

During the reporting period, the inspectors verified by observations, reviews, and personnel interviews, that the licensee's maintenance activities resulted in reliable operation of plant safety systems and components, and were performed in accordance with regulatory requirements. Inspection areas included the following:

3.1 REVIEW OF MAINTENANCE HISTORY ON SELECTED RADIATION MONITORS

During this inspection period, as part of a monitor operability review (see paragraph 5.2), the inspector selected six RMs and reviewed their maintenance history for the three-year period from 1993 through 1995. A total of approximately 180 WR histories were reviewed. The six RMs reviewed are listed below.

- 0-RE-90-101, Auxiliary Building Exhaust
- 1-RE-90-106, Lower Containment Airborne
- 2-RE-90-106, Lower Containment Airborne
- 1-RE-90-112, Upper Containment Airborne
- 2-RE-90-112, Upper Containment Airborne
- 0-RE-90-122, Radwaste Discharge

Specifically, the inspector reviewed the status of each WR as it progressed from its initiation to its completion. Status codes, which are updated as the status of the WR changes, are assigned to each WR. There are a total of 76 status codes available for use by the licensee's work scheduling group. Each WR history reviewed appeared to be adequately tracked from its initiation to its eventual completion.

The inspector concluded that the licensee's process for tracking the status of WRs was effective.

3.2 REVIEW OF LCO ACTION ENTRIES DURING DG MAINTENANCE

On January 19, 1996, the inspector noted, while reviewing Unit 2 UO logs, that TS LCO ACTION Statement 3.8.1.1.b, Electrical Power Systems- A.C. Sources, had been entered and exited five times between 4:46 a.m., on January 17 and 10:47 a.m., on January 19, for scheduled maintenance activities on DG 2A-A. Three ACTION Statement entries were made after operators had declared DG 2A-A operable upon the completion of 2-SI-OPS-082-007.A, ELECTRICAL POWER SYSTEM DIESEL GENERATOR 2A-A, Revision 9, on January 17. One of the three ACTION Statements was entered for approximately 21 hours and involved a scheduled battery discharge test.

The inspector discussed the multiple TS entries with licensed operators who were concerned that there was a lack of coordination when the maintenance activities were planned for DG 2A-A. Operations personnel initiated PER No. SQ950093PER to document their concern with the work planning process as it related to this scheduled maintenance on DG 2A-A. The inspector also discussed these multiple TS ACTION Statement entries with Work Planning personnel and was informed that the activities which necessitated the ACTION Statement entries were planned evolutions and appeared as such on the 12-week rolling schedule.

The inspector concluded that, in the above example, the licensee did not adequately plan the maintenance activity on DG 2A-A to minimize LCO ACTION statement entry time or to ensure that all scheduled maintenance was completed prior to running the DG operability test. The inspector was informed that the licensee has developed an action plan, dated February 15, 1996, and signed by the plant manager, which addressed the issue of equipment unavailability and actions to be taken when entering LCO ACTION statements of 72 hours or less.

3.3 REVIEW OF 2B-B CHARGING PUMP ROOM COOLER MAINTENANCE

During the week of January 21 through 26, 1996, the inspectors reviewed the licensee's change out of a leaking charging pump room cooler with a new cooler. The activity involved installation of a temporary cooling system during the maintenance process. The temporary cooling system was installed in accordance with the licensee's temporary alteration process. The activity was implemented 24 hours a day until completed on January 25, 1996.

The inspectors reviewed documentation for the change out of the Unit 2, B train charging pump cooler coil including:

- Hold orders associated with the maintenance (paragraph 2.4)
- PORC review of the temporary alteration (paragraph 2.7)
- Work Order 95-14643-03 which documented replacement of the 2B-B charging pump room cooler coil
- Temporary Alteration Control Form 2-96-0001-030 which provided controls and justification for installation of the temporary cooling system for the charging pump room

The inspectors determined that the maintenance activities accomplished on the 2B-B charging pump room cooler coil replacement, including sequencing and control of the temporary cooling system, were accomplished in a good manner. In addition the documentation linkage between the work evolutions and the temporary alteration was clear. However, some minor discrepancies were noted in the documentation which did not affect overall job performance. The inspectors also observed discrepancies during field observations of the maintenance activity. Examples included inappropriate securing of staged equipment in the charging pump room and craft not following personnel safety requirements. These items were discussed with maintenance management and engineering personnel on February 8, 1996.

Coordination of activities was good and documentation was clear and easy to follow. Also, replacement of the Unit 2 charging pump room cooler coils addressed a long standing housekeeping problem associated with leaking coolers in these rooms and improved the material condition of this equipment. However, the discrepancies noted in documentation and in the field identified room for additional improvement in maintenance activities.

3.4 HANDSWITCH TROUBLESHOOTING

The inspector observed maintenance performed by the FIN team on WR C325891. The maintenance consisted of troubleshooting the control circuit of motor operated valve 1-FCV-63-157 which failed to actuate during surveillance testing on January 22, 1996. Surveillance testing was done per procedure 1-SI-SXV-000-201.0, FULL STROKING OF CATEGORY "A" AND "B" VALVES DURING OPERATION, Rev. 0. Valve 1-FCV-63-157 is the hot leg injection valve for the B train safety injection pump. The work order contained an adequate troubleshooting plan which considered all elements in the control circuit. The FIN team identified the cause as high resistance (40 ohms) on contacts in the control room handswitch 1-HS-63-157A. The switch was removed and the contact resistance was checked while operating the switch. The resistance across the contacts, after switch cycling, dropped to less than 1 ohm and remained at that value for 10 switch cycle resistance measurements. The licensee reinstalled the switch and reperformed the applicable sections of 1-SI-SXV-000-210.0 as PMT. The inspector observed the PMT and verified that the valve met the stroke time acceptance criteria. The licensee wrote PER No. SQ960112PER to document the failure of the switch to actuate 1-FCV-63-157.

The licensee identified that the handswitch was a Westinghouse model OT2 switch. This is a sealed type switch. Review of maintenance history identified one other failure of a model OT2 handswitch which was documented on PER No. SQ951531PER. This switch failure was determined to be associated with aging. The failure of 1-FCV-63-157 to operate during surveillance testing due to the high resistance of the OT2 switch contacts represents a second example of a model OT2 switch failure. The inspector will review the PER generated on the 1-FCV-63-157 failure and review corrective actions to determine if there is a generic aging related deficiency with model OT2 handswitches. Also, the licensee's failure trending system will be reviewed to determine how this issue is addressed. This issue is identified as IFI 50-327, 328/96-01-01, Followup on OT2 handswitch failures. Licensee maintenance activities observed on the FIN team troubleshooting of valve 1-FCV-63-157 were acceptable.

3.5 DIESEL GENERATOR MAINTENANCE AND TROUBLESHOOTING

The inspector reviewed the maintenance activities associated with a planned LCO outage on the DG 2B-B. The activities consisted primarily of flex hose replacements, relay replacements, pressure switch replacements, and instrument calibration. The activities were scheduled to be completed in approximately one half of the available LCO ACTION time of 72 hours. The LCO ACTION was entered at 00:09 a.m., on January 23, 1996.

Mechanical maintenance activities for flex hose fabrication and replacement were observed. The evolution was well controlled and accomplished; however, one minor discrepancy was noted between the work order and the work performed. The work order called for the fabricated hoses to be blown out and sealed with lint free rags and tape. The hoses were sealed with tape only. Upon discussion with the licensee maintenance personnel, it was evident that maintenance had decided that the lint free rags were not appropriate and would not be used. This demonstrated an example of maintenance questioning a work order requirement and working around it rather than revising the work order during the review process or prior to performing the work. Maintenance planning personnel subsequently changed the work order to match the work performed.

Several Barksdale pressure switch replacement and calibration activities were observed and were considered good.

Upon completion of maintenance, DG 2B-B was scheduled to be run for PMT checks on several of the maintenance activities. The DG was to be operated per 2-SI-OPS-082-007.B, ELECTRICAL POWER SYSTEM DIESEL GENERATOR 2B-B, Revision 8. On January 25, 1996, the DG was started with the 2B1 engine air start system and was operated unloaded. DG 2B-B was then started with the 2B2 engine air start system. At 7:53 a.m. on January 25, 1996, the DG 2B-B breaker was closed in parallel with the grid and the operator began loading the DG with handswitch 0-HS-82-103 per procedure 2-SI-OPS-082-007.B. At 3600 kW the operator released 0-HS-82-103 from the raise position and the load continued to increase. Attempts to reduce loading with the handswitch were unsuccessful and the operator shutdown DG 2B-B with the emergency stop push button. During the event, the DG load reached 5300 kW. The load exceeded the 4400 kW DG continuous duty rating for a period less than 5 seconds. The licensee concluded that the short term overload conditions did not damage the DG.

Subsequent to the event, the licensee obtained statements from involved personnel and quarantined the area to preserve the status of plant configuration data during the event. These initial efforts were good. At 11:30 a.m., on January 25, 1996, an initial troubleshooting list was developed and work responsibilities were assigned. Initial troubleshooting efforts concentrated on control circuit components, not the electronic governor.

Parallel with the initial troubleshooting effort, another troubleshooting WR was prepared to investigate the electronic governor and DG controls with the engine running. Approximately 8:20 p.m., on January 25, 1996, the licensee started DG 2B-B and began work on the second troubleshooting effort. DG operation was carefully controlled during this evolution using the mechanical governor to help prevent overspeed. The initial engine operation did not exhibit the unstable loading when observed from no load up to approximately 2200 kW.

The DG and governor vendors were contacted. Discussions with these vendor representatives and analysis of observations and measured data indicated that the electronic governor gain and reset settings were not optimized. Additionally, the motor driven potentiometer used for control in droop mode exhibited erratic performance. The licensee readjusted the governor gain and reset settings. A subsequent DG start and load run demonstrated that the engine load response was improved with the new settings. The governor gain and reset settings affect DG control in both the droop (parallel operation) and isochronous (accident) modes. A PMT to verify proper DG load response in accident mode could not be prepared in the remaining LCO ACTION time. The original settings were verified by operability testing after the governor modification to the DG 2B-B in October, 1994. The licensee returned the 2B-B electronic governor gain and reset settings to the original values to return the DG control to the configuration which met the October 1994 operability test. The licensee determined that the loading handswitch circuit exhibited slow response during testing, and provided appropriate guidance to operators.

The inspector witnessed portions of the troubleshooting activities. The electronic governor gain and reset setting on all four DG governors was observed after the DG 2B-B governor adjustments and they were close.

During observations of the troubleshooting activities, the inspector determined that the work appeared to be fragmented and not thoroughly coordinated by management. Significant senior management involvement was not evident until late in the LCO ACTION time frame. It appeared that availability for certain parts were not checked until late on the evening of January 25, 1996, with approximately 24 hours left in the LCO, while the potential causes were identified approximately eight hours earlier. The inspector considered that some of these activities could have been accomplished in parallel for maintenance which is under TS LCO ACTION constraints. Management and work activity controls did not appear as well coordinated as would be expected for an LCO maintenance activity.

The inspector concluded DG 2B-B maintenance during the LCO ACTION was good; however, the troubleshooting efforts following the DG load control problem appeared to be fragmented and not thoroughly coordinated.

3.6 EFFECTIVENESS OF LICENSEE CONTROLS

During this period, the inspectors evaluated the effectiveness of the licensee's controls in identifying, resolving, and preventing problems in the area of maintenance.

3.6.1 REVIEW OF FAILURE OF MAIN FEED PUMP STEAM SUPPLY CHECK VALVE

The inspectors reviewed PER No. SQ950619PER which documented a failure of a main feed pump low pressure steam supply check valve. NRC Inspection Report 50-327,328/95-15 described this component failure and indicated that the licensee's failure evaluation would be reviewed. The inspectors reviewed the failure evaluation and concluded that the evaluation was adequate. The licensee concluded that the valve was oversized and in a turbulent flow configuration which caused the disc post/nut to impinge on the valve stop and wear until failure.

3.6.2 REVIEW OF LICENSEE EVALUATION FOR SUDDEN PRESSURE RELAY FAILURE

The inspectors reviewed licensee activities related to sudden pressure relay actuation on 'A' phase of Unit 1 main bank transformer. This issue was described in NRC Inspection Report 50-327,328/95-16 and LER 50-327/95-10. The inspectors reviewed the licensee's evaluation of the sudden pressure relays and concluded that the evaluation was thorough. The licensee developed a team to evaluate sudden pressure relay performance and the evaluation included testing to determine relay performance. The team's final report was not complete; however, the licensee indicated that the apparent cause was relay bellows deformation due to overpressurization with the relay isolated during transformer maintenance activities. This was a result of a poor work practice. The inspector considered the licensee's evaluation acceptable.

3.7 SURVEILLANCE REVIEWS

During the reporting period, the inspectors ascertained, by direct observation of licensee activities, whether surveillances of safety significant systems and components were being conducted in accordance with TSs and other requirements. The inspection included a review of the following procedures and observation of surveillances:

3.7.1 REVIEW OF RESIDUAL HEAT REMOVAL PUMP 1B-B TESTING

On January 11, 1996, the inspector observed performance of 1-SI-SXP-074-210.B, RESIDUAL HEAT REMOVAL PUMP 1B-B PERFORMANCE TEST, Revision 0, and reviewed the SI upon the successful completion of the test. This SI was being used for the first time and replaced 1-SI-SXP-074-128.B which had previously been used to meet the ASME/ANSI Section XI requirements. The inspector discussed the SI with the AUOs performing the test and the system engineer who was observing the test and recording system operating data.

3.7.2 REVIEW OF DIESEL GENERATOR 2B-B TESTING

On January 26, 1996, the inspector observed performance of 2-SI-OPS-082-007.B, ELECTRICAL POWER SYSTEM DIESEL GENERATOR 2B-B, Revision 8, and reviewed the SI upon successful completion of the test. The inspector noted fuel oil pressure exceeded the limit stated in Appendix B of the procedure by 1 psig, and the overvoltage relay annunciation came in (locally) on DG start up. A test deficiency was written for the fuel oil pressure (a non-TS item). WR C-329318 was written to correct the problem during the next DG outage. The inspector determined the overvoltage relay annunciation was an expected alarm upon DG startup.

3.7.3 SURVEILLANCE REVIEW CONCLUSIONS

The inspectors concluded the personnel performing the tests were knowledgeable of the procedures and that the surveillances were conducted in a good manner.

3.8 FOLLOWUP REVIEWS

(Closed) LER 50-327/95-13, Missed Surveillance During Mode 6. The issue involved two Mode 6 TS surveillance requirements which were not met on October 10, 1995, due to inadequate training of licensed operators in the use of the 12-week schedule. Surveillance requirement 4.9.2

required that each source range neutron flux monitor be channel checked once every 12 hours. Surveillance requirement 4.9.8.1 required that at least one RHR loop has a flow rate of greater than or equal to 2000 gpm verified at least once every 12 hours. Neither of the two surveillances was completed within the allowed 12 hour period.

Several days prior to October 10, when the SI packages were assembled, the schedule indicated that Unit 1 would be in Mode 5, rather than Mode 6, on the midnight shift of October 10, 1995. Therefore, a Mode 6 SI package was not prepared and sent to the control room for performance. Operations personnel did not realize that the SI package was not delivered to the control room and the SRO failed to correctly read the updated 12-week schedule which showed that the SI was required to be performed on the midnight shift for October 10.

The inspector verified that the licensee initiated the following corrective actions. The operator-at-the-controls shift periodic instructions were revised to provide a more comprehensive list of routine daily and shiftly surveillances. A required reading memorandum was issued for licensed operators to (1) inform them of the correct methodology to be used in reading the 12-week schedule, (2) emphasize that the 12-week schedule is the definitive source for determining the surveillances required to be performed on a shift, and (3) emphasize the importance of verifying surveillances received from the Technical Information Center prior to performance. Finally, the licensee has begun an evaluation of the overall surveillance process and will submit recommendations to licensee management early in 1996.

Failure to perform TS surveillance requirements 4.9.2 and 4.9.8.1 on October 10, 1995, is a violation of TSs. This licensee-identified and corrected violation is being treated as a non-cited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This item is identified as NCV 50-327/96-01-02, Failure to Perform the Surveillance Requirements of TSs 4.9.2 and 4.9.8.1.

Within the areas inspected, one IFI and one NCV were identified.

4.0 ENGINEERING (37551 and 92903)

During the reporting period, the inspectors conducted periodic engineering evaluations for regional assessment of the effectiveness of the onsite engineering staff. The inspection included a review of the following activities:

4.1 REVIEW OF COPPER FOULING ON SECONDARY SYSTEM INSTRUMENTATION

During this period, the inspector reviewed the effects of copper fouling on secondary system flow instrumentation. The inspector noted that during the U1C7 outage, chemical cleaning and sludge lancing of the SGs resulted in approximately 550 pounds of copper being removed from each SG. The inspector discussed the effect of copper fouling in the secondary system with plant chemistry personnel, system engineering personnel, and reviewed the current procedure for conducting calorimetric calculations. The licensee currently has copper tubes in both the Unit 1 and Unit 2 main condensers. Copper fouling of feedwater flow instruments is a condition which occurs during operation. The most important flow instrumentation subject to copper fouling is the feedwater flow nozzles. These instruments are used to measure power output by performance of calorimetric calculations. The licensee's procedure corrects for any feedwater flow errors due to flow instrument fouling by monitoring parameters for change during operation. If a change is noted, then correction factors are introduced into the licensee's calculations to assure that maximum power levels are not exceeded.

The inspector noted the licensee is scheduled to retube the main condensers with titanium tubes during each unit's next outage (Unit 2 - spring of 1996; Unit 1 - spring of 1997). These actions should essentially remove all copper components from the secondary system. After each condenser is retubed, the licensee plans on using chemicals to remove residual copper from the secondary systems. Completion of these activities should essentially remove the source of copper fouling.

The inspector reviewed 0-PI-SXX-000-022.0, CALORIMETRIC CALCULATIONS, Revision 7, and determined that appropriate steps were included to calculate a feedwater flowrate using equipment other than the feedwater flow nozzle outputs. Then correction factors were included in the procedure to assure conservative flow values are included in the calculations.

Based on the reviews, the inspector determined the feedwater flow nozzles experience copper fouling during current operational cycles. However, the fouling is closely monitored by engineering during operation, and conservative flow correction factors are added in power output calculations prior to any operational or safety limits being reached.

4.2 EFFECTIVENESS OF LICENSEE CONTROLS

During this period, the inspectors evaluated the effectiveness of the licensee's controls in identifying, resolving, and preventing problems in the area of Engineering. Four PERs were selected for review during this inspection. The PERs were analyzed in detail to determine the licensee's effectiveness in performing the following:

- Initial identification and characterization of the problem
- Elevation of problems to proper level of management for resolution
- Root cause analysis
- Disposition of any operability/reportability issues

- Implementation of corrective action including evaluation of repetitive conditions

- Expansion of the scope of corrective actions to include applicable related systems, equipment, procedures, and personnel actions

REVIEW OF CAUSE OF UNIT 1 REACTOR TRIP ON DECEMBER 8, 1995

On December 8, 1995, a manual trip was initiated on Unit 1 because of a loss of level control on SG#4. The loss of level control was due to a broken line in the control air supply to the number 4 feedwater regulating valve. PER No. SQ952227PER was written to document the equipment failure and to initiate an investigation of the event. Based on discussions with the licensee's engineering personnel and review of Work Order 95-01701-00, dated March 22, 1995, the inspector determined that SG#4 inlet control valve 1-FCV-003-0103, had been modified by maintenance with the installation of quick disconnect test fittings. The issue of whether or not this plant modification was permissible under the approved ANSI N45.2.11-1974 design control program was reviewed by the inspector. The following approved design output documents were reviewed during this effort:

- Design Criteria SQN-DC-V-32.0, Auxiliary Control Air System

- Project Engineering Specification No. N2E-884, Instrument and Instrument Line Installation and Inspection, Revision 1

- Drawing No. CCD 1-47W600-123, Mechanical Instruments and Control, Revision 0

- Drawing No. CCD 1-47W600-192, Mechanical Instruments and Controls, Revision 5

- Drawing No. 47W600-1, Sequoyah Nuclear Plant Units 1 and 2 Instrument and Control, Piping Bill of Material, Sheets 6,9,18,19, and 55

Based on the above review, the inspector concluded that the requirements of Engineering Specification N2E-884, paragraph 3.2.25.1 for installing test tees and quick disconnects in non-seismic instrument lines were acceptable. The extent of condition investigation performed by the licensee was also determined to be adequate. The root causes were identified as inadequate function and inadequate scope because neither vibration nor vibrational effects were considered in the work planning process. A significant contributing factor was identified in the use of close nipples, which was at one time acceptable. Close nipples are for connecting the air lines to the valve positioner, and use is now prohibited by Engineering Specification N2E-884 and Procedure MAI-24, INSTALLATION, INSPECTION, AND DOCUMENTATION OF INSTRUMENT FEATURES, Revision 6. The corrective action plan developed for this issue was reviewed and determined to be acceptable with the following exception.

The inspector determined that a significant contributing factor was inadequate organization to organization interface between nuclear engineering and maintenance in that Engineering Specification N2E-884 failed to clearly identify the conditions under which paragraph 3.2.25.1 may be implemented. Specifically, it failed to identify a new failure mode that may be introduced during implementation of this requirement. The inspector discussed this issue with TVA management who concurred with the inspection finding. It was the inspector's understanding that the scope of the corrective actions will be expanded to include this root cause to ensure adequate recurrence control.

REVIEW OF UNIT 1 EXCITER PROBLEMS

On November 27, 1995, at approximately 1:40 p.m., intermittent swings were observed by the operators on secondary plant instrumentation channels. Operations also noticed slight swings in two BOP raw water controllers, a slight modulation open of loops 2 and 3 atmospheric reliefs, and red and green lights on all six MSR steam valves. Power was reduced to less than fifty percent, the turbine-generator was tripped, and the reactor was stabilized at approximately one percent power. All perturbations stopped when the exciter breaker was opened. PER No. SQ952152PER was written to document and initiate investigation of this event.

The inspector reviewed PER No. SQ952152PER and determined that a final report of the investigation results had not yet been completed. Two requests for extending the due dates for development of the corrective actions were made and were approved by station management. The first extension changed the due date from December 28, 1995 to January 18, 1996, with the second extension changing the due date from January 18, 1996 to February 2, 1996. Discussions with TVA engineering personnel and review of the inprocess document revealed that the exciter failure was caused by grounding of a manufacturer supplied jumper cable on a current limiting resistor support. A second ground, later identified on the #9 pole winding, completed the circuit for a ground fault of the excitation system. Corrective actions documented on the PER for restart of the unit were reviewed and determined to have been acceptable.

PER No. SQ952333PER was written to document a manual reactor trip of Unit 1 on December 25, 1995, because of meter indications that showed main generator electrical megawatts fluctuating from 100 to 150 MWE. Subsequent inspections of the generator exciter field revealed that there was a hard ground on exciter pole #7. A second ground was also determined to have been established by a short in cable 1G637 that was routed from the voltage regulator cubicle to the MCR voltmeter on panel 1M1.

TVA identified the cause for the coil failures to be related to coil insulation design and workmanship. The coil from the November 27, 1995 failure (pole #9), will be tested and evaluated for the failure mode by Altran Material Engineering Inc. Additionally, the coil from the December 25, 1995 failure (pole #7), will be tested and evaluated by

Westinghouse for the failure mechanism. Westinghouse also has six other coils which will be tested and examined for evidence of the various potential causes of failure. Reports documenting the findings of these tests and examinations are due from Altran on January 26, 1996, and from Westinghouse on February 2, 1996.

The inspector reviewed PER No. SQ952333PER and determined that the licensee is adequately pursuing investigations/tests to identify the failure mechanism for the excitation system failures, with the following exception. A significant contributing root cause involving organization to organization interface deficiencies between TVA and Westinghouse was not addressed in the PER. The deficiencies involved procurement inadequacies related to a lack of program controls for evaluating the design/refurbishment of the Unit 2 exciter. TVA was informed of the inspector's observations and acquiesced in the inspection finding.

REVIEW OF UNIT 1 PSRV LEAKAGE DURING STARTUP

PER No. SQ952057PER documented a problem with an Unit 1 PSRV which began to leak during startup following the U1C7 RFO. The inspector reviewed the PER and determined that PSRV leakage (startup and in-service) had been a recurring problem at Sequoyah. The licensee has implemented several hardware and administrative changes since the 1988 restart in an attempt to correct the problem. However, none of the implemented corrective actions have corrected the PSRV leaks. The root causes determination and recurrence controls delineated in the PER did not demonstrate final resolution of this problem. Additionally, a request for an extension of the due date for developing corrective actions for this issue was made and approved by plant management. The original due date of December 14, 1995, was changed to January 19, 1996. At the time of the inspection the developed corrective actions were still not available despite the due date having been passed.

CONCLUSION

The inspector concluded that the PERs reviewed generally demonstrated adequate root cause analysis. Technical evaluations and tests/examinations performed to determine equipment failure were thorough and competently performed. However, expeditious resolution of deficiencies were not demonstrated and significant contributors to root causes involving organization to organization interface inadequacies were not included in the PERs. The interfaces were both internal and external to TVA. Additionally, some requests for extension of the due dates for developed corrective actions indicated weak commitment for expeditious resolution of some equipment problems.

4.3 FOLLOWUP REVIEWS

(CLOSED) IFI 50-327, 328/94-25-01, Resolution of the Opening of Unit 1 Containment Vacuum Relief Valve Initiated by an ABI on Unit 2. The issue involved a review of the licensee's long term corrective action plan to prevent opening of containment vacuum relief valve during an ABI.

On February 8, 1996, the inspector attended briefings related to and observed portions of the performance of STI-154, EFFECT OF ANNULUS VACUUM FANS ON ABSCE, Revision 0. The objective of the test was to collect data concerning the ability of the Auxiliary Building Gas Treatment System to maintain the auxiliary building secondary containment enclosure at a negative pressure of -0.25 inches water gage or greater while both annulus vacuum fans were discharging air into the ducting on the suction side of the ABGTS fans. The purpose also was to determine if the annulus vacuum system could maintain the annulus at a negative pressure of -5.0 inches water gage concurrent with an ABI. The test attempted to accomplish this while blocking open one of two ABI dampers (2-FCV-030-055 or 2-FCV-030-049). Based upon the results of the STI, a permanent plant change would be implemented to block open the two dampers which would then allow annulus vacuum to be maintained following an ABI.

STI-154 was performed as part of the corrective action to PER No. SQ940505PER which identified a condition where the containment vacuum relief valves (1,2-VLV-030-571,572,573) may open upon loss of the normal annulus negative pressure of -5.0 inches of water gauge. This would occur when the annulus pressure exceeds the containment pressure and the resulting pressure differential is greater than the vacuum relief valve setpoint. Any condition that results in loss of annulus vacuum can potentially result in the vacuum relief valves opening.

The STI was successful and it provided data which supported the plant modification to permanently block open ABI dampers 2-FCV-030-055 and 2-FCV-030-049. The results of the STI will be presented to PORC for review. Based upon inspector review of STI-154, direct observation of the STI by the inspector and discussion of the test results with the system engineer, this item is considered closed.

(CLOSED) URI 50-327,328/95-04-01, Resolution of Unit 1 RHR Water Hammer Event. This issue involved an apparent water hammer event on the Unit 1 RHR system. Background for the event was discussed in inspection reports 50-327,328/95-04, 95-06 and 95-12.

The inspector reviewed the licensee's engineering evaluation which included the civil engineering evaluation concerning the qualification of piping, components, equipment and supports and the ECCS operability evaluation. Licensee civil engineers determined that piping, equipment and supports were acceptable for continuous use. The evaluation further stated that if the piping should experience another significant water hammer in the future, engineering must re-evaluate the correctness of assumptions and conclusions for continuous use/applicability. The ECCS operability evaluation stated the amount of gas potentially in the RHR system piping had been analytically determined to be approximately 13 cubic feet (8 cubic feet of this amount was verified by ultrasonics to be in the RHR discharge piping). This amount of gas is not considered to be a challenge to the ECCS system's performance in an accident. For a large break LOCA, the sweeping of the gas into the RCS is not considered a safety problem since the amount of trapped gas in the RHR system is very small compared to the reactor vessel volume above the reflood level. The same scenario would occur for RCS breaks in the intermediate break size range. For a small break LOCA, the RCS pressure would, for most small break LOCA break sizes, remain above the cut-in pressure of the RHR pumps and the RHR pumps would operate on recirculation.

Inspection report 50-327, 328/95-12 identified five corrective actions initiated by the licensee to prevent recurrence of the RHR water hammer event. Those five corrective action items have been closed by the licensee.

- The RHR Section XI pump test procedures were revised to require procedure performers to notify the technical support system engineer to be available, as necessary, to monitor piping for water hammer on pump start.

- An "issue" was submitted to the technical support manager to provide accessible vents from high point locations on the RHR cold leg and hot leg injection headers inside containment. It was determined that the benefit of installing an accessible or automatically operated high point vent on the hot leg injection piping was not cost effective and was not included in the issue. The issue was assigned a high priority, but will be reassessed when more data is available concerning the rate of gas buildup.

- The licensee determined that outleakage for the Unit 1 CLA #1 had stopped and therefore there was no longer a source of pressurization and subsequent outleakage from the RHR discharge piping. Also, there was no measurable CLA outleakage to the RHR discharge piping on Unit 2. All measurable Unit 2 CLA outleakage was determined to be the Hold Up Tanks.

- The licensee determined that the leakage specification for the RHR secondary check valves (in new condition) was 0.1 gallons per day at the specified test pressure. In service, the valves see less seating pressure which may result in increased leakage even when the valve is in the optimum condition. Since there was no measurable leakage for the Unit 1 or 2 CLAs to the RHR system, no WRs for check valve rework was required.

- The licensee concluded that check valve testing in the low leakage range of less than 0.5 gallons per day was not feasible.

During October and November 1995, five additional items were added to TROI to support resolution of PER No. SQ950029PER.

- The RHR pump quarterly operability test procedures were revised to require valves 1,2-FCV-74-16 and 1,2-FCV-74-28, the first isolation valves downstream of the RHR heat exchangers, to be closed prior to RHR pump start in the recirculation test mode. This action eliminated the adverse effect (water hammer) of piping voids in the RHR injection piping inside containment on RHR pump miniflow operation. Closing the valves isolated the voids from the portion of the system in recirculation.

- The licensee developed a methodology for estimating gas volume based upon RHR system flow measurements which will allow trending of gas buildup over a full operating cycle to establish a "normal" gas buildup rate. If the accumulation rate challenges the maximum allowable limit, then the data can be used to justify the installation of continuous high point vents.

- The licensee reviewed the original engineering evaluation for PER No. SQ950029PER concerning the qualification of the RHR piping, components, equipment and supports, to confirm correctness of assumptions and conclusions for continuous use/applicability. That review concluded that the original evaluation was still acceptable.

These first three corrective action items have been completed. The fourth and fifth corrective actions have due dates of March 4, 1996, and June 15, 1996.

- The fourth action item, due March 4, 1996, directs the licensee to develop a methodology for evaluating gas void momentum effect on RHR injection piping loads, determine the relationship of piping void size to pipe loading and establish maximum allowable void size based upon piping structural margins, and to document the results in the final FPI International report.

- The fifth action item, due June 15, 1996, directs the licensee to review the priority of installing a RHR continuous venting plant modification based upon observed gas buildup rates and maximum allowable void size.

The inspector reviewed the licensee's completed corrective actions and the engineering evaluations and concluded that the evaluations were good and that the licensee had taken appropriate actions to address the water hammer issue. The inspector noted, however, that the licensee did not expeditiously pursue resolution of the RHR water hammer issue. As noted in inspection report 50-327,328/95-04, the water hammer event was first observed in January 1995, yet three corrective action items were not completed until the fall of 1995 and two additional items are not due for completion until mid-1996. Based on the inspector's review of the licensee's corrective actions, URI 50-327,328/95-04-01 is considered closed. However, since there are two licensee corrective action items still open on this issue, the inspector will review those two items upon their completion. That inspector followup item is identified as IFI 50-327,328/96-01-03, Review Methodology For Evaluating Gas Void Momentum

Effect On RHR Injection Piping Loads and Review Licensee's Reevaluation of RHR Continuous Venting Plant Modification.

Within the areas inspected, one IFI was identified.

5.0 PLANT SUPPORT (64704, 71750, 82301 and 92904)

During the reporting period, the inspectors conducted reviews to ensure that selected activities of the following licensee programs are implemented in conformance with the facility policies and procedures and in compliance with regulatory requirements.

5.1 RADIOLOGICAL CONTROLS REVIEWS

On January 11, 1996, a large area of floor space on the 669' elevation of the auxiliary building, near the waste condensate tanks, became contaminated. No personnel contaminations were reported as a result of this event. The licensee initially believed that one possible source of the contamination was a vent line, from the tritiated drain collector tank which is located on the 653' elevation, which ties into the ventilation ductwork on the 669' elevation and then exhausts to the auxiliary building exhaust system. Further evaluation by the licensee could not substantiate that to be the source of the contamination. PER No. SQ960050PER was initiated to document this event. On January 17, 1996, a similar contamination event occurred in the same area. The licensee initiated PER No. SQ960096PER to document this second event.

The licensee indicated in PER No. SQ960050PER that a previous event had occurred in July 1995 and was documented in PER No. SQ950940PER. The July 1995 event apparently was believed to have been caused by personnel error and that PER was dispositioned by coaching the personnel on proper equipment operation. The July 1995 PER indicated that this type of improper venting/leakage had occurred on other occasions.

After the January 11, 1996, event, the inspectors questioned the licensee on several occasions as to what compensatory actions were being taken to prevent recurrence. On January 19, 1996, two days after the second 1996 contamination event, the operations superintendent issued Standing Order 96-007, Sequoyah Nuclear Plant-Resin Transfers and Rad DI Backflushing, which directed the Radwaste Operator to monitor the ductwork on the 669' elevation for leakage during backflush operations. No additional instructions were given operators regarding restricting backflush activities which could potentially result in a similar contamination event. It was not apparent to the inspector that any other immediate corrective actions were taken. However, a Work Order was written to clean out the Tritiated Drain Collector Tank collection header.

On February 13, 1996, the licensee finalized a corrective action plan which included actions designed to determine the source of the water and how it was able to get in the ductwork. The corrective actions would attempt to determine if the water came from a leak or if there was some unusual operating condition that caused the water to collect in the ductwork. Action items were also assigned to operations and radcon to prevent recurrence of the event and to prevent any possible personnel contaminations. All the planned corrective actions are due to be completed by March 22, 1996.

The inspector concluded that the eventual corrective action plan implemented by the licensee for this event was satisfactory. However, the inspector noted that the licensee, although frequently questioned by the inspectors, did not aggressively implement appropriate compensatory actions to prevent recurrence until February 13, 1996.

5.2 RADIOLOGICAL EFFLUENT, WASTE TREATMENT, AND ENVIRONMENTAL MONITORING REVIEWS

During this period, the inspector evaluated RM operability by reviewing monthly chemistry records for January and February 1993; August through December 1993; January through December 1994; and January through December 1995. These reports listed ODCM monitors which were inoperable and required compensatory sampling. The inspector reviewed these reports for periods of inoperability for the following ODCM RMs:

- 0-RM-90-101, Auxiliary Building Exhaust
- 0-RM-90-122, Radwaste Discharge
- 0-RM-90-133/140, ERCW Effluent Header
- 0-RM-90-134/141, ERCW Effluent Header
- 1-RM-90-400, Shield Building, Noble Gas Vent Rate Activity Monitor
- 2-RM-90-400, Shield Building, Noble Gas Vent Rate Activity Monitor

These monitors were chosen because they had some of the highest maintenance activity (see paragraph 3.1) for the three year period of December 1992 through December 1995. The following table summarizes the inspector's findings. It should be noted that the number of days inoperable is an approximate number in that the inspector rounded the reported numbers to full days.

MONITOR ID	DAYS INOP 1993 7 Months	DAYS INOP 1994 12 Months	DAYS INOP 1995 12 Months
0-RM-90-101	5	6	4
0-RM-90-122	35	7	20
0-RM-90-133/140	28	8	29
0-RM-90-134/141	48	30	8
1-RM-90-400	17	106	18
2-RM-90-400	11	18	17

The inspector also reviewed, for 1993 and 1994, the specific dates of inoperability for the six monitors. The inspector concluded that the licensee appropriately reported, in the Annual Radioactive Effluent Release Report, monitors which were inoperable greater than 30 consecutive days (two periods >30 days inoperability were reported for 0-RM-90-134/141, and one period >30 days inoperability was reported for 0-RM-90-133/140, in 1993; one period of inoperability >30 days was reported for 1-RM-90-400 in 1994).

Based on these reviews, the inspector concluded that, although some monitors experienced long periods of inoperability, they were reported appropriately in the Annual Radioactive Effluent Release Report. The inspector also determined that there were no restrictions in the ODCM on the length of time the licensee can take grab samples.

The inspector also reviewed UO Logs for TS required monitor 1,2-RM-90-106, Lower Containment Airborne, and for 1,2-RM-90-112, Upper Containment Airborne. The RM-90-112 monitors can be used as backups to the 106 monitors. These monitors are used to detect RCS leakage into containment. The inspector reviewed the logs for references to these monitors and for recorded entries into TS LCO ACTIONS 3.3.3.1 and 3.4.6.1. The UO logs reviewed included:

Unit 1: June 1,3-25, 1993
September 15-23, 1993
September 25 - October 1, 1993
April 1-15, 1994; and
August 15-31, 1995

Unit 2: March 1-5, 9, 11-15, 1994

The inspector noted most LCO ACTION periods were very short (minutes in length), and were entered while instrument malfunction alarms were cleared, filters changed, etc. Typically, the longest periods of inoperability (>1 hour) were associated with the performance of SIs.

The inspector concluded, from this review, that the 106 and 112 monitors did not enter long periods of monitor inoperability for the reviewed time frames.

Within the areas inspected, no violations were identified.

6.0 EFFECTIVENESS OF LICENSEE CONTROLS IN IDENTIFYING, RESOLVING, AND PREVENTING PROBLEMS (40500)

6.1 REVIEW OF STATUS OF THE SIP

The inspector reviewed the status and progress of the SIP, developed during 1993. The SIP was a part of the licensee's overall activities and improvement strategies that were to take place following the shutdown of the units in 1993. A review of the SIP status identified that 17 items remained open. The inspector selected the following SIP items to review, which had been closed by the licensee during 1995.

- SIP item DD45-502, Revise SSP-12.11 to move requirements in the instruction body onto checklists for evaluation of compensatory measures.

- SIP item DD2-517A and B, associated with completion of the prioritization of the MIL items per BP-205. These items were identified as complete, however the licensee has continued to enhance this process, based on a re-evaluation of the importance of factors such as operator work-a-rounds and the age of an item.

- SIP item AA1-505D, associated with development of flow diagrams for system 43, Sampling System. This effort, conducted under DCN S-11545-A, created drawings for the turbine building local sample sinks, condensate demineralizer local sample sink, the hot sample rooms sample sinks, the post accident sampling facility sample sinks, the chemistry lab titration room sample sinks, the hydrogen detection and analyzers, and the auxiliary and reactor building sample sinks. In addition, this effort involved the revision of numerous secondary drawings.

The inspector concluded that the licensee was continuing to make satisfactory progress on the SIP items. The inspector noted that several SIP items associated with hardware modifications had been closed out during 1995 by reference to an open MIL item. The MIL is used by the licensee to, among other things, establish prioritization for hardware modifications. The licensee implements the management of the MIL through TVA Business Practice BP-205, Issue Management.

The inspector noted that plant management ensured that SIP items remained visible by inclusion in the monthly Business Plan and Performance Report of November 1995. The inspector observed that the Business Plan and Performance Report identified the SIP items as only a small subset of several 1996 focus areas. Examples of key activities in the focus areas were work order/WR process improvements, clearance redesign, fire protection improvements, 1993 Post Restart Actions (SIP backlogs, etc.), and various improvements in the corrective action program effectiveness. The inspector discussed, with licensee personnel, the improvements in the corrective action program effectiveness, to determine whether the various key activities were receiving appropriate management attention and support. From these discussions, the inspector concluded that licensee management has developed and was supporting various initiatives to improve the overall safety performance of the facility.

6.2 REVIEW OF THIRD PARTY ASSESSMENT OF LICENSEE'S CORRECTIVE ACTION PROGRAM

During this period, the inspector reviewed an assessment conducted by an independent third party of the licensee's corrective action program. The assessment concluded that the effectiveness of the corrective action program at Sequoyah improved during the past six months. Problem reporting thresholds were lower and management support of the program was evident. However, areas needing additional improvement included apparent cause determination, management involvement when performing root cause analysis, and quality of equipment root cause analysis. The inspector considered the third party evaluation of the status of the corrective action program at Sequoyah to be similar to findings identified during inspection activities.

The inspector concluded the third party evaluation of the licensee's corrective action program demonstrated good management initiative and involvement in improving the performance at Sequoyah.

6.3 REVIEW OF LICENSEE NUCLEAR ASSURANCE ASSESSMENT/AUDIT PROCESS

On February 13, 1996, the inspector met with the Sequoyah Quality Assurance Manager and members of his staff to review results of recent assessments and audits. The licensee discussed results of a recent maintenance/modification follow-up performance evaluation, security upgrade and freeze protection assessments, and reviewed the results of audits conducted in the last three months. The inspector noted the assessments and audits were thorough and focused on areas in which both good performance and weaker performance were observed. In those cases where licensee actions were not in accordance with expectations or requirements, PERs were written to address the issues.

The inspector concluded that the licensee's Nuclear Assurance organization continued to provide meaningful assessments of performance in operations, maintenance and other areas. The assessments identified areas in need of improvement to line management so that corrective actions could be implemented. In addition, the audit program accomplished good audits as required by regulations, in addition to also focusing on areas in need of improvement.

7.0 OTHER NRC PERSONNEL ON SITE

On February 2, 1996, Mr. Mark S. Lesser, Chief, Branch 6, Division of Reactor Projects, visited the Sequoyah Nuclear Plant. Mr. Lesser met with the Senior Resident Inspector, licensee senior management, and toured the plant.

8.0 UFSAR REVIEWS (71707, 62703, 37751)

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR Report descriptions.

During a portion of the inspection period (February 1-17, 1996), the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

9.0 EXIT

The inspection scope and findings were summarized on February 20, 1996, by William E. Holland with those individuals identified by an asterisk in paragraph 1. Interim exits were conducted on January 12, 19, 26, February 1, 2, and 9. The inspector described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

TYPE	Item Number	Status	Description and Reference
IFI	50-327,328/ 96-01-01	OPEN	Followup on OT2 Handswitch Failures (paragraph 3.4)
NCV	50-327/ 96-01-02	CLOSED	Failure to Perform the Surveillance Requirements of TSs 4.9.2 and 4.9.8.1 (paragraph 3.8)
IFI	50-327,328/ 96-01-03	OPEN	Review Methodology For Evaluating Gas Void Momentum Effect On RHR Injection Piping Loads and Review Licensee's Reevaluation of RHR Continuous Venting Plant Modification (paragraph 4.3)
LER	50-328/95-05	CLOSED	Closure of the 2A-A Safety Injection Pump Suction Valve Placed the Unit in Limiting Condition for Operation 3.0.3 (paragraph 2.9)
LER	50-327/95-13	CLOSED	Missed Surveillance During Mode 6 (paragraph 3.8)
IFI	50-327, 328/ 94-25-01	CLOSED	Resolution of the Opening of Unit 1 Containment Vacuum Relief Valve Initiated by an ABI on Unit 2 (paragraph 4.3)
URI	50-327, 328/ 95-04-01	CLOSED	Resolution of Unit 1 RHR Water Hammer Event (paragraph 4.3)

10.0 ACRONYMS

ABGTS	Auxiliary Building Gas Treatment System
ABI	Auxiliary Building Isolation
ABSCE	Auxiliary Building Secondary Containment Envelope
ANSI	American National Standard Institute
ASME	American Society of Mechanical Engineers
AUO	Assistant Unit Operator
BOP	Balance Of Plant
BP	Business Practice
CCD	Configuration Control Drawing
CCS	Component Cooling System
CFR	Code of Federal Regulations
CLA	Cold Leg Accumulator
DCN	Design Change Notice
DG	Diesel Generator
DI	Deionizer
ECCS	Emergency Core Cooling System
EPRI	Electrical Power Research Institute
ERCW	Essential Raw Cooling Water
FCV	Flow Control Valve
FIN	Fix It Now
gpm	Gallons Per Minute
ID	Identification
IFI	Inspector Followup Item
INOP	Inoperable
kW	Kilowatt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss Of Coolant Accident
MAI	Modification Addition Instruction
MCR	Main Control Room
MDAFW	Motor Driven Auxiliary Feedwater
MIL	Master Issues List
MSR	Moisture Separator Reheater
MWE	Megawatts Electric
NCV	Non-cited Violation
NE	Nuclear Engineering
No.	Number
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
PER	Problem Evaluation Report
PI	Periodic Instruction
PM	Preventive Maintenance
PMT	Post Maintenance Test
PORC	Plant Operations Review Committee
psig	Pounds Per Square Inch Gauge
PSRV	Pressurizer Safety Relief Valve
RCS	Reactor Coolant System
RFO	Refueling Outage
RHR	Residual Heat Removal
RM	Radiation Monitor

SG	Steam Generator
SI	Surveillance Instruction
SIP	Site Improvement Plan
SQ	Sequoyah
SRO	Senior Reactor Operator
SSP	Site Standard Practice
STI	Special Test Instruction
TROI	Tracking and Reporting of Open Items
TS	Technical Specification
TVA	Tennessee Valley Authority
U1C6	Unit 1 Cycle 6
U1C7	Unit 1 Cycle 7
UO	Unit Operator
URI	Unresolved Item
UFSAR	Updated Final Safety Analysis Report
WR	Work Request